"COMPUTER-BASED SIMULATION OF AUCTIONS OF OPTION CONTRACTS AND OF FUTURES CONTRACTS IN THE COLOMBIAN WHOLESALE ELECTRICITY MARKET"

Final Report – Chapter 6

Prepared for:

Comisión de Regulación de Energía y Gas (CREG)

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Overview of Proposed Forward & Options Market

1. GOALS OF THE OPTIONS & FORWARD MARKET:

The proposed financial derivatives market has several potential benefits. Some of these benefits are highlighted in the TERA report, and some are overlooked. A liquid financial derivatives market for wholesale electricity in Colombia could:

1. provide a market-based estimate of the value of incremental generation capacity in the future, replacing the current computer based capacity payment system.
2. provide participants the ability to manage the financial risks associated with the uncertainty of future electricity prices.

Goal 1: At present, the CREG employs a computer model to estimate capacity charges within the system. The model considers current and historical hydro conditions (rainfall, reservoir levels), demand estimates, and asset development plans among other factors to determine an appropriate value of capacity . Many markets around the world have moved toward a market-based approach to estimating the value of future capacity. By allowing market participants to enter into options on power in the future the market is permitted to assign values in the form of option premiums. The negotiated option premium reflects the value of an additional MW of capacity with a cost of production equal to (or close to) the strike price of the option. Given this information, potential investors have a market signal of the value of the generation assets they may be considering building.

This proposed structure removes the burden from the CREG of attempting to estimate the value of capacity, and may also provide signals as to which types of generation the market values more highly. Specifically, the value of options at different strike prices will provide insight into the value of plants with different marginal costs. Consider the following scenarios:

Call Option Strike Price / Marginal Cost	Indicative Generation Type	Theoretical Option Value (excl. intrinsic)	Market Value Scenario 1 (excl. intrinsic)	Market Value Scenario 2 (excl. intrinsic)
$5/MWh	Hydro	$ 3.00	$ 2.50	$ 2.75
$15/MWh	Baseload (gas)	$ 4.50	$ 4.50	$ 4.70
$30/MWh	Peaking (gas)	$ 3.00	$ 3.50	$ 3.00

The table above shows three different option strike prices, the type of generation that would have similar marginal production costs, and the theoretical option value (excluding the intrinsic value[1]). Scenario 1 shows example market prices for the options. In this scenario,

[1] For a general description of forwards, futures and options, see Appendix II in chapter 1.

the market value of the $5 strike price option is below the theoretical value. The market value for the $15 strike price is the same as the theoretical value, while the market value of the $30 strike price option is significantly higher than the theoretical value. This set of market prices implies to a potential investor that the market prefers an incremental MW of peaking capacity (as insurance against spikes) to an additional MW of hydro capacity.

Scenario 2 shows the $5 and $30 strike price options are undervalued relative to theoretical value, but the $15 strike price option is overvalued relative to the theoretical value. This could imply that the market values an additional MW of baseload gas power (i.e. combined cycle) over additional peaking or hydro generation. Of course, these examples assume sufficient liquidity and efficiency in the market such that the quoted prices are “real”.

Goal 2: Power markets tend to exhibit much higher volatility than other commodity or asset markets due to the absence of effective storage. Allowing producers and consumers to manage the financial risks associated with future power purchases and sales should allow them to obtain financing more easily, as well as encourage investment by firms that would be hesitant to invest without the ability to protect themselves from the risks associated with the spot market.

The revised structure proposed by The Consortium in the First Report (*October, 2002*) and described in detail herein attempts to achieve the above goals of the options and forward market, although a significant amount of regulatory change will be required over the coming years.

2. PROPOSED FRAMEWORK:

The following section outlines the proposed framework, given The Consortium’s review and critique of the TERA proposal. Many of the elements are similar, with some adjustments that The Consortium feels would make the proposed structure more effective at accomplishing the ultimate goals of the CREG. There are also some new recommendations that The Consortium feels were not included in the original proposal that the CREG should consider when implementing the final strategy, to ensure acceptance and sufficient liquidity in the market. The recommendations are based on our experience in other markets and our knowledge of the current and proposed situation in the Colombian wholesale electricity market. Any recommendations herein must be reviewed and discussed with potential market participants to ensure acceptance of the proposed framework and ongoing liquidity in the marketplace.

