

**Report on “Proposal for Determining and Assigning the Reliability  
Charge for the Wholesale Energy Market” and “Electronic System of  
Standardized Long-Term Contracts (SEC)”**

**by**

**Frank A. Wolak  
Department of Economics  
Stanford University  
Stanford, CA 94305-6072  
wolak@zia.stanford.edu**

**March 30, 2005**

## **1. Background and Purpose of Report**

The Comisión de Regulación de Energía y Gas (CREG) has proposed a new mechanism for determining and assigning the reliability charge in the Colombian wholesale electricity market (CxC) and an electronic system of standardized long-term contracts (SEC). This report provides an economic analysis of these two proposals. As background for preparation of this report, on Dec 13 and 14 of 2004, I participated in meetings with CREG to discuss the details of both proposals. This was followed by meetings on January 24 and 25 of 2005 with wholesale market participants to understand their perspectives on these proposals. Several stakeholders submitted written comments in English during February of 2005. Comments were received from Empresas Públicas de Medellín (EPM), EMGESA, ISAGEN and ACOLGEN. On March 7 of 2005, I met individually with several stakeholders groups, specifically ACOLGEN, ACCE, ANDI, SSPD, ANDESCO and ASOCDIS. I also met with staff from the Bolsa de Valores to discuss how it handled futures trading within the context of the Colombia legal system. On March 8 of 2005, I met with CREG to present and discuss a preliminary version of this report. On March 9 of 2005, this preliminary version was discussed in a public meeting of stakeholders.

This report uses a benefit versus cost framework to assess the viability of the two proposals. Specifically, are the expected benefits associated with adopting each proposal greater than the expected cost of implementing that proposal? Because CREG has the option to retain the current market design, the relevant baseline for assessing both the costs and benefits of adopting either proposal is the current market design. While it is extremely difficult to determine the change in market and regulatory risks borne by market participants as result of adopting these proposals, a clear understanding of which market participants are likely to be significantly impacted is an important input to the process of deciding whether to adopt these proposals. A third phase of the evaluation process is determining whether there are alternative approaches for achieving CREG's stated goals for these two proposals in a manner that yields greater net benefits to market participants at a lower risk.

Although there is a clear need to revise the existing mechanism for compensating generation unit owners for supplying capacity to the Colombian wholesale market, many

aspects of the current CREG proposal argue against its implementation. Compared to the current capacity payment mechanism, it is unclear if the CREG proposal would reduce the total capacity payments by Colombian consumers or increase the likelihood that Colombian suppliers maintain and construct sufficient generation facilities to meet future demand. However, these conclusions do not imply that the current capacity payment mechanism should be maintained. There are a number of alternative approaches to maintain generation resource adequacy that should be more cost-effective for Colombian consumers and increase the likelihood that suppliers reliably meet Colombia's future energy needs. This report outlines two potential alternatives that build on the strengths of CREG CxC (CCxC) proposal and the existing capacity payment mechanism (ECxC).

The CREG's SEC proposal has the potential to improve the efficiency of Colombia's forward energy market. However, the major issue is whether any form of the SEC proposal yield benefits to market participants that are sufficient to justify the significant set-up and operating costs necessary to offer it. To this end, my report first proposes that CREG undertake a benefit-versus-cost analysis for the SEC. I then describe a minimum set of functions for the SEC that have a high likelihood of yielding benefits to market participants in excess of their set-up and operating costs. Because a major motivation for the SEC is to serve better the needs of all market participants, there are aspects of the current CREG proposal that could greatly benefit from further stakeholder input. The most significant addition recommended by a number of stakeholders is a clearinghouse within the SEC when it first begins operation. The experience of other standardized futures markets around world suggests that this is a necessary condition for a successful standardized futures and options market.

The remainder of the report proceeds as follows. In the next section, I first summarize CREG's stated objective for adopting each proposal. I then briefly describe the essential features of each proposal. The third section discusses the benefits versus costs of adopting each proposal. A major component of these discussions is a comparison of the existing market design to one with these proposals in place. The fourth section describes two alternative approaches that achieve the stated goals of the CCxC and SEC proposals while yielding greater net benefits to market participants and at

a lower risk. This section also discusses how these two alternatives would be integrated with the SEC if it was adopted.

## **2. Summary of CREG Proposals**

The Colombia market has had a capacity payment mechanism in place since January of 1997. CREG estimates that by December of 2006, Colombian consumers will have paid approximately \$US 5 billion in capacity payments (page 15, CREG-038). Assuming an average annual electricity demand over this ten-year period of 45,000 gigawatt-hours (GWh), implies an average capacity payment per megawatt-hour (MWh) of electricity consumed over this time period of approximately \$11/MWh. This per-MWh capacity charge is a substantial fraction of the average wholesale price of electricity, which provides a strong motivation for CREG exploring more cost-effective approaches to ensure future generation adequacy.

Colombia currently has an active forward market for electricity. However, it is primarily a bilateral market with limited price transparency. One reason is that bilateral markets can advantage large market participants relative to smaller ones, because larger firms are able to recover the fixed cost of engaging in the necessary research to learn the market-clearing price over a larger volume of output. This logic implies that even if the smaller firm's average cost of production is the same as the larger firm, its average total cost of production and selling in the bilateral market is higher. For example, suppose that both the large supplier and small supplier produce at an average cost of \$25/MWh and it costs each of them \$500 per month to undertake the necessary research and marketing efforts to sell their output at the highest possible price in the bilateral market. If the large firm sells 500 MWh and the small one only 100 MWh, then the small firm's average total cost is \$30/MWh versus \$26/MWh for the large firm. CREG's SEC proposal attempts to address this asymmetry in the cost of participating in forward markets by small versus large firms.

There are two potential outcomes from forming a standardized futures market. The first is the change in total research and marketing costs, including the costs of setting up and operating the standardized market. Suppose the monthly cost of setting up and operating the standardized futures market is \$800 and both the big and small firms are

each able to reduce their monthly research and marketing costs to \$80 as result of having the standardized market to trade in. This implies a reduction in total research and marketing costs of \$40, the difference between \$1000 and \$960, the monthly cost of the standardized market (\$800) and the total cost of the big and small firms participating in this market (\$160). The second effect is the re-distribution of the relative burden of total research and marketing costs as a result of forming the standardized market. In particular, suppose the standardized market is funded by a \$/MWh trading charge on suppliers. In this case, there is a total of 600 MWh = (500 MWh + 100 MWh) traded through the market and the cost of market is \$800, so the trading charge is \$1.33/MWh. This implies that the large firm would pay \$667 = (\$1.33/MWh x 500 MWh) and the small firm would pay \$133 = (\$1.33/MWh x 100 MWh) per month.

The total cost to large firm of participating in the standardized market would be \$747 = (\$667 + \$80) and the total cost to the small firm would be \$213 = (\$133 + \$80). Thus, as result of the formation of the standardized market the smaller firm would face a significantly lower cost of selling its output relative to the large firm. This would reduce the gap between the average costs of the large and small firms. In this case, the large firm's average cost of producing and marketing electricity would be \$26.50/MWh and small firm's average cost of producing and marketing electricity would be \$27.13/MWh. This \$0.63/MWh difference is significantly smaller than the \$4/MWh difference for the case of no standardized market.

Although it is certainly possible that forming a standardized futures market will reduce the total cost of all suppliers trading in the forward market, it is unclear where these overall cost savings will come from, unless the each firm is able to reduces its in-house research and marketing operations substantially because of the existence of a standardized futures market. One potential source of benefits that the SEC proposal is aimed at realizing is increased market liquidity. Selling standardized products can lead to greater liquidity—the ability to transact large volumes without significant impacts on the market price. This occurs because market participants concentrate more of their hedging activities in these standardized products rather than in specialized bilaterally negotiated hedging instruments. A more likely outcome from establishing a standardized market is

that the overall research and marketing costs (including the cost of the standardized market) will increase.

Even if these total research and marketing costs fell, depending on the mechanism used to pay for the standardized market, some market participants will pay more than they did in the absence of the standardized market. In this example, the large firm paid \$500 per month in the absence of the standardized market, whereas with the standardized market it pays \$747 per month. Substantial wealth transfers among market participants as a result of forming a standardized market are likely, even if there are no overall cost savings. These wealth transfers are likely to be the dominant impact of forming a standardized futures market. This example illustrates why there are so few standardized futures markets for electricity—the overall cost savings from forming these markets are small to non-existent and there are substantial research and marketing cost shifts among market participants which imply that some market participants will avoid trading in the standardized market. This leads to a revenue shortfall for the standardized market operator and ultimate demise of the market.

## **2.1. Capacity Payment Proposal**

CREG's stated objective for the redesign of the capacity payment mechanism is "to ensure that there is sufficient installed generation capacity to supply future demand." (page 6, CREG-0-38). CREG distinguishes two dimensions of reliability of supply: (1) safety of operation of the system, which has primarily to do with the ability of the system to respond to short-term contingencies and (2) sufficiency of supply, which corresponds to the system's ability to meet its future demand needs. CREG further states that achieving these goals requires establishing a capacity payment mechanism. As I discuss later, there are alternative approaches that are less costly to consumers than capacity payment schemes for achieving the primary goal of sufficient installed generation capacity to supply future demand.

I will now describe my understanding of the major feature of the CREG proposal. This discussion will highlight the major differences between CREG's proposed capacity payment mechanism (CCxC) and the existing one (ECxC).

The CCxC scheme has both an administratively-set component and a market-determined component. The administratively-determined component is paid based on a prospective system dispatch for a two-year period using a high-demand forecast for that period prepared by Unidad De Planeacion Minero Enegetica (UMPE). A major input into this prospective dispatch process is a monthly price supply curve for every month of the year. A discussion of the functional form of this price supply curve is given on pages 30-31 of CREG-038. Fossil fuel suppliers must also submit to CREG an estimated variable cost, expressed in \$/kWh, using the unit's primary fuel and a variable cost using a substitute fuel, if one exists. The nameplate capacity of each generation unit is deflated by its historical availability factor before it is entered into the prospective dispatch process. Extremely dry hydro conditions are assumed and the hydrology facing each generation unit is updated on a monthly basis to account for energy produced and water inflows during that month. A lower bound or minimum operating level on the unit's reservoir is also imposed in the dispatch process. If the reservoir hits this lower bound, the available capacity of the unit in the prospective dispatch is set equal to zero. Each day of the prospective dispatch period is divided into three periods—low demand, intermediate demand and peak demand.

The average generation unit-level dispatch quantities for the period December 1 to April 30 of the second year of the prospective dispatch are what CREG calls the unit's "firm energy". The period December through April is chosen to determine the MW value of firm energy for each generation unit because these months are the historical dry period in the Colombia. This generation unit-level firm energy value is multiplied by the administratively determined dollar per kW-month capacity charge to compute the monthly firm energy capacity payment for that generation unit. The current CREG proposal is to use the monthly share of the annual fixed cost recovery of a conventional gas-fired combustion turbine peaking generation unit as the level of the \$/kW-month capacity charge. The current value of this charge is \$US 5.25 per kW-month, although part of the CREG proposal is to allow this value to change over time to reflect the monthly capital recovery of a 150 MW combustion turbine facility with a 25-year life with an assumed rate-of-return that takes into account the reasonable capital costs (long-term bonds, own cost-of-capital and debt) to the firm, including country-specific risk.

