# CREG EXPERT PANEL ON ELECTRICITY MARKET REFORM

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# FOREWORD

I have been asked by CREG, as a member of an international panel of experts, to consider market reforms and proposals on the following four topics:

- Scarcity Price, Reliability Charge and capacity;
- spot market;
- market for long-term contracts; and
- mechanisms to elicit investment in renewable energy.

This document contains my analysis and recommendations. These are based on written input from the CREG (listed in References at the end of the document), other written material (also listed in References) as well as input from various meetings with representatives from government authorities, the industry, consumers and other interests. CREG organised two sets of meetings to discuss the various proposals, first at 27-29 June 2016 and then at 5-7 October 2016. I have attempted to take into account comments and viewpoints expressed in these meetings.

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# CONTENT

In light of the El Niño event of 2015-16, which severely tested the capacity or firm-energy market, CREG has put forward a set of proposals. Below I first present CREGs proposals before providing a discussion and presenting conclusions and recommendations.

### CREGS PROPOSALS

CREG proposes two measures designed, on the one hand, to encourage the entry of new generators with low variable costs and, on the other hand, to achieve an efficient allocation of the Reliability Charge among existing generators without affecting system reliability (CREG, 2015c):

- allocation of Firm Energy Obligations to new plants; and
- adjustments to the Reliability Charge allocation rule for existing plants.

The additional auction will be for Firm Energy Obligations of up to 20 years and will be conducted as a sealed-bid, first-price auction with a maximum (reserve) price equal to the current Reliability Charge. CREG will determine the beginning of the obligation period as well as the total quantity of firm energy required. Participation in the auction will be restricted to generators with variable operating costs less than or equal to 80 per cent of the Scarcity Price. The realised Reliability Charge (which may be different from (i.e. lower) than the current Reliability Charge) will only apply to new plants selected in this auction.

Two alternative methods for allocating Firm Energy Obligations to existing plants are put forward:

1. Firm Energy Obligations are allocated based on average prices offered in the spot market in the year prior to the allocation. First, demand is allocated proportionally among the group of plants with average prices less than or equal to the average

Scarcity Price. If this is not sufficient to cover demand, the remainder is assigned proportionally among the group of plants with higher prices.[2]

2. Firm Energy Obligations are allocated in annual auctions, in accordance with a suggestion made by Cramton (2015). In these auctions, new as well as existing plants may be allowed to participate.

### AUCTIONS FOR NEW PLANTS

A purpose of CREGs proposal not strictly related to the firm-energy market is to encourage entry of generation technologies with low variable costs, in order to substitute plants with higher variable costs. It is argued that the current high-cost plants tend to increase not only the spot price, but also contract prices, resulting in demand having insufficient contract coverage and high exposure to spot-market risk.

Restricting participation to generators with low variable costs risks increasing the total cost of energy. Since the variable and fixed costs of (efficient) generation plants are inversely related, plants with low variable costs have high fixed costs. Plants with low variable costs therefore require large margins, or high fixed payments, in order to cover their fixed costs. In a firm-energy auction restricted to plants with low variable costs, the resulting Reliability Charge is likely to be higher than if the auction is open to all types of plants. Indeed, by restricting participation to a certain type of plants, one risks excluding the most efficient plants from an overall perspective, that is the plants that can deliver energy at the lowest total cost. In particular, since most of the costs of existing plants are sunk (i.e. independent of whether these plants operate or not), their actual cost of operation may well be relatively low compared to new plants.

### ALLOCATION OF FIRM ENERGY OBLIGATIONS TO EXISTING PLANTS

Firm Energy Obligations are currently allocated to existing plants on a *pro rata* basis relative to their firm energy, so as to cover demand. Holders of obligations receive the Reliability Charge as defined in earlier auctions for new plants.

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[2] CREG is suggesting a mechanism whereby plants that are willing to make the necessary investment to reduce their operating costs (i.e. switch fuel) can be classified within the first, low-cost group.

If one were to replace this administratively relatively simple rule, an auction would seem sensible. The reason is that an auction will tend encourage the most cost efficient supply of firm energy.

The alternative – allocating Firm Energy Obligations based on bids in the spot market – may go some way in ensuring a low cost supply of firm energy, but not as far as an auction. This is partly because the allocation rule is crude – treating all plants with, respectively, costs above and below the average Scarcity Price as the same – but also because costs in a scarcity event may differ from those in normal times. An auction allows generators to treat each plant individually and to take conditions in a scarcity event into account.

An auction may also deliver a lower price for Firm Energy Obligations than the current Reliability Charge, thereby reducing the electricity bill for consumers. Indeed, with the Reliability Charge as a ceiling, the price for Firm Energy Obligations from existing plants could not exceed this level.

However, it is not obvious that such a ceiling should be put in place. In particular, it may be that securing a sufficient amount of firm energy requires calling on plants that would not be willing to accept the Reliability Charge. In particular, in a situation with a Scarcity Price that is low compared to variable costs (maybe even lower than the variable costs of certain plants), it may be necessary to pay these plants a higher price than the current Reliability Charge in order to make them willing to provide firm energy.

Allowing for direct competition between new and existing plants may further ensure an efficient supply of firm energy. However, care will have to be taken to design the market such that competition becomes effective, in particular taking account of the different contractual requirements (esp. regarding contract duration) of new and existing plants.

### THE SCARCITY PRICE

An issue not specifically addressed by CREG, but which is raised by a number of others, is changes to the Scarcity Price. These proposals range from adjusting the

Scarcity Price upwards (through changes to the basis for its calculation) to removing it all together.[3]

Before considering these proposals, it may be useful to review the basic economics of the Scarcity Price.

The Scarcity Price serves two purposes: it provides a ceiling for consumer prices, and it defines events in which Firm Energy Obligations are activated and holders of such obligations are called upon to supply electricity.

In order for demand to be covered when the spot price hits the Scarcity Price, sufficient amounts of Firm Energy Obligations and corresponding generation resources must be available. This has recently been done by holding auctions for capacity, in which generators bid for the price at which they are willing to enter into Firm Energy Obligations, the so-called Reliability Charge.

Clearly, the resulting Reliability Charge depends on the Scarcity Price. A higher Scarcity Price would have reduced the burden on holders of Firm Energy Obligations – since these obligations were less likely to be called – and hence lowered their offers for the Reliability Charge.

