THE WORLD BANK

CENTRAL AMERICA

Regional Programmatic Study for the Energy Sector

CENTRAL AMERICA REGIONAL ELECTRICITY MARKET STUDY

DRAFT FINAL REPORT
October 2, 2009

LIST OF ACRONYMS

AGC	Automatic Generation Control
AMM	*Administrador del Mercado Mayorista* (Administrator of the Wholesale Electricity Market, Guatemala)
ARESEP	*Autoridad Reguladora de los Servicios Públicos* (Public Utilities Regulatory Authority, Costa Rica)
ASEP	*Autoridad Nacional de los Servicios Públicos* (National Authority in Public Services , Panama)
CA	Central America(n)
CAF	*Corporación Andina de Fomento* (Andean Development Corporation)
CABEI	Central American Bank for Economic Integration
CAFTA	Central America Free Trade Agreement
CCHAC	*Comité de Cooperación de Hidrocarburos de América Central* (Central America Hydrocabons Cooperation Committee)
CEAC	*Consejo de Electrificación de América Latina* (Central America Electrification Council)
CEL	*Comisión Hidroeléctrica Ejecutiva del Río Lempa* (Salvadorian state-owned power utility)
CENACE	*Centro Nacional de Control de Energía* (National Center for Power Control, Mexico)
CFE	*Comisión Federal de Electricidad* (Mexican state-owned power utility)
CND	*Centro Nacional de* Despacho (National Dispatch Center, Panama)
CNE	*Comisión Nacional de Electricidad* (National Electricity Commission, Honduras)
CNE	*Comisión Nacional de Energía* (National Energy Commission, Nicaragua)
CNE	*Consejo Nacional de Energía* (National Energy Council, El Salvador)
CNEE	*Comisión Nacional de Energía Eléctrica* (National Electricity Commission, Guatemala)
CNFL	*Compañía Nacional de Fuerza y Luz* (Costa Rican state-owned power utility)
CRIE	*Comisión Regional del Interconexión Eléctrica* (Regional Regulator)
CVT	*Cargos Variables de Transmisión* (Variable Transmission Charges)
DEE	*Dirección de Energía Eléctrica* (Power Directorate, El Salvador)
DT	Derecho de Transmission (*Transmission Right*)
EIA	Energy Information Administration
ENATREL	*Empresa Nacional de Transmisión Eléctrica* (National Transmission Company, Nicaragua)
ENDESA	Spanish power utility
ENEE	*Empresa Nacional de Energía Eléctrica* (Honduran state-owned power utility)
ENEL	*Empresa Nicaragüense de Electricidad* (Nicaraguan state-owned power utility)
EOR	*Ente Operador Regional* (Regional Operator)
EPR	*Empresa Propietaria de la Red* (Regional Transmission Company)

ETESAL	*Empresa Transmisora de El Salvador* (Salvadorian Transmission Company)
ETESA	*Empresa de Transmisión Eléctrica* (Panamanian Transmission Company)
GDP	Gross Domestic Product
GGD	*Grupo Generador a Despachar* (Dispatchable Generation Unit)
GGP	*Grupo Generador* (Generation Unit)
IADB	Inter-American Development Bank
IAR	*Ingreso Anual Autorizado* (Authorized Annual Income)
ICE	*Instituto Costarricense de* Electricidad (Costa Rican national power utility)
ICP	*Interconexión Eléctrica Colombia-Panamá (*binational company for the Colombia-Panama interconcection)
INDE	*Instituto Nacional de Electrificación* (Guatemalan state-owned power utility)
INE	*Insituto Nacional de Energía* (Nicaraguan state-owned power utility)
IRHE	*Instituto Nacional de Recursos Hidráulicos y Electrificación* (Panamanian state-owned power utility)
ISA	*Interconexión Eléctrica* (Colombian transmission company)
IPP	Independent Power Producer
kWh	Kilowatt hour
LAC	Latin America and the Caribbean
LNG	Liquefied Natural Gas
MC	*Mercado de Contratos* (Contract Market)
MEM	*Ministerio de Energía y Minas* (Ministry of Energy and Mines, Nicaragua)
MEM	*Mercado de Electricidad Mayorista* (Wholesale Electricity Market, El Salvador)
MEM	*Ministerio de Energía y Minas* (Ministry of Energy and Mines, Guatemala)
MEMN	*Mercado de Energía Mayorista de Nicaragua* (Wholesale Electricity Market, Nicaragua)
MER	*Mercado Eléctrico Regional* (Regional Electricity Market)
MINAET	*Ministerio del Ambiente, Energía y Telecomunicaciones* (Ministry of Environment, Energy and Telecommunications, Costa Rica)
MM	*Mercado Mayorista* (Wholesale Electricity Market, Guatemala)
MME	Mercado Mayorista de Electricidad (Wholesale Electricity Market, Panama)
MM	*Mecado Mayorista* (Wholesale Electricity Market)
MWh	Megawatt hour
MRS	*Mercado Regulador del Sistema* (System's Market Regulator)
OECD	Organization for Economic Co-operation and Development
PIEM	Program for Mesoamerica's Energy Integration
PM	*Participante del Mercado* (Market Participant)
PPA	Power Purchase Agreement
PPP	*Plan Puebla-Panamá*

REDCA	*Red Centroamericana de Fibras Ópticas* (Central American Telecommunications Network)
RMER	*Regulación del Mercado Eléctrico Regional* (MER regulations)
RTR	*Red de Transmisión Regional* (Regional Transmission Network)
SENER	*Secretaría de Energía* (Energy Ministry, Mexico)
SERNA	*Ssecretaría de Recursos Naturales y Ambiente* (Environment Ministry, Honduras)
SICA	*Sistema de Integración Centroamericana* (Central America Integration System)
SIEPAC	*Sistema de Interconexion Electrica para América Central* (Central American Electrical Interconnection System)
SIGET	*Superintendencia General de Electricidad y Telecomunicaciones* (General Superintendence of Power and Telecommunications, El Salvador)
SNI	*Sistema Nacional de Interconexción* (National Interconnected System)
TOE	Tonne Oil Equivalent
TPES	Total Primary Energy Supply
TWh	Terawatt hour
USD	United State Dollars
UT	*Unidad de Transacciones* (System Operator and Market Administrator of the Wholesale Electricity Market, El Salvador)

Vice President:	Pamela Cox
Sector Director:	Laura Tuck
Sector Manager:	Philippe Benoit
Task Team Leader:	David Reinstein

This report is the product of a collaborative effort between the World Bank and ESMAP. The report was prepared by a core Bank team consisting of David Reinstein (Task Team Leader), Almudena Mateos (LCSEG), and Alberto Brugman (consultant). Peer Reviewers included Jonathan Coony (ETWES), Luiz Maurer (AFTEG) and Pedro Antmann (ETWEN).

The Team is grateful for valuable guidance provided by Juan Miguel Cayo (Senior Energy Specialist), Fernando Lecaros (Consultant) and Philippe Benoit (Energy Sector Manager).

Central America Regional Electricity Market Study
TABLE OF CONTENTS

1. Executive Summary

INTRODUCTION AND CONTEXT OF THE STUDY

1. The six Central American countries of Panama, Costa Rica, Honduras, El Salvador, Nicaragua, and Guatemala share a long tradition of regional integration, including a common market, substantial intra-regional trade, as well as coordinated commercial policies, such as the Central American Free Trade Association (CAFTA) with the U.S.

2. In the electricity subsector the most significant example of regional integration consists of the SIEPAC[1] interconnection line, which is expected to link the six countries in early 2010. The interconnection has been a long term effort, starting in the early 90s and culminating in 2010, with the support of IDB and the Government of Spain, which required overcoming numerous obstacles given its multi-country character, before financial closure, which was achieved in 2003.

3. SIEPAC was designed to bring the benefits of integration to the six countries and to improve their national power systems. Due to the relatively small size of the power system in each of the region's nations, the opening of the regional market was seen as a means for creating a larger market that enhanced competition among power producers. The goal is for the regional market to gradually allow qualified agents to buy or sell electricity no matter where they are located in Central America. Additionally, a regional market with clear and uniform rules is expected to offer incentives for building larger and more efficient power plants, sparking investments that would help reduce the costs of electricity in the region and strengthen the reliability of its electricity systems[2].

4. The study on the Central America regional electricity market[3] is part of a programmatic energy study carried out to analyze different aspects and issues faced by the region through the development of four modules: overview, short-term measures, regulatory issues and renewables development. The overview module provides a broad outline of the energy sector, identifying major issues both at the regional and individual

---

[1] SIEPAC is the acronym for *Sistema de Interconexión Eléctrica para los Países de América Central*
[2] USAID 2008
[3] The Central American Region covers the isthmus connecting Southern Mexico to South America at Colombia. It is made up of seven countries with a combined population of around 40 million people. These are Guatemala, El Salvador, Honduras, Costa Rica, Nicaragua, Panama and Belize. The seventh country, Belize, is not part of SIEPAC. For the purposes of this study 'Central America' and 'the region' are used to refer to the six SIEPAC countries together unless stated otherwise

country levels. The short-term measures module examined the scope and effectiveness of both supply side and demand side actions to address actual or looming shortages, while the renewables development module analyzed the stage of development of different large power projects based on hydroelectric generation and geothermal sources in order to identify needs for advancing the underlying studies and the mechanisms required to finance them.

5. This module on regulatory issues was conceived to examine the medium to long term requirements oriented towards developing regional power plants and minimizing long term costs, which constitute the basic justification for the SIEPAC project. As the national markets evolve towards integration and increased trade, there are still barriers to full development of the regulation and implementation of the Regional Electricity Market (MER). This study first describes each of the national markets, including their rules for inclusion of international transactions, and then analyzes the legal, regulatory and institutional framework of the Regional Electricity Market. This exercise leads to the identification of barriers to the development of the regional electricity market and some courses of action that could help overcome them. Several of those barriers are already being addressed by the electricity regional and national regulatory bodies.

CHALLENGES FACED BY THE CENTRAL AMERICA ENERGY SECTOR

6. The energy sector in Central America faces several challenges[4]: (i) addressing the vulnerability to the fluctuations in oil prices, which has increased significantly in the last 15 years, mainly as a result of the shift from hydro to thermal based systems; (ii) keeping supply and demand in balance in a region that faces increasing shortfalls of electricity production; (iii) reversing an irregular track record regarding the regulation of the power sector and its financial sustainability; (iv) addressing weaknesses in the institutional foundations required to develop renewable resources, including hydro; (v) promoting the penetration of modern energies in the domestic sector of certain countries in the region; and (vi) improving access to electricity in several countries.

7. **The precarious balance of supply and demand makes Central America vulnerable to an electricity crisis.** Because individual country markets are small,

[4] See report for the Overview Module for a comprehensive description of issues and challenges in the Central America Energy Sector.

operating costs are disproportionately high. In those countries with strong state presence in the power sector, capacity additions are made at a loss which is absorbed by the state. In general, however, there is low system reliability due to insufficient generation capacity and/or insufficient transmission infrastructure. Should Central America not take the necessary measures to: (i) increase energy security; (ii) develop renewable energy potential; (iii) improve the efficiency of its power markets; and (iv) address the integration agenda more decisively, an energy crisis could be unavoidable.

8. **An enlarged, well-functioning market would gradually help Central America address some of the shortcomings of the electricity sector.** Countries in the region are expected to benefit from increased security and reliability of electricity supply from the early days of the interconnection. An improved investment environment that facilitates the financing of larger projects (e.g. regional hydroelectric plants) is expected to "naturally" follow. Savings from reduced operating and investment costs would be realized in the medium to long term, as the regional market consolidates and eventually evolves into more advanced pool arrangements. According to the regional organization CEAC, SIEPAC would produce savings on operation costs on the order of 4% and fuel savings of about 3% after 8-10 years based on indicative expansion planning exercises. In addition, preliminary estimates show that SIEPAC would result in 1 million tons of avoided CO_2 equivalent per year.