In addition, market rules and characteristics of the final financial products should be reviewed at least annually to gauge successes and failures, and to ensure that participants are not being disadvantaged by the structure of the market and any unforeseen market events.

2.1. MARKET DESIGN

When designing an options and forwards market, it is important to consider the many factors that could affect the success of the market as a whole. Success, in many markets, is defined by the amount of liquidity that the market can maintain and by the impossibility of market players to influence market prices. For implementing an efficient options and forwards market, careful design of the following characteristics is essential to ensuring active market participation and acceptance.

- Buyer and Seller Participation
- Low Transaction Cost Contract Design
- Reference prices
- Settlement options
- Option strike prices
- Contract volumes
- Contract tenors
- Option Premiums

2.1.1. BUYER AND SELLER PARTICIPATION

The TERA report highlights the potential problems of forcing one side to participate (consumers) but not the other (generators). The report accurately characterizes this situation as a "short squeeze" created by regulation. One alternative proposed by TERA is to allow unfilled bids to be filled at "index," which they propose determining as the average of the previous several minutes' transaction prices. This solution may expose participants to prices at which they do not wish to transact, and could also lead to manipulation in the event that the "squeeze" results in price increases.

As an alternative to the structure above, The Consortium recommends a structure that would require suppliers to sell a portion of their generation in the form of options, thus creating a more balanced market in terms of volumes to buy and sell. This balanced market should remove the structural asymmetry that results from forcing one side of the market to buy while the other side is not forced to sell, and speed up the auction process by arriving at an agreed upon price more quickly. This structure should also increase liquidity in the secondary market by avoiding the imbalances that could result from consumers trying to sell their options immediately to avoid holding onto positions that they do not want.

2.1.2. LOW TRANSACTION COST CONTRACT DESIGN

Designing contracts that encourage secondary market activity should be a key goal of the market development. An active secondary market for options and forwards would allow participants to adjust their positions to be consistent with their desired risk profile, as well as provide continuously updated signals as to the value of capacity. Guaranteeing liquidity in a secondary market is a significant challenge facing the CREG in the development of the market. One of the largest obstacles to liquidity in markets is high transaction costs.

The physical characteristics of the contracts themselves can dramatically affect transaction costs. Physical paper contracts cost more to trade than electronic contracts that are entries in a computer. Most commodity markets (exchanges and OTC) transact electronically in one form or another, from electronic bulletin boards and online exchanges to electronic "documentation." The goal of these efforts is to decrease the cost of transacting in the marketplace and increase liquidity. In the specific case of the Colombian market it is impossible to predict transaction costs at this early stage of development, but due to the high probability of relatively low liquidity in the early stages (compared to NYMEX or a stock exchange) inexpensive solutions should be sought out for many transaction cost items.

Transaction costs can be broken down into two general categories: direct costs and indirect costs.

Direct Transaction Costs

- **Bid/Offer Spread –** The bid/offer spread refers to the difference between quoted offers to buy and sell a given commodity or security. This generally acts as a direct measurement of liquidity in a market and can be one of the most significant direct transaction costs facing players in a market. Large bid/offer spreads (indicative of low liquidity) are typical in electricity options markets, and can result in costs that exceed 20% of the face value of the transaction. During times of high risk, bid/offer spreads may be as wide as 50-75%.

- **Brokerage Fees –** In cases where transactions are matched through the use of a broker, direct cash costs are incurred by each counterparty. Brokerage fees in the US power markets typically range from US$ 0.01 – 0.05 per MWhr or approximately 0.1% of the total value per MWhr.

