Report on Monitoring Competition in the Central American Electricity Market

by

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1. Introduction

This report responds to the Terms of Reference (TOR) attached to the end of this document as an appendix. The objective of the TOR is "to identify an action plan for activities to be undertaken by the CRIE [Central American Electricity Regulator] in order to design and put in place the necessary mechanisms for the surveillance of competition in the MER [Central American Regional Market]. In doing so, the consultant will make an appraisal of the state of competition in individual existing markets and the MER as it has been proposed." This project is comprised of the following three activities: (1) review of the existing documents on the MER, (2) a field trip to the headquarters of the CRIE and Central American Regional Market Operator (EOR) in San Salvador to discuss the workings of these institutions and the details SIEPAC project, and (3) the preparation of an action plan for market monitoring for the CRIE that will foster a competitive Central American regional market.

My visits to El Salvador on August 11 to 13, 2003 and Guatemala on August 13-15, 2003 form the basis for the analysis of the state competition in the Central American electricity market and the proposed action plan for monitoring the MER given below. During the El Salvador visit, I met with the consultants working for the Unidad Ejecutora (Executing Unit) of the SIEPAC project, the regulator of the El Salvador electricity market, representatives from the EOR, and staff from the El Salvador Ministry of Economy. In Guatemala I met with staff and one Director from CRIE, staff from the Guatemala electricity regulator (CNEE), staff from the Guatemala market operator (AMM). I made a presentation on measuring and mitigating market power in wholesale electricity markets in El Salvador and a presentation market design and monitoring to control market power in wholesale electricity markets in Guatemala.

This report will first discuss the role of electricity market monitoring in limiting the ability of market participants to engage in behavior that degrades system reliability and market efficiency I will first describe the three basic roles of the market monitor and how these should be carried out. The third section will focus on problems specific to monitoring electricity markets in Central American countries. The defining features of these markets are: (1) small peak demand, (2) a small number of competitors, (3) limited transfer capacity across the markets, (3) no indigenous fossil fuel sources, and (4) little legal foundation for regulatory oversight and competition policy. Examples from the El Salvador and Guatemala electricity markets will be used to illustrate a number of these points. This section also describes details of the operation of the wholesale markets in each of these countries and of the operation of the MER to needed to characterize the market monitoring challenges facing Central American countries and the regional market.

The fourth section addresses the difficulties associated with monitoring an international regional market, such as the MER. A useful analogy can be drawn from United States (US) experience with interstate market monitoring, where differences in market structures, typically vertically integrated regulated-monopoly versus wholesale market, across states can cause the unilateral profit-maximizing actions of certain market participants to yield outcomes that are harmful to market efficiency and system reliability throughout interstate market. This section argues that similar outcomes are likely under the current Central American Regional market design. Using lessons from the US experience, recommended changes in the Central American Regional market design are provided and a proposed market monitoring plan is given for this modified regional market design.

The final section summarizes two action plans for market monitoring in the MER. The first assumes that the MER it is a separate from the six country-level markets, which appears to be the working assumption of the CRIE and country-level regulatory bodies. Although this assumption may be plausible given the current capacities of the transmission inter-connections between the six Central American countries, my experience with regional markets in other parts of the world suggests that this assumption is likely to be invalid for the inter-connections between countries that will exist after the SIEPAC line is put into operation. For this reason I propose second action plan that recognizes the possibilities for arbitrage across country-specific markets and the MER. This action plan provides recommendations for the distribution of responsibilities among the various country-level and regional regulatory agencies. This section also provides a recommended implementation sequence for this market monitoring plan.

2. Monitoring and Mitigating Market Power

There are three basic roles of the electricity market monitoring process: (1) disseminating information to existing and prospective market participants, (2) ensuring compliance with the market rules, and (3) protecting against behavior that degrades market efficiency and system reliability. Successfully fulfilling each role requires much greater regulatory authority and sophistication on the part of the market monitoring process than the previous one. Consequently, the optimal market monitoring process is crucially dependent of the initial conditions in the industry or country, although there are minimal requirements that must exist in any market. I will first describe these minimal requirements and then discuss the tradeoffs that the market monitors and regulators face as a result of initial conditions in the industry and the existing legal or political environment in the country.

2.1. Information Collection and Dissemination

A minimal requirement of any market monitoring process is to provide "intelligent sunshine" regulation. This means that the market monitor must have access to all information needed to operate the market and be able to perform analyses of this data and release the results to the public. At the most basic level, the market monitor should be able to replicate market-clearing prices and quantities given the bids submitted by market participants, total demand and other information about system conditions to ensure that the market is operated in a manner consistent with what is written in the market rules. To the extent that the market monitor is able to perform more sophisticated analyses of market performance, this aspect of the market monitoring process can be more valuable. There should be no limitation on the market monitor's access to data either submitted to the system operator by market participants or produced by the system operator.

Besides all of the information needed to operate the energy and ancillary services markets and the transmission network, the market monitor should also have the ability to request information from market participants on a confidential basis to perform further analyses. This can be accomplished through provisions in the agreement that each market participant must sign to be able to take part in the wholesale market. As a pre-condition to participate in the market, all entities should be required to provide information to the market monitor.

The market monitor should be subject to an economic cost-benefit test on its data requests. The market monitor must be able demonstrate with a reasonable degree of certainty that the expected benefit to the entire market from obtaining this data exceeds the cost it imposes on the market participant providing it. The type of information all suppliers should be required to provide is the heat rate and variable operating and maintenance costs for all of the generation units they own. The market monitor might also request information on the forward contract sales of a specific market participant.

Rather than have ex ante limitation on the type of data it can request, the market monitor should have open-ended authority to request information subject to the economic cost-benefit test described above. To enforce this authority, the market monitor should also have the ability to penalize market participants for failing to provide the requested data in a reasonable period of time. This penalty provision should be written into the agreement that each market participant must sign in order to take part in the wholesale market.

Access to all bids, schedules, production, and market outcomes and the ability to request and receive data from market participants in a timely manner is the minimal data collection authority necessary for an effective market monitoring process.

Wholesale markets that currently exist around the world differ considerably in terms of amount of data they make publicly available and the lag between the date the data is created and the date it is released to the public. Nevertheless, among the industrialized countries there appears to be a positive correlation between the extent to which data submitted or produced by the system operator is made publicly available and how well the wholesale market operates. For example, the Australian electricity market makes all data on bids and unit-level dispatch publicly available the next day. Australia's National Electricity Market Management Company (NEMMCO) posts this information by market participant name on its website. The Australian electricity market is generally acknowledged to be one of the best performing re-structured electricity markets in the world (Wolak, 1999). On the other hand, the former England and Wales electricity pool kept all of the unit-level bid and production data confidential. Only members of the pool could gain access to this data. It was generally acknowledged as one of the poorer performing electricity markets in the world (Wolak, 1999). The UK government's displeasure with pool prices eventually led to the New Electricity Trading Arrangement (NETA) which began operation on March 27, 2001. Although these facts do not provide definitive proof that rapid and complete data release enhances market efficiency, the best available information on this issue provides no evidence that withholding this data from the public scrutiny enhances market efficiency.

The public data release should identify the market participant and specific generation unit associated with each bid, generation schedule, or output level. Masking the identity of the market participants, as is done in all US wholesale markets, limits the disciplining value of public data release on the behavior of market participants. Under a system of masked data release, market participants can always deny that their bids or energy schedules are the ones exhibiting the unusual behavior. The primary value of public data release is that it puts all market participants at risk for explaining their behavior to the public. In all US markets, the very long lag between the date the data is produced and the date it is released to the public, at least six months, and the fact that the data is released without identifying the specific market participants virtually eliminates much of the enormous potential benefit of public data release.

Another potential benefit associated with public data release is that it enables third-parties to undertake analyses of market performance. The US policies on data release also severely limit the benefits to this aspect of a public data release policy. Releasing the data with the identities of the market participant masked makes it impossible to definitively match data from other sources to specific market participants. For example, some market performance measures require matching data on unit-level heat rates or input fuel prices obtained from other sources to specific generation units. Strictly speaking, this is impossible to do if the unit name or market participant name is not matched with the generation units.

The long time lag between date the data is produced and the date it is released also greatly limits the range of questions that can be addressed with this data. Taking the example of the California electricity crisis, by January 1, 2001, the date that masked data from June of 2000 was first made available to the public, the exercise of unilateral market power in California had already resulted in more than $5 billion in overpayments to suppliers in the California electricity market (Borenstein, Bushnell and Wolak (2002), hereafter BBW (2002)). Consequently, a long time lag between the date the data is produced and the date it is released to the public has an enormous potential cost to consumers that should be balanced against the benefits of delaying data release.

The usual argument against immediate data release is that suppliers could use this information to coordinate their actions to raise market prices. Although the immediate availability of information on bids, schedules and actual unit-level production could allow suppliers to design more complex state-dependent strategies for enforcing collusive market outcomes, it is important to bear in mind that coordinated actions to raise market prices are illegal under US anti-trust law and under the competition law in virtually all countries around the world. The immediate availability of this data means that the public also has access to this information and can undertake studies examining whether coordinated actions are occurring. Therefore another argument in favor of immediate public data release is that it increases the likelihood of detecting coordinated actions to raise market prices, because any entity could access this data and examine whether there was evidence of coordinated behavior.

Coherent arguments in favor of masking the identity of market participants in the publicly released bid, schedule and production data are more difficult to find. Assuming that the concerns with public data release enhancing the ability of market participants to coordinate actions had been addressed, it is difficult to determine what market efficiency-enhancing benefit results from masking the identity market participants. As noted above, masking the identity of the market participant only limits the “sunshine regulation” value of public data release.

An important aspect of the public data release question is the distinction between data that the market monitor can request and receive from market participants and data that must be released to the public. There is a natural boundary between these two types of data. Any data that the system operator requests from market participants or produces as a result of operating the market should be released to the public. Information about market a participant that is unnecessary to operate the market yet may impact the bidding, scheduling or production behavior of that market participant should not be released to the public. A prime example of information that does not need to be released to the public is the forward contract position of a supplier. Although, as discussed in Wolak (2000) the forward contract position of supplier can impact its bidding, scheduling and operating behavior, knowledge of this type of information is not needed by the system operator to operate the spot market or the transmission network. However, the day-ahead energy schedules, bids into the spot market, and actual production decisions of each supplier, information that should be released to the public, may depend on the supplier's forward contract holdings.

Because of the fundamentally financial nature of forward market transactions sold by electricity suppliers, it is very difficult to get accurate information on the true forward market position of electricity suppliers. They can re-trade forward market obligations among themselves to yield forward market positions far above or below their expected production of electricity. A number of studies of electricity trading in the US before by Enron meltdown in late 2001 estimated that each electron ultimately delivered through a US wholesale electricity market was bought and sold in forward markets more than five times. For this reason, even if the regulator attempted to collect this forward market data from suppliers on a regular basis it would not be very useful. For example, if the regulator specified a minimum quantity of forward contract sales for each supplier it regulated, these suppliers could undertake forward contract transactions with affiliates not subject to regulatory oversight to meet these minimums. Moreover, those affiliates not subject to oversight by the regulator could then re-construct the holding company's desired forward contract holdings. Consequently, routinely collecting the forward contract positions of suppliers could cause them to render this information of little or no use to the regulator through these sorts of affiliate transactions.

There is a strong argument for keeping any forward contract positions the regulator or market monitor might collect confidential. As noted in Wolak (2000), the financial forward contract holdings of a supplier are major determinants of the aggressiveness of their bids in the spot market. Only if a supplier is confident that it will produce more than its forward contract obligations will it have an incentive to bid or schedule its units to raise the market price. Competitors recognize this incentive created by forward contracts when they bid against competitors with forward contract holdings. Consequently, public disclosure of the forward contract holdings of market participants can convey useful information about the incentives of individual suppliers to raise market price in both bid-based and cost-based markets.