BACKGROUND ON ELECTRICITY INTERCONNECTIONS AND POWER POOLS[5]

9. The search for a more reliable and secure electricity supply has been the determining factor in the decision to build power system interconnections and to enter into inter-utility electricity exchange agreements among neighboring countries around the world. Development experience and operation of power pools in Europe and the United States indicate that the power pooling arrangements have, for the most part, evolved from simple interconnections between neighboring utilities to support each other in case of emergencies into more sophisticated formal legal entities with differing responsibilities in system operation and power market regulation.[6]

10. **Cross-border interconnections open up opportunities for the exchange of a range of energy services that enable a more reliable supply of electricity**. There are five main types of power exchanges that can happen between countries: (i) firm energy sales, (ii) backup exchanges for emergency support, (iii) marginal exchanges of spinning

[5] See Appendix 1 for a more detailed description on power pools

[6] ECA 2004

reserves; (iv) occasional exchanges, in which no guarantee of capacity is given; and (v) compensation exchanges made in kind[7]. These exchanges facilitate the delivery of reliable electricity supply at minimum cost as they lead to: lower generation capacity reserve requirements, the ability to achieve scale economies, the opportunity to interchange economic energy, an increase in load and fuel diversity, the creation of opportunities for sale of surplus firm energy, and the provision of emergency support on major break downs.[8]

11. In a developing country context, as is the case of the Central America Regional Electricity Market (MER), the creation of a regional power market by a group of smaller economies can reduce the risks and help the pool match supply and demand more efficiently. The existence of a pool enhances a project developer's ability to finance and construct power generating facilities that are closer to available energy sources situated in smaller market economies, and utilizing cleaner and sustainable energy resources. A pool can make the development of a country's or sub-region's capital-intensive power projects more attractive to both domestic and international investors and lenders, reducing risks by creating a broader demand pool of utilities/off-takers for the production of proposed generating facilities. In the medium to long term, as the MER evolves and the volume of exchanges increases, planning and commissioning of additional cross-border interconnection facilities would be necessary.

12. **Benefits of power pools are gradually realized by the member countries as the regional market evolves.** In the short to medium term, the two main benefits of power pools are: (1) increased security and reliability of electricity supply and (2) improved electricity sector investment environment. In the medium to long term, the main benefits would be: (3) reduced operating costs and (4) reduced investment costs through integrated planning on a multi-system basis.[9] The results would benefit all consumers in the region by lowering prices and improving power supply quality and safety and would eventually result in a reduced environmental impact due to power development.

13. **A common and flexible legal regulatory framework and harmonized commercial rules are critical success factors in creating regional power pools**. Once consensus is achieved on putting in place a common legal and regulatory framework, another critical success factor is to maintain flexibility in the setting up of a viable, multi-

---

[7] Charpentier & Schenk 1995
[8] World Bank 2008
[9] USAID 2008

country, organizational structure to leverage the individual and collective capabilities of the system operators. Moreover, the deployment of clear, fair, transparent and harmonized commercial rules of practice for cross-border trading in energy services (e.g. pricing principles, settlement of transactions, technical standards for metering, arbitrage procedures, etc.) also requires the introduction of measures to enhance the capabilities of the system operators, who will in addition be responsible for the expansion of cross-border interconnection facilities. [10]

14. **Power pools evolve over time**. Power pools worldwide have evolved over time from simple interconnections between neighboring utilities that support each other in emergencies to more competitive power pools based on sophisticated formal legal entities with differing responsibilities in system operation and power market regulation.[11] While "loose pools" rely on coordinated dispatch between the countries to conduct the power exchanges defined contractually through bilateral power purchase agreements, in more advanced pools (i.e. "tight pools") centralized dispatch takes the place of coordinated dispatch, requiring substantial investment for IT systems and an advanced level of harmonization of regulatory frameworks[12] In the more advanced new pools, dispatching is not based on costs, but rather on the bid price of each generator (i.e. on a competitive basis), which means "open access"[13] of the market, at least at the wholesale level.

THE CENTRAL AMERICA REGIONAL ELECTRICITY MARKET (MER)

15. **In the past, electricity trade in the Central America region was limited mostly to bilateral transactions in the spot market**. The main objective of these transactions was to take advantage of energy surpluses and differences in marginal generation costs. Trade was active in the early 2000´s, although restricted by the capacity of existing transmission links, but it has dwindled in recent years due mainly to a tight supply/demand balance in most of the countries in the region. This situation is expected to change with the commissioning of the SIEPAC transmission line and the actions planned in most countries to expand the generation capacity and improve the reserve margins.

---

[10] World Bank 2008
[11] USAID 2008
[12] ECA 2004
[13] One the most successful open access pools in operation today is right next to the Central America region, in Colombia. Colombia exchanges electricity on a daily auction basis with Venezuela and Ecuador. The Colombian regulator has implemented a scheme that does not interfere or distort considerably domestic prices and benefits nationals of both exchanging countries (i.e. importer and exporter) taking advantage of the complementary seasonal hydrological and weather conditions.

16. **The Central American Electrical Interconnection System (SIEPAC) project is an initiative to create an integrated regional electricity market among the six Central American countries.** It consists of a 1,800 km–long, 230 kV single-circuit transmission line, with 15 substations, comprising 20 transmission segments, which will be finalized in 2010[14], increasing to 300 MW the capacity of power interchanges between most countries in the region[15]. The stated objectives of the SIEPAC project are: (i) to improve security of supply by widening reserve margins, (ii) to reduce the problem of electricity rationing in capacity deficit countries, (iii) to achieve improved operating efficiency and reduce generation fuel consumption, (iv)to introduce greater competition into the domestic markets, (v) to lower end-user electricity costs, (vi) to attract foreign investment to the region's energy sector, and (v) to contribute to the economic development of the region.

17. **Restructuring of the Central American national power sectors has yielded differing sector structures**. In the 1990's the countries approved new laws and regulations that initiated restructuring processes in their power sectors. Those reforms aimed to promote private participation in a sector that had been traditionally controlled by fully integrated state-owned companies. Costa Rica and Honduras reforms were limited to the opening of the generation segment to private participation. However, significant reforms to liberalize electricity markets were implemented in Guatemala, El Salvador, Nicaragua, and Panama. These countries implemented vertical and horizontal unbundling of generation, transmission and distribution activities, creating specialized companies in the electricity sector, as well as permitting retail competition for large consumers. Likewise, the role of the State was restricted, total or partially, to the formulation of policies, the exercise of regulatory functions, and the administration of concessions.

18. **In 1996, the six Central American countries agreed to the creation of the Regional Electricity Market.** The Framework Treaty for the Central American Electricity Market (*Mercado Eléctrico Regional* [MER]) was ratified by the Governments in 1998 based on the principles of competition, gradualism and reciprocity. To support the MER, the Treaty also created the regional regulatory commission CRIE (*Comision Regional de Interconexión Eléctrica*), the regional system operator EOR (*Ente Operador Regional*), and

---

[14] Except for one of the Costa Rican segments, which will be finalized in 2011.

[15] The second circuit of the SIEPAC project could increase trade capacity to 600 MW between countries (450 MW between Costa Rica and Panama) and the Panama-Colombia DC link could provide a 300 MW capacity for power interchanges.

the company owner of the grid EPR (*Empresa Propietaria de la Red*). In this sense, the MER is the only example of an international electricity market having its own regulatory body and system operator with participating agents from national electricity markets of several countries.

19. **The MER was designed as a 7th market, not as a substitute for the national markets**. The regional electricity market established in the Treaty and developed in the Rules of the MER (RMER) is not an integrated regional electricity market, but a 7th market superimposed on the six national markets. As such, the MER has been designed as a "loose pool" arrangement in which dispatch will be coordinated but not centralized as in more sophisticated pool designs. The MER has its own rules and will operate based on the following premises: (i) regional electricity trade can take place in a regional contract market and a spot market; (ii) all MER agents with the exception of the transmission companies can purchase and sell electricity freely and will have open access to the transmission system; (iii) MER generation agents can install power plants in any of the member countries and sell energy at regional level; (iv) the MER is a market with its own rules, independent of the national markets, which makes energy transactions using the regional transmission grid (RTR) and the national networks. .

20. The Second MER Protocol, which was agreed in 2007, includes the following relevant adjustments or clarifications to the MER: (i) all agents of the national markets (i.e. generation, transmission, distribution and commercialization companies as well as large consumers), as ratified by the legislation of each country, are MER agents and could participate in regional electricity trading; if a country permits the existence of companies with integrated activities, they must be separated in business units with independent accounting; (ii) national interconnection systems and lines that make possible the regional energy transfers are part of the regional transmission grid, whose availability and use will include charges that consider variable transmission charges, the toll and the complementary charge; (iii) the governments will carry out the necessary actions to gradually harmonize the national with the regional regulations, permitting the normative coexistence of the regional and national markets for a harmonious MER functioning.

21. **Harmonization of the national regulations is expected to happen gradually, allowing for firm energy interchanges in which the contracted energy will have priority to supply the demand in the country where the buyer is located.** Currently, the regulatory frameworks of all electricity markets foresee actions to guarantee local self sufficiency in electricity supply. One of the main agreements included in the Second MER

Protocol refers to the gradual regulatory harmonization for the implementation of the rules of the regional market (RMER). It is understood that this will allow the firm energy trading in the MER, which in turn would facilitate the financing of regional plants. This basic concept makes it necessary to modify the national regulations which provide supply priority for national demand in most CA countries. This would be possible under the assumption that the MER Treaty is a supranational mandate.

BARRIERS TO DEVELOPMENT OF THE CENTRAL AMERICA REGIONAL MARKET

22. The MER design provides a general framework whose ultimate objective is to allow and promote long-term firm power trade among Central American countries in order to facilitate the financing of economical regional generation plants. Achieving this goal will be a clear test of the options for long-term success of the market. However, several regulatory and institutional barriers could hinder, unless properly addressed, the accomplishment of those objectives. In addition, lack of political will on the side of the national governments, could also delay the successful development of the MER, regardless of the regulatory and institutional efforts. This section discusses the main barriers identified and proposes some options to address them.

23. **The asymmetry in the national markets can lead to a lack of reciprocity in the treatment of market agents.** There is a lack of reciprocity of the vertically integrated national electricity markets prevailing in two Central American countries (Costa Rica and Honduras) with the more open electricity markets already structured in the other four countries (Panama, Nicaragua, El Salvador and Guatemala). This is a source of asymmetry given that regional generators (and national generators in the last four countries) cannot directly contract electricity with potential distribution, commercialization and large consumers located in Honduras and Costa Rica. Also, potential regional generators located in these two countries would not have clear rules yet permitting them access to the national transmission grids. However, both ICE and ENEE will have the opportunity to sell to distribution and commercialization companies and large consumers in Panama, Nicaragua, El Salvador and Guatemala.

24. **Regulatory harmonization has to be completed in order to facilitate market operations.** There is a lack of harmonization of national and regional regulations at the operative and commercial levels. National electricity regulations must be harmonized

with regional regulations in order to facilitate market operations and regional long-term firm power contracts between qualified agents. This issue should be solved in order to implement the RMER (in substitution of the transitory regulations – RTMER -) and the appropriate interfaces so that MER regulations can harmoniously work with the corresponding regulations in each country.

25. **In most countries, domestic demand still has priority in case of power shortages, which creates a risk for firm contracts in the regional market.** The way the regional market was designed would allow all SIEPAC members to benefit from the surplus of one country to cover deficits in another country, a win-win situation. However, to ensure that all countries benefit equally from the regional interconnection, the national supply priority in case of power shortages will have to be adjusted in the national markets according to the Second MER Protocol in order to permit the effectiveness of the firm energy contracts in the MER. In this regard, the Framework Treaty, the Protocols and the associated regulations define the specific sanctions regime to apply in cases of non-compliance with the MER rules, as well as arbitration mechanisms for the solution of disputes.

26. **Price controls lead to misallocation of resources and can imperil the success of a regional market.** During the reform processes in the power sector, the stated objective was to achieve a situation where electricity would respond to normal supply and demand signals (as in the case of oil products), rather than to managed criteria which either distort the wholesale price or institute unsustainable subsidies. Unfortunately, regulatory authorities have not been resilient enough to resist political influence; changing the rules of the game by setting ceilings for market prices, and otherwise impeding true marginal costs to reflect on power sector transactions in the wholesale markets. Increased support to national regulatory institutions would help avoid these kinds of shortcomings

27. **Increasing prices of electricity in exporting countries and availability of cheaper electricity in importing countries can spur opposition both from consumers and from existing generators.** If MER energy trading is included in the national economic dispatches, prices may be higher in electricity exporting countries, while they would be lower in the importing countries. This is a necessary market rule to guarantee non-discrimination among the national markets (i.e. agents in an exporting national market will face the same spot price as for occasionally exported energy).