There are several significant differences between this aspect of the proposed capacity payment mechanism and the existing one. First, under the ECxC it is the responsibility of CREG to determine which units operate (and how much energy they produce) under the prospective dispatch. Under the present scheme, CREG determines the opportunity cost of water, and from that information, the optimal dispatch of each hydroelectric unit for each supply period throughout the prospective dispatch scenario. Under the proposed capacity payment scheme, each unit owner submits a monthly price supply function that expresses its willingness to supply energy to the prospective dispatch. This monthly supply function then places an upper bound on the unit owner's daily bid price for that generation unit into the spot market during that month. The unit owner is free to bid less energy into the spot market than that capacity of its generation unit at or below this bound on its daily bid price. Consequently, by regulating the quantity it is willing to supply into the market the supplier can avoid selling too much energy if the price bid bound resulting from the unit's price supply function is set too low relative to the current opportunity cost of water in the system. Fossil units are also expected to submit bids into the spot market that are at or below the variable cost figure that was submitted to the prospective dispatch. However, this variable cost bound can be changed if the supplier is able to justify to CREG that its input fuel prices have increased significantly.

A second significant difference between the CxC proposal and the current capacity payment mechanism is that the ECxC compensates generation unit owners for the capacity necessary to meet the daily demand peaks through an administrative process that does rely on price supply functions submitted by hydroelectric suppliers. Specifically, the ECxC first computes the Theoretical Remunerable Capacity (CRT). The first step in this process estimates the total amount of energy that would be expected to be dispatched during the dry season under low hydrology assumptions using basic parameters of the system set by UPME and the Centro Nacional de Despacho's (CND) long-term simulation model. The unit-level values of average energy produced that result from the prospective dispatch are converted to capacity figures using a conversion factor, K. The K-factor is chosen so that sum of all values of CRT over all plants in the Colombian system equals 105% of the maximum peak demand for that

month. Generation owners are then entitled to collect capacity charges equal to this capacity figure times \$US 5.25/kW-month. In contrast, the CCxC mechanism only pays the average amount of energy produced from these units during the dry season times appropriate \$/kW-month charge.

The shortfalls in revenues to generation unit owners under the CCxC scheme relative to the ECxC scheme can be recovered through a market-based mechanism that purchases the difference between the total of the average energy supplied from each generation unit in the Colombian system during that month under the prospective dispatch and the maximum peak demand during that month. All plants and portions of plants that do not receive a payment under the firm energy capacity allocation process are eligible to participate in the auctions that procure what CREG calls “firm power capacity”. For example, suppose a 300 MW unit owner only had an average energy dispatched in the prospective dispatch of 200 MW. The unit owner would be eligible to sell 100 MW deflated by the historical average availability of the generation unit during peak hours in the firm power capacity auction.

Recall that the amount of a unit’s capacity sold as firm energy capacity is equal to the nameplate capacity of the unit times the historic average availability in all hours of the year. The following simple example clarifies this point. Suppose the  $A_1$  is the historical average availability of the unit and  $C_E$  is the average amount of energy produced during the peak months of the year in the second year of the prospective dispatch. Let  $A_2$  equal the historical average availability of the unit during the peak period of the day—hours 18 through 21. The maximum amount of capacity that the generation unit owner can bid into the firm power capacity auction is equal to

$$C_{\text{Peak}} = (A_2 * C - C_E)$$

where  $C$  is equal to the nameplate capacity of the generation unit.

Under the CCxC mechanism there will be 5 separate auctions, one for each month of the peak period from December to April. Under this auction each supplier can bid a single price and quantity pair, up to the value of  $C_{\text{Peak}}$  for that generation unit. These bids will be stacked from the lowest to the highest priced to construct a step-function aggregate supply curve. The market-clearing price for firm power will be set equal to the bid price of the highest bid price necessary meet the demand for firm power. As

discussed above, the demand for firm power is the difference between the monthly maximum peak demand in the prospective dispatch and the total amount of firm energy allocated during that month, which is equal to average amount energy produced in the Colombian system during that month in the prospective dispatch. Each generation unit owner that sells capacity in the monthly peak power capacity auction will be paid four times the product of the market-clearing price times the firm power capacity sold from that generation unit. The factor “four” is necessary to account for the fact that this firm capacity is purchased for the four peak hours of the day from hour 18 through hour 21. The monthly total capacity payment obligations of consumers is the sum of the administratively determined monthly \$/kW-month charge times the total quantity of firm energy capacity purchased during that month plus the market clearing price of firm power capacity times the total quantity of firm power capacity purchased for that month.

Under both the proposed and existing capacity payment mechanisms, these total capacity payments must be recovered through monthly wholesale energy revenues. At the start of each month, CND estimates the total amount of energy that will be dispatched. The total amount of capacity payments that must be recovered in the month is divided by this estimate of total monthly energy sales to yield a \$/MWh floor on bids into the wholesale electricity market. This bid floor ensures that wholesale energy prices will be sufficient to recover the monthly total capacity payment obligation. Because actual demand for each hour of the month is not known until after the month, bids into the spot market use a price floor based on CND’s forecast of monthly production, but settlement (payments by retailers and large customers to generation unit owners) is based on the actual production during the month.

The CREG proposal envisions a secondary capacity market for suppliers to purchase additional firm power capacity and firm energy capacity in case they are unable to meet their obligations in real-time. This secondary market will be run on a monthly basis. Those suppliers with generation capacity that was not allocated firm energy capacity in the prospective dispatch or firm power capacity in the subsequent firm power capacity auction are eligible to participate. Suppliers bid a \$/kW price and a MW quantity up to the amount of unsold capacity from the generation unit into this secondary market.

## 2.2. Electronic Standardized Contract Market Proposal

CREG's stated objective for establishing the SEC is "to provide the market with a mechanism which generates the necessary liquidity for its future development, make commercialization (retailing) more dynamic, allow(s) for progress in the sector through the use of new financial tools in accordance with agent's demands and to achieve greater benefits for the sector" (page 2, CREG-005). CREG also argues that the SEC will reduce the transactions costs associated with settling forward contracts, including the costs of resolving disagreements among market participants.

CREG proposes to trade standardized futures contracts and options contracts in the SEC for various types of energy for monthly and yearly delivery. These contracts will be differentiated according to the hours of the day that they clear against the spot market or Bolsa price. I say "clear" rather than "deliver" because the SEC contracts are purely financial in the sense that they do not require the seller to deliver energy or the buyer to consume energy. The both the futures and option contracts involve payment flows between market participants as a result of the value of PC, the contract price, and PS, the spot or Bolsa price, during the clearing hour. For a futures contract, if PC is greater than PS, then the buyer of a 1 MWh contract pays the seller of the contract ( $PC - PS$ ). If PS is greater than PC, then the seller of the contract pays the buyer of the contract ( $PS - PC$ ). Under this clearing scheme all retailers or large loads pay for all of the energy they consume at the Bolsa price and all suppliers are paid for all of the energy they produce at the Bolsa price. The combination of these spot and futures contract payment flows ensure that if the supplier produces at least the futures contract quantity and the retailer or large load consumes at least the futures contract quantity, then the generation unit owner is guaranteed to receive and the retailer or large load is guaranteed to pay the contract price for the contract quantity of energy during that hour.

To increase the likelihood that standardization of the products offered by the SEC will increase liquidity in market for spot price hedging instruments, CREG dramatically scaled back the dimensions along which it planned to differentiate the standardized contracts relative to the original SEC proposal issued in January of 2004. There will be three sets of contracts, all of which clear 7 days per week. One set will clear between the hours of 6 pm to 9 pm. A second set will clear between the hours 9 am to 10 pm. The

final set will clear during all 24 hours of the day. All contracts are for 1 MWh during all hours in which they clear, with following two exceptions. During all Saturday hours 0.95 MWh is the contract quantity. During all holiday and Sunday hours, 0.80 is relevant contract quantity.

The CREG proposal will offer put and call options that clear against these same three sets of hours for 7 days per week. These contracts will use the same quantity deflation factors for Saturdays and Sundays and holidays. One complication with issuing standardized option contracts is determining a standard strike prices for the options. The CREG proposal does not specify how the strike prices for these options will be determined. The CREG should investigate the applicability to the Colombia market of the method used by the Nord Pool financial market to set standardized options strike prices. For a description of the procedure used, see page 7 of Nord Pool (2002).

CREG also proposes to use a Yankee or American auction mechanism to trade these futures and options contracts. This is a pay-as-bid auction mechanism for selling multiple quantities of an identical item. If there are N items for sale then the winning bidders are those whose bids maximize the revenues received by the sellers. It is unclear how this auction mechanism will set the prices that market participants trade at when there are both supply and demand bids. If suppliers are paid as-bid for contract sales and retailers and large loads pay as-bid for their contract purchases, there will be a surplus that must be distributed to suppliers and demanders. CCxC mechanism does not describe how this merchandising surplus will be distributed among buyers and sellers.

The CREG proposal states that it will be mandatory for retailers to purchase their forward contracts for energy from this market. The proposal states that “the energy required to attend any end user connected to the National Interconnected System (SIN) should be acquired by the respective company providing the service using the SEC...” (page 30, CREG-005). This requirement only applies to energy purchases more than three years in advance of the clearing date. CREG proposes to allow bilateral contracts of duration greater than three years. These contracts must be standardized as a take-or-pay or option contracts so that they can be incorporated into the SEC when time to delivery on the contract becomes less than or equal to three years (page 27, CREG-039), although the CREG proposal does not describe how this will occur.

The CREG proposal will also establish the Administrator of the System of Commercial Interchanges (ASIC) as the operator of the SEC. This will require ASIC to set initial margin levels and maintenance margin levels for all market participants. The CREG proposal provides a sample initial margin computation (pages 13-14, CREG-039). A procedure for making margin calls is outlined and rules for liquidating positions if margin calls are not met is specified. All of these functions are to be carried out by ASIC without a formal clearinghouse. Instead, individual market participants appear to be required to continue to serve as counterparties to the transactions that they complete through the SEC, despite the fact that SEC is assumed to be an anonymous futures and options market trading standardized products. The costs and benefits of these conflicting goals for the proposed SEC will be discussed in detail later in this report.

### **3. Benefit versus Cost Analysis of Proposals**

When considering a market design change, it is important to have a clear statement of the overall objective of the market design process. Without an objective function for the design process it is impossible to perform a benefit versus cost analysis of a proposed change because the impact of different dimensions of the proposal cannot be compared using a common metric. For example, the proposed change may increase a variable,  $Y$ , that the policymaker values and decrease another variable,  $X$ , that the policymaker values. Without an objective function,  $V(X,Y)$ , that trades off how the policymaker values  $X$  versus  $Y$ , it is impossible to determine which policy is optimal. My metric for assessing the benefits and costs of proposed market design changes is their impact on the annual average delivered price of electricity to Colombian consumers. In terms of this objective function, the goal of the market design process is to find those market rules that lead to the lowest possible annual average delivered price of electricity consistent with the long-term financial viability of the electricity supply industry in Colombia. Included in the requirement that the market design provide for the long-term financial viability of the industry is the requirement that a pre-specified level of reliability of electricity supply be maintained. By choosing an objective function for the market design process I am able to rank market design proposals, because each proposal is a

collection of different market rules each of which has a different net impact on the annual average delivered price of electricity to Colombian consumers.

There are many possible objective functions for the market design process. The one I have chosen is generally consistent with CREG's stated objectives (summarized above) for its proposed capacity payment mechanism (CCxC) and the standardized electricity contract market (SEC). While one might argue that attempting to minimize the annual average delivered price of electricity to Colombian consumers should not be the sole objective of the market design process, it is important to bear in mind that a major motivation for electricity industry re-structuring around the world is reducing the delivered price of electricity to final consumers. Moreover, if two market designs are identical in all other dimensions, I would expect regulators in all markets around the world to choose the one that leads to the lower annual average delivered prices.