In this regard, the experience of California is instructive. The lack of long-term contracts between the suppliers to California and the three load-serving entities in California—Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric—was public information. Consequently, all suppliers knew that all other suppliers to California had virtually no forward contract obligations to the three California retailers. This meant that each supplier knew that all of the other suppliers were net sellers of electricity at very low levels of output from their generation units. Therefore all suppliers could be confident that all other suppliers would find output-withholding strategies profitable.

If the three large California retailers had had significant forward contract obligations from a number of suppliers and the magnitude of their forward contract holdings from each supplier was private information, then no supplier would know the levels of output at which other suppliers are long relative to their forward contract positions. Consequently, keeping forward contract positions confidential can have a beneficial impact on the competitiveness of spot market outcomes, because no supplier knows the critical output levels beyond which other suppliers would like to raise the market price, which makes it more difficult to determine those systems conditions when all suppliers find withholding strategies unilaterally profit-maximizing.

A simple example illustrates this point. Suppose there are five firms, each of which owns 100 MW of capacity. In a world without forward contracts, all suppliers know that if demand is above 400 MW, then all firms are pivotal in the sense that some output from their capacity is needed to serve demand assuming all other firms supply their maximum output. When demand is above 400 MW, all suppliers know that all other suppliers are pivotal, so that unilateral withholding strategies are very profitable for all suppliers. For example, if demand is 450 MW, all suppliers would know that at least half of their capacity is needed to meet demand regardless of how much their competitors supply. In contrast, if all suppliers have forward contracts for 70 MW, then even at a demand of 450 MW, they should all bid very aggressively because all suppliers know that if they do not bid aggressively for at least 70 MW of their capacity they could end up having to meet some their forward market obligations through extremely expensive spot market purchases. In addition, suppose that suppliers did not know the forward contract obligations of each their competitors, only the aggregate forward contract quantity, in this case 350 MW. This lack of information should cause some suppliers to put positive probability on the event that some of the remaining suppliers have more than the average forward contract coverage of 70 MW. A supplier that believes its competitors have more forward contract obligations would then bid more aggressively for at least 70 MW, its forward contract obligation, to guarantee that it sells at least that amount of energy in the spot market. This example demonstrates the disciplining effect of forward contracts on the spot market behavior of suppliers and the competition-enhancing benefits of uncertainty about the forward contract holdings of a supplier's competitors.

Although the forward contract positions of specific market participants should not be released to the public, the regulator should regularly collect information on the forward contract holdings of electricity retailers. The difference between the quantity of energy the retailer expects to sell (at a retail price that does not vary with the hourly wholesale price) and the retailer's forward contract holdings is its exposure to spot price risk. The regulator must monitor the spot price risk exposure of retailers because there is a substantial moral hazard problem in electricity retailing. Retailers can sign fixed-price supply commitments with customers and purchase the energy from the spot market when spot prices are low and earn high profit levels. To avoid large losses during periods of high spot prices, the retailer can simply declare bankruptcy. Consequently, the regulator or market monitor must ensure that at all times the retailer has sufficient forward contract coverage for its retail load obligations so that it does not find it expected profit-maximizing to engage in such a high-risk strategy. The regulator must ensure that the retailer finds it expected profit-maximizing to meet its retail load obligations and remain in business during periods with high spot prices, rather then declare bankruptcy.

A final aspect of the data collection portion of the market monitoring process is concerned with scheduled outage coordination and forced outage declarations. A major lesson from wholesale electricity markets around the world is the impossibility of determining whether a unit that is declared out of service can actually operate. Different from the former vertically integrated regime, declaring a "sick day" for generation unit--saying that it is unable to operate when in reality it could safely operate--can be a very profitable way for a supplier to withhold capacity from the market in order to raise the wholesale price of electricity. To limit the ability of suppliers to use their planned and unplanned outage declarations in this manner, the market operator and market monitor much specify clear rules for determining a unit's planned outage schedule and for determining when a unit is forced out. For example, before the start of each year, suppliers should submit to the system operator a schedule of planned outages for each of their units. The system operator will compile the planned outage schedules submitted by all suppliers and verify that they do not compromise system reliability. If they do, then the system operator will suggest modifications to achieve a schedule of planned outages for all units consistent with reliable system operation. Although the system operator should attempt to accommodate the wishes of each supplier, it must have ultimate authority on setting the final schedule for all planned outages. Once this planned outage schedule is set, it should be released to the public. Modifications of these unit-level planned outages schedules during the year are subject to the approval of the system operator. These modifications should be released to the public once they are approved. A similar process should be followed with scheduling planned transmission line outages. The system operator should coordinate the planned transmission outage process with all of the transmission owners and the generation unit owners. It should also make the final decision on when both generation units and transmission lines can be taken out for maintenance.

To deal with the issue of unplanned generation outages, the system operator should specify the following scheme for outage reporting. Unless a unit is declared available to operate as part of the bidding or scheduling process up to its full capacity, the unit is declared fully out or partially out depending on the amount capacity from the unit bid into the market at any price at or below the current price cap. This definition of a forced outage eliminates the problem of determining whether a unit that does not bid into the market is actually able to operate. By definition, such a unit should be assumed to be forced out. The system operator should therefore count all capacity from a unit bid in at price at or below the price cap as capacity that is unavailable. If only a portion of its capacity is bid into any of the markets at or below the price cap, the remaining capacity of the unit should be defined as forced out. Information on unit-level forced outages according to this definition should be publicly disclosed each day on the system operator's web-site.

This disclosure process cannot prevent a supplier from declaring a "sick day" to raise the price it receives for other energy it sells into the market. However, it can make it more costly for the market participant by registering all hours when a unit does not bid into the market as forced outage hours. For example, if a 100 MW generation unit is neither bid nor scheduled in the spot market during an hour, then it is deemed to be forced out for that hour. If this unit only bids 40

MW of 100 MW during an hour, then the remaining 60 MW is deemed to be forced out for than hour. The market monitor can then periodically report forced outage rates based on this methodology and compare these outage rates to historical figures from these units before re-structuring or from comparable units from different wholesale markets. In addition, if the wholesale market makes capacity payments to generation units, then the amount of capacity a unit owner should be allowed to sell should be based on the capacity of the unit multiplied by the 12-month rolling average of availability factor of the unit computed based on these outage rates. For example, if the 100 MW unit only bids into the market during half of the hours of the year, then it should only be allowed to sell 50 MW of capacity, because this is the average amount of capacity the unit provides to the market.

A similar process should be followed for unplanned transmission line outages. The market monitor should compile information on the hourly amount of available transmission capacity. As soon as outages or de-ratings occur, this information should be made publicly available. The market monitor should also compile the annual distribution of hourly transmission capacity availability and make this information publicly available. This information can also be used by the regulator and system operator to implement penalty and sanctions schemes for transmission owners that fail to maintain their transmission facilities in a manner consistent with good utility practice.

In closing this section, I will summarize the important aspects of this phase of the market monitoring process. The market monitor should have access to all data submitted to the system operator to run the market and operate the transmission network. This data should be released to the public, identifying the specific generation unit and owner of that generation unit. This data should be released as soon as possible subject to any concerns about rapid data release enhancing the ability of suppliers to coordinate their actions. For the reasons discussed above, I do not believe these concerns should preclude data release the day after actual market operation, as is the case for the National Electricity Market (NEM) in Australia. The market monitor should also have the ability to request and receive subject to the cost-benefit test described above (verified by the regulator if the parties providing the data object to the request) confidential data from any market participant. The market monitor or regulator should collect information on the forward contract holdings of all electricity retailers to ensure that they are prudently managing their spot price risk. For the reasons discussed above, there is limited value in regularly collecting forward contract data from suppliers. The market monitor or regulator should collect information on the planned outages of generation and transmission facilities throughout the control area and disseminate this information to the public immediately. The system operator should also keep a complete accounting of amount of generation capacity that does not bid into the market at or below the price cap on the spot market during any hour and the amount of transmission capacity that is available each hour. This information should also be disclosed to the public within a reasonable time lag.

2.2. Ensuring Compliance with Market Rules

The second feature of a successful market monitoring process is the authority of the ISO to assess penalties and sanctions for verifiable market rule violations. Both the costs of operating the market and the costs of participating in the market will be lower if all market participants are confident that the market rules will be obeyed and contractual commitments honored regardless of system conditions. Expected profit-maximizing market participants will factor in the cost of contract enforcement into any benefit/cost calculation they make for a contractual commitment under consideration. If these costs are expected to be significant because one party does not believe that some of the terms of the contract are unlikely to be honored by the other party, the other party will be less likely to enter into this commitment. Consequently, there is a clear market efficiency-enhancing benefit to reducing the costs of contract enforcement and the likelihood of market rule violations through a transparent penalty and sanctions process administered by the system operator and market monitoring process.

Penalty and sanction mechanisms for this purpose are the norm in other markets. Two examples are noteworthy. First, Federal Energy Regulatory Commission (FERC) in the US has long authorized provisions in natural gas pipeline tariffs that permit them to collect scheduling, imbalance, and overrun penalties if the pipelines demonstrate that these are necessary to deter shipper behavior which threatens the integrity of the pipeline system or which imposes unjustified costs on other shippers or the pipeline. Typically, these penalties are specified in the jurisdictional pipelines' tariffs and establish fixed penalties for each million BTU (MMBTU) in excess of particular thresholds. The penalties are set high enough to make crossing the specified thresholds economically unattractive to shippers.

Second, the Securities and Exchange Commission (SEC) has long allowed self-regulatory organizations (e.g., the New York Stock Exchange) to monitor and penalize market participants. The New York Stock Exchange (NYSE) is the leading self-regulatory organization (SRO) in the U.S. securities industry. In its role as an SRO, the NYSE, through its Market Surveillance Division develops rules and evaluates the performance of market participants. The NYSE recently adopted rules for stock analysts in an effort to combat conflicts of interest between investment banking and research arms of brokerage houses. In response to the highly publicized accounting scandals of Enron and Worldcom, the NYSE has proposed corporate governance rules that would apply to listed firms. The NYSE Market Surveillance Division takes disciplinary action for certain rules violations, and refers other matters warranting formal disciplinary action to the NYSE Division of Enforcement (or the SEC for matters outside NYSE jurisdiction). The NYSE Division of Enforcement acts as the prosecutorial arm of the NYSE and can initiate a formal charge against a member firm. If formal charges are warranted, a formal proceeding involving an Exchange Hearing Panel follows. Appeals of Panel decisions are made to the Board and thereafter to the SEC. SROs like the NYSE, in conjunction with SEC rulemaking and oversight, have worked well in financial markets for decades. This is a useful model for wholesale electricity markets where system operators, working with the market monitor, develop and enforce tariffs, in conjunction with enforcement and oversight by the industry regulator.

2.3. Four Guidelines for Determining Penalties and Sanctions

This section suggests four guidelines for determining penalties or sanctions for market rule violations. First, the penalty and sanction mechanism should focus on verifiable market rule violations. Determining a violation should involve little judgment on the part of the market monitor. An analogy to a speeding ticket is useful. If the market monitor measures the speed of the car and finds that it exceeds the posted speed limit, then it should assess a pre-specified penalty. The penalties and sanctions process should not involve a finding of intent in order for the market monitor to assess a penalty. An example of a market rule violation covered by this procedure is if a market participant submits a bid to supply given quantity of energy within a given response time and it fails to meet this response time. For example, suppose a supplier bids to provide 50 MW within 10 minutes from the time the unit is called. If the supplier fails to provide any of the purchased energy when it is called upon, the unit owner should be penalized for failing to meet this contractual commitment.