Furthermore, the capacity needed to cover demand depends on the level of the Scarcity Price. A higher Scarcity Price discourages demand, and hence reduces the need for capacity. The Scarcity Price therefore trades off price protection for consumers on the one hand and the cost of capacity on the other. At the extreme, when the Scarcity Price is set so high that the spot price never hits the ceiling, there is no need for either Firm Energy Obligations or reserve capacity to back these obligations (Oren and Garcia, 2016).[4]

Moreover, the Scarcity Price affects the choice of technology for plants bidding in the Firm Energy Obligation auctions. With a higher Scarcity Price, and, consequently, a smaller chance of Firm Energy Obligations being activated, generating plants will

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[3] See eg. Andeg (2016), Battle and Barroso (2016) and Oren and Garcia (2016).

[4] This argument is based on the assumption that market prices are allowed to reach levels that reduce demand below available capacity.

run less frequently under these obligations. At the margin, therefore, generators will choose technologies that are cost efficient with infrequent operation; that is, they will choose technologies with low fixed costs and high variable costs.

In other words, a higher Scarcity Price leads to a smaller reserve capacity, consisting of plants with higher variable costs and lower fixed costs. Conversely, a lower Scarcity Price requires a larger reserve capacity, consisting of plants with lower variable costs and higher fixed costs.

When considering the various proposals concerning the Scarcity Price it must therefore be remembered that this price cannot be seen in isolation from the Reliability Charge. Indeed, the current Reliability Charge is the result of an auction, where the Scarcity Price was an essential parameter; a higher Scarcity Price would have lead to a lower Reliability Charge.

Moreover, if the Scarcity Price were to be raised without a corresponding reduction of the Reliability Charge it would mean a transfer of revenues from consumers (who would have less protection against high prices and hence pay, on average, higher prices) to generators (who would receive higher prices for their energy).

One argument for raising the Scarcity Price is that it has turned out to be lower than the variable costs of some generators with Firm Energy Obligations; these generators were in 2015 faced with the obligation to generate at a negative margin. However, the margin between the Scarcity Price and variable cost – whether positive or negative – contains a risk that generators accept when taking on Firm Energy Obligations and for which they are paid the Reliability Charge. It is not clear, therefore, that negative margins in themselves provide an argument for chancing the Scarcity Price.

One could, however, argue that the indexing to Fuel Oil No 6 has produced a Scarcity Price that is not in line with the underlying principles on which this price was originally constructed. It may therefore make sense to revisit the implementation of these principles to see whether an adjustment to the index, or a substitution with another index, may better reflect these principles.

It should be remember that a change in the Scarcity Price will affect the Reliability Charge both in the proposed annual auctions for existing plants and in auctions for new plants (in the latter case, a change to the Scarcity Price may also impact on technology choice).

## CONCLUSION AND RECOMMENDATIONS

The 2015-2016 scarcity event revealed certain weaknesses of the current capacity or firm-energy market. Firstly, the formula for the Scarcity Price turned out not to be robust enough to withstand opposition from certain parts of the industry and political pressure; CREG eventually had to increase the Price. Secondly, it is not clear that installed capacity was sufficient to cover demand; avoidance of rationing was partly due to the introduction of other measures, in particular financial incentives for saving energy. Nevertheless, these weaknesses do not in themselves warrant a fundamental reform of the capacity market. Except for a series of unfortunate and unforeseen incidents, which are unlikely to be repeated, the 2015-2016 event did not reveal aspects of the capacity mechanism that were not already known. Also, while problems did occur the main objective of avoiding rationing was achieved. I will therefore not make suggestions for fundamental changes, either to the Scarcity Price or other elements of the capacity market.[5]

Nevertheless, it may be worthwhile to consider whether the implementation – in particular, the indexing to Fuel Oil No 6 – is in line with the underlying principles on which the Scarcity Price was based. The calculation of the original Scarcity Price seems to have been based on two principles; on the one hand, the Scarcity Price should reflect the cost of the marginal thermal unit, and, on the other hand, the Scarcity Price should lead to the calling of Firm Energy Obligations with a certain frequency. As far as the first principle is concerned, it is clear that in 2015-2016 the Scarcity Price did not reflect marginal cost, and as such the formula should be adjusted; the most direct and natural way to do so would be to change the fuel indexing (possibly to an index that includes multiple fuels). However, before

[5] Of course, one could reasonably discuss the rationale and design of the Colombian capacity market more generally (see eg. Oren and Garcia, 2016). The point made here is just that recent events in themselves do not justify such a discussion.

undertaking such an adjustment one would have to consider the frequency with which Firm Energy Obligations will be called, which would require a re-doing of the original exercise. One cannot therefore answer the question of whether the Scarcity Price is in line with underlying principles before undertaking further study. Moreover, to the extent that the two original principles do not lead to the same result, CREG would have to decide which of the two principles should have priority.

In any case, if such an evaluation leads to an updating or recalibration of the Scarcity Price, plants with existing Firm Energy Obligations should either be held to their original contracts or be offered new contracts with a suitable redefined Reliability Charge.

Irrespective of any changes to the capacity market, CREG should strengthen the commitments on holders of Firm Energy Obligations to ensure that they do not breach their obligations but deliver firm energy when required. Under current rules, generators that do not deliver according to their obligations have to pay for the energy in the wholesale market; these incentives are however not necessarily strong enough (especially when the wholesale price is below the cost of delivering the energy). Additional incentives would have to come in the form of explicit penalties; these must be sufficient to ensure that the cost of adhering to the Firm Energy Obligations is less than the cost of non-delivery. A system of penalties would presumably have to be combined with a system of financial guarantees, to ensure that penalties are paid when required.

CREG should also consider whether certain critical plants should be provided with special contracts (maybe as some sort of “strategic reserve”), to account for their unique characteristics and ensure their availability in scarcity periods. Such a scheme should be restricted to plants that are not only critical, but also likely to be unavailable (moth-balled or closed) without specific measures. Since the number of such plants is likely to be small, and since they presumably have well-known characteristics, contracts could be on a “cost plus” basis; that is, payments could be made based on an assessment of costs (including the costs of keeping plants available) plus a reasonable level of profits. Ideally, the terms should be made sufficiently attractive to ensure that generators find them economically attractive, but in some cases it may be necessary to make participation mandatory.