The remainder of this section will focus on a benefit versus cost analysis of the CCxC and SEC proposals in terms of their expected impact on the annual average delivered price of electricity to Colombia consumers. This discussion recognizes that a number of aspects of these proposed market rule changes will also influence the reliability of supply and therefore the likely volatility in wholesale electricity prices. The existing market design and ECxC mechanism play an important role in this discussion because they represent the base case relative to which the costs and benefits of the CCxC and SEC will be evaluated.

### **3.1. Benefits versus Costs of Existing Capacity Payment Mechanism**

The discussion of the benefits and costs of the CCxC proposal should be prefaced with a short discussion of the costs and benefits of the ECxC, because many features of the CCxC proposal are part of the ECxC mechanism.

The following question arose during the meeting with stakeholders on January 24 and 25, 2005: What benefits do Colombian consumers derive from the existing capacity payment mechanism (ECxC)? As discussed earlier, the average delivered price of electricity is significantly higher as a result of the capacity payment mechanism. A number of stakeholders argued that the major reason for a capacity payment mechanism was to insure that there was sufficient generation capacity able to produce energy to meet

demand during the extremely low hydro conditions that can occur during a severe El Nino weather condition in Colombia. Stakeholders also emphasized that the current capacity payment mechanism had yet to be tested by a severe El Nino event. Ayala and Millan (2003, p. 132) note that even the El Nino event that occurred in 1997 to 1998 revealed a number of weaknesses in ECxC. In particular, the capacity payment mechanism did not adequately compensate the units that actually contributed to system security during that time period.

Subsequent discussions during the January 25 and 26 stakeholder meetings seemed to indicate that a number of entities were skeptical that the current capacity payment mechanism was sufficient for the Colombia electricity supply industry to survive a severe El Nino event without having to resort to some emergency interventions in the wholesale market, including demand rationing. This skepticism seems well-founded given the rules governing the operation of the ECxC. In particular, suppliers receive a fixed payment each month—the product of \$US 5.25/kW-month and the MW value of CRT for each generation unit they own. Regardless of how much, if any, energy is actually produced by the units, the ECxC mechanism pays unit owners for the value of CRT that emerges from the prospective market simulations performed by CND. Actual system conditions in the future could be very different from what is input into the simulation used to compute the value of the CRT for each generation unit. Input fuel prices, hydro conditions, the availability of that generation unit and other generation units in the system, and the configuration of the transmission network could all change in a manner makes this unit unable to deliver its electricity to final consumers. Except for the availability of the generation unit, all of these factors are outside of the control of the unit owner. This implies that all generation unit owners that receive a capacity payment have a number of valid reasons why their generation units are unable to provide the energy and capacity implied by the prospective dispatch. Consequently, the ECxC does not provide a firm contractual obligation for a supplier to provide any energy and certainly not the amount implied by the sum of the MW values of CRT across all of its generation units.

CREG has attempted to implement penalties for non-compliance with their capacity obligations for suppliers that receive capacity payments. However, it is extremely difficult, if not impossible, to determine if the reason a unit is unable to

provide the energy implied by its value of CRT is because of actions it can control or actions outside of its control. CREG requires generation units receiving capacity payments to bid into the spot market if they are able to provide energy. How much energy the unit owner has available to produce and the appropriate bid price for this energy are magnitudes that are difficult for the regulator to determine. For this reason it is difficult to determine how a hydro supplier awarded a specific value of CRT should be penalized if it does not provide the total amount of energy implied by this value of CRT during the peak months of the year. There are number of reasons why it may be unable to do so. For example, it may not have enough water behind the dam (because of El Nino weather conditions) to provide this energy or the transmission network may be congested so that the supplier cannot deliver its energy to final consumers, despite bids into the spot market that demonstrate a willingness to do so.

Selling capacity under both the ECxC and CCxC requires the unit owner to bid its unit into the spot market, if it is available to provide energy, at or below \$US 125/MWh, the first step in the administratively set rationing cost curve. Requiring suppliers to bid into the spot market if they are available is worth very little to consumers, because unit owners still have considerable discretion to withhold energy from the spot market. It is impossible for the regulator to determine whether a plant is truly able to operate and at what level it is available to operate. This is one lesson learned from the events in the California electricity market from June 2000 to June 2001 when over the four month period from January 2001 to April of 2001 the average hourly value of generation capacity declared unable to operate averaged approximately one-quarter of the installed generation capacity in the California ISO control area. Wolak (2003) discusses how this problem of verifying the true availability of generation units contributed to the cost of California electricity crisis.

Requiring suppliers to bid into the spot market at or below \$US 125/MWh is of very little value consumers under most system conditions, if a large fraction of final demand is covered by forward financial contracts for energy between suppliers and load-serving entities and large consumers. Under these conditions, a supplier would not expect to increase its profits by being able to submit a bid price above this rationing cost, because this bid would have very small likelihood of being accepted. In addition, if

this bid were accepted, it would yield a market price that would cause suppliers that are short relative to their forward contract obligations to make large payments to the load-serving entities that had purchased the other side of these fixed-price forward contracts, so that consumers would experience little harm from these high prices. Finally, if severe El Nino conditions arose, requiring suppliers to bid at or below this level would set spot prices that do not reflect the opportunity cost of water and may therefore increase the likelihood of rationing in future periods. With an active demand side of the wholesale market, allowing suppliers to bid above this level will set prices that would cause a sufficient reduction in demand to eliminate the need to ration electricity in future periods.

The above discussion illustrates why some stakeholders are skeptical that Colombian consumers have received tangible reliability benefits from the existing capacity payment scheme. The ECxC provides no contractual guarantee that a supplier receiving a given capacity payment for each of its generation units will ultimately inject the amount of energy implied by the value of CRT for each of these units. Moreover, even if the supplier does inject this amount energy into the system during the peak months of the year (either from units that it owns or through purchases from other suppliers), there is no contractual guarantee this energy will be injected during the hours when the CND needs this energy to maintain system reliability.

Another shortcoming of capacity payment schemes such as the ECxC and CCxC is that they pay suppliers for having generation capacity in the ground, not for the energy they produce or are likely to produce. Viewed from this perspective, it is not hard to determine if a supplier has not provided the product purchased—installed generation capacity. However, this perspective also makes it difficult to understand how this capacity payment mechanism provides the best possible signal for investment in new generation capacity. First, the ECxC does not pay suppliers to build new generation capacity. It only pays suppliers with existing generation capacity. Second, owners of existing generation capacity receive a capacity payment that is proportional to the total MWs of CRT they are allocated in the prospective dispatch. The higher value of CRT, the higher capacity payment a supplier will receive. If a generator is allocated a zero value of CRT for one of its units, it does not receive a capacity payment under the ECxC.

Despite these shortcomings, the ECxC and the CCxC, to a lesser extent, encourage suppliers to construct generation units that receive high values of CRT relative to their installed capacity. However, the question remains as to whether or not this generation capacity is actually needed to serve future demand or it displaces high cost generation units that are equally effective at meeting demand in the dispatch process which then leads to excess generation capacity that may depress spot electricity prices. To understand how this capacity payment mechanism leads to excess generation investment, consider the following example. Suppose there are two types of generation units: peaking units and base load units. The cost function for base load units is  $C_1(q) = F_1 + c_1q$  and the cost function for peaking units is  $C_2(q) = F_2 + c_2q$ , where  $F_1 > F_2$  and  $c_1 < c_2$ . Because of the lower variable cost of operation, a base load unit is likely to be awarded a higher value of CRT for same amount of nameplate capacity as a peaking unit. This implies more capacity payments for the base load unit relative to the peaking unit. Consequently, even though a small peaking unit may be a lower-cost solution to meet the forecast increase in annual electricity demand for the Colombian system, the difference in capacity payments to the base load unit and the higher level of variable profits (revenues minus variable costs) that the base load unit earns from selling energy at the market-clearing may be sufficient to cause it to be more profitable for a supplier to construct a larger base load unit rather than the smaller peaking generation unit. This unilateral incentive of entrants to favor base load units caused by both the ECxC and CCxC will encourage over-capacity and an inefficient mix of installed generation capacity to meet the annual load duration curve.

This incentive to install the inappropriate mix of generation capacity can even impact existing generation units. An existing 100 MW combustion turbine (CT) generation unit may have a variable cost that is too high for it to be dispatched for much energy in the prospective dispatch. However, this generation capacity is less expensive to construct than a 100 MW combined-cycle gas turbine (CCGT) facility with a significantly lower heat rate. The CCGT facility will receive a significantly higher CRT value in the prospective dispatch. This higher CRT could yield capacity payments that make it profit-maximizing for the supplier to convert its CT unit to a 100 MW CCGT unit, even though a 100 MW CT is the least-cost way to meet this future energy

requirement. Moreover, the 100 MW CT may have a higher availability factor than the CCGT unit, so that the investment in the CCGT technology caused by the ECxC and CCxC may lead to a reduction in the reliability of supply in addition to higher costs to Colombian consumers.

This inappropriate mix of generation facilities caused by both the ECxC and CCxC can raise average spot energy prices relative to what they would be in system with the least cost mix of generation capacity. Because of the bias towards the construction of generation units that have high values of CRT, this mechanism can lead to a pattern of spot prices throughout the year with a significant number periods when the spot price is slightly lower than the level it would be with the least-cost mix of generation capacity. In the remaining higher demand hours of the year, the spot price will be significantly higher than it would be with a lower cost mix of generation capacity. If these spot prices are sufficiently high, the combination of these two effects can lead to higher average spot prices for the year. Even if the annual average price doesn't increase, prices within the year should be more volatile than would be the case with the least-cost mix of generation capacity to serve demand.

The reliance of the ECxC and CCxC on the prospective dispatch to determine all or some of the capacity payments received by each generation unit owner creates an additional source of risk faced by a supplier. This is the risk that its generation units will be displaced in the prospective dispatch by new generation capacity or existing generation capacity that reduces its variable cost. As noted above, an existing CT unit could invest in necessary equipment to convert to CCGT capacity in order to earn a higher total capacity payment under either the ECxC or CCxC. Because all generation unit owners have the option to sell their capacity in the firm capacity auction under the CCxC, the risk associated with the prospective dispatch is greater for the ECxC than the CCxC. Consequently, for generation capacity unlikely to supply any energy in the prospective dispatch, the overall capacity payment risk associated with ECxC is greater than that associated with the CCxC.

The incentives that suppliers have to exercise unilateral market power in the spot market is unaffected by existence of the ECxC or the CCxC. In particular, for the same amount of total generation capacity in the control area, distribution of ownership of this

generation capacity among suppliers, and the levels of fixed-price forward contracting for energy for each market participant, suppliers in a market with capacity payments have the same incentives to exercise unilateral market power in the spot market as those in a market without capacity payments. Because ECxC and CCxC payments are fixed monthly payments for installed generation capacity, they do not impact the profit-maximizing bidding behavior of suppliers in the spot energy market. Consequently, these capacity payments alone do not limit the ability of suppliers to exercise unilateral market power in the spot market, except to the extent that they provide additional financial incentives for suppliers to build new generation capacity. This logic once again raises the question of what are benefits that Colombian consumers realize from capacity payments to suppliers.