The California market provides a concrete example of the increased costs of system operation that can result from the system operator not having the ability to ensure compliance with its market rules. During the first three years of operation of the market, suppliers would often refuse dispatch instructions from the ISO based on bids they submitted to the real-time energy market. Refusing a dispatch instruction can be a very effective mechanism for a supplier to raise the market price. For example, a supplier might receive a dispatch instruction for 100 MW from a unit bid in at \$50/MWh. Suppose that this supplier also has bids for 30 MW at \$100/MWh and 70 MW at \$300/MWh and it knows that there are very few MWs bid in above \$50/MWh. Consequently, it would be expected profit-maximizing in the absence of penalties for violating market rules, for the supplier to refuse to respond to the dispatch instruction for 100 MW at \$50/MWh in hopes of having the 30 MW at \$100/MWh accepted and set the market price or a portion of the 70 MW at \$300/MWh taken and set the market price. Although this incentive to refuse dispatch instructions exists in all markets, it was especially problematic in California because this behavior would impact the price the supplier would receive for all output sold in the California ISO's real-time market. Particularly during the period May 2000 to June 2001 many suppliers sold a substantial amount of their output in the ISO's real-time market with no forward contract coverage, so that virtually all of their output was paid this elevated price. Besides raising the market price, the fact that suppliers routinely refused to respond to the California ISO's dispatch instructions required the system operators to carry more generation reserves because they could not be sure that all of the bids in the ISO real-time market would respond to a dispatch instruction. In addition, the system operators often had to make purchases outside of the California ISO's formal markets to ensure that enough energy was available to meet demand, which further increased the cost of wholesale energy.

The second guideline is that the penalty associated with a market rule violation should be sufficiently high to make it unilaterally unprofitable for a market participant to violate the rule. Limiting the magnitude of the penalty to ordering the firm that violated the market rules to return the profits gained from their violation will not deter violations. Under this scheme, firms would have little to lose from violating rules because their violation may not be detected and, even if it is detected, they are not made any worse off than if they had followed the rules in the first place.

The third guideline is that the mechanisms for imposing penalties and sanctions should be set in advance and the relationship between a specific market rule violation and the amount of the penalty assessed should be as transparent as possible. Returning to the above example of failing to comply with a dispatch instruction, the ISO could require that the supplier either find a like replacement for the power the unit is unable to provide or require the owner to make the payments necessary to hold harmless all market participants for its failure to meet its contractual obligations. Making the relationship between a specific market rule violation and the penalties assessed as transparent as possible achieves two goals. First, it limits the opportunities for the system operator and market monitor to exercise discretion in setting penalties. Second, it allows market participants to formulate the best possible cost-benefit assessment associated with a specific market rule violation.

The fourth guideline is that the penalty associated with a market rule violation should not exceed the harm this market rule violation causes to all market participants. This guideline addresses the tendency regulators often have to set penalties sufficiently high to deter market participants from engaging in behavior that has any likelihood of violating the market rules. Excessive penalty levels have a cost. They cause market participants to focus on avoiding being penalized for a market rule violation rather than on producing electricity at least cost or purchasing wholesale electricity at least cost. For example, setting a cost of failing to respond to a dispatch instruction too high could cause suppliers to avoid participating in the wholesale market or to downgrade the maximum amount of energy they are willing to sell from each of their units.

A mechanism to ensure that participants obey the market rules is an essential component of any organized market. Because all suppliers must sell electricity through a common transmission network that can become congested, it is even more important that they have strong incentives to obey the market rules. A transparent penalties and sanctions mechanism that makes it expected profit-maximizing for participants to honor their contractual commitments will significantly enhance market efficiency. The penalty assessed for a given market rule violation should be sufficient to cause an expected profit-maximizing supplier not to attempt to violate the market rule. Assuming that magnitude of penalty is sufficient to deter a rule violation, the amount penalty should be no larger than the economic harm this market rule violation imposes on all other market participants.

2.4. Protecting Against Behavior Harmful to Market Efficiency and System Reliability

The final feature of an effective market monitoring process deals with deterring behavior that is harmful to system reliability and market efficiency. This is the most complex aspect of the market monitoring process to implement, but it also has the potential to yield the greatest benefit. This involves a number of inter-related tasks. In a bid-based market, the monitor must design and implement a local market power mitigation mechanism. The market monitor must also determine when a market rule detracts from system reliability and market efficiency and suggest and implement the necessary changes in this market rule. The market monitor must determine when market outcomes cause enough harm to some market participants to merit regulatory intervention. Finally, the market monitor must determine when significant enough harm occurs to one or more market participants to suspend market activities temporarily.

Local Market Power Mitigation (LMPM) Mechanism. In all bid-based markets there is a clear need for a local market power mitigation mechanism to limit the ability of suppliers to exercise local market power through the bids they submit when there is insufficient competition to meet a local energy need to rely on bids to set the price a supplier is paid for this energy. An LMPM mechanism must determine when a supplier has local market power worthy of mitigation, what the mitigated supplier will be paid, and how the amount the supplier is paid will impact the payments received by other market participants. It is increasingly clear to regulators around the world, particularly those that operate markets using Locational Marginal Pricing (LMP) that formal regulatory mechanisms are necessary to deal with the problem of insufficient competition for local energy needs.

Formulate and Implement Efficiency-Enhancing Market Rule Changes. The market monitor must determine which market rules detract from market efficiency or system reliability and formulate and help implement the appropriate market rule changes. Because factors such as the level and geographic distribution of demand, the mix of input fuels used and ownership shares for generation capacity in the control area, and the configuration of the transmission network can all change over time, market rules must also change. The market monitor must therefore continually analyze and assess the market efficiency impacts of various market rules. Once it has identified a deficient market rule, it must then work with the system and market operators to devise the changes necessary to address this deficiency. This duty underscores the importance of the market monitor as an entity that analyzes market performance using the data it has compiled.

Penalize Behavior Harmful to System Reliability and Market Efficiency. The market monitor is the first line of defense against harmful market outcomes. Persistent behavior by a market participant that is harmful to market efficiency or system reliability should be subject to penalties and sanctions. However, in order to assess these penalties the market monitor must determine intent on the part of the market participant. The market rules should contain a general provision prohibiting persistent behavior detrimental to system reliability and market efficiency. The goal of this provision is to establish a process for the market monitor to intervene to prevent a market meltdown. As discussed in Wolak (2003a) it is possible that system conditions can occur when the unilateral expected-profit maximizing actions of market participants can result in enormous consumer harm. There are instances when actions very profitable to one or a small number of market participants can be extremely harmful to system reliability and market efficiency. There must be a well-defined process for the market monitor to intervene to protect market participants and correct the market design flaw allowing this harm to occur.

Determine When Market Activities Can Be Temporarily Suspended. The market monitor must have the ability to suspend market operations on a temporary basis when system conditions warrant it. The suspension of market operations should only occur after pre-specified administrative procedure have been followed and the only option available to the market monitor to prevent significant harm to market efficiency and system reliability is the suspension of market activities. This authority to temporarily suspend market operations is necessary because bid-based markets, and cost-based markets under some system conditions, can sometimes become wildly dysfunctional and impose enormous harm over a very short period time. For example, in the New England ISO during the early stages of the market, there were short-lived severe distortions in the Installed Capacity and Operating Capacity markets. During the California ISO's first summer, the market for Replacement Reserve experienced extremely high prices for a short period. Under these circumstances, the market monitor should have the ability to suspend market operations temporarily until the problem can be dealt with or a longer-term regulatory intervention or market rule change can be implemented.

Allowing enormous harm to be imposed on consumers or other market participants makes very little sense under these sorts of circumstances The remainder of this section will describe a general mechanism for determining if a supplier engages in persistent behavior detrimental system reliability and market efficiency and what the appropriate standards are for determining whether market operations should be suspended.

There is a significant downside to giving the market monitor the ability to intervene in the market. To the extent that the market monitor is influenced by the political environment, it may be tempted to intervene to pursue political ends rather than allow politically favored electricity retailers to pay higher prices for electricity or politically favored suppliers to receive lower prices for the electricity they produce. That is why the market monitor must follow a well-defined process before it is allowed to make a finding of persistent behavior harmful to system reliability and market efficiency and to suspend market operations temporarily.

The major difficulty associated with implementing this market rule is that the market monitor would have to infer from a market participant's behavior whether its bidding, scheduling or operating behavior intended to harm system reliability or market efficiency. If the market monitor identifies behavior that is detrimental to system reliability, and has clear evidence (e.g., a whistleblower or internal correspondence) that the market participant engaged in this behavior with full knowledge that it significantly harmed system reliability or market efficiency, penalties may be imposed without first going through the administrative process described below.

However, it seems very unlikely that the market monitor would have direct evidence of intent, particularly if there is a market rule that imposes significant penalties on the market participants that admit to engaging in this type of behavior. Enforcing a "behavior detrimental to system reliability and market efficiency" provision would be more difficult if this market rule also imposed the very reasonable requirement that this detrimental behavior must also have a significant impact on market outcomes. This would require the market monitor to make the often very subjective determination of what constitutes a "significant" market impact. Despite these difficulties with determining intent and significant market impacts, an administrative procedure along the lines discussed below can adequately address these complications in making the finding of "intent to impose significant harm."

A necessary first step in any process for determining intent is the ability to demand and receive information from market participants. This reinforces the need for a pre-condition for participation in the wholesale markets that each entity agree to provide, in a timely manner, all information necessary for the market monitor to undertake an investigation of intent to impose significant harm to system reliability or market efficiency. As discussed above, this agreement to provide information should be subject to the constraints that the information request is necessary to undertake the current investigation and does not impose costs on the market participant that are out of line with the alleged harm that the market participant is imposing.

The market monitor should implement the following multi-stage process for determining intent and imposing penalties commensurate with harm caused by these actions. It is counterproductive for the market monitor to prohibit actions that are difficult to define and even more difficult to determine if they occur, such as gaming, market manipulation, or false scheduling. Prohibiting these ill-defined activities without first finding intent and significant harm will cause market participants to avoid behavior that often enhances market efficiency and system reliability that might be interpreted by the market monitor as one of these prohibited actions. Instead, the market monitor's process for determining intent should recognize that it is extremely difficult to distinguish legitimate profit-maximizing behavior from actions that intend to harm competition and market efficiency without some exchange of information between market participants and the market monitor. In addition, behavior that might be interpreted by some observers as gaming or market manipulation is often rendered unprofitable by the actions of other market participants. Consequently, these sorts of market efficiency or system reliability problems can often be solved through information provision by the market monitor to the market at large, thereby eliminating the need for further action.

Thus, rather than prohibit a list of seemingly nefarious but nebulous actions, the market monitor should instead adopt a general provision against behavior by any market participant that intentionally causes significant harm to market efficiency or system reliability. A key feature of this market rule is a transparent process for identifying intentional behavior detrimental to system reliability or market efficiency. This should include a process for taking the actions necessary to stop this behavior or the harm that it causes. The focus of this process should be on stopping as quickly as possible intentional behavior that the market monitor determines causes significant harm to market efficiency and system reliability.

The first step in this process is to identify behavior that is likely to harm to market efficiency and system reliability. Two findings are necessary for the process to continue to the next step. The market monitor must first determine if this behavior is persistent, and if it has the potential to impose significant harm either because it is very persistent or extremely harmful when it does occur. The next stage of the process involves alerting all market participants to the existence of this behavior and publicly disclosing the identity of the market participant engaging it. The goals of this stage of the process are to subject this market participant to public scrutiny and to provide all market participants with information that they can use to take actions that attempt to render this behavior unprofitable. This public disclosure is very important step in the process of determining intent because all market participants, including the market participant engaging in the behavior, know that the market monitor has publicly stated that this behavior is harmful to system reliability or market efficiency. Consequently, continued behavior by this market participant that imposes significant harm provides strong evidence in favor of a finding of intent.

In most cases, this stage of the process will put an end to the behavior or the harm it causes. However, in those instances when the actions are sufficiently profitable to the market participant or group of market participants that they continue to cause significant harm, the market monitor should initiate a formal investigation of intent. To do this the market monitor needs the ability to request and receive in a timely manner the information from the offending market participant necessary to make a credible determination of intent to impose harm. An important goal of this information gathering effort is for the market participant to provide information to the market monitor showing that there is no direct causal link between its behavior and harm to system reliability or market efficiency.

If the market monitor's information gathering efforts reveal substantial evidence of a direct causal link between this market participant's behavior and the presumed harm, then the market monitor should find that this market participant did intend to harm system reliability or market efficiency. If there is an affirmative finding of intent, the market monitor may need to collect additional information to determine the appropriate magnitude of penalties. The requirement to provide this information would be a contractual obligation between the system operator and each market participant that is a pre-condition for participation in the market. For this reason, the market monitor should have the authority to impose penalties on this market participant for failure to comply with reasonable and necessary information requests in a timely manner. The willingness of each market participant to be subject to these penalties should also be a pre-condition to participation in the wholesale market.