- **Exchange Fees –** Purchasing a seat on many exchanges can be relatively expensive for small players but does not require too large an investment for larger companies. Clearing members on the NYMEX typically pay between US$ 0.5MM and US$ 1.5MM for a membership seat. Exchanges are typically non-profit, and primary market seat sales revenue is used simply to fund the operations of the exchange and provide a first-loss reserve level to cover the event of default. Seat sales in the secondary market do not provide cash to the exchange. Other markets differ in membership fees. Participants who do not own seats typically transact through brokers who embed exchange fees into their commissions. In general, exchange fees are very small and charged on a per contract basis. The NYMEX, for example, charges clearing members approximately US$ 0.80 per contract traded.

  Often, researchers look to comparable exchanges to estimate the costs of exchange fees. Many cite local stock exchanges (i.e. La Bolsa de Colombia) as relevant examples. This could lead to many inaccurate conclusions due to fundamental structural differences in the two markets. First, equity exchanges, unlike many commodities exchanges, generally have no credit exposure as the exchange itself does not perform a clearing function. In cases of dispute, broker-dealers generally negotiate with their customers to resolve the problems. In rare cases where a broker-dealer becomes insolvent, regulatory or legal alternatives are sometimes explored (i.e. SIPC). Second, since the exchange itself has no credit exposure, equity exchanges typically do not determine margin rules. These structural differences, combined with the relatively low volatility of equities (compared to electricity), result in a very different fee structure for equity markets (i.e. NYSE) and commodities exchanges (i.e. NYMEX).

Indirect Transaction Costs

- **Collateral –** Costs associated with collateral and credit requirements can dwarf the direct transaction costs addressed above. The opportunity costs of posting cash collateral can be very significant. Recent events in the US energy markets, where debt has been refinanced and capital investment decisions postponed as a result of margin calls from counterparties, underscores the importance of weighing these transaction costs.

- **Letters of Credit and Reinsurance –** As an alternative to cash collateral, the cost of obtaining LCs and reinsurance on transactions can quickly escalate into the millions of dollars per year for even relatively high credit quality counterparties. This is especially true in instances where transactions are long dated in nature, as the transactions in Colombia would tend to be. Banks and re-insurers typically demand high fees for this type of guarantee because of the potentially massive cost associated with the insolvency of electricity companies with long dated transactions on their books.

Keeping these transaction costs under control is critical to establishing liquidity in the primary and secondary markets. Some of these costs are more easily controlled than others. Specifically, the consortium recommends the following steps to increase the probability of maintaining liquidity in the secondary market:

- Conduct and settle transactions electronically to reduce transaction costs and encourage more active participation.

- Standardize contract terms as much as possible to reduce the costs associated with contract and collateral settlement.

- Remove minimum maintained contract quantities from the secondary market, allowing participants to adjust their positions as they deem appropriate based on their desired risk profiles.

- Provide financial incentives to encourage market makers to enter the secondary market in an effort to reduce the bid/offer spread. Typical incentives include a one time or monthly payments for a market maker to guarantee a market or a fee per MWhr transacted.

- Establish centralized collateral management with netting agreements and other collateral optimizing techniques to reduce the credit costs of transacting. For a more detailed discussion of this topic, see the section entitled *Clearing and Credit Risk Management* in this document.

2.1.3. REFERENCE PRICE AND SETTLEMENT

The underlying price for the proposed market is usually the price at which market participants would have to buy or sell electricity at the time needed if there were no contracts in place. In Colombia, that market is *La Bolsa*. As such, *La Bolsa* is a logical candidate to be the underlying price index.

Pricing will be based on a central hub location to be determined in the future based on analysis of the grid and location of plants. The price in *La Bolsa* at the central location will be used to determine settlement of the contracts. Forward and option contracts in the Colombian wholesale electricity market will be financially settled. Payment will be made based on the difference between the *La Bolsa* price at maturity and the contract or strike price.