Fixed-price forward contracts for energy signed between suppliers and retailers provide significant market power mitigation benefits to the spot market for energy. As discussed in detail in Wolak (2000), the amount of fixed-price forward contracts for energy that a supplier has sold significantly limits its incentive to bid to raise the spot price. Unless the supplier sells more energy in the spot market than its forward contract obligation during that hour, it has an extremely strong incentive to take actions to reduce, rather than increase the market-clearing price of energy in the spot market. Specifically, until the supplier covers its forward contract position, it is a net buyer of energy from the spot market and has a strong incentive to take actions that keep wholesale prices as low as possible. Consequently, a market with the same amount of generation capacity and distribution of ownership of this capacity will have lower average spot prices and significantly less volatile spot prices, the larger is the fraction of each supplier's generation capacity that has been sold in a fixed-price forward contract for energy.

This discussion leads to the following conclusions about the existing capacity payment mechanism. First, it provides very little protection against the sorts of adverse system conditions that would significantly degrade the ability of the system to meet its future load obligations—specifically, severe El Nino weather conditions. Second, it provides no contractual guarantee that the CRT quantity awarded in the prospective market simulations performed by the CND will actually inject the required amount of energy when it is needed. Third, imposing the requirement to bid into the market if

available on generation units that receive capacity payments provides limited benefits to consumers because of the extreme difficulty in verifying whether a supplier is truly available to provide a given amount of energy. Fourth, the ECxC and CCxC provide only indirect incentive for suppliers to construct new generation capacity and a strong incentive to construct the inappropriate amount and mix of generation capacity necessary to serve demand. Fifth, the prospective dispatch subjects suppliers to changes in their capacity payment revenue stream that may bear little relation to changes in their contribution to system security. Finally, the presence of the ECxC or CCxC alone does not limit the incentive of suppliers to exercise unilateral market power in the spot market for energy.

### **3.1. Benefits versus Costs of CCxC**

The CCxC mechanism also has all of the above shortcomings and benefits of the ECxC. The two major differences between it and the existing scheme can be thought of as attempts to reduce the delivered price of electricity to final consumers. However, there are substantial reliability risks in the short term and long term associated with these proposed changes. The increased long-term risks result from the CCxC paying only for firm energy through an administrative process and purchasing firm power through an auction mechanism. The increased short-term reliability risk results from the fact that the price supply curves submitted by hydroelectric generation unit owners and the variable cost curves submitted by fossil fuel generation unit owners to the prospective dispatch are strict upper bounds on bid prices that these suppliers can submit to the spot market.

#### **3.1.1. Long Term Reliability Costs of CCxC**

The increased long-term reliability risk associated with the CCxC is caused by the fact that the price paid for firm power depends on the bids of market participants. This creates additional uncertainty in the revenues generation unit owners can expect from capacity payments. This also creates the equivalent amount of uncertainty in the capacity payment obligation of Colombian consumers. It is unclear whether or not total annual capacity payments will be higher or lower under the CCxC, but the volatility in total annual capacity payments across years will be significantly higher. This is because it is extremely difficult to run a competitive market for installed capacity. The demand

for firm power capacity is completely inelastic and the total supply of generation capacity that can provide firm power is fixed. This creates circumstances where one or more suppliers of firm power can be pivotal. A supplier is pivotal if some of its capacity is needed to meet demand regardless of the supply decisions of its competitors. Under this circumstance, there is no limit to the price that a pivotal supplier can bid and still have some of its capacity taken to meet demand. This implies that there no limit to the market-clearing price for firm power if one or more suppliers is pivotal.

To understand this point, consider the following example. Suppose the demand for firm power is 2000 MW and there are 6 suppliers, five of which each have 350 MW of firm power to sell and one which has 600 MW to sell. The supplier that has 600 MW to sell is pivotal, because regardless of the bid prices of the other five suppliers, at least 250 MW ( $=2000 \text{ MW} - 5 \times 350 \text{ MW}$ ) of its capacity is needed to meet the demand for firm power. If this supplier knows that it is pivotal, then its profit-maximizing bid price has no limit, which implies that the market-clearing price for firm power also has no limit. In this case, only the large supplier is pivotal, because performing this same calculation for any of the other five firms implies that the market demand of 2000 MW can be served by the remaining four firms with 350 MW to sell and the large firm with 600 MW to sell.

This concern about the firm power auction being subject to extreme amounts of unilateral market power is much more than a theoretical possibility. Assuming that the results of the prospective dispatch used to allocate firm energy is publicly available, it is relatively straightforward for all generation owners to determine how much capacity each of its competitors has leftover to sell in the firm power auction. Assuming the demand for firm power is made public before the auction, each generation unit owner can perform the above calculations to determine whether it is pivotal before submitting its bid to the auction for firm power. Even if market participants are uncertain about the demand for firm power and amount of capacity each of their competitors can sell, they should be able to obtain fairly precise estimates of these magnitudes and the degree of uncertainty in these estimates. Consequently, it is very likely that without a cap on the maximum bid into the firm power auction, there will be circumstances when the market-clearing price for firm power is extremely high. Given the concentration of generation ownership in

Colombia and annual pattern of electricity demand, these circumstances should occur with a high probability during the months of December to April.

Because the marginal cost of supplying an additional MW of firm power capacity (given that a supplier has an additional MW available to sell) is equal zero, there are also likely to be system conditions when the market-clearing price for firm power is close zero. This can occur when there is significantly more total capacity available to sell than the demand for capacity and none of the suppliers is close to being pivotal to serve this demand. Returning to our previous example, if the demand for firm power is 1000 MW then it is extremely likely that market-clearing price for firm power will be close to zero. The logic underlying this statement is that each supplier knows that its competitors have significantly more capacity to sell than the market demand, which implies that unless each supplier bids very close to its marginal cost of supplying an additional MW of firm power capacity, it will not sell any firm capacity. This logic implies that all suppliers have a strong incentive bid very close to zero, the marginal cost of supplying an additional MW of firm power from its installed generation capacity, which should yield a market-clearing price very close to zero.

These two examples imply that the market-clearing price from the firm power auction is likely to be extremely volatile, ranging from very close to zero to the maximum possible bid price, depending on the aggregate supply of capacity available to sell firm power relative to the aggregate demand for firm power and the number of pivotal suppliers. These examples imply that no clear predictions are possible about whether the total amount of capacity payments received by generation unit owners will increase under the CxC proposal. My best estimate is that these capacity payments are likely to rise over time, because the Colombian market currently has significantly more generation capacity installed than is currently needed to meet its peak power needs. However, demand is likely to grow over time and the probability that at least one supplier is pivotal in firm power auction should increase so that average price emerging from the firm power auctions are likely to increase. Because these high firm power prices are the result of the exercise of unilateral market power by suppliers bidding into the firm power auction, rather than true scarcity of installed generation capacity, suppliers will have less of an incentive to construct new generation capacity to bid into the firm power auction.

The incentive to invest in new capacity is reduced because these suppliers know that increased competition to supply firm power (that results from building new generation capacity) is likely to cause firm power prices that are extremely close to zero by the logic described above.

Consequently, my overall conclusion is that the firm power auction will increase the volatility of total capacity payments. Initially, this aspect of the CCxC proposal will most likely result in lower total annual capacity payments to Colombian generation unit owners relative to the ECxC, which should imply lower average delivered prices of electricity to Colombian consumers. However, over time both the volatility and level of annual capacity payments is likely to become larger than total annual capacity payments under the ECxC.

### **3.1.1. Short Term Reliability Costs of CCxC**

The short term reliability cost of the CCxC arises from the requirement that hydro suppliers submit price bids into the spot market that are less than the relevant point on the price supply function (for the amount of water the supplier currently has behind its turbines) submitted to the prospective dispatch used to determine firm energy quantities. Fossil fuel suppliers are required to submit price bids into the spot market that are less than or equal to the variable cost they bid into the prospective dispatch. Both of these constraints on bid functions into the spot market can result in an extremely inefficient dispatch of generation facilities. Alternatively, this requirement causes suppliers to submit price supply functions and variable costs bid into the prospective dispatch that are severely distorted from the supplier's true willingness to provide energy.

Suppliers can be expected to submit price supply functions that provide significantly less energy to the prospective dispatch at a given price than they are truly able to provide because it is expected profit-maximizing to sell less firm energy capacity in order to have more capacity available to sell firm power capacity and to preserve sufficient flexibility to bid high prices into the spot market for energy. All of these actions have the potential to increase wholesale energy costs to consumers relative to a scheme that does not impose these constraints.

In those instances when a hydro supplier's price supply function constrains its bid prices into spot market, this restriction can increase the cost of that supplier managing its water level. Specifically, if the opportunity cost of water during an hour is higher than the cap on that supplier's price bid, it must manage usage water by setting the maximum amount of energy it is willing to sell into the market during than hour, rather than by bidding its opportunity cost of water and making all of its capacity available to the market. A similar logic applies to fossil fuel units that would find it unilateral profit-maximizing to bid higher than the variable cost they bid into the prospective dispatch. Consequently, restrictions on the bid prices of both fossil fuel and hydro suppliers can cause them to offer less capacity into the market in order to raise the spot price to the level they believe equals the current opportunity cost of water in Colombia. This incentive to withhold energy from the spot market can also have short-term reliability consequences, because it reduces the ability of the system operator to meet demand under all possible system contingencies.

Because suppliers have a strong incentive to preserve the flexibility to bid higher prices in the spot market, their bids into the prospective dispatch are likely to lead to a dispatch of generation units that is very different from what would occur in the spot market. This will lead to a dramatically different mix of generation units selling firm energy capacity from the mix of units that subsequently sell energy in the spot market. This logic implies that many of the units that sell firm power capacity or sell neither firm energy nor firm power capacity will be selling energy in spot market, which exactly contradicts the results of the prospective dispatch. This can have both short-term and long-term reliability consequences. In the short-term, the system operator will gain very little useful information about the actual dispatch from the prospective dispatch used to determine generation unit-level firm energy amounts. In long-term, the distribution of capacity payments among generation unit owners should enhance the incentives for an inefficient mix of generation capacity and excess investment in generation capacity.

### **3.1.3. Conclusions from Analysis of CCxC**

In summary, although these bid caps on prices into the spot market are designed to limit ability of suppliers to exercise market power in the spot market and thereby

reduce the average delivered prices to consumers, they are unlikely to be effective because suppliers will account for these restrictions on their bids into the spot market when formulating their bids into the prospective dispatch. Even with these upper bounds on their bid prices, suppliers still have the ability to limit the amount of energy they are willing to supply at this bid price. Consequently, suppliers will have an increased incentive to withhold generation capacity from the spot market as a way to achieve their unilateral profit-maximizing prices for energy. This is likely to lead to more volatile spot prices and a less reliable supply of wholesale electricity, without an accompanying reduction in the average spot price of electricity. For these reasons, imposing these requirements on hydroelectric and fossil-fuel supplier bids into the spot market does not appear to be in the interest of consumers or suppliers.

### **3.2. Benefits versus Costs of Proposed SEC**

The major challenge associated with justifying the existence of the SEC is the fact that any private entrepreneur could have set up such a market during the almost ten years that the Colombian wholesale electricity market has been in operation. Clearly, all market participants would derive some benefits from the existence of the SEC. However, the crucial issue is whether the total benefits all market participants receive are sufficient to justify the non-trivial costs of establishing and operating the SEC.

The fact that no privately-owned profit-maximizing company chose to establish a SEC implies that the sum of the benefits that market participants derive from the existence of a centralized futures and options market is unlikely to be greater than the total cost of establishing and operating such a market. This logic implies that any argument in favor of establishing a standardized futures and options market based on a benefit versus cost analysis must demonstrate the existence of a benefit from such a market that cannot be captured without the government mandating the existence of such a market. This benefit must also be sufficiently large to overcome the apparent negative net benefits from a private entrepreneur operating the SEC. The sum of the private benefits and benefits from the government mandate must exceed the cost of setting up and operating the SEC, in order for its existence to reduce the delivered price of electricity to Colombian consumers.