CREG should carefully consider whether new capacity is required to ensure that there is a sufficient amount of firm energy available. In the case that it is deemed necessary to elicit new capacity, this should be done by auctions that are technology neutral – in particular, not dependent of specific levels of variable costs – to ensure the most efficient supply of firm energy. As explained above, the total cost of delivering firm energy depends on both variable (running) and fixed (capacity) costs, as well as the frequency with which plants will be operating. More specifically, there is a trade off between low variable costs and low fixed costs, and the less frequently plants are operating, the better plants with low fixed costs (and high variable costs) perform. Replacing plants with high variable costs with plants with low variable costs does not necessarily reduce total costs, especially since the capacity costs of existing plants are already sunk.

Allocation of demand to plants offering firm energy should be done based on an annual sealed-bid, first-price auction, rather than an administrative procedure based on mean price offers in the spot market. As discussed above, auctions are not only more likely to provide an efficient outcome than an administrative procedure, but also allows for direct competition between new and existing plants.

## SPOT MARKET REFORM

CREG is suggesting various reforms to the current short-term or spot-market design, notably the introduction of a day-ahead and an intraday market. These changes are relevant for a number of issues, including market power, demand-side participation, intermittent generation resources, risk exposure, co-ordination with the natural-gas sector and efficient decision-making.

Below I first briefly describe the current market design before outlining the proposal for the new market design. I then discuss aspects of the proposed market design in relation to the above-mentioned issues.

In the current spot market, generators submit offers for each of their units at 8 am on the day before operation. An offer consists of one price for all 24 hours, the availability for each of the 24 hours, as well as various technical characteristics, including starting and stopping costs.

Based on generator offers and a forecast of demand, The National Dispatch Centre (Centro Nacional de Despacho, CND) calculates a so-called indicative dispatch by selecting, for each hour, the units that can meet demand at the lowest cost within the constraints of the network.

Generators are informed about how much energy they are expected to supply from each of their units hour by hour at 3:15 pm on the day before operation. Generators may, under specific technical conditions, alter their availability or re-declare capacity. Re-declarations that do not meet the relevant conditions, or are not notified in advance, are subject to penalties.

CND also calculates prices, based on an optimisation of the system that does not take network restrictions into account. These prices are announced to market participants.

During the day of operation, CND may undertake re-dispatch to accommodate changes in the availability of generating units and deviations in actual demand from the demand forecast.

After the day of operation, price determination and financial settlement is undertaken. In this *ex post* calculation of the so-called ideal dispatch, the price is set hourly according to the price offer of the marginal generating unit (i.e. the most expensive unit dispatched during the relevant hour) without taking network restrictions into account; that is, for each hour there is a single spot price for the whole market.[6] Financial settlement is undertaken by XM, the market organiser, based on hourly quantities and prices, taking account of (bilateral) contract positions.

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[6] Imbalances due to network restrictions (ie. the difference between actual dispatch and the ideal dispatch), or congestion costs, are valued according to an engineering-based method of cost determination.

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.

However, unlike in the current market design, 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. Financial settlement will also be done in the same way as now, based on differences between energy positions resulting from the economic dispatch and contract positions.

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. Non-regulated users may participate directly in the day-ahead market or let traders bid on their behalf.

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.[7,8]

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, the second auction covers the period 9 am to the end of operation, while the last auction covers the period from 5 pm to the end of operation. In each auction, generators make offers

[7] In the description of the intraday market, CREG says that "between 3:30 and 4:00 pm, the per hour price formed in the market and the aggregate amount of energy committed will be reported" (CREG, 2015a, Section 3.2).

[8] Note that when grid restrictions bind, there will be discrepancies between economic and physical dispatch; that is, the day-ahead contract position of a generator may not match the output that the generator is obliged to supply.

in the same format as in the day-ahead market.[9] 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.

Below I discuss aspects of the proposed market design.

### *EX ANTE* VERSUS *EX POST* PRICE DETERMINATION

In the new market design, prices are set *ex ante* (i.e. before operation) rather than *ex post* (i.e. after operation). Generators (and consumers) will therefore know prices at which they trade earlier than they now do and before operation. Note, however, that even in the current market design indicative prices, corresponding to those in the new day-ahead market, are provided to market participants before the day of operation. The difference between the current and new market design, therefore, is that only in the new market design do market participants actually trade at these prices. To the extent that uncertainty about trading prices deters efficient operational decisions, the new market design will tend to alleviate this problem.

Earlier price determination benefits market participants who make decisions that would (potentially) depend on realised price. For example, thermal generators who source fuel in the gas spot market may consider it an advantage to know the electricity price before making bids for gas.[10] There may also be price-sensitive consumers who want to regulate their load according to prices. For most market participants, however, it should not matter much whether prices in the spot market become known before or after operations; in particular, as long as offers are based on (opportunity) costs – and these are known – generators should be willing to supply whenever they are called upon to do so.

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[9] 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".

[10] Note, however, that in the current market design generators are committed to the physical dispatch and hence will have to secure the necessary amount of fuel irrespective of prices.

Whatever its merits, it should be noted that moving price determination forward can be done without any other change to the current market design. In particular, one could calculate prices in the indicative dispatch and make (initial) financial settlements based on these. Deviations between indicative and actual dispatch could then be priced as is currently done *ex post*, with financial settlement based on net financial positions between the *ex ante* and *ex post* markets.

### COMMITMENT

Generators that do not adhere to their obligations as defined by the indicative dispatch complicate, and, at worst, undermine, system operations. It is however difficult to see that the new market design contributes much to the solution of this particular problem.

In the new market design offers are commercially binding; that is, generators obtain the right to receive payments according to the economic dispatch (or to make payments, if they are over-contracted in the contract market). However, generators have the same possibility not to adhere to their supply obligations as under the current market design. Whereas under the current design generators save variable (fuel) costs and lose spot market revenue if they declare units partially or completely unavailable, under the new design they will receive day-ahead prices for energy not supplied but will have to pay for this energy according to (intraday or final) spot-market prices. To the extent that supply decisions are influenced by economic considerations, it is not clear whether the incentive to supply according to the indicative dispatch is stronger or weaker under the new market design than under the current design.