However, this will not favor final consumers in the exporting countries or generators in the importing countries.

28. **Lack of long-term transmission rights will hinder the signature of long-term contracts.** Regional long-term firm energy contracts for the development of new regional power plants would have to be agreed for periods of 10 to15 years. However, this type of contracts needs to be supported by Transmission Rights that will be assigned through auctions, initially for short-term periods (one month) or at most for one year. The EOR will forecast nodal prices periodically for only 2-year horizons, while the transmission planning is expected to be done for 10-year horizons. These issues would have to be properly conciliated in order to support the regional long-term firm energy contracts associated to new regional power plants.

29. **Limited capacity and resources at CRIE, the regional regulator, make it vulnerable to national interests.** Addressing the more substantial harmonization problems would require additional analysis and the preparation of a strategy that also takes into account the national views and interests. However, there is a lack of technical staff and computerized support in the CRIE and the commissioners meet only about four times a year. Under these circumstances, the role of CRIE could become very weak and face the risk of a situation in which national interests may prevail over the regional ones. It is evident that CRIE requires an urgent institutional reinforcement to foster an adequate preparation of the platform for the initial operations of MER.

30. **Bilateral agreements independent from the MER would restrict the benefits of the interconnections with Mexico and Colombia.** Guatemala - Mexico and Panama - Colombia are in the process of interconnecting their respective power systems, allowing for future bilateral international electricity interchanges. In both cases, bilateral agreements are being discussed and are advancing in their implementation. Apparently, Guatemala´s position is that power interchanges through the Guatemala – Mexico interconnection will be commercially agreed independently from the MER. In the case of the Colombia – Panama interconnection, the governments of both countries would have decided that its development would be at their promoter´s own risk, implying a contract carrier type of use for this link and, consequently, limiting the free access to agents not involved in its development. Although not a barrier to regional market development *per* se, this issue would have to be analyzed in order to properly coordinate with MER

regulations, which are interpreted as providing free access to those links, in order to avoid potential drawbacks in the development of the MER

31. **Higher demand volumes would be required for the development of high capacity regional plants**. Local demand of the distributors, traders, and large consumers and associated competitive processes to purchase electricity is for relatively small volumes. Under current market conditions, it would be expected that individual long-term firm energy contracts would be of relatively minor volumes (i.e. associated to 50 MW peak demands or lower). The development of the MER based on high capacity regional plants (i.e. with 150 MW of installed capacity or more) and on the interconnections with Colombia and Mexico, would require higher contracting volumes with agents that might be located in different countries. In order to facilitate this process, rules and competitive processes coordinating energy purchases with multiple agents will have to be implemented (or a more formal long term energy market).

RECOMMENDATIONS

32. Based on the barriers identified, this study discusses some options to address each of them. Those options include: (i) support to the implementation of the necessary market reforms in Costa Rica and Honduras, including the definition of clear rules for participation in the MER of agents other than ICE and ENEE; (ii) support to the national regulators; (iii) assistance for the implementation of rational pricing and subsidy schemes; (iv) adjustment of the market rules (RMER) to allow for longer term and less complex assignation of transmission rights; and (v) provision of additional technical and financial support to CRIE so that it can properly carry out its activities and assume a strong role in the regional market.

33. It is also suggested that the development of a mid-sized regional plant with support from the IFIs could create the necessary incentives to overcome some of the existing regulatory barriers. The development, in the short-term, of a mid-sized regional generation plant with the participation of both private investors and national governments could generate strong incentives for the different players in the market to find workable solutions to overcome the barriers arising from incomplete regulatory harmonization and unclear or not-fully developed MER rules.

2. Introduction

34. The Central America Regional Electricity Market (MER) is very unique in the sense that it is the only example of an international electricity market having its own regulatory body and system operator with participating agents from national electricity markets of several countries. This market is designed to trade mainly electricity and transmission capacity. More importantly, the SIEPAC initiative illustrates that it is possible to create a relatively advanced regional electricity trading arrangement between countries that are at differing stages of internal market development.

35. Economic integration of the Central American countries has followed a natural evolution. The continuous increase in the demand for goods and services has been accompanied by political and institutional arrangements leading to the materialization of commercial and trade agreements aiming to benefit the nationals of all the integrated nations at the lowest possible cost. This is particularly true in the electricity sector, which provides a key development service for the achievement of sustainable growth.16 In fact, electricity integration through cross-border power trade had been discussed by the Central American Countries since the late 1970s.

36. Integration initiatives in the region are channeled through the Central American Integration System (*Sistema de la Integración Centroamericana*—SICA), created in 1991, which manages different organizations under it. In the energy sector, two regional organizations are part of SICA: the Central America Electrification Committee (Comité de Electrificación de America Central—CEAC), and the Central America Hidrocarbons Cooperation Committee (Comité de Cooperación de Hidrocarburos de América Central—CCHAC), which were organized over 15 years ago.

37. Since its creation, CEAC has progressively acquired a high profile role in the electrical integration of the region. It is composed of representatives from the energy

[16] The six Central American countries of Panama, Costa Rica, Nicaragua, El Salvador, Honduras, and Nicaragua share a long tradition of regional integration, including a common market, substantial intra-regional trade, as well as coordinated commercial policies, such as the Central American Free Trade Association (CAFTA) with the U.S. Belize, by contrast, has developed practically in isolation, with little trade with its regional neighbors, and an orientation towards partnerships with Caribbean countries.

authorities of the different countries, and it has provided a forum for supporting initiatives such as the regional power market, the SIEPAC project, and the interconnections with Mexico and Colombia.

38. Small national markets and poor market integration have been obstacles to the benefits of the economies of scale associated with the development of large-scale energy projects. The concept of a regional market was first discussed in 1987 and materialized with the SIEPAC initiative. SIEPAC consists of two interdependent projects, the development of a regional electricity market (MER) and the construction of a 1,800km power line that will interconnect the six Central American countries, thereby facilitating the interchange of electricity among them and opening the potential for trade with Mexico and Colombia. SIEPAC would also bring efficiency gains through integrated economic dispatch, shared reserve margins, and exploitation of complementarities in demand and supply. According to CEAC, SIEPAC would produce savings on operation costs on the order of 4% and fuel savings of about 3% after 8-10 years based on indicative expansion planning exercises.

39. SIEPAC is not the only energy sector development and integration initiative in the region. The Program for Mesoamerica's Energy Integration (PIEM) includes a project to build a natural gas transmission system connecting the Central American countries to gas supplies from Mexico and Colombia. PIEM also includes a project to build a petroleum refinery and an LNG terminal in the region. Expanded natural gas and oil product availability would diversify the feed stocks for electricity production and potentially lead to reduced short- and long-run generation costs. Besides providing support to larger scale generation projects, the regional transmission network would also create the sufficient market scale needed to anchor large investments such as the LNG terminal or the gas transmission network included in the PIEM.

40. However, interconnection and integration have very different meanings. Integration, which is the means by which the full benefits of the interconnection can be captured, calls for a wide range of institutional coordination measures, many of which have already been put in place by the countries, such as the creation of the regional regulator (CRIE) and the regional operator (EOR). These entities have established procedures for dispatching regional resources at least cost, but there still remains a gap

insofar as the procedures and guarantees to develop regional power plants and, in general, to fully integrate the market.

41. For instance, there are still gaps and barriers to achieve long-term firm power transfers that include, among others: the lack of reciprocity between countries with market-based sectors (Panama, Nicaragua, Guatemala, and Honduras) and those countries which maintain an integrated sector (Honduras and Costa Rica), rules for prioritizing domestic demand (Honduras and Panama), price controls and generalized subsidies (El Salvador and Nicaragua), transmission rights which are still to be defined on a long term basis, the lack of harmonization between national and regional regulations, and the limited capacity of CRIE.

42. This report analyzes the status of development of the Central American integrated electricity market, including the institutional, legal, regulatory and contractual framework of both the MER and each of the six national markets. It then identifies the main barriers that would have to be addressed in order to ensure a successful evolution to full operation of the SIEPAC interconnection, which would improve security of supply and operating efficiency, eventually contributing to the economic development of the region.

43. The major challenge faced by the regional market is how to exploit the potential offered by the transmission line and the MER regulatory and institutional framework by attracting energy projects of a regional scale17. Achieving this goal will be a clear test of the options for long-term success of the market. For it to happen, the regulatory framework and the regional institutions must demonstrate their credibility to investors. In this sense, the early use and performance of the line will serve as a pilot in this process of trust-building.[18]

44. Once the SIEPAC line is commissioned, there will be pressure to use it in order to generate revenues to meet the existing debt servicing obligations. This may prove to be an

---

[17] A generation project is considered as regional when part of its generation is assigned to cover the demand of another country. A regional plant will have long-term contracts with neighboring countries. In the case of a merchant plant that operates exclusively in the spot market and does not have associated long-term contracts, it will be considered as regional generation if the neighboring countries can rely on its supply to balance their supply/demand equation.

[18] Economic Consulting Associates (ECA). “Regional Power Sector Integration: SIEPAC Case Study”, July 2009.

important incentive motivating the development of regional generation projects since the shareholders of EPR[19], the company that owns the transmission line, are also major market players with government backing. Therefore, they are well positioned to bear the demonstration risk associated to pilot regional projects.[20]

[19] EPR is the acronym for *Empresa Propietaria de la Red.*
[20] Same as 18.

34.

3. Power sector in Central America[21]

3.1. Introduction

45. The energy subsector of the Central American countries (Panama, Costa Rica, Nicaragua, El Salvador, Honduras, and Nicaragua) presents broad similarities as a consequence of common geographic features, such as mountain ranges which have a good potential for developing hydro power, substantial geothermal resources in several countries, and very limited oil resources. In fact, in terms of native energy production, biomass accounts for 67 percent, followed by other renewables such as hydro, geothermal, and wind (28 percent), and 5 percent from native oil production.

45. Central America yields a primary energy matrix which is indicative of developing countries that still lack penetration of modern technologies for power generation, as evidenced by 37 percent of Total Primary Energy Supply (TPES) coming from firewood and residues. In the more developed countries, such as Costa Rica and Panama, this value lies on the order of 17 percent. The proportion of firewood and residues in total demand is on the order of 42 percent (around 18 percent-20 percent for Costa Rica and Panama), which confirms the former statement. Comparative values for South America and the US yield 19 percent and 3 percent, respectively.

46. Due to the differences in the rate of growth of electricity supply between countries in the region, the combined share of Panama and Nicaragua in the regional market has decreased from 34% to 24% while Honduras and Guatemala have increased their combined share from 26% to 38%. El Salvador and Costa Rica have maintained their shares at about 15% and 25%, respectively. In 2007, Nicaragua was the smallest market in the region with an 8% share, followed by El Salvador, Panama and Honduras with about 16%, Guatemala with 21% and Costa Rica with 24%.

47. In terms of sectors of consumption, the residential sector in Central America is the major consumer, with a share of 43 percent, which contrasts with 17 percent and 19 percent in South America and the US, respectively. Other sectors which account for the

[21] Sections 3.1., 3.2., and 3.3. have been extracted from the report: "Central America. Regional Programmatic Study for the Energy Sector – Umbrella Module". For a complete analysis of the energy sector in Central America, please refer to that report.

remainder of energy consumption in Central America are the transport (29 percent) and industrial (21 percent) subsectors. The share of electricity in total energy consumption is still low as compared to South America (17 percent) or the US (20 percent), an indication of low electricity use and electricity coverage.

48. Primary energy supply per capita is on the order of 0.67 toe, an increase from 0.57 toe in 1985, but it remains low by Latin American and Caribbean (LAC) standards, which averages 1.1 toe per capita. This is indicative of low GDP; in the US GDP per capita is about 7 times greater than in Central America, and energy use is about 11 times greater. Energy intensity, i.e. the energy per dollar of GDP, was around 143 toe per million dollars, which is low by US standards (213 toe/M$) but comparable to OECD Europe (154 toe/M$).

3.2. Electricity Supply and Prices

49. In regard to electricity supply, the region generated around 38TWh in 2007, equivalent to around 70 percent of the annual electricity supply of a medium-size country in LAC, such as Chile or Colombia. Generation as a whole has grown at a rate of about 6 percent per annum since 1990, with a lower rate since 2000 (higher in Guatemala, lower in Panama). Generation capacity is on the order of 9,700 MW, again similar to 70 percent of Colombia or Chile.