### **3.2.1. Regulatory Benefits of Proposed SEC**

One source of benefits from the government mandating the existence of the SEC is that it can improve the effectiveness of CREG's regulatory activities. A potential benefit to the regulatory process that could justify the existence of the SEC results from using the futures and options prices from this market to set the wholesale prices that vertically integrated retailers and other load-serving entities are able to charge their regulated retail customers. During the initial meeting with CREG on December 13-14, 2004, it was noted that CREG finds it challenging to set retail rates for the regulated customers of vertically-integrated retailers that can withstand political scrutiny, because of the difficulty CREG has in determining the appropriate wholesale price of energy that should be included in the retailer's price to its regulated consumers. A suitably chosen portfolio of futures and options prices from the SEC could be used to construct a wholesale price index that would then be used to set this regulated retail price. This price index should be easier for CREG to defend in the political arena because it is set through an anonymous auction process that is open to all suppliers, retailers, and traders. These prices could therefore be defended as the collective best estimate by all market participants of the future spot price of electricity given the information available at the time the futures or option price was set.

Although these prices are set through an anonymous auction mechanism, this does not mean that they would not be subject to the attempts of suppliers to exercise unilateral market power. However, the attempts of a supplier to exercise unilateral market power would be disciplined by the bidding behavior of all other Colombian suppliers and potentially all Colombian retailers if they are able to submit price-responsive demand bids into this market, rather than the attempts of single buyer to limit the price paid in a bilateral negotiation.

It is unclear whether purchases through a standardized market such as the SEC versus bilateral negotiations will lead to lower delivered prices to consumers. There is large literature in economics studying the efficiency properties of bilateral markets versus centralized markets. The overall conclusion is that centralized markets favor low cost and small suppliers and high willingness to pay and small demanders, because both of these parties capture greater net benefits from transacting through a centralized uniform-

price market (see Hall and Rust (2003)). Although there are no general theoretical results demonstrating which market mechanism leads to lower average prices, there are several of experimental economics studies that have found that centralized markets yield greater net benefits to buyers and sellers and lower average prices than bilaterally negotiated markets (see Rassenti, Smith and Wilson (2003)).

The regulatory benefits from government provision of the SEC argue in favor of changing the proposed auction mechanism to a uniform market-clearing price rather than a pay as-bid process. This will make computing price indexes based on SEC prices more straightforward than would be the case if averages or weighted averages of pay-as bid prices were used to compute these indexes. Under a uniform price auction, there would be a single price set for all contracts traded for same product. This uniform price could be determined from the intersection of the aggregate supply bid curve and the aggregate demand bid curve for each product auctioned. If the experimental economics results discussed above carry over to the Colombian electricity market, then implementing a uniform price auction for the SEC could lead to lower average prices than currently proposed pay as-bid design.

An index of futures and options prices from the SEC could also be used to construct a risk-sharing regulatory mechanism to provide incentives for retailers to make their total energy purchases from forward and spot markets in a least cost manner. For example, the monthly wholesale energy costs that a retailer is allowed to recover from its retail customers could be set equal to a target price times the total amount of wholesale energy purchased in that month. The hourly value of this target price could be set equal to a weighted sum of the index of SEC futures and options prices and the spot market price for that hour. With this revenue cap on amount of money the retailer can recover from its regulated customers, the retailer will have a strong incentive to procure the portfolio of wholesale electricity used to serve its regulated customers in a least-cost manner.

### **3.2.2. Benefit versus Cost Test for Government-Mandated SEC**

Recognizing the benefits from the Colombian government mandating the existence of the SEC still leaves unanswered the question of whether the net benefits of

the SEC are positive. Any estimate of the impact of the SEC on the average delivered price of electricity to Colombian consumers is uncertain. One way to address this issue is to allow market participants to compute this estimate. This is accomplished by requiring market participants to recover the costs of setting up and operating the SEC within the existing retail rate structure, rather than recovering these costs as a pass-through on all retail electricity bills.

Assume for simplicity that input fuel and labor costs are constant. If the government mandating the existence of the SEC would lead to lower delivered prices of electricity to Colombian consumers, then it should be possible to keep average retail rates at their current level and require all market participants in the aggregate pay for the cost setting up and operating the SEC without a reduction in the total profits earned by market participants. Offering the SEC under these terms and conditions faces market participants with the appropriate benefit versus cost calculation. Rather than see only possible benefits from existence of the SEC, market participants will now also see the expected costs they will have to pay for its existence.

This mechanism also provides strong incentives for CREG to design a SEC that has the greatest likelihood of realizing positive net benefits if it is adopted. If CREG proposes a SEC that is too costly, market participants can be expected reject it because they are unable pay for it within the existing retail rate structure. This mechanism also provides strong incentives for CREG to design a rate structure for trading in the SEC that allocates the costs of setting up and operating the SEC in a manner that generates the greatest net benefits from its existence.

Moreover, if market participants decide that the SEC has positive net benefits then this mechanism provides strong incentives for them to realize these net benefits through staff reductions and other actions to reduce their own marketing and trading costs more than the costs they will pay for activities in the SEC. In contrast, if costs of the SEC are recovered as a pass-through on all retail electricity bills, market participants have less of a financial incentive to take actions to reduce their marketing and trading costs.

For all of these reasons, I would recommend that the SEC only be adopted if the costs of setting up and operating it are recovered within the existing retail rate structure.

It is contrary to my market design objective to establish the SEC, if doing so increases the average delivered price of electricity to Colombian consumers. This would imply that Colombian consumers are pay more for their electricity, so that suppliers and retailers can earn increased profits, which seems contrary to CREG's regulatory mandate to protect Colombian consumers.

### **3.2.3. Mandatory Participation in Proposed SEC**

CREG proposes to make participation in the SEC mandatory in the sense that all hedging of less than three years in advance must be done using products sold through the SEC. Besides the legal problems associated with enforcing this prohibition discussed in a number of the written stakeholder comments and in oral comments made during the January 2005 stakeholder meeting, there are other reasons why such a prohibition should not be adopted by CREG. First, it is important bear in mind that it is practically impossible to prohibit bilateral trading outside of the standardized market. For example, despite the existence of the New York Stock Exchange (NYSE), two people can trade shares of common stock listed on the NYSE. The US government and the NYSE does not try to limit such transactions, however these two parties do provide the same guarantees for this bilateral transaction that are available for trades through the NYSE.

By this logic, attempting to prohibit all bilateral energy transactions outside of the SEC would result in endless legal disputes over what constitutes a violation of this prohibition. As has become extremely clear from the Enron bankruptcy and energy company bankruptcies in the United States, there are many ways to unwind a given financial transaction to disguise its true intent. Market participants can always find financial products to buy and sell that mimic the payoffs of a bilateral energy transaction. For example, two market participants could arrange a flow payment that depends on the spot price of electricity during a number of hours of the day and the level of output of certain generation units during those hours. This payment flow could be designed to replicate exactly the terms and conditions of payments flow between buyers and sellers of bilateral energy contracts even though no party formally bought or sold electricity. This simple example illustrates the extremely difficult challenges that CREG will face if it attempts to make participation in the SEC mandatory.

A second reason not to make transacting in the SEC mandatory is that it may unnecessarily increase the delivered price of electricity to final consumers. For example, if there is a beneficial transaction to consumers than could be done more inexpensively outside of the SEC, forcing this transaction into the SEC will increase cost of the transaction and ultimately the delivered price of electricity to consumers. As noted earlier, if the SEC uses a uniform price auction to set the market price, then this mechanism will allow smaller market participants to avoid paying the costs of marketing and research necessary to estimate the market-clearing price for their bilateral transactions. Instead, they can simply bid their true willingness to supply energy or true willingness to pay for energy and receive or pay the resulting uniform market-clearing price. Consequently, there is likely to be a demand for the services that the SEC provides by a number of market participants for some fraction of their total energy needs without a mandatory participation requirement. This will attract other suppliers and retailers to the SEC.

A third reason not to make the SEC mandatory is that doing so will make it a *de facto* monopoly provider of hedging products. State-sanctioned monopolies have little incentive to produce at minimum cost and little incentive to provide the diversity and quality of products that market participants desire, because retailers and large loads wishing to hedge their spot price risk must purchase SEC's products. If the SEC faces competition from bilateral transactions, it will have a strong incentive to limit the fees it charges for transacting in its markets and provide the range of products and services that customers demand at least cost. Alternatively, if CREG makes participation in the SEC mandatory, it must also undertake a significant regulatory and monitoring effort to ensure that the SEC's operating costs are kept as low as possible and that customers' needs are being served by the products and services that the SEC offers. Because regulation and monitoring is not costless, making the market mandatory should account for this additional regulatory oversight cost to consumers, which can be largely avoided if participation in the SEC is not mandatory.

A final argument against making the SEC mandatory is the fact that no other electricity futures market in the world makes hedging in their financial market mandatory. Even the Nord Pool futures market, the largest electricity futures market in

world relative to the size of the electricity demand that it ultimately served, only clears a small fraction of the total amount of energy produced in the Nord Pool region. For 2003, Nord Pool estimates that approximately 31% of the forward contracts cleared in the Nord Pool are contracts from Nord Pool's financial markets (Nord Pool, 2004a). Other standardized electricity futures markets only clear a very small fraction of the total amount of energy ultimately consumed. For example, the New York Mercantile Exchange's (NYMEX) PJM (Pennsylvania, New Jersey, Maryland, and parts of Delaware and Virginia) futures market price only clears a trivial fraction of the total amount of energy consumed in the PJM control area. During the first three years of the California market, the California Power (CalPX) was primarily a mandatory day-ahead forward market for the large retailers associated with California's three investor-owned utilities—Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric. The CalPX established a standardized forward contract market called the “block forwards” market in the first half 1999. The largest outstanding position in this market at any time during its existence was less than 5% of total California demand.

The international experience with standardized futures and options markets for electricity suggests that it is virtually impossible to set up a voluntary market that trades a significant fraction of the energy ultimately delivered in the wholesale electricity market. The experience also supports the conclusion that it is extremely difficult to run a standardized futures and options market that is able to recover its set up and operating costs from its trading charges. A number of countries around the world with well-functioning wholesale electricity markets have had private entrepreneurs set up standardized futures and options market. A few of these standardized markets have captured sufficient trading volume to remain financially viable, but a large number of have gone out of business or continue survive because of implicit or explicit subsidies from the government.

This outcome should not be surprising given the small number of goods and services that are traded through standardized markets. Virtually all goods and services bought and sold by firms and consumers are traded through bilateral markets. With voluntary participation, a standardized market must offer both buyers and sellers a superior service to what either them are able to obtain from the bilateral market.

Otherwise, the unsatisfied party to the transaction will not participate in the standardized market. This fact explains why there are so financially viable standardized markets. Either buyers or sellers are able to find more favorable terms on the bilateral market for a significant amount of their transactions.

This logic also suggests that the net benefits of SEC are likely to be negative, even after accounting for the regulatory benefits of mandated government provision. The SEC design that has highest probability of positive benefits should focus on offering only those products that maximize the regulatory benefits of mandated government provision and leave the provision of all other products and services to the bilateral market. This should result in a SEC that has a very low start-up and operating costs. However, both of these costs should still be recovered from the fees charges to electricity market participants with no changes in the existing regulatory rate structure. As noted above, this will provide the strongest possible incentives for market participants to reduce their internal marketing and research costs and for the management of the SEC operate its standardized markets at least cost.