However, to the extent that generators have market power the incentive to exercise such power may be weaker with the proposed market design. When a generator declares unavailability of a unit it tends to raise the market price. Under the current design this price effect increases the revenue earned on those units that do actually produce; under the new market design the price effect raises the cost of replacing the energy not supplied.

On the other hand, the flexibility of the proposed market design will in itself tend to reduce the firmness of generators' physical availability, since they have the possibility to adjust their positions in the intraday market. In fact, the more efficient is the intraday market the less important it becomes what generators offer in the day-ahead market; in particular, rather than bidding sincerely in the day-ahead market generators may delay their supply decisions to the first stage of the intraday market, where they can make offers for all 24 hours.[11]

It would seem that ensuring that generators adhere to their commitments for physical delivery, including avoiding unnecessary capacity re-declaration, requires strengthening the rules for non-delivery. A problem with the current set up is that it is difficult to decide whether the stated reasons for non-delivery are in fact correct; in order to remedy this problem, one must be willing to increase investigative efforts. If this is deemed difficult or undesirable, one would have to make the rules stricter, by reducing the scope for re-declaration. Specifically, one could – as is done in some jurisdictions – introduce a system of penalties for any re-declaration (perhaps complemented with a strict rule of *force majeure*). Whether or not such a strengthening of the rules is warranted depends on the costs incurred on the system by non-delivery.

### INTRADAY MARKET

The intraday market provides market participants with the opportunity to adjust their initial positions both closer to and during the day of operation.

The benefit of this opportunity depends on the extent to which the conditions of market participants change from the time of initial bids and offers to actual operations. While some such changes may be important – such as changes in the availability of generation units – it is unlikely that the conditions of most generators and consumers change much over such a short period.

CREG has suggested that trade in the intraday market takes place in three stages, for, respectively, the entire 24 hour period, for the last two thirds of that period and,

[11] It is therefore not evident that *"The establishment of a day ahead energy market encourages agents to have more discipline regarding the dispatch and therefore allows greater certainty about resources that will be dispatched on the day of the operation. This is essential for allocating the costs of changes in generation by agents for technical or economic reasons for covering the demand related to these events."* (CREG, 2015).

finally, for the last third. The optimal frequency of trade depends on both the frequency of changes to underlying market conditions and the number of market participants affected by such changes. If changes are few and far between trade can take place only infrequently; if, on the other hand, changes occur frequently and affect many market participants, trade should take place more often.

Closely related to the issue of how frequently market participants should be allowed to trade is the question of whether trade should be organised as auctions (as suggested by CREG), or whether market participants should be allowed to trade continuously (as is the case for example in many European electricity market). Continuous trade has the advantage of letting market participants make their bids and offers whenever they find it convenient, but may reduce liquidity since any given bid or offer may not find a taker. By forcing bids and offers to be made at the same time, there is greater likelihood that the market is cleared.

### ECONOMIC VERSUS PHYSICAL DISPATCH

In the current market design there is a close relation between economic and physical dispatch; consumers pay, and generators are paid, according to realised quantities and prices. In the proposed market design, this linked is partly broken; in particular, the initial economic dispatch (i.e. the day-ahead market) does not conform to the initial (or indicative) physical dispatch. As a result, the contractual or financial positions of market participants do not necessarily match their physical positions.

In principle, it is possible to maintain the relation between economic and physical dispatch even with day-ahead and intraday markets. This could be done by basing the day-ahead market on the physical dispatch (i.e. taking network restrictions into account) and undertake full physical re-dispatch based on intraday bids (where participants who do not participate in one of the intraday auctions are treated according to their previous bids). Final settlement can be done as under the current market design, with an *ex post* determination of prices and imbalances. This set up would involve different settlement prices, not only at each stage of the market, but also geographically, to the extent that network restrictions are binding.

Alternatively, one could move further in the direction of delinking economic and physical dispatch, by introducing elements of decentralised (self-)dispatch. This would imply, firstly, that the day-ahead market is cleared without taking network constraints into account, and, secondly, that intraday bids and offers just affect the physical position of participants who are active in that market (with re-dispatch of non-participating agents taking place only when required by system operation considerations).

A complete break between economic and physical dispatch – in line with the model of most European electricity markets – would involve self-dispatch of all participants, with the system operator achieving physical balance by means of a balancing market.

### GATE CLOSURE

In the current market design, gate closure is at 8 am on the day before operations. The proposed market design in effect moves gate closure to 9:15 pm, the last time at which market participants can adjust their positions for the entire day of operation.

One may ask whether gate closure should be moved closer to real time also in the day-ahead market; indeed, a more modest reform of the spot market would be to just move the time of gate closure, without introducing either a day-ahead or an intraday market.

Whether or not gate closure should be moved forward in time depends on the time needed for the market organiser, as well as market participants, to make operational plans. One would think that with the increased capacity and sophistication of information and operational technology it should be possible to reduce the time needed for operational planning.

### MARKET POWER

CREGs proposals do not explicitly deal with the issue of (local) market power (except to the extent that the day-ahead disciplines behaviour in intraday markets, as discussed above). As suggested by Wolak (2016), there may be better ways of dealing with market power than the current, administratively set prices of must-run, constrained on generators. Moreover, it is difficult to see the rationale for paying generators that are constrained off, i.e. unable to supply due to network restrictions.

### AUTOMATIC GENERATION CONTROL

In the current market set up automatic generation control is scheduled on the basis of plant availability data and price offers. The proposed market design does not involve any direct changes to this set up, apart from the fact that availability may be changed through the intraday market. A possible further reform would be to establish a separate market for automatic generation control, as is done in many other electricity markets.

### CONCLUSION AND RECOMMENDATIONS

The current market design has the virtue of simplicity: generators make a single set of offers that form the basis for both dispatch and financial settlement. It has demonstrated its usefulness for a long period of time.

The new design, which builds on well-know elements that are in use in other electricity markets around the world, will surely work. However, it requires more frequent bidding, more re-dispatch and more complicated settlement. A reform will necessarily involve costs, both during the transition period and after the new design is in operation.

Whether or not these costs are worthwhile seems to depend on two issues, namely the extent to which, respectively,

- prices affect market participants operational decisions, and
- market participants would want to adjust their plans during the day of operation.