If the market monitor makes an affirmative finding of intent it would then be required to set the appropriate level of penalties. These penalties should be at least as large as the harm caused by the market participant's actions. The results of the investigation and the market monitor's rationale for its recommended level of penalties would then be forwarded to the industry regulator for final review and implementation.

As should be clear from the above discussion, the major focus of this process should be on eliminating the harmful behavior as soon as possible, not on assigning blame. Only when public disclosure of the actions and the market monitor's own investigation fails to stop or eliminate the harm associated with this behavior should the market monitor attempt to determine intent and assign penalties for this behavior.

To guard against the possibility that there may be circumstances when the unilateral profit-maximizing actions of market participants can lead to enormous harm to consumers, even though individually their actions may not cause significant harm to system reliability or market efficiency, the market monitor should have the ability to suspend market operations temporarily. An example of such a mechanism is the guardrails to competition approach discussed in Wolak (2003b). This mechanism relies on the competitive benchmark analysis discussed in BBW (2002). It sets a prospective measure of the extent to which electricity prices over a rolling 12-month horizon can exceed competitive benchmark level. If the difference between the quantity weighted average market price over the previous 12 months exceeds the quantity weighted average competitive benchmark price computed using the methodology outlined in BBW (2002) over the previous 12 months by more than $5/MWh then an automatic regulatory intervention would be triggered. In Wolak (2003b), I argue that this intervention should be a 12-month period of cost-of-service prices for all suppliers. The idea behind this intervention is that it is viewed as sufficiently Draconian, yet credible to implement, so that suppliers never allow this benchmark to be violated. For example, rather than exercise substantial market power in the spot market, a supplier will sign forward contracts or other spot price hedging arrangement to improve spot market performance before these guardrails are exceeded.

3. Market Monitoring in Central American Countries

This section discusses the major market monitoring challenges that are unique to Central American countries. Most of the specific examples described below come from the two countries that I visited during my trip: El Salvador and Guatemala. However, I am also very familiar with the Honduras electricity supply industry as a result of an earlier visit there. Honduras is currently in the process of transitioning from an industry dominated by a vertically-integrated and government-owned monopoly to more formal wholesale market with a single buyer. Costa Rica has a single vertically-integrated government-owned utility. It is the only Costa Rican agent authorized to participate in the MER. Panama and Nicaragua have unbundled and fully privatized their industries with the exception of the transmission segment, and a small amount of generation capacity in Nicaragua. While their markets may differ from those in Guatemala and El Salvador, the general market monitoring challenges discussed below apply to these countries as well.

One potentially important difficulty in monitoring the MER is the fact that a single company, Union Fenosa, owns combination distribution and retailing companies in Guatemala, Panama, and Nicaragua which serve more than 12 million customers (see Arellano (2003) Table 8), the vast majority of which pay regulated prices set by the country-level regulator (see Arellano (2003) Table 8). The next largest combination distribution and retailing company serves slightly more than 1 million customers (see Arrellano (2003) Table 8). I will first describe the difficulties associated with the market monitor fulfilling the roles discussed in the previous section in these countries. I will then suggest modifications of this generic market monitoring process that address these difficulties.

The collection of data submitted to the system and market operator for use by the market monitor in both El Salvador and Guatemala should be relatively straightforward task. In both countries, the system operator and market operator are the same entity. Similar logic applies to data from the industries in the other four Central American countries, although it may be easier for the market monitor to obtain the legal authority to access this data in countries with formal wholesale markets, rather than in countries with a single vertically-integrated utility such a Costa Rica. It therefore makes sense to impose as a pre-condition for participation in the MER, real-time access by the regional market regulator and regional market monitor to the following information: (1) hourly bids, schedules and actual production in those countries with formal markets and (2) hourly schedules and actual production for those countries without formal markets. By real-time access, I mean the ability to obtain the data from the relevant entity at soon as it is made available to that entity or produced by that entity, because a key feature of a successful market monitoring process is the ability to perform timely analyses of market performance that can be used to inform the regulatory decision-making process.

The fact that there are no indigenous fossil fuel sources also simplifies the process of collecting data on input fuel prices. Input fossil fuels, primarily oil, must be purchased from international markets. Although market participants may decide to hedge their input fuel purchases, the market monitor should obtain information on both daily spot prices for oil and futures prices for oil at various publicly traded locations.

To a first approximation, the Guatemala market dispatches units based on their variable costs, so that information on the heat rates and the variable operating and maintenance costs of these units should be readily available. In fact the Guatemala regulatory body, CNEE, has the authority to validate the heat rates and variable operating and maintenance costs of generation units. CNEE also reviews the methodology used by each market participant to determine its variable costs that enter the dispatch process. Currently, the El Salvador market is dispatched based on the bids submitted by market participants. The 2002 annual report of El Salvador regulatory body, SIGET, does not appear to report the unit-level information required to compute variable cost estimates. Consequently, a provision may need to be added to the market rules requiring unit owners to submit their heat rates and variable operating and maintenance costs to the market monitor and that this information is subject to audits by the market monitor. However, if El Salvador succeeds in it current attempts to implement a cost-based dispatch spot market, this rule change is unnecessary because this unit-level operating cost information must be submitted to the market and system operator in order to set prices and dispatch generation units in El Salvador.

Both markets also rely on forward contracts between suppliers and retailers to schedule generation units on a day-ahead basis. In El Salvador, forward contracts between generators and retailers are declared to the market operator, UT. These contracts are scheduled as submitted unless there are transmission constraints. The system regulatory market, MRS, manages imbalances in the system using demand and supply bids submitted by market participants. UT dispatches the system based on the schedules submitted in the contracts market and bids submitted to the MRS. The bid price of the last unit dispatched sets the price in the MRS if there is no congestion in the transmission network. Otherwise, UT creates separate pricing zones in El Salvador and sets different prices in the MRS in each of these pricing zones. The Guatemala market uses a cost-based dispatch to establish a single system marginal cost. Out-of-merit generation is paid as-bid above this system marginal cost. All generation units and loads throughout Guatemala are paid (suppliers) and pay (load) the same hourly price for energy regardless of their location. Forward contracts prices are treated the same as variable costs in the dispatch and price-setting process, for generation units with forward contracts, All suppliers are paid the spot market price for the energy produced from their units. Forward contracts are settled financially using these spot prices. Units without forward contracts are dispatched based on their filed variable costs.

The Guatemala market introduces market inefficiencies and opportunities for suppliers to exercise spot market power by mixing forward contract prices with regulated variable costs in the dispatch process. It is difficult to see how the least-cost mix of units will be dispatched by treating a market-determined forward price of energy in a bilaterally negotiated long-term contract the same as a regulated variable cost estimate. This method for dispatching units is based on the false logic that the negotiated price in a take-or-pay contract represents a meaningful short-term opportunity cost of operating the unit, rather than as an estimate of the quantity-weighted average price of electricity over the term of the contract as of date it is signed. The Guatemala regulator, CNEE, noted that the dominant contract form in this market is fixed-price for a fixed quantity of energy. This implies that the costs to consumers of this mechanism could be substantial. The generation units backing up these contracts could easily be included in the system dispatch process at their regulated marginal costs rather than at their contract price if the market operator had access to the unit's physical operating characteristics. This sort of rule change should increase the efficiency of the dispatch process because an efficient unit with a high-priced forward contract would be dispatched more frequently based on its variable operating costs. This more frequent dispatch of low variable cost units should, in turn, allow all suppliers to sign long-term contracts at lower prices and still remain financially viable. Retailers should also favor this change because a load-serving entity with a forward contract is indifferent to what generation units produce the electricity it consumes, as long as it has the right to purchase the contract quantity of energy at the contract price.

It is important to emphasize the purely financial nature of all forward market transactions. The buyer of a forward contract effectively purchases insurance against fluctuations in the wholesale price of power for the contracted quantity of energy delivered to an agreed upon location in the network. The seller of this contract need not even own a generation unit. It only agrees to provide wholesale price insurance for the contracted quantity of energy. Tying the provision of spot price insurance at a given location in the transmission network to the construction or operation of specific generation units in the portfolio of the seller of the contract is likely to reduce both system reliability and market efficiency, because opportunities may arise for the seller of this forward contract to change how it operates these units to increase its profits. This is often accomplished by withholding lower cost units at the expense of operating higher cost, less reliable units. Consequently, there should be a clear separation between the financial hedge against spot price volatility at a given location in the transmission network and the real-time price of electricity at that location in the network.

This separation between forward market hedges and real-time system operation provides strong incentives for suppliers to make the least-cost mix of generation units available in real-time to meet their forward contract obligations. That is because the supplier's forward market revenue stream is not impacted by any operating decisions it makes about its generation units. A profit-maximizing supplier will therefore have an incentive to minimize the cost of supplying its fixed-price forward market obligation. The converse of the logic underlying the rationale for a clear separation between forward market transactions and real-time system operation is the reason that generation unit owners are the major sellers of this wholesale price insurance. Ownership of a generation unit allows the supplier to provide spot price insurance very inexpensively, because it has physical assets which allow it to arbitrage the difference between the forward contract price and spot price. The supplier simply runs its unit when their variable costs are below the market price. Otherwise the supplier doesn't run a unit, and instead financially settles with the buyer of the contract using the relevant spot price of electricity.

Giving special treatment to forward contracts in the dispatch can also enhance the ability of suppliers to exercise market power in the spot market. Suppliers may offer a retailer a low capacity price in a forward contract in exchange for a higher energy price, and this would allow the supplier to set a higher system marginal cost in the dispatch process. This potential opportunity to exercise market power and introduce inefficiencies in the dispatch process can be eliminated by dispatching all units based on a common standard for computing their variable costs, and then settling all forward contracts against the resulting system marginal cost. The dispatch process in Honduras treats a substantial number of forward contracts in this manner, so the efficiency of its dispatch process could be significantly improved by entering all units with their variable costs and settling all forward contracts on a financial basis.

Because the El Salvador market is dispatched based on bids, suppliers are able to exercise market power and induce an inefficient dispatch through how they schedule their units in the day-ahead market and bid their units in the spot market. However, these market rules also allow suppliers to make the distinction between a non-firm energy contract and firm energy contracts in the day-ahead scheduling process. If a generation unit has a firm-energy contract then it has priority over non-firm energy contracts, regardless of the cost of operating the generation unit. Awarding scheduling priority to firm energy contracts regardless of their costs enhances the ability of suppliers to distort their unit operating decisions to raise market prices. Rather than allow suppliers to make this distinction, the market operator should make no distinction between non-firm and firm energy contracts and allocate transmission capacity based on the unit-level bids submitted by market participants. This would also increase the likelihood that lower cost units would be chosen to operate, because suppliers would not have the ability to limit the number of generation units the system operator can adjust to maintain system balance.

To summarize the above discussion, wholesale electricity markets should not allow purely financial transactions in the forward market to impact the physical realities of actual system operation. The spot market should dispatch the least cost mix of generation units available to meet demand regardless of the quantity of forward contracts held by retailers. Retailers should engage in forward market transactions to hedge the spot price risk associated with this least cost dispatch. The forward contract obligations of generators should not be used to determine which units are dispatched in real time. Instead forward contracts should be used by both suppliers and retailers to hedge the spot price and quantity risk at their location in the transmission network associated with a least cost real-time dispatch.

Giving suppliers with forward contracts preference in the dispatch process should increase total dispatch costs. More important, at noted above this preference can enhance the ability of suppliers to raise market prices in both bid-based and cost-based markets, because the system operator can only dispatch generation units without forward contract commitments. Market rules which tie spot market behavior to pre-existing forward contracts provides an incentive for suppliers to assign forward contracts to generation units in order to maximize their ability to increase spot prices. Such rules benefit suppliers in two ways. First, they increase the price at which the supplier sells energy in the spot market. Second, they raise the opportunity cost of the supplier signing a forward contract, both of which raise the price of forward contracts for deliveries in the future.