For a participant who is long a call option, profit or loss on the contract at expiration is:

Payoff = MAX(0, LaBolsaPrice – StrikePrice) x Volume

For a participant who is long a forward contract, profit or loss at expiration is:

Payoff = (LaBolsaPrice – ContractPrice) x Volume

2.1.4. OPTION STRIKE PRICES

The option strike prices should be set according to the goals of the options market. In Colombia, the government will likely establish the strike prices of the options based on analysis into the effectiveness of various possible strikes. For example, deep out-of-the-money call options (i.e. $US 70/MWh) would be effective in providing insurance to consumers against large price spikes. These options would be relatively inexpensive, since the number of hours where prices can be expected to be above US$ 70 is relatively low, and use of them would place a cap on the price paid for electricity. Options with strike prices as high as this may not, however, provide potential investors with a very clear picture of the value of baseload capacity.

Alternatively, options with strike prices at or near the marginal cost of an average hydro or gas plant could provide very clear price signals to potential investors regarding the potential value of an additional MW of baseload capacity. By forcing consumers to buy a certain percentage of their needs in the form of these options, companies could invest in new generation with confidence, knowing that they are protected on the down side. These options would not, however, be a very reasonable alternative to insure against price spikes, as they would be too expensive.

The CREG (or other regulatory body charged with the responsibility for setting option strike prices) should understand both the supply and demand side needs and settle on a combination of strike prices that satisfies all market participants to ensure acceptance of the instruments. In addition, if the CREG decides to have numerous options at different strike prices a careful balance must be struck between having too many strike prices, which reduces liquidity in each one, and too few strike prices, which could lead to problems with acceptance.

In order to address the needs of many different producers and suppliers, The Consortium recommends starting with three different option strike prices.

- Options with a strike price of $US 10 per MWhr to serve those participants who desire options on base-load electricity.

- Options with a strike price of $US 30 per MWhr. to assess the market value of slightly higher cost generation (i.e. gas fired).
- Options with a strike price of $US 70 per MWhr. to serve the needs of participants who seek insurance against price spikes and to estimate the value of peaking plants to the market.

This selection of options should provide participants with the ability to achieve their desired risk management goals while providing the market of potential investors clear signals as to the relative value of different types of additional capacity. Of course, as with all of the recommendations in this report, these strike prices should be discussed with participants before implementation of the market and reviewed periodically to ensure that they accomplish the stated objectives of the program.

2.1.5. CONTRACT VOLUMES

Contract volumes can have a large influence on liquidity. Contract volumes that are too large for smaller participants will result in decreased competition, while contract volumes that are too small become logistically difficult to manage and settle. For new markets, contract sizes of 1MW to 10MW are generally appropriate, but the CREG should determine whether these contract quantities are appropriate for wholesale power in Colombia. Perhaps larger or smaller contract quantities would improve liquidity and competition. The CREG must also decide the structure of the volumes. For example, are there peak and off-peak options or are the options for 24 hours? How will seasonality be handled in pricing?

Volume sizes of 1MW per hour per month were selected for the initial stages of the NYMEX electricity futures and options contracts. Many market participants felt that this contract size was too small. That being said, producers and suppliers are likely larger in the US than in Colombia. This is an area where communication between the CREG and market participants is critical.

As a starting point, The Consortium recommends two types of options: baseload (7 days per week and 24 hours per day) and peak (generally weekdays between the hours of (12:00) and 21:59). These options allow participants to manage risks and value capacity in a way that is consistent with electricity use in most areas. We further recommend beginning with volume blocks of 1MW per contract to allow smaller players to participate in the market.

2.1.6. CONTRACT TENOR

The unique goals of the options and forward electricity market in Colombia make this question more difficult to answer than in most developing markets. Traditionally, there is more liquidity in the front months (1-3 months ahead), and liquidity increases in the long end of the curve as the market matures. Because the main goal of this market is to provide long-term price signals, contracts will tend to be longer in tenor. For example, a typical power contract in many markets might be a daily option for one month. This type of contract will not, however, provide an effective long-term price signal. Instead, TERA has proposed longer-term forward and option contracts. An indicative contract in the proposed market might be a strip of daily options for 5 years priced monthly. Options such as this would be more effective at providing long-term price signals.