50. The composition of installed capacity varies quite widely among countries with similar endowments (70 percent hydro in Costa Rica and only 13 percent in Nicaragua) in good measure as a result of the institutional developments which took place in the mid and late nineties. In those years several countries implemented vertical unbundling, and only two (Costa Rica and Honduras) retained a vertically integrated state-owned company. However, all countries allowed the entry of private sector enterprises either through the sale of assets, or by purchasing power from new companies.

51. The participation of new private generation enterprises had both positive and negative consequences. Because of system size and the perception of investment risk, private investors chose to install thermal plants which required less capital and could eventually be moved out of the country if necessary. The thermal option was also least cost during the late 90s due to high efficiencies associated with diesel plants fuelled with bunker oil, and low oil prices. In fact, some of the initial investors, as in Guatemala, chose to install barge-mounted plants. Private sector investment provided much-needed relief to public sector companies with little access to capital. However, it also made the region

increasingly dependent on oil products and on the vagaries of the oil market, with extreme financial consequences in 2006–2008 when the costs of power purchases skyrocketed.

52. As a result of the new power sector organization, hydro's share decreased from 85 percent to around 50 percent, while the share of diesel generation running on residual fuel increased from almost zero to 30 percent. The changes in the generation mix were not uniform: they were felt less in Costa Rica and most in Honduras, where the share of hydro declined from 100 percent in 1990 to 37 percent in the early 2000s.

53. Electricity consumption per capita (780kWh per year) exhibits substantial growth (it has grown by 100 percent over the last 20 years), but continues to be low compared to developed countries, with wide variations within the region: consumption in Costa Rica (1,832kWh) and Panama (1,586kWh) is substantially higher than in the other countries, which consume less than 700kWh in per capita terms. By comparison, OECD Europe is on the order of 6,000kWh and the US is on the order of 13,000kWh.

54. Electricity sales in the region have a high residential sector component (37 percent). Monthly residential consumption per user is on the order of 145kWh, with higher values in Costa Rica (237kWh), Panama (206kWh) and Honduras (180kWh). Interestingly, large consumers that can choose their supplier account for 32 percent of the market in Guatemala, 10 percent in El Salvador, and 6 percent in Nicaragua.

55. Electricity access remains a problem in Central America, particularly in Honduras and Nicaragua with coverage ratios of 71 percent and 61 percent, respectively, with people who lack electricity concentrated in the rural and scarcely populated areas. The population without electricity amounts to around 8 million people in the region, out of a total population of around 40 million. With the exception of Costa Rica (where coverage is 99 percent), access is a high visibility problem which should be tackled on a priority basis.

56. Retail electricity prices in Central America vary according to two sets: the high price countries (El Salvador, Guatemala, Nicaragua, and Panama), with residential prices around 16¢US/kWh, and Costa Rica and Honduras, with domestic prices on the order of 8¢US/kWh. Governments have struggled to keep retail prices low for the residential sector in order to avoid the political fallout resulting from increases due inter alia to the increase of fuel prices and generation costs. This has given rise to bitter disputes between the regulators and the power companies, whether public or private. To avoid increasing prices Governments have resorted to instituting subsidies, with varying degrees of success; in

Guatemala, El Salvador, and Nicaragua, hydro power plants owned by state enterprises financed a substantial portion of the subsidies; in Honduras, Costa Rica and Panama subsidies were financed directly through the national budget.

57. Targeting of subsidies has been diverse in the region. At one extreme, the Salvadoran authorities intervened in the wholesale market and instituted a generalized subsidy which quickly got out of hand in late 2008 with the increase in oil prices. In the other countries, subsidies have in general been limited to domestic consumers within a range which is on the order of 0–150kWh of consumption per month, although the upper bound is as high as 500kWh per month in Panama.

58. Electricity losses continue to be a problem for many of the utilities in the region. Privatization improved loss control in Panama (down from 25 percent in 1990 to around 12 percent), but was particularly unable to do so in Nicaragua (up from 18 percent in 1990 to 28 percent in 2007). Otherwise, loss levels remain acceptable in El Salvador, low in Costa Rica, and high in Honduras; in Guatemala they have remained more or less static at around 16 percent, with room for improvement.

3.3. Power Sector Outlook

59. National expansion plans are prepared by all the countries in the region using similar tools. The common characteristic of the plans prepared for 2008-2020 (years may differ from one country to another) is the reliance on local resources, i.e. an autarchic outlook regarding energy supplies. With the exception of El Salvador (imports of 30MW from Guatemala), and Guatemala (imports of 200MW from Mexico) the national plans do not consider imported energy on a long term basis for supplying their market, as opposed to the integrated approach pursued by the regional market.

60. Central America has a large untapped potential of renewable generation, mostly in hydroelectric generation. The hydroelectric potential in the region is estimated in about 25,000 MW, of which a capacity of only about 4,000 MW or 16% was installed in 2007. Costa Rica, Guatemala and Honduras hold about 70% of the hydro potential in the region. A common characteristic of the national expansion plans is the development of renewables, which leads to investments expected to change the energy matrix of the countries and to reduce the reliance on oil imports. Renewables account for 56 to 87 percent of capacity additions in Costa Rica, Guatemala, Nicaragua, and Honduras. The exception is El Salvador, which does not exhibit a substantial potential in new hydro resources, and Panama, whose

development plan omits some hydro expansion possibilities due to lack of information from private developers.

61. The switch to renewables can be justified when comparing costs of specific projects with those of thermal alternatives. Levelized costs for hydro plants in the region vary between low cost projects (50-60USD/MWh), and high-cost ones (90-116USD/MWh), as compared to open cycle gas turbines and medium speed diesels (in the range of 140-170 USD/MWh). Coal-fired plants can be competitive (around 100-120USD/MWh depending on the fuel price scenario), together with combined cycle gas turbines. The latter options, if adopted, would also contribute to diversify the energy supply in the region making it less dependent on imported oil; however, introducing new gas turbines would probably require a regional supply outlook given scale limitations, including consideration of LNG infrastructure.

62. A regional plan was prepared by the Executive Secretariat for the SIEPAC project. The plan envisages a large participation of hydro generation, together with LNG-based production, complemented with large coal plants. The latter take advantage of economies of scale and become feasible taking into account a regional outlook. The larger share of conventional thermal generation in the regional plan, as compared to the national plans, results from the benefit of developing larger plants, which replace high-cost hydro plants.

63. Developing new hydro in a regional context calls for a realistic assessment of site costs, which would be provided by feasibility studies of different projects. Unfortunately, there is a lack of information regarding project costs, and much of the publicly available technical data in the region dates from the 80s and 90s (with the exception of Costa Rica), before the reforms whereby the private sector took the initiative in future power sector development.

64. Relying on private sector development for hydro projects will require support from Governments in addressing the environmental and social risks if acceptable development costs are to be found (Guatemala was unsuccessful in attracting private sector interest for one of its hydro projects—Xalalá—despite its low estimated development cost). Alternately, as shown in the case of Panama, a combination of long-term contracts and high oil prices provided enough incentives for the development of about 700 MW in hydroelectric projects by private investors. In most cases, innovative schemes will be required, such as those being developed in Costa Rica, which keep valuable information,

such as feasibility studies, within the public domain, while allowing for private development.

3.4. The Central America Regional Electricity Market (MER)[22]

65. During the last decade, the six CA countries agreed to develop a regional electricity market with its own rules, the MER, supported by the SIEPAC interconnection project that will increase the size of the electricity markets and facilitate competition and entry of new players in the market. The MER is the only example of an international electricity market having its own regulatory body and system operator with participating agents from national electricity markets of several countries, designed to trade mainly electricity and transmission capacity.

66. The MER is the 7th electricity market established in Central America and it could be accessed by agents participating in any of the six national power markets. Main figures for demand / supply and international interchanges are summarized in

67.

68. Table 1 below.

Table 1: Central America: Electricity Markets, 2007

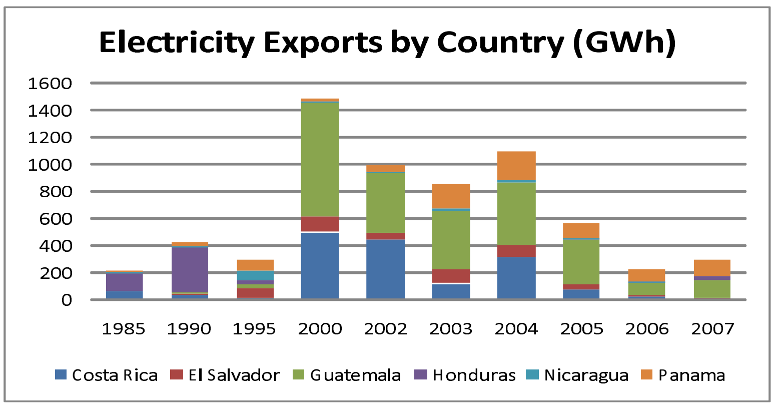
	Guatemala	El Salvador	Honduras	Nicaragua	Costa Rica	Panama	Total (MER)
Inst. Cap. MW	2154.0	1436.5	1572.8	822.3	2182.0	1551.5	9719.4
% Hydro	36%	34%	33%	13%	69%	55%	44%
Peak Dem. MW	1443.4	906.0	1126.0	505.2	1500.4	1024.2	6505.2
Margin %	49%	58%	39%	63%	45%	51%	49%
Net. Gen. GWh	7940.4	5749.4	6333.6	2934.6	8989.5	6286.7	38233.8
Exports GWh	131.9	6.7	23.4	0	5.0	125.0	291.9 (MER)
Imports GWh	8.1	38.4	11.8	64.0	162.1	8.7	293.1 (MER)
Users No.	2´265.419	1´375.795	1´043.299	643.803	1´322.795	738.211	7´389.322
Sales GWh	6533.6	4888.8	4979.3	2096.0	8174.0	5299.4	31971.2
Sales (% of total in CA)	20.4%	15.3%	15.6%	6.6%	25.6%	16.6%	100.0%

[22] See section 6 for a full description of the MER.

	Guatemala	El Salvador	Honduras	Nicaragua	Costa Rica	Panama	Total (MER)
Avg. Spot Price (US/MWh)	89.7	88.9	n.a.	123.4	n.a.	108.5	
Avg. Reg. Price (US/MWh)	178.7	140.1	104.4	158.7	88.8	157.5	
Avg. Reg. Price (% of Costa Rica Avg.)	201%	158%	118%	179%	100%	177%	

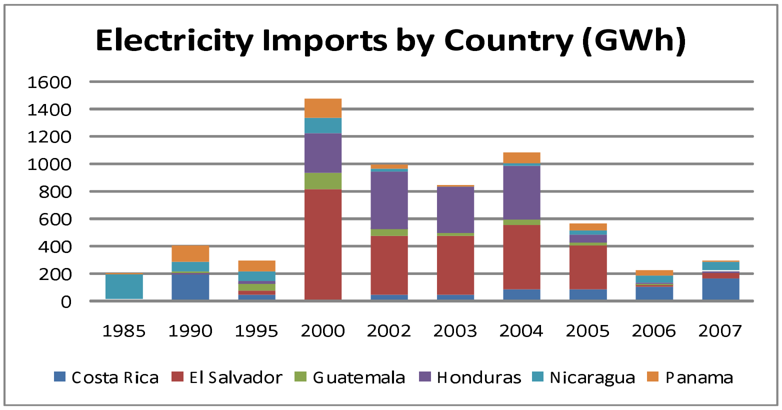
69. In 2007, total installed generation capacity in the six Central American power markets was 9,719 MW, with each country having enough capacity to cover its peak demand. Total net electricity generated in the region was 38,234 GWh, of which 31,971 GWh were sold to final consumers with significant regulated prices differences, the lowest being Costa Rica. International electricity trade in the region through the MER was 293 GWh, representing less than 1 percent of total electricity sales. Main exporting countries were Guatemala and Panama, while the imports were concentrated in Costa Rica, Nicaragua and El Salvador. However, historical international electricity trade reached 1,489 GWh in 2000 (around 6.5 percent of regional electricity sales) as illustrated in Figure 1 and Figure 2. The lowering of the electricity trade in the MER is related to a generalized reduction of the potential of economic electricity exports in all countries associated to lower firm energy reserve margins and lower hydroelectric capacity share in the regional installed capacity.