The above discussion does not imply that the market design should not encourage forward contracting. Particularly, in Central American markets where each country only has a small number of suppliers, each of which owns enough capacity to supply a significant fraction of the country's peak demand, forward contracts are necessary to limit the ability and incentive of these suppliers to exercise market power in the spot market. Even in a cost-based dispatch market, suppliers without forward contracts have a greater incentive to withhold lower cost units to raise the price they are paid for all the energy they produce. However, it is important to emphasize that the beneficial impacts of supplier forward contract holdings on spot market bidding behavior only occur if these contracts are signed at fixed prices.

As El Salvador has discovered, forward contracts indexed to the spot price neither limit the ability nor the incentive of suppliers to exercise market power in the spot market because the supplier is still paid a price that depends on the spot price for energy supplied under the forward contract. Consequently, taking actions to raise the spot price immediately increases the price the supplier is paid for its forward contract sales. Forward contracts limit spot market power if the supplier has sold forward a given quantity of energy at a **fixed** price. This type of forward contract for a fixed quantity of energy and a full or partial energy requirements (variable quantity) contract at a fixed price with the retailer limits the ability of supplier selling the contract to exercise spot market power. Under either type of contract, suppliers have still sold in advance a pre-determined quantity of energy at a fixed price. The only difference between a fixed quantity contract and a full or partial requirements contract with a retailer is that the supplier does not know the specific amount of energy it has sold under the contract until the retailer consumes it.

The markets in El Salvador and Guatemala extent this is false distinction between actual system operation and the forward financial market to how the transmission network is priced. Both markets charge the cost of the transmission network to generators. In El Salvador all generation owners pay $/MW/year charges for use of the transmission network based on maximum power injection for the year, month, day or hour. A supplier that operates only in one month pays 1/12 of the annual charge plus a 25% premium per MW for that month. A supplier than only operates in a single hour pays 1/8760 of the annual charge plus a 40% premium per MW for that hour. In Guatemala, a unit owner pays a $/MW/month charge times the amount of available capacity for the generation unit. The amount of available capacity of a generation unit is, to a first approximation, (1- AF)*CAPMAX, where AF is the availability factor of the unit calculated over the past year and MAXCAP is the capacity of the unit. Charging generation units for the cost of transmission network using these mechanisms unnecessarily distorts operating and the entry decisions of unit owners.

This incentive is most clearly visible in the scheme used in El Salvador to compute the $/MW/hour charge paid by suppliers that only produce during a few hours of the year. This charge is much higher than the $/MW/hour charge paid by suppliers producing in all months of the year. This mechanism creates incentives for market participants to withhold units from the market during some hours in order to avoid paying for transmission charges, rather than being available during all hours of the year. Particularly, when unexpected generation outages occur, market prices will be significantly higher because these units are withheld from the market to avoid the risk of a transmission charge. Because a 1 MWh injection at a given location in the transmission network from a generation unit that operates very rarely provides the same amount of energy and reliability benefit as a 1 MWh injection from a generation unit that operates very frequently, the charge to the supplier for injecting this energy should be the same.

Consistent with the logic expressed above with respect to forward contracts, each day the market should yield as close as possible to a least cost dispatch of the generation units that are physically able to operate. The methods used to pay for the transmission network in El Salvador and Guatemala are inconsistent with this goal because of the incentives they provide for suppliers to withhold their capacity to avoid transmission charges. Because these transmission pricing mechanisms are not based on economic cost causation principles, there does not appear to be any economic benefit that counteracts the inefficiencies caused by these pricing mechanisms. Moreover, these mechanisms can also distort the decisions new generation entrants make about where to locate their units, how large to make them, and what generation technology to use. For all of these reasons, the cost of the transmission network should instead be allocated by load in a manner that introduces the least amount of distortions into the consumption decisions of final consumers. Because the vast majority of the costs associated with the transmission network are not caused by the consumption decisions of any single market participant, the usual approach is to impose a \$/MWh charge on all MWh withdrawn from the transmission network that is sufficient to recover the total costs (including a return on capital invested) of the transmission owner. Fortunately, these costs are a small fraction of the delivered price of electricity, so the potential distortions associated with setting a single \$/MWh transmission charge are small.

The use of availability factors to compute a unit's available capacity reinforces the need for the market monitor to implement the planned and unplanned outage data collection process discussed earlier. For the reasons discussed above, AF should measure the fraction of hours the total capacity of the unit is bid into the market. Specifically, if CAP_{ihd} is the total amount capacity from unit i bid into the market during hour h of day d then AF should be computed as follows:

$$AF = \frac{\sum_{d-1}^{365}\sum_{h=1}^{24} CAP_{idh}}{8760 * (MAXCAP)}.$$

AF is the ratio of the total capacity made available to the market over the past year divided by the potential capacity that could have been made available to market over the same time period. Because capacity payments in the Guatemala market are a fixed \$/MW payment periodically set by the Guatemala regulator times the available capacity of the unit, this method for computing AF provides strong incentives for suppliers to make their units available to the market, instead of withholding them to raise the spot market price.

The data collection portion of the market monitoring process is very important to minimizing the market inefficiencies introduced by a cost-based dispatch market. One might think that market power cannot be exercised in the cost-based dispatch. However, for the reasons discussed below, this is not the case. A more accurate statement is that a cost-based dispatch market limits the amount of market power than can be exercised on an hourly basis relative to a bid-based market. However, it may not limit the amount of market power that can be exercised on annual basis relative to a bid-based market, because a significantly more sophisticated market monitor is required to detect the exercise of market power in cost-based market versus a bid-based market. In a cost-based market all suppliers have a common incentive to increase their variable costs of production, because this sets higher prices for all suppliers. Consequently, supplies have limited incentives to purchase their input fuel in a least cost manner. They also have little incentive to make investments that reduce their variable costs. A relatively straightforward way for a supplier to exercise market power in a cost-based market is to use affiliate transactions or other arrangements to raise its input fuel prices.

The incentive to declare low cost units unavailable may be higher in a cost-based market relative to a bid based market. In a bid-based market, a supplier has two choices for exercising market power. First, it can declare low cost units unavailable to operate in order create an artificial scarcity of generation capacity. Second, it can simply bid these low cost units at higher prices in order to raise the market price. In a cost-based market, this second option is unavailable. Only if low cost units are declared unavailable can a supplier artificially raise the market price by forcing the system operator to dispatch high cost units to meet system demand instead of these low cost units. This withholding behavior allows a supplier to raise the price it is paid for all of the energy it sells in the spot market. In other words, if suppliers are able to exercise unilateral market power, the incentives for inefficient dispatch of units are higher under a cost-based versus bid-based market, and this inefficient dispatch is typically the result of suppliers declaring low cost units unavailable in order to raise the market price. This logic emphasizes the need for the market monitor to collect information on generation unit outages—both planned and unplanned—and to put in place mechanisms that make it costly for generation unit owners to have excessive levels of unplanned outages. It also emphasizes the need, described earlier, for explicit definitions of unplanned and planned outages.

This discussion also highlights the importance of the data collection component of the market monitoring process in a cost-based market. Rather than simply verifying that a supplier's reported input fuel costs equal its actual input fuel costs and accepting without question the reported heat rates and variable operating and maintenance costs of the generation units it owns, the market monitor and regulator must effectively make a determination of whether all variable costs where prudently incurred. In the case of the heat rates and variable operating and maintenance costs, the question to be answered is: Were these figures computed based on "good utility practice"? Are they consistent with values for these units during the former vertically integrated monopoly regime? Are these figures consistent with values from similar units in other Central American countries?

For the case of input fuel prices, the market monitor must determine whether the supplier purchased its input fuel in a prudent manner from the perspective of managing the spot price risk associated with this input fuel. One approach to this problem is to use the spot price of the input fuel as the relevant input fuel cost regardless of the forward market input fuel purchases of the supplier. This approach is valid when the market monitor is confident that this input fuel spot price is not impacted by the actions of electricity suppliers. For the case of oil, this might involve setting a supplier's input fuel price equal to that day's crude oil price on the New York Mercantile Exchange (NYMEX) times the appropriate conversion factor to reflect the cost of refining crude oil into the unit's input fuel, plus an adder to account for the cost of transporting the input fuel from the refinery to where it is burned. This mechanism would give suppliers strong incentives to hedge the spot price risk associated with their input fuel purchases and prevent the use of affiliate transactions to raise their input fuel prices, because the maximum input fuel costs supplier's are able to recover is unaffected by their purchasing decisions.

There are other strategies for providing incentives for suppliers to make their filed variable costs as close as possible to their minimum variable cost of supplying electricity. All of these strategies require the market monitor and regulator to recognize the incentive impacts of the mechanism used to validate the variable costs used in the dispatch process. This is simply another way of saying that a cost-based dispatch market increases rather than reduces the day-to-day regulatory burden on the market monitor and regulator relative to a bid-based market. Filed variable costs must be continually monitored to insure that consumers and suppliers are not excessively burdened by inflated variable costs numbers. In a bid-based market this prudency check is unnecessary if suppliers face sufficient competition, because they will find it unilaterally profit-maximizing to reflect their minimum costs of supplying electricity in the bids they submit to the spot market.

4. Monitoring the Central American Electricity Market

This section has four goals. The first is to propose a market monitoring process within the current seventh market paradigm used by the CRIE. The second goal is to describe the challenges facing the market monitoring process for this market operation and monitoring paradigm for the MER. I argue that certain aspects of this design can create significant opportunities for suppliers to engage in activities that degrade system reliability and market efficiency throughout the Central American region, particularly once the SIEPAC line is put into operation. Consequently, the third goal is to suggest modifications of this market operation and monitoring paradigm that limit these opportunities. These modifications recognize the highly integrated nature of the regional market that will exist with the completion of the SIEPAC line. For this reason, I argue that the current regional market design is best thought of as the first step in the transition to a full-integrated regional market, rather than as a seventh market that operates independently of the six national markets. The fourth goal is to propose an action plan for the development of a regional market monitoring process for the MER (as required by the TOR given in the appendix attached to this document) that recognizes the existence of far greater opportunities for market participants to engage in behavior that is harmful to the reliability of the regional transmission network and the efficiency of the regional market following the completion of the SIEPAC line.

4.1. Market Monitoring Under Existing Paradigm for MER Operation

Assuming that the MER is a separate from the six country-level markets is likely to yield an effective market monitoring process if there are only limited opportunities for suppliers to trade energy between country-specific markets and the MER. The current transmission inter-connections between Central American countries are sufficiently small and unreliable for substantial amounts of electricity trading to take place. Consequently, virtually any market monitoring process based on should be adequate the

Consistent with the international experience with market monitoring discussed in Wolak (2004), the regional framework outlined earlier, the regional market monitor should have access to the data from operation of the MER. The regional market monitor should also be able to request additional information from participants in the MER, if this

4.2. Shortcomings of the Current MER Operating Paradigm

The limited amount of transmission capacity currently in place across the countries of Central America may give the false impression that there is little need for significant market monitoring activities for the regional market. One advantage of the limited interconnections across countries in Central America is that it bounds the magnitude of profits that suppliers can earn from exercising of market power in the regional market. Specifically, at the present time, it is very likely that there is not enough transfer capacity across the countries for many of the strategies that market participants might use to exercise market power (that also impose significant harm to market efficiency and system reliability) to be profitable enough to pay for the fixed cost associated with implementing them. However, with the significantly larger interconnections that will exist when the SIEPAC line is in place, many of these strategies could become sufficiently profitable to justify these up-front costs. For that reason, it is extremely important that the market monitoring process be in place far in advance of the completion of the SIEPAC line in order to anticipate and correct any potential problems before they have the opportunity to cause substantial harm to system reliability and market efficiency.