In order to give clear signals to the market as to the value of capacity and allow participants to manage the risks associated with seasonal conditions, The Consortium recommends that the auction begin with monthly options extending for one, two, and five years.

2.1.7. OPTION PREMIUMS

The premiums associated with long term options for power are often very large due to the significant volatility and time to expiration. The large cash requirements could place an undue amount of financial strain on market participants. Furthermore, upfront payment of the whole option premium places all of the credit risk on the shoulders of the option buyer. The TERA report recommends amortizing the option premium over the life of the contract (i.e. each month between the contract date and the performance period) to reduce the burden on the option buyer. An added benefit of this premium payment structure is that the credit risk of performance becomes shared between the option buyer and seller. For example, in the event that a generator were to declare bankruptcy and be unable to perform under the obligations of the contract the option buyer would lose only those premiums already paid, rather than the entire option premium. For these reasons, The Consortium agrees with TERA and recommends that option premiums be paid in this way. The table below summarizes the characteristics of the proposed financial instruments.

2.2. OPTION CONTRACT CHARACTERISTICS

Specification	Contract	Value
Trading Unit	Option Contract (Baseload & Peak)	1 MW
	Forward/Futures Contract	1 MW
Reference Price	Option Contract (Baseload & Peak)	Central hub (TBD)
	Forward/Futures Contract	Central hub (TBD)
Price Quotation	Option Contract (Baseload & Peak)	$ US per MWhr
	Forward/Futures Contract	$ US per MWhr
Trading Months	Option Contract (Baseload & Peak)	Monthly for 1 year, 2 years and 5 years.
	Forward/Futures Contract	Monthly for 1 year, 2 years and 5 years.
Exercise	Option Contract (Baseload & Peak)	Daily exercise over the delivery month.
	Forward/Futures Contract	No optionality
Delivery Hours	Baseload Option	7 days per week, 24 hours per day

		(7x24)
	Peak Option	10 hours per day, Monday – Friday (5x10)
	Forward/Futures Contracts	7 days per week, 24 hours per day (7x24)

2.3. THE AUCTION PROCESS:

The TERA report recommended an iterative, quarterly auction process to determine the market price for options. Regulation will require consumers to purchase a portion of expected future needs in the option auctions. The TERA report further details the process by which the auction could be conducted, citing various alternative approaches. The purpose of this section is to address some of the issues omitted from the proposed framework, including:

1. Who should manage the auction process?
2. Should a minimum size or credit worthiness criteria be a requirement to participate in the auction?
3. How much volume should be auctioned to begin with?

2.3.1. MANAGEMENT OF THE AUCTION

Another issue the CREG must consider when establishing the new market is who will be responsible for managing the auction process. In general, three alternatives exist for the management of the auction process: i.) the MEM; ii.) an existing exchange or; iii.) an external management agency.

1. The current market administrator (MEM) is familiar with many of the unique facets of the Colombian market and is a "known quantity" to the participants in the marketplace.
2. Utilizing the infrastructure and experience of an existing exchange to manage the auction often seems like an attractive alternative. This alternative is likely to be very expensive for participants, as an established exchange will have large margin requirements and likely require a government guarantee to protect itself against the substantial credit risk involved in settlement of power derivatives.
3. Establishing an external agency to manage the auction process and collateral requirements may be the best alternative for the CREG. It allows the market administrator to continue to do its job without becoming overburdened with an additional role, and allows for separation of the current market environment and the new proposed structure in the early stages.

2.3.2. MINIMUM CREDIT QUALITY

Many exchanges and even bilateral markets require a minimum credit quality to participate to protect participants from potentially massive credit losses in the event of a counterparty default. This is often considered the first line of credit protection. Smaller, less credit worthy counterparties can remove this barrier to market entry by securing letters of credit from banks or posting collateral, but this is often an expensive alternative.