Figure 1: Electricity exports by country (1985-2007)



Source: CEPAL & Consultant processing

Figure 2: Electricity imports by country (1985-2007)



Source: CEPAL & Consultant processing

3.5. MER illustrative power interchanges and marginal cost perspective

3.5.1. Simulation of MER power interchanges

70. International electricity interchanges in the MER were examined under a reference demand/expansion scenario and without considering interchanges with other neighboring countries (i.e. Mexico and Colombia). This exercise was done through an illustrative demand / supply and marginal cost estimation obtained with the SDDP model[23] and using a data base updated by XM[24] in February 2009 (as illustrative, non official, rough estimation[25]).

71. Appendix 2 includes a brief description of the SDDP model and a synthesis of the data base used. Prices of Fuel Oil No. 6 and 2, main electricity price drivers in the CA electricity markets, were adjusted to USD 0.96/Gal and USD 2.97/Gal, respectively, according to 2009 forecasts done by ETESA (Panama) based on short term EIA (Energy Information Administration) recent forecasts. In the illustrative simulation, a variable transmission charge of USD 7.5/MWh was used for each of the international interconnections. Table 2 summarizes the result of the simulations.

Table 2: Central America Aggregated Power Demand/Supply Balance & International Interchanges

[23] The SDDP (Stochastic Dual Dynamic Programming) model was developed by the Brazilian firm PSR. It is an optimization / simulation model of complex hydrothermal power systems operations which is extensively used in the CA countries. Appendix 1 includes additional details.

[24] XM (www.xm.com.co) is the Colombian firm in charge of the Colombian power market administration and system operation. This company update each month of the SDDP (MPODE in Colombia) model data base of the Ecuador, Colombia and Central American power systems.

[25] The scope of work was limited to the SDDP application without major analysis and without updating or reviewing the available data base.

	DEMAND	G. HYDRO	G.THERMAL	IMPORT	EXPORT	MW IMP-EXP 1/
	GWH	GWH	GWH	GWH	GWH	MW
2,009	42,634	19,509	23,121	1,564	1,564	325
2,010	44,631	20,360	24,272	2,228	2,228	462
2,011	47,008	23,396	23,611	2,438	2,438	506
2,012	49,425	24,810	24,615	2,200	2,200	457
2,013	51,957	26,183	25,775	2,341	2,341	486
2,014	54,568	28,624	25,944	3,128	3,128	649
2,015	57,247	31,492	25,755	2,774	2,774	576
2,016	60,029	35,339	24,690	4,262	4,262	885

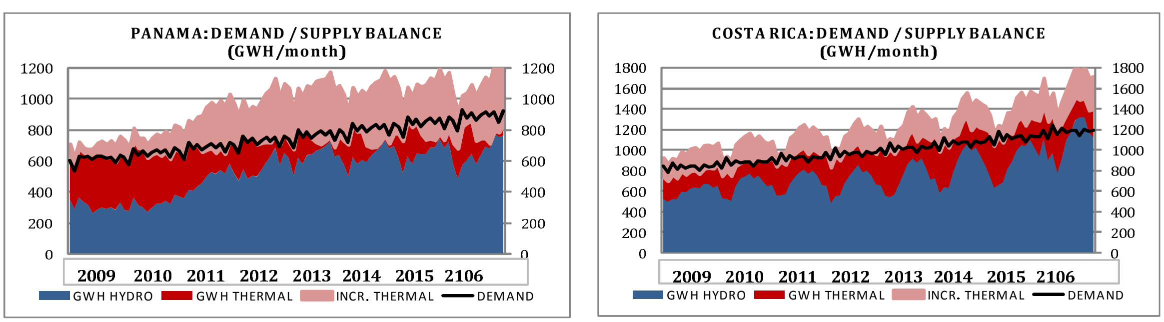
1/ Estimated with 0.55 load factor

72. In summary, the results obtained from the SDDP illustrative power market simulation suggest that international power interchanges among CA countries could increase to the order of 2,500 GWh/year during the next five years. Illustrative forecasts for each country are presented in Figure 3, Figure 4 and Figure 5 (with electricity demand in black, average hydroelectric generation in blue, average thermal generation in red and maximum additional thermal generation in pink (assuming maximal thermal generation with 85 percent average availability)).

Figure 3: Illustrative National Demand/Supply Balances for Panama and Costa Rica

PANAMA (GWH)					
	DEMAND	G. HYDRO	G.THERMAL	IMPORT	EXPORT
2,009	7,343	3,681	3,907	96	345
2,010	7,730	3,775	4,063	112	219
2,011	8,202	5,609	2,538	186	131
2,012	8,671	6,672	2,160	150	311
2,013	9,141	7,610	1,310	464	243
2,014	9,613	7,553	1,367	791	97
2,015	10,093	7,787	1,570	803	66
2,016	10,602	7,744	1,540	1,345	28

COSTA RICA (GWH)					
	DEMAND	G. HYDRO	G.THERMAL	IMPORT	EXPORT
2,009	10,043	7,132	2,199	873	161
2,010	10,556	7,938	2,407	490	279
2,011	11,083	8,342	3,023	263	545
2,012	11,636	8,329	3,363	416	472
2,013	12,218	8,870	3,992	334	978
2,014	12,834	10,137	3,883	242	1,428
2,015	13,485	10,588	3,934	292	1,330
2,016	14,176	13,153	3,448	115	2,540



Source: SDDP illustrative simulations of the CA power markets

73. Panama shows a balance of initial net exports to Costa Rica and, even with increasing hydro generation by 2012, it becomes a net importer from Costa Rica after 2014 as a way to reduce fuel costs. Costa Rica appears as an initial net importer due to a tight initial available capacity with respect to demand, a situation that changes with additional thermal capacity being installed by 2010 and with new hydroelectric plants commissioned during 2010 through 2016. It becomes a net exporter after 2011.

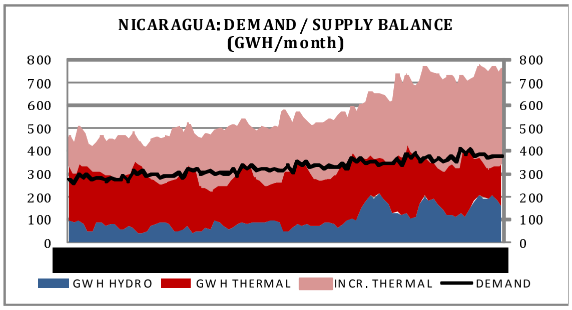
Figure 4: Illustrative National Demand/Supply Balances for Nicaragua and El Salvador

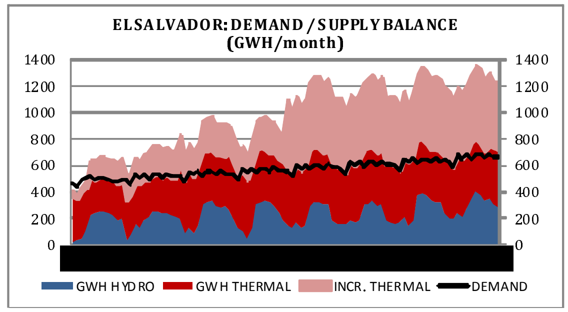
NICARAGUA (GWH)

	DEMAND	G. HYDRO	G.THERMAL	IMPORT	EXPORT
2,009	3,350	893	2,914	72	529
2,010	3,523	760	2,854	179	271
2,011	3,680	738	2,629	464	151
2,012	3,844	982	2,604	383	126
2,013	4,016	861	2,917	518	279
2,014	4,201	1,785	2,693	639	916
2,015	4,397	1,771	2,716	531	620
2,016	4,596	1,934	2,437	1,197	971

EL SALVADOR (GWH)

	DEMAND	G. HYDRO	G.THERMAL	IMPORT	EXPORT
2,009	5,839	1,988	3,494	414	57
2,010	6,092	2,186	3,494	508	97
2,011	6,353	2,721	4,873	38	1,278
2,012	6,626	2,566	4,986	95	1,021
2,013	6,911	2,566	5,054	27	736
2,014	7,208	2,742	5,060	15	608
2,015	7,518	3,183	5,039	15	719
2,016	7,842	3,474	5,004	21	657





Source: SDDP illustrative simulations of the CA power markets

74. Nicaragua is initially a net exporter due to optimization interchanges. During 2011-2013 it becomes a net importer to reduce fuel costs, becoming again a net exporter during 2014 – 2015 due to new hydro plants and turning into a net importer in 2016 to reduce fuel costs. El Salvador changes its importer status by 2013 due to new high capacity LNG generation for this market.

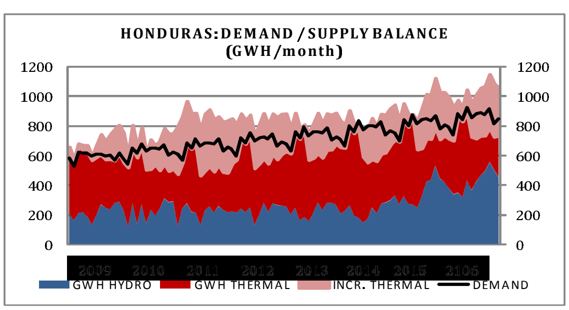
Figure 5: Illustrative National Demand/Supply Balances for Honduras and Guatemala

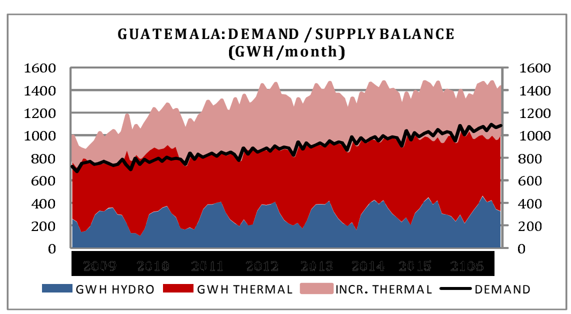
HONDURAS (GWH)

	DEMAND	G. HYDRO	G.THERMAL	IMPORT	EXPORT
2,009	7,164	2,616	4,601	99	152
2,010	7,539	2,714	3,896	939	11
2,011	7,941	2,598	3,960	1,487	105
2,012	8,337	2,766	4,483	1,150	62
2,013	8,793	2,745	5,062	991	5
2,014	9,261	2,688	5,153	1,424	4
2,015	9,741	4,289	4,558	917	22
2,016	10,234	5,063	4,105	1,132	66

GUATEMALA (GWH)

	DEMAND	G. HYDRO	G.THERMAL	IMPORT	EXPORT
2,009	8,896	3,200	6,007	10	320
2,010	9,192	2,986	7,557	0	1,351
2,011	9,749	3,390	6,588	1	230
2,012	10,311	3,497	7,019	5	210
2,013	10,878	3,530	7,441	8	101
2,014	11,450	3,719	7,789	17	75
2,015	12,012	3,875	7,938	216	16
2,016	12,579	3,971	8,157	452	2





Source: SDDP illustrative simulations of the CA power markets

75. Given a moderate thermal based expansion program, Honduras remains mainly as a net importer during 2010 – 2016 in order to reduce fuel costs. Guatemala remains basically a self-sufficient market, based on assumed coal power plants expansion, up to 2014, becoming a net importer during 2015 and 2016 to reduce fuel costs.

3.5.2. Potential impact of international power trade on national marginal costs

76. The illustrative simulation made with the SDDP model allowed to obtain estimations on the evolution of the short term marginal costs of electricity in each one of the countries, which would also govern the evolution of the wholesale electricity prices. In general, marginal costs decrease after 2009 due to the reduction assumed for the fuel oil prices and to the increase in hydroelectric power generation with new hydropower plants expected to be commissioned in the region after 2009. For comparative effects, each country was also simulated individually and the impact of the increase in prices with exports and the decrease associated with imports were established. These effects are summarized in Figure 6.

Figure 6: Illustrative Impact of International Power Interchanges on National Marginal Costs

Source: SDDP illustrative simulations of the CA power markets

4. Central American electricity markets: institutional and regulatory framework

4.1. Introduction

77. In the 1990's, the Central American (CA) countries approved new laws and regulations that initiated restructuring processes in their power sectors. Those reforms aimed to promote private participation in a sector that had been traditionally controlled by state owned companies totally integrated (i.e. vertically and horizontally). Significant reforms to liberalize electricity markets were implemented in Guatemala, El Salvador, Nicaragua, and Panama; while in Costa Rica and Honduras reforms were limited to the opening of the generation segment to private participation. The new regulatory frameworks redefined the conditions for electricity service in most CA countries. The role of the States was restricted, total or partially, to the formulation of policies, the exercise of regulatory functions, and the administration of concessions.