The fact that all Central American countries must currently rely on imported fossil fuels limits the magnitude of persistent across-country price differences in wholesale electricity, which further limits the size of potential harm. Similarities between the input fuel mix, customer mix and hourly load profiles across the countries increases the market-efficiency-enhancing benefits of regional market monitoring. For example, the share of hydroelectric capacity in the country's mix of generation capacity appears to be highly correlated with which industries in Central American are generally thought to operate most efficiently. For example, Costa Rica is often put up as the example of an extremely efficient industry. However, it also has, by far, the largest fraction of hydroelectricity capacity, at 71% of installed capacity. This implies that almost ¾ of the energy consumed in Costa Rica is produced from units with virtually no variable cost. There is only the opportunity cost of fossil fuel not consumed. Costa Rica's closest competitor is Panama with a hydroelectric share 57% of installed capacity. The market with the lowest fraction of hydroelectric capacity is Nicaragua with 16.5% of installed capacity. It generally thought to be the least efficient industry. (All of these figures are taken from Arellano (2003)).

This very informal analysis of market performance underscores the importance of rigorous competitive benchmark analyses as described in BBW (2002) for making more accurate comparisons of market performance across countries. This methodology controls for the impact of such inherent advantages as a lower input fuel prices or a largest share of hydroelectric capacity and determines which market is more efficient at translating input fuel costs and other input costs into output prices. Because of the similarity of the market structures in the six Central American countries, country-specific market performance measures computed using a common methodology should provide very valuable input to both the country-level and regional market monitoring process. These indexes could be used to identify what market rules enhance market efficiency and which market rules detract from market efficiency in each country. A necessary condition for computing these indexes is access to the market outcome data for each country. This underscores the need for the regional market monitor to have access to all of the data that each country-level market monitor collects.

4.2.1. Shortcoming of Seventh Market View of Regional Market

The view that the regional market is the seventh electricity market in Central America rather than an over-arching regional market that all suppliers and load-serving entities potentially have the opportunity to participate in could lead to the implementation of market rules that enhance the ability of suppliers to exercise market power. As noted above, once the SIEPAC line is put into operation the scope of regional trading of electricity will increase considerably. This increased scope of regional trading will dramatically increase the profitability of strategies that suppliers will use to exploit differences in market rules between the markets in specific countries and the regional market.

One potentially profitable strategy for all market participants is to arbitrage differences between the price set in the regional market for power in a given country and the price set by the system or market operator in that country. For example, a firm might purchase 10 MWh of electricity at $40/MWh in one country and then subsequently sell this same energy in the regional market for $50/MWh. While small transactions to exploit price differences across markets may not impose much harm to system reliability and market efficiency, as the size and frequency of these transactions increases, the potential harm to system reliability and market efficiency grows.

California provides an instructive example of this problem. Virtually all of the supplier strategies pursued during the period June 2000 to June 2001 were also employed during the first two years of operation of the California market. However, the overall performance of the market as measured by the efficiency that it translated input prices into electricity prices was comparable or superior to all other markets operating in the United States during the period. However, during the summer of 2000 when the amount of imports available from the Pacific Northwest declined considerably, these strategies occurred more often and imposed significantly more harm to system reliability and market efficiency. Moreover, the market rule changes implemented by the Federal Energy Regulatory Commission (FERC) effective January 1, 2001 to limit the amount of market power suppliers could exercise in California failed to recognize that California was only part of a larger regional market in the western United States. As a consequence, for the most part, these remedies enhanced the profitability and harm associated with suppliers in California exercising their unilateral market power. This point is discussed in detail in Wolak (2003a).

For this reason, it is better to learn from the experience of California and explicitly recognize that the Central American regional market integrates six separate markets to form a single market. This view explicitly recognizes both the major source of costs and benefits associated with the formation of a regional market. This view does not imply that all hydroelectric resources must be dispatched in a coordinated manner. The California experience shows this is not necessary in order to have an integrated regional market. California has more than 6,000 MW of hydroelectric resources within the state. The Pacific Northwest, primarily the states of Idaho, Oregon, and Washington, has approximately 32,000 MW of hydroelectricity capacity. Finally, the province of British Columbia in Canada has slightly less than 10,000 MW of hydroelectricity capacity. Energy from each of these three hydroelectric sources is sold in California almost every day. However, there is no coordinated dispatch of hydroelectricity resources at the regional level.

However, both of the out-of-state hydroelectric suppliers are free to use their water resources to meet local energy needs first, and this is in fact what they do. In-state hydroelectric suppliers submit bids to supply electricity from their units to the California ISO. Out-of-state suppliers in the Pacific Northwest and Canada also submit bids to provide imports to California. All of these bids compete against bids from in-state and out-of-state fossil fuel suppliers to determine which entities can sell energy in California. The regional coordination takes place to the extent that all of the suppliers providing energy to a given congestion zone in the California

ISO control area are paid the same price. This requirement limits the ability and incentive for suppliers to arbitrage locational price differences in a manner that degrades system reliability.

Countries in the Central American regional market should also be allowed to dispatch their hydroelectric resources as they see fit to serve their local needs. However, the regional market design should make the cost of these decisions to each country as transparent as possible. For example, if a country decides to withhold its hydroelectric resources from the regional market to provide insurance against future energy shortages inside its boundaries, the regional energy price should be allowed to rise to reflect the reduced supply from this country. In addition, if the decision of a country to withhold its hydroelectric resources turns out to be correct because hoped-for rainfall does not materialize, this country should not be required to sell its hydroelectric energy in the regional market unless it is appropriately compensated. The regional market should not perpetuate any subsidies across customer classes or over time that are part of any of the industries in any of the six countries. On the contrary, the regional market should be designed to limit the opportunities for suppliers in any of the countries to engage in behavior that degrades system reliability and market efficiency, even though it may be unilaterally profitable for that supplier.

The seventh market view of the regional market does not emphasize the importance of coordinating market rules across these markets to limit the opportunities suppliers have to engage in behavior that is harmful to system reliability in a given country but extremely profitable to a specific market participant. Another potentially large source of inefficiencies related to this issue results from operating a bid-based regional market on top a cost-of-service market in one country and a bid-based market in another country. If El Salvador is successful in transitioning to a cost-based dispatch market this should be less of a concern. However, if the regional market is ultimately composed of countries with bid-based and cost-based markets, one can easily imagine circumstances where a supplier in one country is required to submit cost-based bids in both the country-level market and the regional market. A supplier in a country with a bid-based market country may then sell power in its own market that it has arranged to purchase in the regional market from this cost-based bidder. In this way, suppliers in markets with greater flexibility may be able to exploit the limited flexibility given to suppliers in other counties. The possibility of this sort of strategic behavior should be recognized and accounted for in the regional market design.

These differences in market rules across countries and within countries (between the regional and national markets) can create significant opportunities for suppliers to raise prices in the regional or national market and profit from this anticipated price difference through a financial transaction. For this reason, a major goal of the regional market monitoring process should be coordinating market rules across the markets to limit these opportunities. This market rule coordination process should be completed before the SIEPAC line is put into service.

Another potential source of market inefficiencies from the seventh market view is the congestion management mechanism used in the regional market. The current version of regional market uses transmission loss functions across countries computed from simulated power flows under a range of system conditions to set prices in the regional market that reflect transmission losses. Although these transmission loss functions are based simulations computed from a range of representative network models for the regional market, these loss functions do not account for the actual state of the transmission network at the time the market is operated. Moreover, these loss functions do not recognize the potential for transmission congestion within in each country's market in the process of determining locational prices in the regional market. As Bohn, Caramanis and Schweppe (1984), henceforth BCS, note, the price of electricity should account for line losses associated with a complete characterization of the actual transmission network configuration at time the system is dispatched. The BCS approach does not price transmission losses using a loss function computed from simulations of transmission losses under representative system conditions. It uses the most up-to-date estimate of the configuration of the transmission network at the time the generation units will actually operate.

Specifically, the BCS optimal locational pricing mechanism minimizes the total cost of meeting all demand throughout this estimate of the actual transmission network, accounting for transmission losses, and transmission capacity constraints. As BCS note, a first step in determining the optimal locational price in their procedure is the selection of what they call a "swing bus." According to BCS, all locational prices are set relative to this swing bus. The optimal price is then the sum of the price of energy at the swing bus, scaled up by transmission losses to deliver to this location, plus terms that reflect the costs of transmission constraints in the network constraining the ability of suppliers to deliver electricity to this location in the network. Another way to express the BCS optimal locational price is as the increase in the minimized system-wide costs associated with serving one more unit of demand at that location in the transmission network in a manner that respects transmission constraints and line losses.

One lesson from electricity re-structuring in the United States is that changes in the transmission network representation that simplify the BCS locational pricing algorithm must recognize that these simplifications create opportunities for suppliers to earn profits from exploiting differences between the actual transmission network relevant for a given hour of the day and the transmission network model used to by the market operator to set prices. For example, until very recently, the New England ISO ran a single price market which set a uniform price for energy each hour throughout the entire New England control area, whether or not there was transmission congestion. Generation units dispatched out of merit order because of congestion were paid an uplift charge as compensation. New England ISO operators quickly discovered that the incidence of out-of-sequence generation dispatch instructions increased substantially, because suppliers were able to profit from differences between the actual transmission network (which experienced congestion) and the transmission network used to set the market price (which assumed congestion could not occur).

California runs a zonal market similar to the Central American regional market, although this zonal market does not price transmission losses. Suppliers are routinely able to take advantage of the fact that energy accepted in the zonal market-clearing process can not be used in real-time to meet actual system demand because of the location of the generation resource relative to the location of demand. Under the California market any energy accepted in the day-ahead zonal market is paid the day-ahead zonal price, even if it is subsequently bought back from the ISO in real-time by the generation unit owner because this energy cannot be used to meet real-time demand. This subsequent purchase back from the ISO typically occurs at a price substantially below the day-ahead zonal price, so that the supplier can effectively get paid a positive sum of money for doing nothing. This strategy is so infamous in California that it has its own name—the DEC game.

When the California Power Exchange (CALPX) was in operation, under this strategy a supplier would bid low enough into the day-ahead zonal market to obtain a day-ahead energy schedule of say 50 MWh at the zonal price of $40/MWh. However, this energy could not be used to serve load in real-time because of its location in the transmission network. In real-time this supplier would buy this 50 MWh back from the ISO typically at a lower price, say $10/MWh. In this case, the supplier would earn $1500 = ($40/MWh - $10/MWh)*50 MWh for scheduling 50 MWh in the day-ahead market and then buying this energy back at a significantly lower price, while not having to produce any actual electricity. This strategy is profitable because the day-ahead energy market does not recognize all of the transmission constraints that are relevant to actual system operation in the price-setting process.

These same concerns also relevant to the Central American electricity market because it sets zonal prices using across-country transmission loss functions (what are called CVT curves) in a radial transmission network model of the Central American region. The BCS optimal locational marginal pricing approach would employ a looped network model for the entire Central America region to set prices at each location in the Central American regardless of which country it is located in. Similar to the case of the New England ISO single price model and California zonal model, ignoring transmission constraints within countries in the regional market pricing process by employing a simplified regional network model can create opportunities for market participants in the regional market to exploit differences between the actual regional transmission network and the model of it used to set prices that introduce harmful market inefficiencies.

While there are a number of ways to prevent suppliers from exploiting differences between the transmission network configuration used to operate the system and the configuration used to set electricity prices, the major lesson for the Central American market is that this issue must be addressed through some explicit regulatory intervention if a zonal market design is retained for the regional market. Otherwise, suppliers will find profit-making opportunities such as those described above too tempting to resist, particularly in a market with more transmission capacity across countries, as will be the case with the SIEPAC line in place.

The pricing of transmission losses using these CVT functions also appears to provide a further an invitation for suppliers to attempt to exploit differences between the prices they are paid for energy in the national market of each country (that does not typically price transmission losses) and the regional market (that does price transmission losses). Because of the small interconnection capacity between the countries that currently exists, the actions suppliers take to exploit these profit opportunities may not significantly harm system reliability or market efficiency under most system conditions. Alternatively, these actions may not be sufficiently profitable given the present amount of interconnection capacity across the markets to justify their implementation. This circumstance is unlikely to continue to be the case when the SIEPAC line is put into service.