If market participants are sensitive to prices, it is beneficial to determine prices *ex ante* rather than *ex post*. Moreover, if market participants frequently want to adjust their plans, it is beneficial to introduce intraday trading.

Note that these issues can, at least in principle be viewed in isolation: the desirability of a day-ahead market depends on the price sensitivity of market participants, whereas the desirability of an intraday market depends on the needs of market participants to adjust their plans as time evolves.

I recommend that

- CREG carefully reviews the suggested benefits of the spot market reform to ensure that these are sufficient to justify the inevitable cost of a more complex market design;
- CREG considers limiting the reform to the introduction of a day-ahead market; and
- if an intraday market is introduced, CREG considers whether continuous trading should be allowed.

Furthermore, irrespective of whether day-ahead and intraday markets are introduced, I recommend that

- gate closure is moved closer to the day of operation;
- the demand side is allowed to bid actively in the spot market; and
- CREG considers revising the current system for dealing with (local) market power.

## MARKET FOR LONG-TERM CONTRACTS

CREG has proposed the establishment of a new mandatory market for standardised long-term financial contracts.

The current market for long-term contracts is based on bilateral contracting. Suppliers of regulated consumers are obliged to tender contracts for their demand, and the price obtained in such contracts may be fully or partly passed on to their regulated consumers according to a specific formula. Contract durations are typically up to 2-3 years.

In addition to the bilateral contracts market, Derivex provides an exchange for financial contracts. There is little activity in this market.

CREGs proposal must be viewed on the background of a number of observations and criticisms that have been put forward concerning the current contract market, including

- a wide variation of contract types;
- different terms for different groups of customers;
- incomplete contract coverage of demand;
- little secondary trade; and
- limited opportunities for handling credit risk.

Below I first describe CREGs proposal before discussing its merit and presenting conclusions and recommendations.

## CREGS PROPOSAL

The new market will be based on a centralised auction-mechanism for standardised, annual energy contracts for regulated and non-regulated demand (CREG, 2016f).[12] In these auctions, generators will bid for the right to supply a target level of demand, set by CREG, with mandatory participation for (a certain fraction of demand from) regulated consumers.

Two types of contracts are suggested, for regulated and non-regulated consumers respectively. Both products are for one MWh-day for a year, but while the profile is flat for non-regulated consumers (i.e. the same amount of energy for each hour of the day), the profile follows the aggregate load-curve for regulated consumers (i.e. the amount of energy varies over the day).

The target for demand in any given year will be set based on information from suppliers and in accordance with projections of UPME. The target is defined as a curve, giving total demand as a function of price from a pre-defined price ceiling. The amount of contracts sold, and the contract coverage of demand, will consequently depend on the realised auction price. Separate demand targets will be set for regulated and non-regulated demand, respectively.

[12] A number of other proposals for organised contract markets have been put forward, see eg. Cramton (2007), Oren and Garcia (2016) and Wolak (2016).

Auctions will be held four times a year. In the first two auctions of any given year, contracts for years +2 and +3 will be traded, while in the second two auctions, contracts for years +3 and +4 will be traded.

The auctions will be conducted either as sealed-bid (closed envelope) or a descending clock (where prices are lowered from a ceiling until the target is met). The type of auction will depend on an assessment of competition for contracts. If competition is deemed to be sufficient, a descending clock will be chosen; otherwise the auction will be sealed-bid. The price of contracts is set at the level that clears the market.[13]

Contracts are financial and settled on a monthly basis as differences between the contract prices and spot market prices. Contracts for a given month are allocated to buyers and sellers one month before the month of delivery or liquidation. Sellers receive payments according to the price in the auction at which their energy was sold, while buyers pay the average weighted price of the auctions for the relevant period.

CREG favours a solution for billing and collection in which contracts are allocated randomly between buyers and sellers, but it also puts forward an alternative in which sellers receive a fraction of the purchases of each buyer.

Participants will be required to post warranties for participation in the auction, for fulfilment of the obligations resulting from the auction (from the closing of the auction to liquidation of contracts) and for ensuring payments once contracts are liquidated. A series of alternative forms of risk coverage are suggested, including bank bonds, transfer of existing credits in the MEM, prepayment, mutual agreement, letter decreasing the amount of the bond and a central counterparty clearing house.

CREG suggests that contracts could be traded bilaterally on a secondary market.

[13] CREG also proposes a ”preference margin” that establishes a minimum price difference between the regulated and the non-regulated products.

The proposal for a new market for standardised contracts seems to arise mainly from two features of the current, bilateral market. First, terms and conditions differ considerably across the market, particularly between the regulated and the non-regulated segments. Second, parts of demand are not fully covered by contracts.

The first feature is to a large extent explained by the different characteristics of buyers, especially with regard to the (perceived) risk of transacting with them. However, it may also be explained by vertically-integrated utilities discriminating between their own subsidiaries and other market participants, particularly between regulated and non-regulated consumers.

The second feature seems, at least partly, to result from the unwillingness of generators (especially hydro generators) to contract beyond their firm energy (ENFICCs). In order to obtain full coverage, buyers may therefore have to contract with generators with high variable costs, at prices that are deemed unsatisfactory.

CREG proposes to deal with the varying credit risk of buyers by effectively pooling this risk and allocating it proportionally to sellers (either *pro rata* or in a probabilistic manner). Since the identity of counterparties will not be revealed until a month before contracts are activated, market participants will be facing uncertainty about their actual credit risk all the way up to liquidation of contracts.

An alternative way of handling counterparty or credit risk, used in many electricity markets around the world, is to establish a central entity (a clearing house) such that buyers and sellers conduct their trade with this entity rather than with each other. While establishing such an entity raises a number of detailed issues, it is a solution that has demonstrated its usefulness in many other markets.

The issues arising from vertical integration will be dealt with by mandating vertically integrated utilities to offer their regulated demand in the market. Such utilities will however be able to hedge by making corresponding offers in the auction. Moreover, by offering contracts corresponding only to the demand of their regulated consumers, these utilities are free to trade on bilateral terms with other market participants. It would seem necessary to mandate the participation of a sufficient part of generation in order to ensure that all participants compete on equal terms with their vertically integrated competitors (cf. Oren and Garcia, 2016).