Despite my strong aversion to making the SEC mandatory and my skepticism that it will provide positive net benefits to Colombian consumers, if CREG decides to move forward with the SEC, during the initial stages of this market there should be minimum participation requirements on all market participants. For example, retailers and free consumers could be required to hold a total quantity of SEC contracts that is greater than or equal to some fraction of their total energy consumption during the month. Each month ASIC could verify their SEC contract holdings for that month and report this information to CREG. Penalties could then be assessed for under-participation in the SEC.

The argument for minimum participation requirements is that during the initial stages of the market there will be many aspects of the SEC rules that will need to be fine-tuned. If participation in the early stages is completely voluntary then some market participants may not trade in the SEC because they believe that certain aspects of the market are poorly designed and therefore higher cost to use relative to the bilateral market. By having a significant volume of transactions at the start of the SEC, the process of learning what aspects of the market are working well and what aspects are not

will take place more quickly. In addition, with significant trading volume from the start of the SEC, far more problems are likely to be uncovered relative to the case of voluntary trading in the SEC and the smaller average trading volumes that result. Starting with minimum initial levels of participation from all market participants appears to provide the best balance of protecting market participants from the costs of potential flaws in the initial design and capturing the benefits of large trading volumes in terms of their ability to uncover and correct market design flaws.

#### **3.2.4. Diversity of Products Offered in Proposed SEC**

The SEC proposal released in June of 2004 (CREG-039) describes a significantly smaller number of futures and options products than were described in the January 2004 SEC proposal (CREG-005). However, it would still be worthwhile to perform a detailed cost versus benefits analysis of each of the products offered in the SEC, because I am skeptical, for the reasons described above, that many products will pass the positive net benefits test of reducing average delivered prices of Colombian consumers.

There are several of reasons why a very small number of products should be offered in the SEC. First, by offering so many different products, there is a substantial risk that the market for individual products will become extremely thin, which will significantly reduce the potential benefits from establishing a centralized futures and options market. Second, many complex hedging instruments can be constructed from combinations of a small number of futures and options. For example, a market participant wishing to purchase year-long hedge against spot prices for 100 MW can purchase 12 monthly contracts. Third, suppliers and retailers always have the option to sign specialized bilateral hedging instruments to manage risks that cannot be easily hedged in the standardized market. This is another argument in favor of not making participation in the SEC mandatory. Market participants can manage a significant fraction of their spot price risk through purchases of small number of standardized hedging instruments sold through the SEC. The remaining idiosyncratic spot price risks faced by a retailer, free customer, or supplier can be hedged through bilateral agreements made outside of the SEC.

As emphasized earlier, the benefits versus cost analysis of whether to offer a product in the SEC should focus on maximizing the net benefits that this product can provide to market participants through the regulatory process. A major source of the benefits to consumers from the SEC is the regulatory transparency and credibility that prices from this market provide. For this reason, the products offered in the SEC should be designed to achieve this goal. This implies focusing on a very small number of standardized products that are likely to be demanded in significant volume by as many market participants as possible. This would imply focusing on a standardized monthly product for a few of types of energy, such as base load and intermediate load energy.

A couple of monthly options contracts could be offered to hedge peak period spot price risk. This mix of futures and options contracts should allow market participants to hedge the majority of their spot price risk, yet still leave a role for bilateral contracting arrangements. This minimalist approach to the SEC keeps the start-up and operating costs of the SEC as low as possible to maximize the likelihood that consumers receive benefits from its existence that are in excess of these costs. The Nord Pool experience is instructive on this issue. When Nord Pool first started its financial futures market three types of energy futures contracts were offered, peak-load, off-peak load and base load contracts. During the 1993-1994 time period, peak load and off-peak contracts were removed from exchange trading due to low trading activity and in an attempt to increase volume in the base load contracts (Nord Pool, 2004b). Given that both the Nord Pool and the Colombia are hydroelectric dominated systems, it may make sense for the SEC to focus only on base load contracts during the initial stage of the market. If offering this product cannot be shown to yield positive net benefits, then it makes very little economic sense to offer other futures contracts and options contracts.

### **3.2.5. The Role of a Clearinghouse in Proposed SEC**

CREG has made substantial progress in improving the settlement and margin processes in the SEC between the January 2004 document and the June 2004 document. The June 2004 document (CREG-039) proposed a procedure for setting an initial margin for a futures contract, a process for setting the maintenance margin, and a procedure for making margin calls and liquidating the positions of those market participants unable to

meet their margin requirements. Requiring margins and managing margin requirements is crucial to the proper functioning of a centralized futures market. In particular, without margin requirements and a process for managing them, market participants whose forward market position is significantly different from the spot price at the time the contract is cleared could decide not to deliver on the contract. For example, if a supplier has sold a retailer a fixed price forward contract for delivery at \$25/MWh and the spot price at delivery is \$40/MWh, unless the supplier stands a chance of losing a significant amount of money in its margin account, the supplier may decide to default on its contract and sell its output in the spot market for a significantly higher profit.

As Duffie (1989, p. 58) notes, “At the heart of futures markets procedures is the system of collateral margins that has evolved as a means to reduce default risks.” The current CREG proposal does not have an important safeguard against default risk that is common to virtually all standardized futures and options markets currently operating—a clearinghouse. As Williams (1986, p. 10) notes, “Modern clearinghouses are concerned not only with the offsetting of contracts, but also with the collecting and disbursing of margin.” For this reason, it seems extremely prudent for CREG to include in the SEC proposal a provision for a clearinghouse. Williams (1986, p. 14) also states

For much of the early history of futures exchanges, if a party became bankrupt the person with whom he contracted absorbed any loss left unprotected by margin. Beginning in the 1920s, however, the clearing associations of the major exchanges accepted the responsibility, often unwillingly, of collecting margins and interposing themselves as a party to the trades. Hence, they became responsible for the performance of contracts made between their members. In today’s market, even though two members contract between themselves, the identity of the opposite party is lost as soon as the clearinghouse receives notice from them of the transactions after the close of trading. Once the clearinghouse processes the transaction, the long is responsible to the clearinghouse for margin and for accepting delivery, while the short is responsible to the clearinghouse for margin and making delivery.

The fact that this role of the clearinghouse have evolved over almost 100 years of operation of formal futures and options markets suggests that it is an essential element of an efficient market.

Having the clearinghouse as the counter-party to any contract that is bought or sold further enhances the anonymity of transactions through the SEC. This also makes it possible to tailor the necessary margin a market participant must hold to its net position in futures and options contracts and its overall financial health. Without a clearinghouse that each market participant deals with, it is be very difficult to require different margin levels for different market participants without disclosing the identity of the market participants holding the other side of the future or option contract. In particular, if a seller is told that its counterparty must post a larger than average security deposit and margin percentage, the seller can infer that it is dealing with a market participant with a higher default risk. This disclosure destroys many of the benefits of anonymous trading and can limit the market efficiency benefits of a centralized market.

A second major role of the clearinghouse is to determine the net outstanding position of each type of contracts at the close of each trading day. Williams (1986, p. 8) describes an early example of the functioning of a clearinghouse:

...at the close of business each day, every member of the clearinghouse submitted a list of his transactions. The clearinghouse combined these lists into a grand roster, which it presented each morning to the clerks of the member firms, who met together in a "settling room." Aided by this grand roster, the clerk of the house with a bought contract not yet offset looked for the clerk of the firm that had sold it. The clerk, in turn, was looking for a clerk representing a firm from which his firm had bought. This search expanded until the original buyer was found to have sold to someone on the circuit, at which point the ring was complete. The clerks would then mutually cancel the trades or "ring out the deals." All differences would be paid in reference to an official settlement price, as posted by a committee of the exchange during the day.

In modern futures markets, participants electronically submit a list of transactions to the clearinghouse and it pays or asks for the balance due on all of the transactions of its members. Consequently, all market participants deal with the clearinghouse, not

individual market participants. Because market participants will want to hold margin levels based on their net, rather than gross, futures and options positions, unless there is some entity that can compute and verify its net position, this will not be possible.

This function of the clearinghouse is another source of potential benefits from the SEC. Market participants can realize tangible savings in financing costs if they are only required to provide margin on their net position in the futures contracts and options rather than on the sum of their bilateral positions. For example, suppose that a market participant A has two bilateral positions with market participants B and C, each of which exactly cancels the other. For example, the market participant A could have bought a futures contract from market participant B and sold it at a higher price to market participant C. With a clearinghouse, this would be recognized as the market participant A having a zero net position and it would not be required to hold any margin. However, if the purchase and sale were bilateral transactions, each trading partner would want market participant A to post margin to ensure compliance with its contractual obligations. The SEC, with anonymous trading and a clearinghouse function, has the potential to allow all market participants to incur lower financing costs for their forward market transactions that would be the case if these took place through bilateral markets.

Another benefit of the SEC with a clearinghouse function is that it has the potential to distinguish between differences in forward contract prices that retailers and large customers are able to obtain due to differences in credit risk from price differences due to differences in the unilateral market power that a supplier is able to exercise in a specific supplier and buyer interaction. During the public meetings with stakeholders, several market participants complained that less credit-worthy buyers must pay higher prices for bilateral contracts for future deliveries of electricity than more credit-worthy buyers. One explanation for this is that the supplier is incorporating the increased risk of non-payment into the price it offers the less credit-worthy buyer. Another explanation is that suppliers are exercising unilateral market power when they sell at higher prices, because they are exploiting the fact that there are fewer suppliers willing to sell to the less credit-worthy buyers.

Because the SEC is an anonymous market, it has the potential to eliminate this second mechanism that may cause less credit-worthy buyers to pay higher prices for

future electricity deliveries. Suppliers selling futures contracts in a SEC with a clearinghouse deal transact with the clearinghouse. Buyer purchasing futures contracts also transact with the clearinghouse. The clearinghouse has no financial interest in enhancing the ability of suppliers or buyers to exercise unilateral market power, because it recognizes that both the buyer and seller must benefit from trading in the SEC or the transaction will not occur. Its primary concern is making sure that default does not occur. The clearinghouse accomplishes this by managing the initial margin and charges in margin levels of market participants based on their credit risk. Consequently, a less credit-worthy market participant will find that the clearinghouse requires greater margin levels to prevent default relative to a more credit-worthy market participant. However, both the buyer and seller interact with the clearinghouse so there is no way for a seller to exploit differentially its unilateral market power on the basis of the credit risk of its counterparty. Instead, both the buyer and sell bid into the anonymous market and transact at the uniform market-clearing price with the clearinghouse. The clearinghouse individually manages the default risk of each market participant.

Because of these potential benefits from a clearinghouse function in the SEC and the reduction in default risk that a clearinghouse provides, CREG should have a clearinghouse function in the SEC from the start. Rather than incur the initial expense of a formal clearinghouse for all market participants from the start, a preferable starting strategy would be to have two tiers of market participants in the SEC, primary traders and secondary traders. Primary traders would be required to satisfy stringent set of credit requirements. All primary traders would jointly manage and operate the clearinghouse function for their benefit. Secondary traders are the market participants that are unable to satisfy these stringent credit requirements. They would be required to have primary traders transact on their behalf in the SEC. Competition among primary traders would discipline the credit risk premium these secondary traders would have to pay to transact in the SEC. Secondary traders could become primary traders when they are able to meet the credit requirements of primary traders. This two tiered system of traders would address the competing needs of a clearinghouse function and the ability to tailor margin requirements and other financing costs to the credit risk of individual market participants without requiring the significant fixed cost of a formal clearinghouse for all market

participants. This process could be delayed until sufficient net benefits from the existence of the SEC had been demonstrated to justify this investment.