This potential for significant harm to system reliability and market efficiency from market participants exploiting rule differences between the markets in each country and the regional market when the SIEPAC line is in operation suggests are alternate view of the development of the regional market. Specifically, the regional market should balance two competing goals: (1) limit the ability of market participants to exploit these market rule differences, and (2) harmonize market rules across countries as quickly as possible, with the ultimate goal of a single integrated regional market.

4.3. Transition to a Single Central American Electricity Market

This section outlines a transition process to a single Central American electricity market. While the ultimate goal is a single integrated market for all six Central American countries, the fact that such an outcome has not yet occurred in many parts of the US suggests that this could be an extremely long transition process. I will describe specific market rules that should be put in place during the initial stages of the regional market to insure this result occurs as rapidly as possible, without exposing consumers to significant risk of harmful market outcomes. An important component of this transition mechanism is an effective regional market monitoring process. Therefore, the subsequent section discusses the development of a regional market monitoring process to achieve the ultimate goal of a fully integrated regional market. A major focus of this discussion is how this regional market monitoring process would interact with the country-level regulators and the regional market regulator.

4.3.1. Transitional Market Rules

The initial stages of the Central American market should focus on facilitating exchange between countries, rather than facilitating exchange between market participants across countries. There are three major reasons why this is the most prudent approach to developing an integrated Central American market as rapidly as possible without exposing market participants to the risk of significant harm. This approach to regional market development will limit the opportunities for suppliers to engage in behavior that may be privately profitable but very harmful system reliability and market efficiency. For example, the fact that Costa Rica has a vertically-integrated monopoly supplier of electricity and El Salvador currently operates a bid-based spot market suggests the regional market participants in either of these countries may be able to exploit differences in market rules between their national markets and the regional market behavior, to the detriment of system reliability and market efficiency.

The second reason relates to the difficulties associated with monitoring an inter-regional market where a market participant in any country can buy or sell from a market participant in any other country, versus monitoring a market where all trades must take place across countries through their respective system operators. Because of the enormous legal and administrative difficulties associated with market monitoring across national boundaries, a country-to-country market should be the most manageable approach to sorting through these difficulties. Successfully dealing with these legal and administrative challenges for a country-to-country regional market will significantly reduce the cost of dealing with them for an agent-to-agent regional market.

The final reason is related to the first two. Participation in the Central American market is voluntary. The geography of Central American implies that the success of this regional market depends crucially on all six countries being willing to participate in this market. Consequently, restricting trade in the regional market to transactions between market and system operators in the various countries appears to be the best way to provide adequate assurances to stakeholders and politicians in the six countries that they have the ability to protect their domestic interests during the initial stages of the market. Market rules that focus on inter-country trade initially should receive more support from the political process in all of these countries, which should speed the development of the Central American regional market.

It should be emphasized that these initial restrictions on inter-regional electricity trading among individual market participants in each country should be removed as soon as the regional market monitoring process is sufficiently well developed in terms of both its legal foundation and its expertise and experience to counter the greater risk of harmful market outcomes that can result from increased opportunities for inter-regional trading.

Although there many different ways to implement this initial phase of the regional market, at a minimum, there should be a hierarchical relationship between the country-level market and the regional market in the sense that all transactions across countries should take place through the country-level market or system operator. A straightforward way to implement this hierarchical relationship would be to require all markets to submit their excess supply curves from their country-level markets to the regional market operator. Following the completion of the day-ahead scheduling process, each country would submit to the regional market operator the excess supply function coming out of their market.

To see how this would work, consider the following simple example. Let $S_j(p)$ denote the aggregate bid supply curve for country j and $D_j(p)$ the aggregate bid demand curve. The excess supply curve for country j is $ES_j(p) = S_j(p) - D_j(p)$. Countries that don't operate formal wholesale markets, could simply submit an excess supply function to the regional market operator. Given the six country-level excess supply functions, the regional operator could then solicit demand bids for the regional market from the operators in each of the six countries and prices in the market could be determined by minimizing the as-bid costs of meeting these country-level demands accounting for transmission losses (as estimated by the CVT functions) and treating these excess supply bid curves as each country's willingness to supply power to the regional market. This approach to operating the regional market would limit the ability of specific suppliers to exploit both spatial and temporal differences in prices in the Central American market because all bids a market participant makes in its own market would remain valid for the regional market.

Operating the regional market in this manner limits the opportunities for individual market participants to exploit differences in market rules across the six countries, yet still allow economically beneficial trades of electricity to take place across the countries. This is accomplished by requiring that a bid in any country's wholesale electricity market is also a bid in the Central American regional market. With the existing transmission capacities across countries, it is unlikely that this scheme will lead to significant transfers of electricity across countries. With the expanded transmission capacity across countries that the SIEPAC line will bring there is the possibility of significant transfers across countries. For this reason, individual countries should also have the option to end this excess supply curve at any quantity of net sales or purchases. For example, if $ES_j(p)$ is the unrestricted excess supply curve for country j, the system operator for this country should be able to specify values of purchases and sales in the regional market at which $ES_j(p)$ becomes completely inelastic with respect to price. The option for a country to set minimum and maximum values on $ES_j(p)$ provides it with further flexibility to limit the amount it will participate in the regional market. However, it is important to emphasize that imposing restrictions on trading in the regional market in this manner is consistent with the goal stated earlier that each country should bear the full costs of its decision not to participate in the regional market to the extent that it is economically able to.

For example, if the demand for energy in the regional market is sufficiently high and this country decides to set the point at which its excess supply bid function, $ES_j(p)$, becomes vertical at a relatively low level, then prices in the regional market for this country (as well as in other countries) could be very high. To make this example more concrete, suppose Country A has 100 MWh of untaken bids from its own wholesale market at prices less than price cap in the regional market, but instead chose to limit the amount it would sell in the regional market to 50 MWh. If the demand in the regional market is sufficiently high, then Country A risks setting a price in Country A in the regional market and prices other countries in the regional market that are close to the price cap in the regional market because it is withholding supply from the regional market. Conversely, if Country A has sets a small lower limit on the amount of energy it will buy back from the regional market, then it risks setting very low prices in the regional market if there is a significant amount of supply bid into the regional market at low prices.

The ability of the system operator in a country to limit the amount of trading in the regional market should be retained in the second phase of the regional market, when all market participants within each country are permitted to participate in the regional market. The market should transition to this next phase only if the regional market regulator in consultation with the regional market monitor and country-specific regulators is confident that consumers in the six countries are unlikely to experience significant harm as a result of this market rule change. This phase in the regional market should allow individual suppliers the option to impose upper and lower bounds on how much of their bids into their country's market can be used in the regional market. For example, immediately following the close of their country's day-ahead market, each supplier would be notified how much energy they are required to supply. Each supplier would then be allowed to specify an upper bound on the amount of additional energy it is willing to sell in the regional market or the maximum amount of energy it is willing to buy from the regional market.

Specifically, each market participant has the option to specify where its own aggregate excess supply bid curve becomes vertical both above and below the market-clearing price in their own country's wholesale market. Each supplier's bids are still required to be the same in both the country-level market and regional market. The major change from the first phase is that each market participant can specify minimum and maximum amounts that it is willing to buy or sell in the regional market. The system operator in each country would also retain the option to place limits on the aggregate amount of transfers in and outside of its boundaries.

The final stage of the market would allow and market participants to submit different bids the market in their country and the regional market, but the rule that allows the system operator in each country to limit the total amount of transfers across the countries would be retained. The market should transition to this phase only if the regional market regulator in consultation with the regional market monitor and country-specific regulators is confident that consumers in the six countries are unlikely to experience significant harm as a result of this market rule change.

The option for the system operator to limit flows across the markets is needed for two reasons. The first concerns the reliability problems associated with managing large flows across the countries. In particular, because the regional market does not price all possible congestion in each of the countries in the regional price-setting process, the system operator in each country must have the ability to limit inter-regional transfers so that it has the ability to manage this within country congestion using its own resources in real time. The ability to limit inter-country transfers also gives the system operator in each country the ability to limit the magnitude of inter-regional trading by specific market participants aimed at exploiting differences in market rules across the countries as described above. For example, if in either the second or third phase of the transition, the system operator in one or more countries or regional market regulator or market monitor finds that significant amounts of this sort of trading is taking place, then regional market regulator can limit the amount of trading in the regional market for any country, or any country can unilaterally limit the amount of flows in and out its market.

4.4. Transitional Regional Market Monitoring Process

The development of the regional regulatory process should be coordinated with the transition to a fully integrated regional market. Because the Central American market encompasses six countries, overseeing this multi-country market is far more challenging than would be the case if it that same geographic market was contained in any single country. Participants in the regional market are only bound by the SIEPAC treaty signed by their respective governments. Consequently, at any time in the future a single country or group of countries could refuse to abide by a pre-existing or proposed regional market rule. If this happens, the remaining countries in the market can do very little to punish this behavior relative to what would be possible if the market was under the legal jurisdiction of a single country. This implies that the regional regulatory and market monitoring process must place much less reliance on explicit penalties and sanctions and other forms of coercion to obtain compliance with market rules.

The market monitoring process must instead rely on the promise of future benefits from current compliance with the regional market rules and the cost of unfavorable publicity in the court of public opinion associated with violating a market rule. The lack of a comprehensive legal foundation for the regional market regulatory process implies that the credibility of its regulatory process depends crucially on the credibility of the national regulatory process in each country and the willingness of country-level regulators to enforce the decisions of the regional regulator. Specifically, if the decision to impose penalties or sanctions on a market participant or country by the regional regulator is enforced by the relevant national regulator, this will significantly increase the credibility of the regional regulatory process.

The procedure the regional regulator uses to determine behavior harmful to system reliability and market efficiency in the regional market also requires the assistance and support of the national regulators. In this case, the regional regulator may be forced to pit the national regulators in several countries against the national regulators in several other countries. This can occur because the market participant or country engaging in this behavior in the regional market may be the state-owned company or other politically-favored company in one country. Under these circumstances, the regional market monitor must coordinate with the country-level regulators to ensure that it is able to take the appropriate action in the regional market and that these actions will be enforced by the national regulator in the country of the market participant that is engaging in the detrimental behavior

More generally, one very important lesson from wholesale market regulation in the US is that a successful wholesale electricity market requires close cooperation between state regulators and the federal regulator, something that is still a work in progress in the US. Although the market oversight process would seem to be enhanced by setting up a hierarchy where the state regulators are subservient to the federal regulator, this approach does not work in the US, because states effectively have the ability to opt out of this process if they are dissatisfied with the federal regulator, often to the detriment of consumers within their jurisdictional boundaries. As noted above, similar logic applies to the six countries in the Central American regional electricity market. Consequently, the design of the regional regulatory process must recognize that the primary source of the regional regulator's authority is the authority of the national regulators. Even though the SIEPAC treaty may have endowed the regional regulator with specific powers, as noted above, the regional regulator has little recourse if one country or a group of countries unilaterally decides not to obey certain regional market rules

4.4.1. Independent Market Monitoring Committee

One solution to this problem is an independent regional market monitor or market monitoring committee for the Central American electricity market. An independent source of information about and analysis of the performance of the regional market and the markets in each of the six countries would improve both the credibility and overall effectiveness of the regional regulatory process. Particularly, during the early stages of the market, the regional regulator will most likely spend a significant fraction of its time trying to convince country-level regulators that certain market participants in their countries may be taking actions that a contrary to the goal of a fully-integrated regional market. Consequently, it is essential that the regional regulatory process have access to the best available data and economic analysis. In addition, this analysis must also be effectively communicated to as wide an audience as possible because the regional regulator will often have to make its case in the court of public opinion rather than in any formal court of law.

Because the option of compelling market participants or system operators and market operators in specific countries to behave in a certain way under threat of penalties is not generally available to the regional regulator, public persuasion will play a far greater role. If the regional regulatory process has access to the best possible information on market performance and state-of-the-art independent economic analysis, this part of its job will be much easier. Particularly during the earlier stages of the market, the regional regulatory process will resemble negotiating multilateral electricity trading arrangements among countries and their regulators rather than a traditional regulatory process.