This issue is especially important if the auction and secondary market administrator serves only as a matchmaker for bilateral contracts. In such a situation, a firm may be forced to take the credit exposure of another market participant that in the normal course of business they would not have done. This can lead to a default hurting the unlucky participants who were paired with the defaulting party while having no impact on the other participants.

The CREG should carefully consider this issue and adopt a plan that allows a sufficient number of market participants to ensure liquidity and competition, but protects the market participants from potentially devastating credit losses. Without performing credit analysis of the potential participants in the marketplace, it is impossible to determine a minimum credit quality. However, as a general rule The Consortium recommends determining the minimum credit quality of the top 10 to 20 potential participants (in terms of expected volume transacted) and making that credit quality the minimum. Since the majority of the volume transacted in the marketplace will likely be the from 10 –15 participants, this methodology allows for all of them to participate, plus other counterparties with equal or higher credit ratings. Companies with lower credit ratings may also participate but may be required to post collateral or a surety bond as a form of credit guarantee to gain access to the market.

2.3.3. INITIAL AUCTION VOLUME

Making a transition from the current system of capacity payments to a market based approach presents a significant challenge to the CREG. If the new regime is phased in too fast, participants will likely reject it due to a lack of understanding. Schemes like this tend to be more successful if initial auction volumes are small. For example, regulation may require that in the first year five to ten percent of expected capacity and load for a five year forward period must be sold and purchased. An example of a large industrial customer

Year	Expected Demand	Call Option Volume (10% of expected demand)
1	40 MW	4 MW (4 Contracts)
2	40 MW	4 MW (4 Contracts)
3	40 MW	4 MW (4 Contracts)
4	50 MW	5 MW (5 Contracts)
5	50 MW	5 MW (5 Contracts)

These percentages are likely small enough not to discourage participation but large enough to require that analysis be brought to bear on the transactions. The goal of the market should be to build volume until the minimum quantity is such that if a new generator came into the market and wanted to hedge 100% of their volume, then that quantity should not exceed 10% of total market volume.

2.4. CLEARING & CREDIT RISK MANAGEMENT IN THE PRIMARY & SECONDARY MARKET

In general there are three structural alternatives available when establishing a new financial derivatives market.

1. Formal exchange (central clearing and collateral management)
2. Bilateral, over the counter negotiations (clearing and collateral management negotiated between counterparties)
3. Centralized collateral management

Each of these alternatives has advantages and disadvantages associated with them. For a thorough analysis of credit risk in power markets, please refer to Appendix VIII at the end of this chapter.

2.4.1. FORMAL EXCHANGES

In a formal exchange structure, the MEM (as an example) would take the role of a clearinghouse and would become the counterparty or middleman for all transactions. The clearinghouse would absorb any default by a participant. For taking these risks the clearinghouse receives a small payment for each transaction.

While this is a theoretically ideal situation due to the elimination of credit risks to counterparties, implementation becomes very difficult. To be effective an exchange must have a very high credit rating (for example, AAA). Only with such a rating is it possible for the exchange to guarantee that defaults will be covered. For a new clearinghouse, this represents a very large initial capital investment. AAA rated entities usually require a minimum of US$ 100MM in cash or acceptable alternative (i.e. guarantee from a AAA rated parent or insurance company) and must have relatively stable cash flows. Given the inherent risk of a power clearing operation, significantly greater capital could be required. In addition, systems often costing US$ 10MM or more are often required to establish an effective exchange.

Further, to protect itself the clearinghouse must actively manage the risk of the positions and require frequent collateralization of the mark to market exposure of the positions. This requires an active market and day-to-day activity by the clearinghouse and market participants. The capital and collateral requirements coupled with the extreme event risk are likely to make it impractical for a formal exchange to be developed.

Although central clearing is a highly desired concept, to date no group has offered a clearing service for power contracts that has been widely accepted. The potential magnitude of loss in the event of a default is simply too large for most clearinghouses to accept.