### **3.2.6. Conclusions from Analysis of Proposed SEC**

The major conclusions from my analysis of the SEC proposal are summarized below. First, a more detailed cost versus benefits study of the SEC should be undertaken before it is implemented given that no private entrepreneurs have found it profitable to start a standardized futures and options market for the Colombian electricity supply industry in its eight years of operation. This suggests that the private benefits from the market do not exceed the costs of starting and operating the market. Consequently, any argument to justify the SEC should be based on the benefits that it can provide to the regulatory process or other sources of benefits that cannot be captured unless the government mandates the existence of this market.

Unless the existence of the SEC yields positive net benefits, establishing it can only increase the delivered price electricity to Colombian consumers. To ensure that this does not occur, the SEC should only be implemented with two pre-conditions. First, the revenues needed to recover all of the start-up and operating costs associated with the SEC must be recovered from the fees charged to market participants for transacting in the SEC. Second, market participants must be required to recover the costs of participating in the SEC within the context of the existing regulatory rate structure. These costs should not be recovered as a pass-through to final consumers, or market participants will have little incentives to take the actions necessary to realize the net benefits to consumers from the existence of the SEC.

If the SEC is found to have positive net benefits, the set of products offered by the SEC should be dramatically reduced to focus on capturing the major source of benefits—improving the transparency and credibility of CREG’s regulatory activities. With this in mind, the SEC should start by offering a monthly base load energy futures contract and only proceed to offer other futures and options products if it is able to cover the costs of operating the SEC from revenues transactions in the base load energy futures contract. The SEC should also implement a uniform market-clearing price auction rather than the pay as-bid scheme in the current proposal. This should increase the liquidity and value

that many market participants derive the existence of the SEC and increase the regulatory credibility of prices that it produces.

Participation in the SEC should not be mandatory, although CREG should require retailers to hedge a minimum fraction of their demand with standardized futures and options contracts from the SEC during the initial stages of the operation of the market. Finally, the SEC should establish a clearinghouse function so that all parties will contract with the clearinghouse and it will manage margin requirements for individual market participants based on their financial health and liquidate positions in the SEC in the event that a market participant fails to meet these requirements. While it not necessary to establish a formal clearinghouse at the start of the market, a formal clearinghouse function does appear to be necessary for the ultimate success of the SEC.

#### **4. Two Alternatives to CCxC Proposal**

There are two possible approaches to achieving the goals of the CCxC proposal that have a greater likelihood of yielding lower delivered prices to Colombian consumers with less risk to system reliability than the CCxC and ECxC. The first proposal retains many features of the ECxC and CCxC mechanisms by paying generation owners for their installed capacity based on the results of a prospective dispatch using CND's estimates of the variable cost of fossil fuel units and the opportunity cost of water for hydroelectric units. This scheme modifies the characteristics of the capacity obligation purchased from generation unit owners receiving capacity payments to increase its system reliability value to Colombian consumers. This modification also establishes secondary market for this new capacity product. This scheme is designed to make minimal changes in the ECxC mechanism yet achieve a significantly higher level of system reliability at the same total capacity costs to Colombian consumers.

The second alternative is designed to transition to a wholesale market where suppliers recover their total fixed and variable costs from selling energy and reserves in the forward and short-term markets without an administratively determined capacity payment. This mechanism provides a contractual guarantee to consumers against the high short-term prices and demand rationing that may accompany a severe El Nino event.

This mechanism has the greatest likelihood of yielding significant net benefits to Colombian consumers from wholesale electricity competition.

The mechanism initially promises suppliers the same total capacity payments as the ECxC. It gradually phases out this guaranteed income stream set through an administrative process and requires to suppliers to earn their revenues through forward and spot energy sales. This mechanism converts the ECxC into a product that fosters development of a liquid market for forward financial contracts for energy that suppliers can trade among themselves. If it is adopted, the SEC can be an important component of this liquid forward market for energy.

#### **4.1. Available Capacity (AC) Obligation**

The primary goal of this modification of the ECxC is to create an available capacity (AC) obligation for suppliers that receive capacity payments. The value of CRT for each generation unit would continue to be determined from the prospective dispatch process run by CND. For each supplier there would be a new concept called the, PCRT, or portfolio value of CRT, which is equal to the total MWs of CRT allocated to that supplier for a given month over all of the generation units that it owns. Each generation unit owner would continue to receive total payments equal to the unit's CRT value times the \$US 5.25/kW-month capacity charge.

The primary difference between the AC obligation and the ECxC is that each supplier would be obligated to ensure that every hour of the day the number of MWs of capacity that it bids, or has other suppliers bid on its behalf, into the spot market at or below the first step on the rationing cost curve equals or exceeds the value of PCRT. For example, supplier A, with a 500 MW value of PCRT and 1000 MW of generation capacity, would be required to bid into the spot market every hour of every day at least 500 MW from its generation units. If enough of these generation units are unavailable, this supplier would have to find additional MWs of generation capacity to bid into the spot market that was not meeting another supplier's PCRT obligations. This supplier would also have to tell CND before the close the day-ahead market which generation units are meeting its AC obligations during that hour. For example, suppose that only 400 MW of the supplier A's capacity is available to bid into the spot market because of

forced or planned outages. Supplier A would then have to find 100 MW of capacity from other generation units in Colombia that are not meeting the PCRT requirement for any other supplier. For example, suppose supplier B owns 800 MW and has PRCT value of 400 MW. If supplier A is able to convince supplier B to bid an additional 100 MW into the spot market at or below the rationing cost and designate it as meeting supplier A's AC obligation for that hour, then supplier A has met its 500 MW AC obligation, despite only bidding in 400 MW of its own capacity. In this example, if supplier B bids in at least 500 MW it has met its AC obligation and the 100 MW AC obligation it provides on behalf of supplier A, because it only needed to bid in 400 MW to meet its own AC obligation.

If a supplier fails to have its entire PCRT value in MWs bid into the spot market, then it is liable for a penalty equal to the shortfall times that highest step on rationing cost curve of approximately \$US 1/kWh. In this example, if supplier A failed arrange the additional 100 MW from supplier B, it would be liable for a \$1000/MWh\*100 MW penalty for that hour. This penalty scheme provides strong incentives for suppliers to meet their AC obligations each hour. It also creates a rationale for a secondary market price for unallocated generation capacity to meet an AC obligation. In this example, I would expect supplier B to receive a payment from supplier A for bidding in 100 MW of its generation capacity to meet supplier A's AC obligation.

This AC obligation has the following reliability advantages relative to the ECxC. First, it provides a financial guarantee that CND will have total generation capacity bid into the spot market at or below the lowest price on the rationing cost curve that is at least equal to the sum of the values of CRT across all generation units in Colombia every hour during that month. Meeting the contractual obligations of this scheme implies that if demand in the month never exceeds the total MWs of CRT across all units in Colombia, then there will always be adequate supply bid into the market below the rationing cost available to meet demand. This mechanism implies the following implicit contract between a supplier and final consumers: In exchange for the total monthly capacity payments associated with that supplier's value of PCRT, the supplier ensures that at least that many MWs (not meeting the AC obligation of other suppliers) are bid into the spot market during all hours of the month.

Suppliers in the aggregate continue to receive the same amount of capacity payments as they did under the ECxC. The costs of any purchases from other suppliers to meet their AC requirements during a given hour must be paid by the individual supplier, because the AC requirement is for all hours of the month and does not excuse a supplier with forced or planned outages. If a supplier has insufficient available capacity from its own units, it must find other Colombia suppliers with used capacity to bid into the spot market on its behalf to meet its AC obligation. The market power of one supplier in the secondary market AC obligation capacity is borne by the suppliers purchasing AC obligation capacity from this market, not final consumers. This should not be a chronic problem because one supplier is unlikely to be consistently on the buying or selling side in this secondary market. Different from the CCxC scheme where market power in the firm power capacity auction translates into higher capacity payments by consumers, the AC obligation pays each supplier a fixed amount and in exchange requires that the total MWs bid into the spot market during each hour of the month on that supplier's behalf to equal or exceed that supplier's value of PCRT.

An additional advantage of this scheme is that it is possible to modify the process of determining the value of CRT for each generation unit so that the sum of all values of CRT across all units in the system can be equal to a larger value if the CNDC determines that it needs more generation capacity available to bid into the spot market each hour. The reliability improvement from AC obligation results from the fact that it provides a contractual guarantee that a minimum total amount of generation capacity will be available to serve demand each hour of the day. In contrast, the ECxC sets a capacity payment and hopes that sufficient capacity will be bid into the market. Under the AC obligation suppliers have a firm financial commitment to bid a certain minimum MWs of capacity that is not committed to meet the AC obligation of any other supplier into the spot market at or below the rationing cost each hour of the day.

The logic behind the regulator picking a total amount of capacity that must bid in each hour rather than setting a \$/kW-month capacity payment and hoping that sufficient capacity to meet demand will bid into the spot market is based on Figure 1. This diagram graphs a supply curve for new generation capacity as a very flat line. This is generally thought to be the case because an enormous number of new natural gas-fired generation

units can be constructed at virtually the same marginal and average total cost. This diagram also graphs the demand curve for new generation capacity. This demand curve is typically thought to be extremely inelastic for the same reasons that electricity demand is extremely inelastic. Consumers in the aggregate have a very high willingness to pay for enough generation capacity to prevent energy shortfalls.

For these supply and demand curves for new generation capacity it is less risky for the regulator to set the level of desired capacity that must be bid in, rather than the level of the capacity price. As shown in Figure 1, if the regulator sets the capacity price 100\*ε% percent too high or too low, the amount of new capacity that will be build is very far away from the optimal amount new capacity equal to  $Q_e$  in the figure. Setting the capacity price at  $(1+\epsilon)P_e$ , slightly above the equilibrium price,  $P_e$ , yields a significantly higher capacity of  $Q_e^{\text{High}}$ . Setting the capacity price at  $(1-\epsilon)P_e$ , slightly below the equilibrium price, yields a significantly lower capacity of  $Q_e^{\text{Low}}$ .

Another reason for the regulator to set the level of capacity that must bid in is that for many years the electricity supply industry was a vertically-integrated utility that set the amount of available capacity necessary to serve demand. Consequently, the regulator and the system operator have significant experience with setting the level of available generation capacity that it is confident will lead to a reliable supply of electricity, and very little experience with determining the level of the capacity payment that will lead the necessary amount of available capacity for a reliable supply of electricity each hour of the day. As Figure 1 illustrates, the risks of setting the wrong capacity payment can be large, either in terms of the excess capacity or a capacity shortfall.

The AC obligation provides a contractual guarantee that the total supply in the spot market bid in at or below the cost of rationing is always greater than the total demand for energy. This is accomplished through the following four key features of the AC obligation: (1) determine the total amount of capacity that must be bid in each hour to reliably meet demand during each hour of the month, (2) use the prospective dispatch process to assign values of CRT to each generation unit so that the sum of these CRT values across all units equals the desired total amount of capacity that must be bid in, (3) make monthly AC obligation payments based on the value of CRT for each generation unit and the \$US 5.25/kW-month charge, (4) require all suppliers to ensure that at least as

many MWs of generation capacity as their value of PCRT is bid into spot market (from their own units or on their behalf) each hour of the month or the supplier must pay a \$US 1000/MW charge for each MW of available capacity that it fails to have bid into the spot market.