A major role of the market monitoring process during the early phases of the regional market will be to convince the politicians and regulators in the relevant countries that the regional market is providing economic benefits to consumers in their country despite the fact that certain stakeholders in each country that may experience profit losses as a result of the operation of the regional market. This fact further emphasizes the importance to the market monitoring process of: (1) having access to the best possible data and methods of analysis, (2) communicating the results to this analysis to a wide audience, and (3) being financially independent of any market participant and regulator, including the regional regulator.

The regional market monitoring process should collect a standardized set of information from each country. The first step in this process should be collecting all information used by the system operator and market operator (if one exists) to operate the system and market (if one exists) in that country, as well as all output produced by the system operator and market operator in each country. All countries should be required to supply this information to the regional regulator and independent market monitor as a pre-condition to participate in the regional market. The regional regulator and market monitor should also have access to all information submitted to the regional market operator and produced by the regional market operator. This data collection and compilation process implies that a significant staffing component of the regional market monitoring process is data compilation and management.

Because the regional regulator should also have access to this same data, one way to keep the staff of the independent regional market monitor at manageable size is to make the database management staff and computer support staff employees of the regional regulator. Only professional staff performing data analysis and writing reports on the performance of the regional and country-level markets need to be employees of the independent regional market monitor. This is independence from the regional regulator is necessary because as employees of the regional regulator, the staff of the regional market monitor may be less inclined to do things that are contrary to the wishes of the regional regulator.

Although the independent regional market monitor and regional regulator are financially independent entities, both should be funded by market participants through a $/MWh charge collected on all transactions through the regional market. This charge should be assessed on all energy purchased through the regional market. There is a natural separation of duties between the regional regulator and the independent regional market monitor. The major goal of the regional regulator should be ensuring compliance with market rules and taking actions to ensure the most efficient market performance possible, specifically enforcing the provision that market participants should not engage in persistent behavior that degrades system reliability or market efficiency. The major goal of the regional market monitoring process should be analysis of market performance and the diagnosis of market inefficiencies uncovered through the analysis of market performance and the formulation of remedies for these market inefficiencies.

Like any regulator, the regional regulator should have the ability to assess penalties and sanctions, although as noted earlier, the regional regulator should recognize that ultimately its authority to do so comes from the country-specific regulators. Consequently, the staffing of the regional regulator should be the similar to any of the country-specific regulators, but in recognition of the need to work closely with the country-level regulators, a portion of the regional regulatory staff should be staff from the six country-specific regulators on temporary leave from their position.

The independent regional market monitoring committee should be staffed with experts in power systems engineering, economics, and law. There should be at least three members of the committee and no more than four members. The ability of the committee to function effectively is reduced if the committee is any larger than four. The committee should be appointed jointly by the regional market operator and regional regulator in consultation with the six country-level regulators. Because the independent market monitoring committee will interact with each of these entities it is important that each is part of the appointment process. To keep the administrative burden associated with the appointment process manageable, the ultimate approval of the committee should be left to the board of governors of the regional market operator, subject to the approval of the regional regulator. This means that if regional market operator board of governors approves the candidates, the regional regulator still must also approve the candidates. The role of the regional regulator's ultimate approval is required to ensure the independence of the committee members from the regional market operator.

Initially, one or more members of the committees should be international experts with experience in electricity market monitoring. These committee members could be appointed for a one-year during which they would help train other committee members and the analytical staff on international best practices in electricity market monitoring. In addition, having international experts would help establish as quickly as possible the credibility and independence of the regional market monitoring process. An alternative approach could be to establish a committee composed of regional experts with international experts initially hired to help train the local experts in electricity market monitoring. The approach of initially having one or two international members with terms of one to two years seems far superior from the perspective of establishing the most effective market monitoring process possible. However, this approach may entail greater expense but the benefit appears to be that international experts will be actively involved in the market monitoring process. In particular, these experts will find it necessary to acquaint themselves with the details of the operation of the regional market and the data produced by the regional market and country-level markets, rather than simply provide advice on market monitoring in the abstract.

The process of being an actual market monitoring committee member will also require the international experts to take an active role in formulating remedies to market design flaws in the Central American regional market and the country-level markets. Finally, because they are international experts appointed to finite terms, the likelihood that they can be influenced by the specific countries or the regional market operator seems unlikely. For this reason, a committee with one or two international experts will more rapidly establish the credibility of this regional market monitoring process and the credibility of the regional market regulatory process.

As discussed above, the three major tasks of the independent market monitor are analysis of market performance, diagnosis of market design flaws and suggested remedies for these market design flaws. Although the market monitor may make recommendations as to whether penalties or sanctions should be imposed on specific market participants, the regional market regulator should make this decision. For market monitoring to be most effective, it should remain within the realm of smart information provision as described earlier.

4.4.2. Regional Market Monitoring Committee as a Facilitator of Information Exchange

A final aspect of the regional market monitoring process deserves emphasis. That is the necessity of communication between the regional market monitor and all market participants and market and system operators in the regional market and all of the country-level markets. The ability to interact freely with all of these entities is essential to producing the best possible analyses of market performance, diagnoses of market design flaws and the solutions to market design flaws. Because of this need for open lines of formal and informal communication with all market participants and regulators, the independent market monitoring committee must necessarily have no explicit power over any entity. Otherwise, disgruntled market participants might be inclined claim that the market monitor was not following due process in making a decision. On the other hand, because the regional regulator can assess penalties and sanctions and implement market rule changes, it must be particularly careful to follow due process and be particularly circumspect about how it interacts with market participants and market operators.

In closing, an independent regional market monitoring committee can help to solve many of the regulatory challenges faced by a multi-country wholesale electricity market. A regional market involving this many countries and with the range of industry structures that exists in Central American has not been attempted anywhere in the world. As noted above, the informational requirements associated with this market monitoring process are substantial. For the reasons discussed above, a region market monitor may be the best possible way to provide this information to the regional market regulatory process.

5. Summary of Recommendations

Experience with inter-regional market integration in the United States suggests that as the amount of available transmission capacity across Central American countries increases, opportunities for suppliers in individual countries to exploit market rule differences between the market in their country and the regional market will increase. Many strategies that impose significant harm to system reliability and market efficiency are likely to become extremely profitable.

This logic suggests an approach to regional market development that initially limits inter-regional trading to the system operators in each of the six countries. Although there are a number of ways to accomplish this goal, the general recommendation given in this report is a hierarchical relationship between the national market and the regional market, where the primary obligation of suppliers in each country is to meet local energy needs, although each country-level market operator should be allowed to trade electricity to the extent it is comfortable.

In fact, the goal of this phase of the regional market is to increase the degree of comfort the politicians and the system operator in each country have with regional electricity trading. This report recommends initially operating the regional market using excess supply functions computed from each country-level market with each market operator allowed to limit the volume of trading it is willing to do with all other countries.

As the degree of coordination between market rules in the six Central American countries increases, greater flexibility to participate in the regional market should be afforded to specific market participants, rather than simply restricted to system operators. This report proposes a transition process that is managed by the regional regulator, working with a new regional entity, an independent regional market monitoring committee.

This committee should be composed of international experts on electricity market monitoring with expertise in economics, engineering and competition law. The primary role of the independent regional market monitoring committee is the provision of "smart sunshine" regulation. This primarily takes the form of gathering data from all of the six country-level markets and the regional market and performing quantitative and qualitative analyses of market performance, market participant behavior and system operator behavior. Data analysis by this market monitoring committee will provide essential input to the regional regulatory process.

The independent market monitoring committee will foster the transition to a more fully integrated regional electricity market in the following three ways. First, the committee will periodically analyze the performance of the regional market and determine whether it is prudent to remove restrictions on which firms can participate in the market or alter the rules governing their participation. Another major role for this committee is to identify market rule differences across countries that can degrade system reliability and market efficiency, and to suggest market rule changes that eliminate these market efficiencies. The third way is to provide input into any decision made by the regional market regulatory to impose penalties for a market participant engaging behavior that is detrimental to system reliability and market efficiency following the process outlined in Section 2.4.

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Appendix
Competition in the Regional Energy Market in Central America
TOR for Consultant Frank Wolak

Background

The establishment of a regional energy market, a goal cherished for more than twenty years by the six countries of the region, is about to become reality with the ratification of the Energy Integration Treaty, the creation of the institutions designed to govern the market, the regional regulator CRIE, the Market operator, EOR and to build and operate the main transmission line of the SIEPAC project which will be commissioned by 2005. The MER is operating on a limited basis under the constraints imposed by the existing infrastructure. Detailed rules of the new market are close to completion.

The MER has raised high expectations in the region. It is hoped that its functioning will not only lead to an optimal allocation of region's energy resources, but will allow real competition in an enlarged market as opposed to the limited competition experienced in small individual markets. The existence of a competitive MER is a crucial feature of the whole integration market and it becomes critical to identify the scope for exercising market power implicit in market structure and market architecture. MER rules are structured as a seventh market superimposed on individual markets and deserve special attention.

Within the support activities to the Plan Puebla-Panamá (PPP) in 2002, SDS/IFM hired the consultant Maria Soledad Arellano to make a preliminary identification of the opportunities for exercising market power implicit in the structure and architecture of the Mercado Eléctrico Regional (MER) as a first stage in the elaboration of more detail studies to identify effective amelioration measures. This study was distributed to the regulators and system operators of the members of MER. The second stage of the study envisages the identification of the amelioration measures and elaboration of an action plan, is the subject of this TOR

OBJECTIVES

The objective of this consultancy is to identify an action plan for activities to be undertaken by the CRIE in order to design and put in place the necessary mechanisms for the surveillance of competition in the MER. In doing so the consultant will make an appraisal of the state of competition in the individual existing markets and the MER as it has been proposed.

ACTIVITIES

1. **Review of existing documentation.** The consultant will review the existing documentation on the MER and will discuss with Bank officials the scope of the work in an initial visit to Washington D. C.

2. **Field Trip.** The consultant will make a field trip to the Headquarters of the CRIE in Guatemala and the EOR in San Salvador to discuss with members of both institutions and the SIEPAC details of MER. While in both countries, the consultant will also discuss details of their individual markets with the operators and regulators. During the trip the consultant will be accompanied by an IDB official, which will be in charge of arranging the meetings and making the relevant contacts.

3. **Elaboration of an action plan**. Based on the previous analysis the consultant will prepare an action plan including a description of the best instruments, given the particular institutional and human resources constraints existing in the region that would allow CRIE to develop a healthy competitive market. This action plan will consider institutional and structural measures and will estimate the resources and further studies required to implement them.

Deliverables

1. Market Power Issues in the Individual Countries and in the MER. This preliminary report will detail the functioning and structure of the markets seeking to highlight the opportunities for exercising market power in each one of them and an outline of the possible mitigation actions. To be delivered 3 weeks after completion of the field trip.
2. Action Plan. Based on discussions of the preliminary report with Bank's officials and CRIE members the consultant will prepare a draft of the action plan and submit it to the Bank by October 31 2003. Once Banks and CRIE officials have issued comments the consultant should submit the Final report by December 15, 2003.

Supervision

The work will be supervised by Jaime Millán from SDS/IFM and Gonzalo Arroyo from RE2/FI2. The Bank will make available to the consultant all information available on the subject and will be responsible for making contacts with country and regional officials for required purposes including arrangements of the field trip.

Honorarium and Payments

The Bank will recognize for this job the equivalent of 18 days of honoraries at US$ 850 per day for a total of US$15,300. The Bank will also reimburse the consultant the amount of US$2,700 for travel in economy class for the two trips needed for these consulting services: a) San Francisco-Washington- San Francisco and b) San Francisco-San Salvador-Guatemala-San Francisco. In addition, it will pay one day per diem in Washington D.C. and travel related cost for a total amount of US$300; three days per diem in El Salvador and travel related cost for a total amount of US$492 (per diem per day: US$ 164); and three days per diem in Guatemala and travel related cost for a total amount of US$534 (per diem per day: US$ 178). The consultant will receive 50% at signing of contract and 50% at satisfactory completion of the assignment.