78. During the last decade, El Salvador, Guatemala, Nicaragua, and Panama established competitive wholesale electricity markets and implemented vertical and horizontal unbundling of generation, transmission and distribution activities, creating specialized companies in the electricity sector, as well as permitting retail competition for large consumers. Also, Costa Rica and Honduras opened their markets to several generators in the form of IPPs. The design of the national wholesale markets took into consideration the limitations imposed to competition by the small size of the national markets, so that the exercise of market power could be adequately controlled. In all cases, economic dispatch is centralized and based on audited variable costs (except in El Salvador, where it was based on prices but is now changing to variable costs).

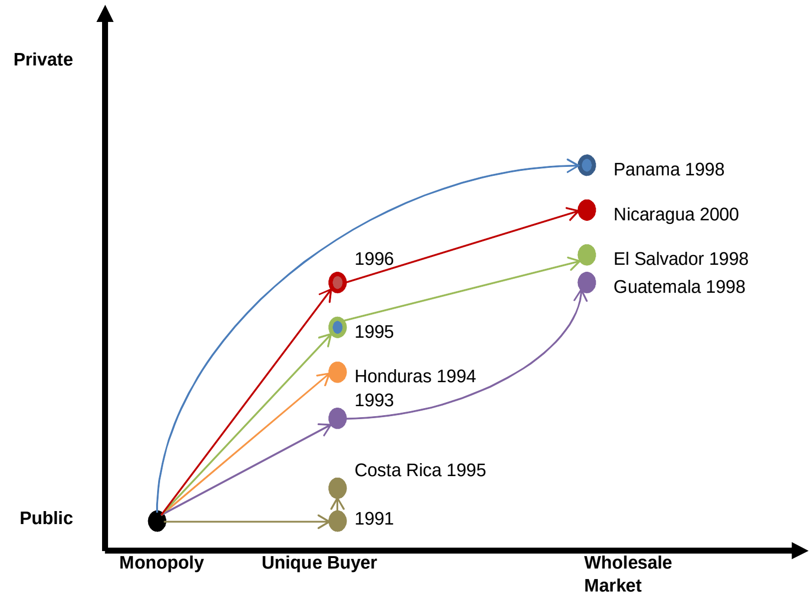
79. Table 3 summarizes the main normative, regulatory and entrepreneurial characteristics of the Central American electricity markets. Figure 7 illustrates de evolution of the wholesale electricity markets and of the ownership structure in the Central American power markets.

Table 3 Central America: Characteristics of Electricity Markets

COUNTRY	Guatemala	El Salvador	Honduras	Nicaragua	Costa Rica	Panama
Firts year of Reforms	1998	1997	1994	2000	1995	1998
Market environment						
Normative Entity	MEM	DGE	GE & SERNA	CNE (MEM)	MINAET	CPE
Regulator	CNEE	SIGET	CNE	INE	ARESEP	ERSP
System Operator	AMM	UT	ENEE	CNDC of ENATREL	ICE	CND of ETESA
Market Administrator	AMM	UT	ENEE	CNDC	ICE	CND
Transmission Company	ETCEE	ETESAL	ENEE	ENTRESA	ICE	ETESA
Vertical integration	No	Yes sep. account.	Yes	No	Yes	No
Horizontal integration	Yes	Yes	Yes	Yes, less 25%	Yes	G 25% D 50%
Industry structure						
Market model	Wholesale competition	Retail competition	Integrated	Wholesale competition	Integrated	Wholesale competition
Generators	42	16	31	12	37	13
Transmissors	3	1	1	1	1	1
Distributors	17	5	1	5	1	3
Traders	14	11	0	0	0	0
Large Consumers	37	2	1	9	0	4
Wholesale market						
Economic dispatch	Cost Based	Price Bids	Cost Based	Cost Based	Cost Based	Cost Based
Spot market price	SRMC with no T constraints	Average of prices based on bid prices of dispatched generators with T constraints	N.A.	SRMC with no T constraints	N.A.	SRMC with no T constraints
Capacity schemme	Yes	No	N.A.	Yes	N.A.	Yes
Capacity price	Regulated	Not applicable	N.A.	Regulated	N.A.	Market based
Long Term Contracts	Competitive biding	Negotiated	N.A.	Tender 80% Demand	N.A.	Tender 80% Demand
Contracts	Financial	Physical	N.A.	Financial	N.A.	Financial
Limit of large consumers	100 kW	0 kW	1000 kW	2000 kW	N.A.	1000 kW
Transmission Charges						
Global remuneration	Annual revenues established for the national grid & O&M costs each 2 years	N.A.	N.A.	Annual revenues established for the national grid & O&M costs each 5 years	N.A.	Annual revenues established for the national grid & O&M costs each 2 years
Tolls	Uninodal charges for the users (generation & demand): conection, maximum demand and use by tension level	Transmission congestion costs paid by involucrated agents	N.A.	Uninodal charges for the users (generation & demand): conection, maximum demand and use by tension level	N.A.	Conection and regional use of the system charges by MW (generation & demand) by tension level
Losses	Transmission losses pay by demand	Transmission losses pay by generators	N.A.	Transmission losses pay by demand	N.A.	Transmission losses pay by demand
Distribution Markets						
Obligation for contracts	Yes	No	N.A.	Yes	N.A.	Yes
Pass through costs	Contracts & Spot	Spot	N.A.	Contracts & Spot	N.A.	Contracts & Spot
Distribution Charges	VAD´s	VAD´s	N.A.	VAD´s	N.A.	VAD´s
Retail Tariffs	Pass-through of efficient G-T-D costs	Pass-through of efficient G-T-D costs	Tariff schedule and adjustments	Pass-through of efficient G-T-D costs	Cost plus methodology	Pass-through of efficient G-T-D costs

Source: *Integración Eléctrica - Retos y Oportunidades*, T. de la Torre, M. Dussan and others, 2008

Figure 7: Evolution of the Central American Electricity Markets



Source: CEPAL

80. In 2007 there were 151 generators in the CA electricity markets. Most of them are small (i.e. below 5 MW) or passive players (i.e. small generators that sell their production to a distribution company or to a single buyer or large generator and operate under PPAs that do not trade in the spot market). Data indicate that only 48 generators participate in the national wholesale electricity markets (including ICE and ENEE as sole generation marketers in Costa Rica and Honduras respectively).

81. On the demand side, there are 39 distribution companies, several of which are controlled by two corporate groups, AES and Unión Fenosa[26]. In all cases, the distribution companies are required to contract the supply of a substantial portion of projected demand using competitive bidding procedures. Today there are 53 large consumers who purchase power directly to several generators in CA. Development of retail competition has been modest in all countries except Guatemala, where it represents about 37 percent of demand. Also in Guatemala, a significant number of large consumers participate directly in the wholesale market and hundreds of smaller consumers are served by traders.

[26] AES controls four distribution companies with 75% of total sales in El Salvador. Unión Fenosa controls two distribution companies with 98% of sales in Nicaragua, two in Panama with 59% of sales and two in Guatemala with 26% of sales.

82. Annex 1 summarizes the number of specialized agents already operating in the CA national electricity markets.

4.2. Costa Rica

83. Power service in Costa Rica is largely under the control of ICE (Instituto Costarricense de Electricidad), its subsidiary CNFL (Compañía Nacional de Fuerza y Luz), and some small municipal utilities and cooperatives. The Government also plays a very prominent role in the power sector, both in the policy, planning, and regulatory areas, and in sector operations. National energy policy and planning are the responsibility of MINAET (Ministry of Environment, Energy and Telecommunications), which serves as the Technical Secretariat to the Energy Board. The power industry regulator is ARESEP (Public Utilities Regulatory Authority), who sets public tariffs for all Costa Rican electricity consumers using cost-of-service pricing.

84. Two laws approved in 1990 (Autonomous or Parallel Power Generation Law 7200) and in 1995 (Law 7508, amending Law 7200, which introduced entry competition for private generation) allowed for up to 30 percent participation in the market of independent power producers (IPPs) with generation capacity below 50 MW. This decision was mainly aimed to spur the development of renewable power plants supported through PPAs (Power Purchase Agreements). However, the development of hydroelectric plants under IPP schemes has been hindered by legal bottlenecks that affect the extension of water concessions beyond 2010 and by the lack of clarity in setting electricity prices in PPAs.

85. As a result, as PPAs terminate and water concessions expire, about 120 MW of hydro capacity will be gradually phased out. This situation is particularly critical in the short term, since private generation contributes 17 percent to net electricity sales. By 2010, 86 percent of this capacity would be lost, increasing the risk of rationing and affecting the economic and financial outlook of the system. As of today, four proposed legal solutions have been blocked in Congress and the last proposal advanced by MINAET is currently pending Congress approval (future treatment of water concessions is included in the project of Hydraulic Resources Law 14585, already submitted by MINAET). In light of this situation, the investment climate for independent producers appears to be extremely difficult.

86. The creation and operation of a comprehensive wholesale electricity market in Costa Rica requires efficient institutional coordination. Additional initiatives for a more comprehensive power sector restructuring have not been successful. MINAET has recently completed a draft for a new Electricity Law which lays out a significant structural reform, including the creation of a national wholesale electricity market, short term electricity trade, and bilateral long term electricity purchase/sale contracts. For the creation of such competitive market, the proposed law includes the unbundling of ICE and the creation of new entities (i.e. a system operator, a market administrator and a regulatory body autonomous from ARESEP).

87. The Vice Minister of Energy at MINAET has maintained the initiative for a new Electrical Law without success given the extended and ambitious versions presented to the Costa Rican Legislative Assembly. However, the new Minister is working on a simplified version aiming at the participation of co-generators and independent power producers in the MER and at the support for the regional market to supply power demand in Costa Rica.

4.3. Honduras

88. ENEE (the National Electricity Company) is the vertically and horizontally integrated state-owned company in charge of generation, transmission, distribution and commercialization of electricity in Honduras. The Electricity Law issued in 1994 defined a new institutional structure and industrial organization for the Honduran power industry. Through this law, the policymaking function was assigned to an Energy Cabinet chaired by the President or by the Minister in SERNA (the Natural Resources and Environmental Secretariat), whose role was to provide technical support. A new regulatory agency, the CNE (the National Energy Commission), was also created.

89. However, the Energy Cabinet has met less than once per year since its inception. Furthermore, SERNA, as secretary and coordinator of the Cabinet, has not played any active role in defining energy policy and in providing the technical groundwork for decision making. The CNE has also had a marginal role due to a lack of political support and resources. ENEE has thus become the *de facto* reference for setting energy policy and regulation. This situation has led to a weak separation of roles between the provider of the public service, the regulator and the Ministry.

90. In addition, ENEE is the sole responsible for transmission and system operations through its dispatch center, which determines the marginal cost of generation. The 1994 law also mandated, subject to approval by Congress, unbundling and privatization of ENEE´s distribution networks by region, but this reform has failed to happen as well. As a result, ENEE still operates as a fully integrated company and is the single buyer responsible for ensuring availability of sufficient power to meet demand. According to the law, power generation can be performed by state agencies or by private or mixed ownership companies. These entities are authorized to sell power both to large consumers and to ENEE. Under this legal framework, private investors are mainly embarked on new generation projects, including hydropower, and sell electricity to ENEE through PPAs.

91. In summary, the implementation of the new sector model established in the 1994 law was partial and had limited success in addressing the issues that had motivated the reform in the first place. Crucially, distribution networks were not privatized as mandated by the law, leaving ENEE as a vertically integrated utility, as sole distributor served from the transmission grid, and in control of all generation facilities (as the single buyer in the system), either as owner or through PPAs.

4.4. Nicaragua

92. Prior to sector reforms, INE (the National Energy Institute) was the Nicaraguan state-owned company in control of the electricity sector, with supply functions as well as responsibility for sector policy-making, planning, development, and pricing. In 1994 the Government created ENEL (the Nicaraguan Electricity Company) as a vertically and horizontally integrated government-owned company in charge of generation, transmission, distribution and commercialization of electricity. ENEL also assumed tasks related to the development and use of energy resources, planning of the electricity sector and system operations. INE remained in charge of the normative and regulatory functions of the sector.