Indeed, there is nothing in CREGs proposal that deals directly with market power of generators. The only way to deal with this is to put constraints on generator price setting. One way would be to set price ceilings, albeit at the risk of discouraging generators from participating in the market and instead do their contracting outside of the organised market. This risk may be reduced by combining a price ceiling with mandating the generators to offer a certain part of their energy in the contracts market. Again, this is unlikely to have a substantial effect unless the ceiling is set low and the mandated quantities high. A more radical solution would be to turn the market around, by having demand bid for a predetermined quantity of generation; this would eliminate the ability of generators to set prices.

CREGs proposal is also unlikely to solve the issue of under-contracting. So long as only a fraction of demand is mandated to participate in the market, and so long as generators are free to choose whether or not to participate, it would seem unlikely that the new market will secure a higher level of contract coverage.

Indeed, it is not clear that the new market will be very attractive for generators. This will of course depend on the price ceiling, but if this is set relatively low – at a level that is attractive to consumers – it may be that participation of generators becomes a concern. In particular, it is difficult to see how the under-contracting issue can be resolved without setting contract prices at unrealistically high levels.

It should be realised that the under-contracting issue arises from fundamental features of the Colombian electricity industry that cannot be dealt with by market design. With the occasional occurrence of dry periods, hydro generators will never be willing to offer amounts of long-term contracts beyond their firm energy, whichever way these contracts are designed and sold. Moreover, the characteristics and importance of hydro warrant a fleet of other generation plants than can fill the void when hydro dries up. Since these plants will be used only infrequently, they should have low fixed and, correspondingly, high variable costs. It follows that these generators will not be willing to enter into long-term contracts at prices that reflect conditions in normal periods. Demand will therefore have to chose between a relatively moderate level of contract coverage, backed by hydro and other generators with modest variable costs, or a high level of coverage at a correspondingly high cost, backed also by generators with high variable costs.

### OTHER ISSUES

Based on the observation that in the current market contracts differ considerably, and that the volumes of contracts traded is low compared to the volumes of energy consumed, CREG suggests the need for standardisation. It is likely that standardisation will reduce transaction costs, but standardisation gives rise to other types of costs. In particular, since in the current market participants are free to write their own contracts, and since they apparently use this freedom to write different types of contracts, a natural conclusion is that freedom of contracting is valuable. Restricting market participants to trade in standardised contracts eliminates the ability to tailor contracts to market participants' individual needs.

CREG proposes a time-varying product for regulated demand. It is not clear how well this curve fits the actual demand for a particular buyer at a particular time, given the underlying variation not only between segments of demand but also over time, between days of the week, weeks of the month and months of the year. It may well be that a flat curve will on average perform just as well, eliminating the need for different products in the regulated and non-regulated segments. Having a single type of contract has the added advantage of allowing for simultaneous competition for the two segments in the auction, as well as trade between these segments in the secondary market.

CREG also proposes that the new contracts will cover a time horizon of up to four to five years. This seems to be longer than in most of the current, bilateral contracts. In electricity markets in other parts of the world, contracts covering a longer time horizon are sometimes offered; however, trade in contracts further ahead than a few years is typically limited.

CREG proposes two alternative ways of conducting auctions. An open auction has the advantage of allowing for price discovery by revealing private information, but it is difficult to see what private information would be relevant here; future market conditions should be more or less common knowledge. Simplicity suggests the use of a sealed-bid auction, especially if trade only takes place in a single, flat product.

Each type of contract will be traded four times. Trade will take place quarterly over a period of one year, no later than two years before the contract is liquidated. This means that there will be limited opportunity for market participants to adjust their positions. Markets in other parts of the world offer more frequent trade, often on a continuous basis up to liquidation.

CREG suggests that secondary trade will take place bilaterally. It is unclear to what extent this will be attractive to market participants, or indeed possible. Contractual terms will differ between buyers and sellers, as well as between sellers, depending on in which auction they sold their contracts. Moreover, the identity of counterparties will not be revealed until a month before contracts are liquidated. There is therefore a risk that the secondary market will be illiquid; in particular, there may be little interest in adding volumes of these contracts outside of the auctions.

## CONCLUSION AND RECOMMENDATIONS

Forcing a new market for long-term contracts, thereby effectively undermining or removing the current bilateral market, is a drastic regulatory intervention with obvious costs. Before making such a move, CREG should be quite certain that the new set up constitutes a real improvement.

Unfortunately, it is not entirely clear that the various proposals for a new contract-market design, including that of CREG, are able to solve the fundamental problems associated with the current market, including varying counterparty risk (to a large extent originating from vertical integration) and unwillingness of generators to offer sufficient amounts of contracts to cover demand in normal times.

CREG should also consider potential measures to improve the current market, including means to handle counterparty risk and the treatment of contract cost pass-through for regulated demand. On the former issue, one might start by carefully considering current regulations, with the aim of reforming regulations that, directly or indirectly, make trading more cumbersome, costlier or riskier for (independent) retailers. In addition, one could encourage the development of standardised contracts (in cooperation with the industry) and credit instruments that more effectively deal with risk. The establishment of an independent entity for dealing with counterparty risk (a clearing house) could, at least in principle, be done without making participation mandatory.

If one does decide to introduce a new market, it should be made simple and transparent, so as to encourage participation and liquidity, with features including

- trade taking place on a platform with a central market-clearing entity;
- a single product with a flat time profile;
- annual contracts that may be split into shorter sections when activated; and
- an introductory auction for each product, followed by continuous trading.

In addition, one should consider carefully how to handle counterparty risk, as well as whether (vertically integrated) generators should be obliged to participate in the market.

## MECHANISMS TO ELICIT INVESTMENT IN RENEWABLE ENERGY

The Colombian government is considering ways to encourage investment in renewable energy. Below, I first present the three alternatives put forward by CREG and then discuss their merits. I end the section with my conclusions and recommendations, including a proposal for a different, and perhaps more suitable design.

### CREGS PROPOSAL

CREG has presented three different proposals for fostering investment in non-conventional renewable energy (FNCERs):[14,15]

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[14] CREG also has a proposal for the incorporation of conventional generation plants as price takers for the existing reliability charge (CREG, 2016a); this may be relevant for FNCERs, but I do not comment further on this here.