## **4.2. Transition to Forward Contracts for Energy**

One complaint against capacity markets and capacity payment schemes is that suppliers receive payments for essentially doing nothing besides existing, because the generation unit has already been installed, yet the owner receives a payment for something that causes it and all firms with installed capacity to incur no costs. Existing generation unit owners are being paid for something that they would do even if they did not receive a capacity payment—own a generation unit that is connected to Colombian transmission network able to supply electricity to Colombian consumers. The available capacity proposal in the previous section partially addressed this criticism by requiring suppliers to bid into the spot market a total MWs of generation capacity each hour that equals or exceeds their PCRT value. If the generation capacity bid into the spot market is actually able to produce electricity, this obligation guarantees that demand will be served at a price that is below the first step on the rationing cost curve. This provides an increased level of system reliability relative to the ECxC. However, electricity consumers still receive very little protection from extremely high energy prices in exchange for their capacity payment.

The argument that electricity consumers receive limited benefits from capacity payment schemes is particularly persuasive for a hydroelectric-based system such as Colombia, where the major reliability worry is whether there will be sufficient water behind the dams to serve demand, rather than enough generation capacity to serve the demand peaks. Every wholesale electricity market in the world that has experienced rationing periods, including California and New Zealand, are hydroelectric dominated. Consequently, the focus on capacity adequacy in hydroelectric based systems seems to be a misguided, because by far the most important reliability worry is energy shortfalls.

My second alternative mechanism addresses both the reliability and economic risks of energy shortfalls, yet maintains an initial connection to the ECxC. This proposal

transitions to a wholesale market without a capacity payment scheme. Instead, the market would rely on high levels of forward contracting for energy at delivery horizons of at least three years for ensuring an adequate supply of energy. Because wholesale electricity prices are likely to be very low if forward contracting for energy scheme was adopted at the present time, some transition period is required to allow electricity demand to grow into the current amount of installed capacity.

This scheme would first convert the ECxC into a fixed price cap option contract of the following form. Suppliers would initially receive the same monthly capacity payments as they did under the ECxC. The prospective dispatch of the ECxC would still be used to determine the value of firm energy (FE) produced by each generation unit and the associated value of CRT for that unit each month. In exchange for receiving the \$US 5.25/kW-month payment per MW of CRT for the month for each generation unit owned, the supplier would be required to make the following payments to consumers each month:

$$\text{Max}(0, P(\text{avg}) - P(\text{bench})) * \text{FE} * (\text{number of hours in the month}),$$

where  $P(\text{avg})$  is the average hourly Bolsa price for the month and  $P(\text{bench})$  is the average hourly Bolsa price for that month over the previous five years or for any representative year or number of years determined by CREG.  $P(\text{bench})$  could also be an administratively set monthly price that reflects the minimum level of economic reliability of supply mandated by CREG. This payment obligation implies that if the average Bolsa price for the month is less than the benchmark Bolsa price for that month, then the unit owner receives the full capacity payment for that month for each generation unit. To the extent that the actual average price exceeds this benchmark price, the unit owner must compensate consumers through payments equal to this average price difference times the number of MW of firm energy allocated to that unit times the number of hours in the month. The total monthly cap option payments made by all Colombian suppliers would be credited to consumers based on their monthly consumption of electricity. Specifically, each consumer would receive a \$/MWh credit on their electricity bill equal the total cap option payments during the month divided by total electricity consumption during the month.

The logic behind this cap option mechanism is that system reliability has an economic component in the sense that reliable supply also implies an acceptable upper bound on the average price for the month. Consequently, this mechanism provides strong incentives for suppliers to bid and operate their generation units to keep the average Bolsa price for the month below this benchmark price. This mechanism rewards suppliers with the full capacity payment for the month if they maintain the benchmark level of economic reliability of supply. Despite providing strong incentive to maintain economic reliability on a system-wide basis, this mechanism does not limit the incentive of individual suppliers to sell as much energy as possible in the highest priced hours of the month.

To transition from an administrative capacity charge to a forward contracts for energy wholesale market, each year the values of CRT and FE that emerge from the prospective dispatch would be deflated by a factor,  $f_i$ , to determine the amount of the monthly fixed payment to unit owner and its monthly cap option payment obligation. This factor would be fixed for the entire year and take on a value between zero and 1, that becomes smaller the larger the value of  $i$  and eventually equals zero, specifically  $1 = f_1 > f_2 > \dots > f_k = 0$ . Each month during the year, the supplier would receive  $f_i$  times the value of CRT multiplied by \$US 5.25/kW-month in exchange for the monthly payment obligation:

$$\text{Max}(0, P(\text{avg}) - P(\text{bench})) * FE * f_i * (\text{number of hours in the month}).$$

This implies that each year the supplier would receive a smaller and smaller total capacity payment for each generation unit, but its monthly payment obligation would shrink according to this same factor,  $f_i$ . As this capacity payment mechanism phases out, suppliers would be free sell this energy in the spot market or through bilateral contracts or standardized contracts traded in the SEC (if it exists). The value of  $f_i$  in the first year would equal one and the value in the final year of the transition would equal zero. A five year transition period from  $f_1 = 1$  to  $f_k = 0$  seems sufficient to allow suppliers and load-serving entities and large consumers sufficient time to make the transition. A five-year transition scheme would imply  $f_2 = 0.75$ ,  $f_3 = 0.50$ ,  $f_4 = 0.25$ , and  $f_5 = 0.00$ .

Throughout this transition period CREG would also have to set minimum set portfolio standards for hedging short-term energy purchases by the load-serving entities

and large consumers. These market participants would be required to meet these standards or face financial penalties. These minimum standards would need to increase as the values of  $f_i$  increase. Eventually, these minimum requirements would eventually set fixed price forward contract coverage of final demand through either swap or cap option contracts for delivery horizons up to at least three years into the future in order to provide adequate insurance against El Niño events.

For example, CREG might require that 1 year from delivery 90 percent of final demand must be covered by a fixed price forward contract and the remaining 10 percent must be covered by cap contracts with some maximum average strike price. At longer horizons to delivery this 90 percent from swap contracts could be reduced and the 10 percent from cap contracts could be increased. For example, at 2-year delivery horizon final demand must have at least 80 percent coverage in swap contracts and 20 percent in cap option contracts, and at a 3-year delivery horizon these numbers could be 70 percent and 30 percent.

To the extent that the retailer has customer paying the real-time price for their electricity consumption, these portfolio hedging standards can be relaxed. However, given the extreme risk of energy shortfalls in the Colombian market due to possibility of extreme El Niño events, CREG must maintain stringent minimum levels of forward contract coverage of final demand at delivery horizons ranging up to 3 years. Shorter delivery horizons face the risk that load could be hedged one or two years in advance but because of an extreme El Niño event, during the third year into the future rationing cannot be avoided because load did not buy a sufficient amount of energy for delivery far enough in advance for suppliers to make the necessary plans to provide it.

One might argue that requiring retailers to purchase their energy needs this far in advance could result in over-procurement because retailers often lose customers. The potential for retailers to lose customers certainly exists. However, this argument fails to recognize that if a retailer loses a customer, the customer typically continues to consume electricity. This implies that an active secondary market for these swap and cap contracts should develop, so that retailers that lose customers can sell these contracts and options, and those that have gained customers can purchase the necessary hedges against spot price risk. The SEC (if it is implemented) can play a major role in fostering liquidity in

this secondary market and in standardizing these swap contract and cap option contracts. By the logic discussed in Section 3, the SEC has the potential to reduce the financing and transactions costs associated with buying and selling these hedging instruments.

## **5. Concluding Comments**

Capacity payments mechanisms are extremely expensive ways to attempt to achieve capacity adequacy in wholesale electricity markets. As I noted during my presentation to the stakeholders in January 2005, there are much lower cost and less risky approaches available. There has also been very little success with capacity payment schemes and capacity markets internationally. The best performing wholesale electricity markets are those with an active forward market for energy and no formal capacity market or capacity payment mechanism. Capacity payment mechanisms provide no guarantee that adequate capacity to meet demand in the future will be built. As noted earlier, both the ECxC and CCxC only promise suppliers a capacity payment if they build generation capacity. For the ECxC, and to some extent for the CCxC, once built, this generation capacity must receive a non-zero firm energy allocation in the prospective dispatch to receive a non-zero capacity payment.

This report has presented two recommended modifications of the ECxC that provide a contractual guarantee of increased grid reliability and a reduced probability of rationing under a severe El Nino event. The first approach maintains the existing capacity payment mechanism and focuses on ensuring reliable supply without regard to the spot price of electricity. The second approach insures a reliable supply and limits the exposure of consumers to the extremely spot high prices that often accompany El Nino events. This approach transitions to an only-energy wholesale market, which is the market design that has yielded the greatest consumer benefits internationally in the United Kingdom, Australia and the Nordic countries.

The key to the success of this market design is to buy the necessary energy far enough in advance of delivery to allow suppliers the maximum flexibility to meet these future obligations at least cost and to limit the ability of suppliers to exercise market power in the short term energy markets.

Given Colombia's hydro dependence, concentrating on ensuring future energy adequacy, rather than constructing generation capacity, appears to be the best possible

way to guard against future rationing events or periods of extremely high spot prices. Key to this transition is CREG setting minimum standards for hedging of spot price risk by load-serving entities and large consumers. This approach can also allow active demand-side participation in the spot market, which can yield significant reliability and economic benefits.

The formation of a standardized futures and options market such as the SEC can provide significant benefits within this proposed energy-only market design. However, CREG should not to recover the costs of implementing the SEC in a manner that dulls the incentive for market participant to take actions that result in Colombian consumers realizing net benefits from the existence of the SEC. Given the very small number of surviving standardized futures and options markets for electricity around the world, it seems prudent for CREG to start with a limited SEC that focuses on realizing the regulatory benefits from its existence. Market participants should be required to pay for all of the costs of the SEC within the existing regulatory rate structure. Once this initial net benefits test for the SEC has been met, CREG could then consider expanding the number of products and services that it offers.

## References

- Ayala, Ulpiano and Millan Jaime (2003) “Colombia: Coping with the Reform Crisis,” in Jaime Millan and Nils Henrik von der Fehr (editors), *Keeping Lights On: Power Sector Reform in Latin America*, Johns Hopkins University Press, Baltimore, MD.
- CREG-005, “Electronic System of Standardized Long-Term Contracts—(SEC),” Document-005, January 16, 2004.
- CREG-038, “Proposal for Determining and Assigning the Reliability Charge on the Wholesale Market, Document-038, June 25, 2004.
- Duffie, Darrell (1989) *Futures Markets*, Prentice-Hall, Inc: Englewood Cliffs, New Jersey.
- CREG-039, “Electronic System of Standardized Long-Term Contracts—(SEC),” Document-039, January 16, 2004.
- Hall, George and Rust, John (2003) “Middle Men and Market Makers: A Theory of Competitive Exchange,” *Journal of Political Economy*, Vol. 111(2), 353-403.
- Nord Pool (2002) Options, April.(available from (<http://www.nordpool.no>)).
- Nord Pool (2004a) Clearing Services offered by Nord Pool Clearing, April (available from <http://www.nordpool.no>)
- Nord Pool (2004b) Trade at Nord Pool’s Financial Market, April (available from <http://www.nordpool.no>)
- Rassenti, Stephen J., Smith, Vernon L., and Wilson, Bart J. (2003) “Discriminatory Price Auctions in Electricity Markets: Low Volatility at the Expense of Price Levels,” *Journal of Regulatory Economics*, Vol. 23(2), pp. 109-128.
- Williams, Jeffrey (1986) *The Economic Function of Futures Markets*, Cambridge University Press: New York, NY.
- Wolak, Frank A. (2000) “An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market, *International Economic Journal*, Summer 2000, 1-40.
- Wolak, Frank A. (2003) “Diagnosing the California Electricity Crisis, *The Electricity Journal*, August/September 2003, 11-37.

Figure 1: Setting Capacity Quantities versus Capacity Prices