93. In 1998 the Power Sector Law introduced significant reforms. CNE (the National Energy Commission) was created to set the sector policies, strategies, and objectives and to approve the indicative plan for the electricity sector. INE was left with regulatory and supervisory functions and concession licensing. ENEL's commercial and operative activities in the power sector were divested by separating transmission activities, system operations, and market administration, which were assigned to ENATREL (the National Transmission Company). CNDC (the National Dispatch Center) is the unit within ENATREL in charge of the operation of the system and of the commercial administration of the Wholesale Electricity Market of Nicaragua (MEMN).

94. ENEL's generation assets were segregated, as well as its distribution assets and functions, which were assigned to two new companies, Disnorte and Dissur. The privatization process resulted in one privatized thermal power company, a management contract for a geothermal power plant, and the sale of the two distribution companies to a single private investor/operator. ENEL remains in control of some hydro and thermal generation and is in charge of some diesel power generators developed through PPAs.

95. A new law issued in 2007 created the MEM (the Ministry of Energy and Mines) as successor to CNE, with additional functions which were transferred from INE such as licensing and oil and hydrocarbons policy, as well as the approval of regulations and norms in the energy and mines sector.

96. A cost-based wholesale electricity market operates in Nicaragua since the end of the 1990's. Generators, distributors and large consumers (i.e. with peak demand above 2,000 kW) participate in this market, which was created to include hourly, short-term opportunity electricity transactions and long-term bilateral purchase/sale electricity contracts. Small consumers served by distribution companies buy electricity at regulated prices. However, in 2005, Law 554 declared an energy crisis and established temporary measures to reduce the impact of high fuel prices on electricity tariffs, including a market intervention by which spot prices were not calculated based on marginal costs, but on a weighted average of the variable costs of dispatched thermal units plus 10 percent. Also, in September 2008, Law 672 mandated to maintain this market intervention until December 2009 [27].

4.5. El Salvador

97. Prior to the reforms introduced in the late 1990s, the power sector in El Salvador operated through the state-owned company CEL (the *Comisión Hidroeléctrica del Río Lempa*), which provided horizontally and vertically integrated generation, transmission and distribution services. The reforms required separation of policy-making, regulatory, and ownership functions. The DEE (the Power Directorate) was created in 2001 as an administrative unit within the Ministry of Economy. It is in charge of elaborating, proposing, coordinating, and executing policies, programs, projects, and other actions in the electricity sector. SIGET (the General Superintendence of Power and

[27] Maintaining such percentage in 10% if international Bunker C prices are lower than 50 USD/B but reducing it to 7% or 5% if international Bunker C prices are 50-75 USD/B or higher than 75 USD/B, respectively.

Telecommunications) is the regulatory body for both the electricity and telecommunications sectors and is in charge of regulating the power market, the distribution companies, and consumer prices. Finally, the CNE (the National Energy Council), created in 2006, is responsible for analyzing the country´s energy situation.

98. The restructuring carried out during 1996-2000 led to the unbundling of generation, transmission and distribution activities and to the horizontal division of generation and distribution into several companies. All the distribution and thermal generation companies were privatized; however, the state-owned generator, CEL, maintained ownership of the hydroelectric plants and created ETESAL (the Salvadorian Transmission Company) as a subsidiary company. UT (the Transaction Unit) was also created as a private company in charge of system operations and of the administration of the wholesale electricity market (MEM).

99. The electricity Law in El Salvador grants a high degree of freedom to market agents and explicitly authorizes vertical integration in generation, transmission, distribution, and supply. The only limitation is the prohibition for generation, distribution and supply companies to own shares in ETESAL. This restriction, together with the existence of a price-based spot market and a commercialization activity with retail competition for all consumers, makes the wholesale electricity market in El Salvador very different from other CA countries.

100. Nevertheless, the market has suffered significant adjustments, initially the result of the fact that the remuneration of generators in the spot market did not generate enough returns to encourage new capacity developments. To address this problem, rules were implemented to allow for competitively-bid, long-term contract prices to be reflected in consumer tariffs. In addition, the Government empowered the regulator to shift to a cost-based market if evidence of market manipulation emerged. Also, in early 2005, facing high spot prices due to increasing fuel prices, the remuneration of generators at marginal cost of generation in the spot market was replaced by a “pay-as-bid” scheme. The spot price was then determined by the weighted average of price bids of generation plants dispatched to meet demand. Moreover, in 2006, given that this new pricing scheme was not effective in controlling further increases in the spot price, the Government decided to subsidize any increase in generation costs above USD 91.1/MWh.

4.6. Guatemala

101. Prior to sector reforms, electricity service in Guatemala was provided by the state-owned company INDE (the National Electrification Institute) through horizontally and vertically integrated generation, transmission and distribution services. The Guatemalan power sector was reformed based on the law issued in 1996 (General Electricity Law, recently updated by the *Acuerdos Gubernativos* 68-2007 and 69-2007), which included separation of policy-making, regulatory and ownership functions.

102. Today, the policy and regulatory bodies are the MEM (Ministry of Energy and Mines) and CNEE (the National Electricity Commission) respectively. MEM is responsible for overall energy planning, including planning of the power system, but has limited capacity to carry out such tasks. Currently, least-cost power sector expansion planning (both in generation and transmission) is undertaken by CNEE but, as mandated in the new legislation, this responsibility will be transferred to MEM when it builds adequate capacity. The 1996 law also created AMM (the Wholesale Electricity Market Administrator) as a private body in charge of system operations and of the commercial administration of the wholesale electricity market (MM).

103. The electricity sector restructuring carried out during 1996-2000 led to the unbundling of INDE's generation, transmission and distribution activities with horizontal division of generation and distribution into several companies, including retail competition for large consumers with peak demand above 100 kW. However, INDE still owns about 60 percent of the hydro plants and also owns and operates about 85 percent of the transmission network. The remaining transmission lines are privately owned and operated.

104. The Guatemalan distribution system is largely privatized, with three major private regional distribution companies: Deorsa, Deocsa, and Eegsa. Also, most of the generation capacity is owned by various private companies that have developed significant thermal generation capacity under PPAs and as merchant plants.

4.7. Panama

105. In 1997, Panama reformed its power sector through the Institutional and Regulatory Framework for the Public Electricity Service Law, regulated by the Executive Decree 22 of 1998. Electricity service in Panama had been previously provided by IRHE

(the National Institute of Hydraulic Resources and Electrification), a state owned company in charge of integrated generation, transmission and distribution services. The new law introduced separation of policy-making, regulation and ownership functions.

106. In 1998 ASEP (the National Authority in Public Services) was created as the regulatory body responsible for overseeing the electricity, water and telecommunications sectors. That same year, IRHE was unbundled in generation, transmission and distribution activities. Eight generation and three distribution companies were privatized. Transmission activities, market administration and system operations were assumed by the state-owned ETESA (the Transmission Company), which is also responsible for identifying and executing transmission expansion programs as well as for providing indicative generation expansion programs. CND (the National Dispatch Center) is the section within ETESA that is in charge of system operations and of the commercial administration of the wholesale electricity market (MME).

5. Central American electricity markets: contracting framework

5.1. National wholesale electricity markets

107. The structure of wholesale electricity supply in Central American countries is considerably diverse. While Costa Rica and Honduras operate with fully integrated power companies responsible for national electricity supply (ICE and ENEE, respectively, the sole wholesale electricity traders in each country), the other four countries have developed competitive wholesale electricity markets with multiple participating agents.

108. All the existing markets are administered by independent market administration bodies: two private companies (UT in El Salvador and AMM in Guatemala), and two dependencies of the national transmission companies (CNDC in Nicaragua, a unit within ENATREL; and CND in Panama, a division of ETESA).

109. In all four markets, the traded products are Energy (MWh) and Power (MW). The "firmness" or "reliability" of electricity supply is associated to power interchanges through the concept of "firm" or "reliable" power (MW), which is generated with certainty in the power plants owned by the generators (producers) and contracted by the consumers (distributors, large consumers) to supply a percentage of their forecasted "peak" demand (MW) and "associated" energy (MWh) (the same percentage is usually applied to contracted peak and energy demands, although in some markets it is possible to contract only firm power). Power interchanges are agreed in the contract markets (with or without "associated" energy) through long term contracts that respond to rules and conditions, different for each market, that define the concepts "firmness" or "reliability".

110. Short-term markets operate according to economic dispatch based on audited variable generation costs in Nicaragua[28], Guatemala, and Panama and on price generation offers in El Salvador[29]. These markets match demand with supply every hour through spot

[28] During 2005 – 2008, Laws 554 (Energy Stability Law), 600 and 664 (Additions and reforms to the Energy Stability Law) were issued in Nicaragua to prevent the adverse price impacts of the increase in international oil prices on electricity consumers. These laws allowed the control of spot prices, which were not calculated based on marginal costs, but on a weighted average of the variable costs of thermal units plus 10 percent.

[29] In 2005, facing high spot prices due to an increase in fuel prices and a tight supply/demand, the government of El Salvador decided to change the rules for the remuneration of generators in the spot market. Payments of transactions in the spot market at marginal generation costs were replaced by a "pay-as-bid" scheme. The spot price was then

transactions (hourly differences between actual generation or demand versus contracted quantities), which are traded at spot prices. In all the spot markets, electricity imports are considered as additional generation, while exports count as additional demand for the economic dispatch of generation and for the definition of spot prices. Annex 2 summarizes main market rules and descriptions of the wholesale electricity markets in Nicaragua, El Salvador, Guatemala and Panama. Table 4 presents key characteristics.

Table 4: Central America: National Wholesale Electricity Markets

	COSTA RICA	**HONDURAS**	**NICARAGUA**	**EL SALVADOR**	**GUATEMALA**	**PANAMA**
Name of the market	Non Existing	Non Existing	Mercado de Energía Mayorista (MEMN)	Mercado Mayorista de Energía (MME)	Mercado Mayorista (MM)	Mercado Mayorista de Electricidad (MME)
System operator & market admin.	ICE	ENEE	Centro Nacional de Despacho (CNDC), a unit of ENATREL	Unidad de Transacciones (UT), private	Administrador del Mercado Mayorista (AMM), private	Centro Nacional de Despacho (CND), a section of ETESA
Traded products	N.A.	N.A.	Power (MW) and Energy (MWh)	Power (MW) and Energy (MWh)	Power (MW) and Energy (MWh)	Power (MW) and Energy (MWh)
Agents	N.A.	N.A.	Producer and Consumer agents	Market participants (Gen., Distr., Traders)	Producer and Consumer participants	Producer and Consumer participants
Electricity Demand	N.A.	N.A.	Hourly energy (MWh) & Daily peak power (MW)	Hourly energy (MWh) & Annual peak power (MW)	Hourly energy (MWh) & Monthly peak power (MW)	Hourly energy (MWh) & Monthly peak power (MW)
Power supply reliability (plant limits to power contracts)	N.A.	N.A.	“Potencia maxima garantizable” determined for each power plant	“Capacidad firme” (adjusted to peak demand) determined for each power plant	“Oferta Firme Eficiente” (adjusted to peak demand) determined for each power plant	“Potencia Máxima” determined for each power plant
Spot market	N.A.	N.A.	-“Mercado de Ocasión”	“Mercado Regulador del Sistema (MRS)”	-“Mercado de Oportunidad”	-“Mercado Ocasional”

determined by the weighted average of price bids of generation plants dispatched to meet demand. Price bids by the state-owned enterprise, determined on the basis of financial considerations, played a role in the stabilization of spot prices. However, in 2006, the new price scheme was not effective in controlling further increases in spot prices and Executive Decree No 57 of 2006 introduced reforms in Art. 67 of the Electricity Law Regulations (Articles 67-A through 67-M), making it mandatory to reflect variable costs in the MRS (the spot market). This situation also allowed the Government to subsidize any increase of generation costs above 91.1 USD/MWh.