[15] While FNCERs cover resources such as biomass, small-scale hydro, geothermal and sea waves, in Colombia the most relevant seem to be wind and solar (photovoltaic) (CREG, 2016d).

- long-term mean-energy agreements;
- pay-as-generated long-term energy agreements; and
- green charges.

I present each of these before discussing of their merits.

### LONG-TERM MEAN-ENERGY AGREEMENTS

In this proposal, generators will be offered Energy Purchase Agreements (EPAs) for annual mean energy (CREG, 2016b). 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 (USD/MWh). Delivery will be liquidated on a daily basis against the spot price, with monthly payments, and with a final annual balance. The term of the contract is 20 years.[16]

The mean-energy contracts will be bought at a price determined in a sealed-bid, discriminatory price (i.e. pay-as-bid) auction. The quantity of energy to be purchased in the auction (the demand) will be defined by CREG.[17] 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 assigned to them.[18] Each participant will submit a mean-energy price offer for each project. Price offers must be lower than the reserve price, which is set by CREG as the average spot-market price for the previous year.[19]

Following this auction, a second auction will be held to determine the buyers of the energy contracts 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. If this auction fails to sell all of the

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[16] Sellers with such contracts will be eligible for Firm Energy Obligations on the same terms as new projects in the relevant Reliability Charge auction.

[17] 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 during the first auction.

[18] Participating generators will have to provide three types of guarantees, covering, respectively, the offer, the construction and start-up of the facilities and the contract.

[19] The average spot-market price is calculated with the Scarcity Price as a cap.

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 energy to suppliers or distributors, the remaining amount will be allocated *pro rata* to regulated demand.

### PAY-AS-GENERATED LONG-TERM ENERGY AGREEMENTS

The second alternative 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.[20] Contracts will be settled on a monthly basis.

The proposed mechanism for assigning these contracts involves holding a sealed-bid, uniform-price 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 over ten years.[21]

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 option is an allocation to all suppliers serving the regulated demand, as a *pro rata* amount of their demand. The second option is to allocate contracts *pro rate* to demand in the spot market.

### GREEN CHARGES

In the third alternative, a Green Charge will be offered for a period of ten years to plants of FNCER technologies. The Green Charge is a percentage of the difference between the average Reliability Charge paid to thermal and hydro generators and average Reliability Charge paid to FNCER plants in USD/MWh.

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[20] As in the first proposal, contract holders may opt in for the Reliability Charge. They must also provide similar sorts of guarantees.

[21] CREG suggests that offer prices may be capped, but it is not clear at what level the cap will be set; is argued that the cap should be below the price in take-or-pay contracts.

The assignment of the Green Charge contracts will be made by a sealed-bid, uniform-price auction. Generators will offer the percentage of the maximum charge they require, capped at 100 per cent. The Green Charge is determined by the marginal successful bidder, i.e. the last plant that crosses the amount to be promoted.

In order to access the Green Charge that was assigned in the auction plants must contract the energy. However, the Green Charge will be paid to all energy supplied. FNCER plants accrue Firm Energy Obligations determined through the application of methodologies determined by CREG.

### DISCUSSION

The three proposals differ in a number of respects, including

- renewable product
- duration of contracts;
- procedure for assigning contracts;
- reserve price; and
- the allocation of purchase obligations or costs to buyers.

These elements could – and perhaps should – be considered independently. For example, the type of renewable product may be considered independently of the duration of the contract; similarly, the procedure for assigning contracts does not depend on the choice of reserve price. One could in fact imagine a large number of different combinations of the various elements, not only the three alternatives considered by CREG.

Below I consider the various elements one by one and discuss how they might best be designed in order to facilitate the overall goal of attracting a sufficient amount of renewables in a cost-efficient manner.[22]

[22] There are other features of the proposals that merit comment. In particular, the proposals involve complicated settlement procedures during the duration of the contracts; this is particularly true for the first proposal, where monthly and annual balancing of accounts will have to take place.

RENEWABLE PRODUCT

In the first two proposals, the renewable product is an amount of energy bought at a fixed price for the duration of the contract; in the first proposal, the amount is mean annual energy, with a cap and a penalty for non-fulfilment, and in the second proposal, the amount is actual energy produced. In the third alternative the product is a premium on actual energy produced, with a requirement that the energy be contracted.

None of these products are directly derived from the distinguishing feature of FNCER technologies, namely their “green” quality – a quality for which the Colombian government is willing to pay. The greenness is related to the energy produced, rather than to installed capacity or other characteristics of technologies or plants. It would therefore seem natural to relate the renewable product to the green value created by the energy produced from FNCER resources, and otherwise threat these technologies as any other technology; in particular, renewable generation should participate in the markets – incl. spot, contracts and firm-energy markets – as any other type of generation. In other words, the green quality of FNCERs provides no argument for paying for their energy at a guaranteed price, as in the first two proposals; the green quality is an argument for an additional payment (i.e. a subsidy) to the energy produced that reflects the value of its green quality (as in the third proposal).[23]

It follows from this line of argument that the renewable product should be defined as a premium on energy produced from FNCERs, over and above what these generators will be paid for their energy in spot and contract markets and the Reliability Charge they obtain for their firm energy, but with no specific obligation on how to participate in these markets.

[23] CREG (2016c) suggests that FNCERs will have higher transaction costs in the (bilateral) contract market than conventional generators and so should be offered a fixed price for their energy. It is not clear to what extent this is true. The argument would become irrelevant if a mandatory long-term contract market is implemented.

CONTRACT DURATION

The duration of contracts differ between the proposals, from 20 years in the first proposal to 10 years in the second and third; the reasons for these differences are not entirely clear.[24]

The duration of contracts is unlikely to matter very much (in particular, whether they are for 10 or 20 years), as long as the size of the price or premium is defined in an auction. Take the case when renewables are paid a premium over and above market prices, as with the Green Charge. Since generators will be concerned with the total amount of revenue, they may be willing to accept a lower premium if the time horizon is longer. The size of the premium will therefore tend be inversely proportional to the length of time for which it will be paid.[25]

From the above reasoning – that the renewable product should be a premium on energy produced reflecting the value of the green quality of renewables – it might seem natural to let contracts last for the lifetime of the plant; as long as the plant delivers the green service, it should be paid for it. However, since the willingness to pay for green output may vary over time, while the price will be fixed for the duration of the contract, it may make sense to cap contract duration.