2.4.2. BILATERAL (OTC) NEGOTIATIONS

In bilaterally negotiated markets, counterparties negotiate the details of clearing and collateral exchange among themselves. In these types of markets, there is no central management or central clearing to guarantee performance. Procedures governing clearing and collateral exchange are detailed in formal agreements (such as an ISDA agreement). This lack of central authority and formal regulation make bilateral markets very inexpensive to start and maintain. These markets generally require a large number of high credit quality counterparties to be successful.

The lack of a centralized collateral management agency in bilateral markets creates the risk of a chain reaction of defaults. Consider an example where one company shows multiple counterparties the same financials for several transactions. In cases such as this, a company may be able to leverage its balance sheet many times over and, in the event of default, refuse to pay several counterparties instead of just one. The resulting credit losses experienced by other counterparties can cause further defaults throughout the industry, as happened in 1998 in the U.S. power markets.

Another potential problem with bilateral markets is the possibility of selective default. Companies on the verge of financial distress may elect to default only to smaller counterparties, and not to their larger ones. This places smaller participants at a disadvantage and could harm liquidity in the future.

2.4.3. CENTRAL COLLATERAL MANAGEMENT

The Consortium feels that this combination of a traditional bilateral OTC market and a formal exchange framework may be the most practical structure for the wholesale market in Colombia. In this proposed structure, parties would transact directly with one another, as in a bilateral OTC market, but a government-administered entity would manage the posting and exchange of collateral for the parties involved. This has several advantages, including:

1. Collateral is kept in escrow so that companies in financial distress do not have the temptation to spend it.
2. Netting of collateral becomes easy in the case where several trades between two counterparties net to one exposure.
3. A central collateral management authority can reduce the probability of chain reaction of defaults by having a better understanding of a company's total exposures.
4. The central authority can ensure that smaller participants are not at a disadvantage by reducing the probability of selective defaults.

As outlined in Report 2, the basic rules of the market could be the following:

1. A level of collateral is set for long and short positions within the Colombian market.
2. Each participant may receive a credit toward their collateral requirement based upon their credit rating.
3. Each participant must post enough collateral such that their collateral plus their credit rating credit is equal to or greater than their total collateral requirement.

4. Each participant will also pay some insurance premium for participating in the market.

To see how this structure would work in practice let us consider the following structure. Company A has purchased daily options on power from Company B for 2003 and 2004. Let us assume that the option premium is determined to be $100,000 per month for 2003 and $125,000 per month for 2004. Each month there is the potential to call on 10,000 MWh. The total cost of the option is therefore $2,700,000. Let us assume that the collateral authority has determined the following schedule for collateral:

	2003	*2004*
Buyers	$2/MWh	$1.50/MWh
Sellers	$5/MWh	$4/MWh

Given this schedule, the total collateral requirements for Company A and Company B would be:

Company A = 120,000MWh* $2/MWh + 120,000MWh*$1.50/MWh = $420,000

Company B = 120,000MWh* $5/MWh + 120,000MWh*$4/MWh = $1,080,000

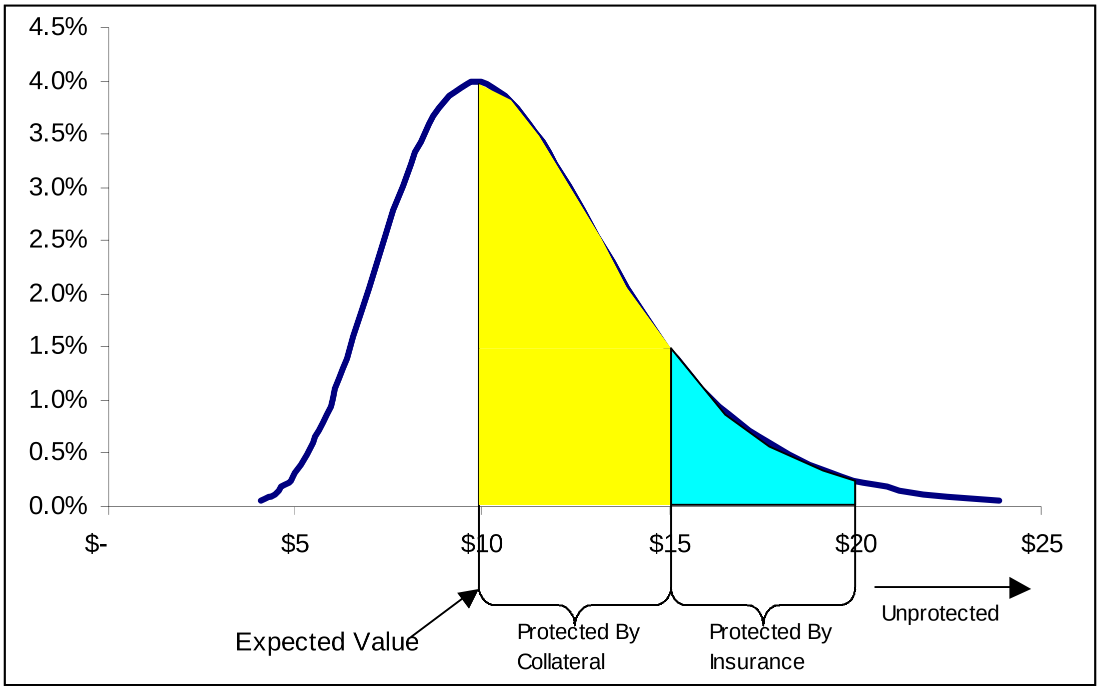
Now assume that the collateral authority has also created the following collateral credit schedule:

Credit Rating	*Collateral Credit*
AAA	$2,000,000
AA	$1,000,000
A	$ 500,000
BBB	$ 250,000
BB	$ 125,000
B	$ 50,000
<B	$ 0

If Company A has a BB rating then they would be given a credit of $125,000 and be required to provide cash or a letter of credit for the remaining $295,000. If Company B has an A credit rating then they would be required to provide $580,000 in liquid collateral.

This provides the first level of protection in the event of a default. The second layer of protection comes from the additional premium. In this situation the collateral authority might require every participant to pay $0.50/MWh purchased or sold, equal to $120,000 from each company. With this protection, the collateral authority can either self insure or purchase insurance. It appears reasonable that the authority should be able to protect up to an additional $5/MWh in the event of a default based upon these premium payments.

The net result is protection for a loss in value of $7/MWh for the seller and $10/MWh for the buyer. The figure below graphically presents these results for the buyer (the seller would have protection on the left hand side of the distribution).



This structure does not completely protect market participants from credit losses, but it does provide a balance between the needs for credit protection in the Colombian market and the constraints on cash to be used for purchasing insurance, bank guarantees, and to fulfill collateral requirements that can be substantial.

3. SIMULATANEOUS OPERATION OF AUCTION & SECONDARY MARKETS:

The primary auction and secondary markets are designed to function simultaneously. Precedents for this type of market structure exist and function well in the market for US Treasury bonds, where certain participants are licensed to participate in primary auctions and the secondary market allows for participation of many other parties. The primary auction market will be characterized by the required participation of buyers and sellers of energy, while the secondary market will allow market participants to adjust their positions to a level consistent with their individual risk preferences. The auction bidding process will be enhanced by the price transparency provided by secondary market transactions, and should reach an equilibrium price more efficiently and quickly with the secondary market providing more accurate beginning points for bids and offers for auctioned contracts.

Optimally, credit risk in the primary and secondary markets will be managed by the same central collateral management agency proposed in this report. Collateral posted to mitigate credit risk within the auction or secondary markets should be fungible between markets, thus making the cash requirements needed to participate in both exchanges more reasonable for many Colombian participants. In other words, collateral posted in the secondary market could be used to offset margin requirements for the auction market.

Developing a new financial derivatives market presents many challenges as well as potential benefits. Above all, the CREG must fully consider the needs of both the generators and consumers in the market and instrument design if the market is to be successful over the long term. By understanding and incorporating these needs, the CREG will ensure an active market that will not require subsidies or assistance because participants on both sides of the market will realize value through participation.