ASSIGNMENT PROCEDURE

In all three proposals, the renewable product is priced and assigned according to a sealed-bid auction.[26] This seems reasonable given that there is unlikely to be much scope for price discovery; the relevant technologies (wind and solar) are relatively standard, and the broader market conditions are essentially common knowledge.

Whether the auction should be discriminatory (as in the first proposal) or uniform (as in the two last proposals) is likely to be of secondary importance; however, since

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[24] It is also not clear why in the first proposal energy prices are in US dollars, while in the second they are in Colombian pesos.

[25] It may be noted that for any given reserve price, the reserve price is more likely to be binding the shorter is the time horizon.

[26] For reasons that are not clear, in the first proposal allocation of contracts to demand will be by clock auctions.

all FNCERs essentially supply the same green product, it would seem natural to pay them the same price. A uniform payment may also be simpler to administer.

### RESERVE PRICE

In the first proposal, the reserve price for FNCER energy is set at the average spot market price. In the second proposal, the reserve price is not specified, but it is argued that the cap should be below the price in take-or-pay contracts. In the third proposal, the reserve price is related to the Reliability Charge.

These price caps seem not only arbitrary, but it is not clear that they will be sufficient to induce the required investment; this is particularly true for the first and second proposals, where the reserve price for renewable energy is set at spot or contract prices.

Ideally, the reserve price should reflect the willingness to pay for the green quality that renewables offer. The reserve price should therefore be set by the Colombian government, rather than by CREG.

### ALLOCATION PROCEDURE

In the first proposal, contracts are allocated to demand (i.e. consumers, or suppliers on their behalf) through an auction, while in the second proposal contracts are allocated administratively, on a *pro rata* basis (either to all or only to regulated demand). In the last proposal, FNCERs will sell their energy through existing markets, while the additional charge will be covered through consumers' firm-energy payments.

It is not clear that the second auction in the first proposal will succeed. The whole rationale for specific support for FNCERs is that the energy is not competitive under current market arrangements, i.e. that it is more expensive than energy from traditional sources. Hence it may be difficult to find buyers for this energy, even if it can be obtained on long-term contracts at fixed prices (and suppliers are allowed to pass on the price to regulated consumers). There is a risk therefore that the second auction will fail and that contracts will be allocated to demand on a *pro rata* basis here also.

More generally, the additional revenues to FNCERs offered through the renewable contracts are effectively payments for a service provided to the community at large – a contribution to the reduction of climate-change risk. One could envisage these payments being financed by general taxation (as is done in some countries), but if they are to be financed by electricity consumers, it would seem most natural to allocated the costs on a *pro rata* basis to all of demand; there does not seem to be compelling reasons – whether for efficiency or fairness – to limit the responsibility for green energy to regulated consumers.

## CONCLUSION AND RECOMMENDATIONS

CREGs various proposals share the feature of being fairly complex, although the degree and type of complexity varies between the proposals. A general recommendation, in accordance with international practice[27], is to choose a simpler mechanism.

Fundamentally, the goal would seem to be to encourage as much renewable energy as possible for a given cost, irrespective of technology (as long as it qualifies as green or FNCER). The mechanism should therefore be directed at actual output.

Furthermore, apart from its green aspect, there does not seem to be compelling reasons to treat FNCER energy differently from other types of energy; in particular, FNCER generators should participate in the markets on the same terms as any other generator.

This suggests that the mechanisms to elicit investment in renewable energy should aim at the additional encouragement (premium or subsidy element) that renewables need in order to be competitive with other types of energy.

The exact details of the auction may not matter much (cf. the variation in mechanisms used around the world), but a simple set up would be to hold regular sealed-bid, uniform price auctions for a given amount of capacity in which

[27] AURES (2016) discusses the main trends in renewables auction design in eight EU countries (Denmark, France, Germany, Ireland, Italy, Netherlands and UK) and four non-EU countries (Brazil, California, China and South Africa) in the past decade.

participants compete for the premium that will be paid to energy generated, over and above what they may be obtain in spot, contract and firm-energy markets. The reserve price is set at a level reflecting the maximum willingness to pay for green energy over and above that of other types of energy. The cost of the premium is allocated to all of demand as a charge on energy consumed.

## APPENDIX: ON THE FIRM ENERGY OF RENEWABLES

A specific issue not directly relevant for the question of how best to elicit investment in renewable energy, but which nevertheless has implications for some of the proposals, is how to set the firm energy or capacity factors of intermittent energy sources.

The rules currently used by the CREG tend to set the capacity factors of FNCERs at very low levels. The argument is that the output from these sources that may be guaranteed with a high probability at any given time is small.

This is of course true if each plant is viewed in isolation; sometimes the wind is not sufficient to move the blades of a windmill, and sometimes there is not enough light for a solar plant to generate any energy. Although the periods may be short, there will be times when renewable energy sources produce little or no energy.

However, the intermittent nature of renewables becomes less important when seen in the context of the overall energy system. In particular, in a system such as the Colombian, with high levels of both storage and installed capacity of hydro, the intermittency of renewables may be close to irrelevant. In such a system, energy may be stored (i.e. hydro resources may be saved) when output from renewable sources are high, in order to be used (i.e. hydro resources produce) when output from renewables are small.

To illustrate, assume that a hydro generator with sufficient storage and generation capacity invests in a windmill. By utilising the hydro resource as swing production, the generator can produce an additional steady stream of output equal to the mean or average generation of the windmill.

This complementarity between hydro and intermittent energy sources would be especially important for defining firm energy, since this relates to periods of scarcity, which are characterised by spare capacity in both hydro dams and turbines. Utilising hydro as swing production, it should be possible in such periods to effectively smooth the overall output even as supply from renewables vary. Then the firm energy of intermittent energy sources such as wind and solar will effectively be related to their average, rather than their minimum, output.[28]

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[28] Note that, in this respect, wind and solar are fundamentally different from hydro facilities with little or no storage capacity; such run-of-river hydro plants will produce little or nothing during scarcity events and hence must have very low firm energy or capacity factors.

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