	COSTA RICA	HONDURAS	NICARAGUA	EL SALVADOR	GUATEMALA	PANAMA
			-Economic dispatch based on variable costs[30]-	-Economic dispatch based on prices[31] and transmission capacities	-Economic dispatch based on variable costs	-Economic dispatch based on variable costs
			-Hourly energy price: marginal cost	-Hourly energy price: marginal price	-Hourly energy price: marginal cost	-Hourly energy price: marginal cost
			-Daily power price: market	-Annual power price: regulated capacity charge	-Monthly power price: regulated reference price	-Power price: contracted (by year or shorter)
Contract market	N.A.	N.A.	Bilateral transactions of hourly energy and daily power	Bilateral transactions of energy ejection, injection & transfer.	Bilateral transactions of power with or without associated energy.	Bilateral transactions of power and/or energy.
Imports	Considere d a Power plant	Considered a Power plant	Considered as Producer Agent	Considered as Power plant	Considered as Power plant	Considered as Power plant
Exports	Considere d add. demand	Considered add. Demand	Considered as Consumer Agent	Considered as Large consumer	Considered as Large consumer	Considered as Large consumer

5.2. Contracting obligations

111. Power service in CA wholesale electricity markets is subject to regulatory obligations for contracted power purchases for the consumers (distribution companies, large consumers), which aim to enforce electricity supply reliability and reduce spot price risks through contracted power with generators. In Nicaragua and Panama, power supply contracts are established through the Supply Guarantee Obligations (*Obligaciones de Garantía de Suministro*) concept, Guatemala applies demand coverage through Firm Efficient Supply (*Oferta Firme Eficiente*) and El Salvador uses long-term contracts subject to Firm Capacity (*Capacidad Firme*) availability.

112. At the end of each year, distributors in Nicaragua must have contracted, in advance, 80 percent of their forecasted demand (for power and energy) for the following year and 60 percent for the subsequent year. In El Salvador, distributors must contract 50 percent of their forecasted demand (for the first year), with 25 percent maximum for each independent contract. In Guatemala and Panama, this commitment refers to 100 percent of peak demand. Large consumers do not have specific contracting obligations in El Salvador

[30] With price controls during 2005 – 2008 (see footnote 28)
[31] With price controls during 2006 – 2008 (see footnote 29)

and Panama, while they have to contract 100 percent of their peak demand in Guatemala and 50 percent of energy demand in Nicaragua.

113. Annex 3 presents the main rules related to power purchases contracting obligations in the CA markets, which are summarized in Table 5.

Table 5: Central America: Wholesale Electricity Contracting Obligations

	COSTA RICA	HONDURAS	NICARAGUA	EL SALVADOR	GUATEMALA	PANAMA
Regulations related to long term contracting	N.A.	N.A.	Supply Guarantee Obligations ("Obligaciones de Garantía de Suministro")	Long Term Contracts & Firm Capacity ("Contratos de largo plazo")	Covering of Firm Demand with Firm Efficient Supply ("Oferta Firme Eficiente")	Supply Guarantee Obligations ("Obligaciones de Garantía de Suministro")
Contracting obligations for distributors	N.A.	N.A.	Power & Energy: 80% of total demand 1 Yr. 60% of total demand 2 Yr.	Power & Energy: 50% of total demand Max. 25% of total demand in one contract	Power 1/: 100% of peak demand	Power 1/: 100% of peak demand
Contracting obligations for large consumers	N.A.	N.A.	Energy: 50% of total demand	Free	Power 1/: 100% of peak demand	Free

1/ . Long term power supply (MW) should be contracted to cover 100 percent of peak demand (MW). Contracted power (MW) may be also associated to contracted energy supply (MWh). If contracted energy supply is lower than energy demand, total energy supply to cover demand must be complemented with short term energy purchases at spot prices.

5.3. Contracting processes

114. Public tenders are the mechanisms used by the distribution companies in CA wholesale electricity markets to select the most favorable electricity supply contracts with the generation companies. Such processes are regulated and supervised by the regulatory bodies of each country (SIGET in El Salvador, CNEE in Guatemala and ASEP in Panama). Different standard terms are applied in each country: a) over 5-year contracts agreed 3-5 years in advance or below 5-year contracts agreed at least 3 months in advance in El Salvador, b) minimum of 5-year contracts and maximum of 15-year contracts in Guatemala, and c) typically 1-year contracts agreed 60 days in advance and up to 15-year contracts in Panama. In some cases, such as in El Salvador, maximum confidential prices may be previously ruled for each tender.

115. Annex 4 contains a detailed description of such processes, including related documentation and guarantees, schedules for presentation of proposals, schedules for study and selection of offers and contract formalization procedures. Table 6 summarizes the main related aspects.

Table 6: Central America: Competitive Electricity Contracting Mechanisms

	COSTA RICA	HONDURAS	NICARAGUA	EL SALVADOR	GUATEMALA	PANAMA
Mechanism	N.A.	N.A.	N.A.	Public Tenders	Public Tenders	Public Tenders
Conditions	N.A.	N.A.	N.A.	- 3-5 years in advance for more than 5-year contracts, 3 months in advance for less than 5-year contracts	-Minimum of 5-year and maximum of 15- year contracts	- 60 days in advance for 1-year supply (typical)
Type of contract				Standard contracts of Firm Capacity & Associated Energy	Firm Capacity & Associated Energy, some cases linked to new power plants	Firm Capacity & Associated Energy
Price constrains	N.A.	N.A.	N.A.	Energy: SIGET confidential reference max. price Power: SIGET regulated price	Free	Free
Multiple buyers	N.A.	N.A.	N.A.	Several Distributors may participate as buyers	N.A.	N.A.
Terms & conditions	N.A.	N.A.	N.A.	Standardized terms & procedures supervised by SIGET	Terms and procedures approved by CNEE	Terms and procedures regulated by ASEP

5.4. Existing contracts

116. Annex 4, section 4.16 summarizes standard clauses included in long-term energy contracts in El Salvador and Annex 4 section 6.2 summarizes typical contract clauses included in long-term energy contracts in Panama[32].

[32] For example, long-term supply contracts in Panama contain the following general conditions: *Definiciones, Documentos del Contrato, Interpretación, Idioma, Asociación en participación (Consorcio o Asociación), Notificaciones y Avisos, Ley Aplicable, Solución de Controversias, Objeto del contrato, Duración – Plazos – Penalizaciones, Potencia Firme Contratada – Energía Asociada Requerida Contratada, Precios, Formas de pago – penalizaciones, Pago de cargos de Transmisión y Distribución, Impuestos y Derechos, Fianza Cumplimiento, Derechos de Autor, No confidencialidad de la información, Derechos de Patente y Licencias, Limitación de Responsabilidad, Fuerza Mayor o Caso Fortuito, Enmiendas, Terminación, Cesión*. The following special conditions are also included: *Comprador, Formula de Energía Asociada Requerida, Potencia Firme Garantizada (si aplica), dirección para notificaciones, Modalidad del suministro, Período del Suministro, Penalizaciones por atraso en la fecha de inicio del suministro, Potencia contratada, Unidades de generación comprometidas, Modalidad de la potencia, Puntos de entrega de la potencia, Puntos de entrega de la Energía, Precio de la Potencia Firme y*

117. Existing power supply contracts have been executed by 118 distributors and large consumers with 66 producers in the Central American wholesale electricity markets. Nicaragua and Panama have contracted 1,083 MW, El Salvador 170 GWh/month (around 350 MW) and Guatemala 7,922 GWh/year (around 1,350 MW). The existing contracts in these four countries add up to a total of about 2,783 MW.

118. Annex 5 contains the information related to these contracts, which are summarized in Table 7..

Table 7: Central America Existing Purchase Energy Contracts

(DISTRIBUTORS AND LARGE USERS)

	COSTA RICA	HONDURAS	NICARAGUA 1/	EL SALVADOR	GUATEMALA	PANAMA
Date	N.A.	N.A.	March 2009	March 2009	2008	2008
Contracted quantity	N.A.	N.A.	219 MW	170 GWh/month	7,922 GWh/year	864 MW
Number of buyers	N.A.	N.A.	5	11	99	3
Number of producers 2/	N.A.	N.A.	5	12	39	10

1/Not including 5 PPA's (Union Fenosa & IPP's), 2/ Not including cogenerators and IPP's

5.5. National frameworks for international power transactions

119. The existing four CA wholesale electricity markets include rules for international electricity transactions. International transactions among regional agents are coordinated by the system operators and market administrators. These bodies may also participate in the regional market through spot transactions under specific temporary circumstances (i.e. emergency interchanges).

120. International power transactions are contracted directly by agents participating in the national wholesale electricity markets. Such contracts are currently subject to the same regulations as the national contracts (i.e. long-term contracts involving power interchanges that must be supported by "firm" available capacity and other regulations).

fórmula de ajuste, Precio de la Energía Asociada requerida y fórmula de ajuste, Penalización por déficit en la entrega de la potencia, Penalización por déficit en la entrega de la energía, Datos transferencia bancaria, Fianza de cumplimiento, Garantía de pago, Período de incumplimiento de la potencia contratada, Aviso de terminación por el Comprador, Período de incumplimiento en el pago, Aviso de terminación por el Vendedor.

121. Currently, the regulatory frameworks of all electricity markets foresee actions to guarantee local self sufficiency in electricity supply, such as: a) the generation – transmission expansion planning (centralized in Costa Rica and indicative in the other four countries), and b) the preferential treatment for the local markets of the long-term firm energy contracts for the regulated markets (in Honduras, Nicaragua and Panama). For example, in Panama the E.D. No. 22 (Art 30) explicitly establishes that the National Dispatch Center will give priority to supply the domestic market.

122. However, El Salvador and Guatemala have already advanced in the implementation of national market rules to support the MER:

- *El Salvador*: the regulatory framework in this country is clear with respect to MER transactions: UT is responsible for coordinating the operational and commercial requirements for the MER, considering the EOR as a regional counterpart to coordinate the transactions of import and export of electricity. CRIE. UT will manage the bilateral transactions for import and export contracts in accordance with the provisions in the regulation of the regional electricity market adopted by the CRIE and coordinated by the EOR. Each import or export contract involving a Salvadorian agent shall be reported to the UT as a bilateral transaction.

- *Guatemala*: the recent *Acuerdo Gubernativo* No. 692007 issued in Guatemala recognizes international transactions as the purchase or sale of power and energy from other countries. It also recognizes that the characteristics of the contracts could be considered as a firm offer or firm demand within the wholesale market, as appropriate. Agents and large users of the wholesale electricity market may transact imports or exports through the MER or with the market of any other country with which the National Interconnected System is connected.

123. Annex 6 describes the main national regulations governing international interchanges in the CA wholesale electricity markets, which are also summarized in Table 8 below.

Table 8: Central America: National Frameworks for International Power Transactions

	COSTA RICA	HONDURAS	NICARAGUA	EL SALVADOR	GUATEMALA	PANAMA
Trading Agents	ICE	ENEE	Producer Agents (Exports) and Consumer Agents (Imports)	Generators (Exports), Distributors (Imports), Traders (Exports &	Producer Participants (Exports) and Consumer Participants (Imports)	Producer Participants (Exports)and Consumer Participants (Imports)

	COSTA RICA	HONDURAS	NICARAGUA	EL SALVADOR	GUATEMALA	PANAMA
				Imports)		
Coordinator of Interchanges	ICE	ENEE	CNDC	UT	AMM	CND
Spot Interchanges	N.A.	N.A.	-Coordinated by CNDC with other market coordinators -Prices include transmission & losses charges	-Coordinated by UT with other market coordinators	-Traded directly by market participants or by AMM (emergency interchanges)	-Coordinated by CND with other market coordinators -Prices include local market charges
Contracts	N.A.	N.A.	-Physical commitments -Daily power commitments -Hourly energy commitments -Long term (>6m), Medium term (6m-7d), Short term(<7d) -Prices include market charges	-Subject to SIGET supervision -Explicitly subject to MER rules (i.e. long term firm power interchanges are allowed)	-Imports and exports subject to "Firm Efficient Availability" for traded power -Additional associated energy trading	-Subject to ASEP supervision -Power and energy commitments for at least 12 months -Exports subject to generation & transmission capacity availabilities -Priority of local supply (Long Term Local Supply Studies)
Transitory priority for local power supply	No	Yes	Yes	No	Yes	Yes

6. The Central American Regional Electricity Market (MER)

6.1. Introduction

124. The Central America Regional Electricity Market (MER) is very unique in the sense that it is the only example of an international electricity market having its own regulatory body and system operator with participating agents from national electricity markets of several countries. This market is designed to trade mainly electricity and transmission capacity. More importantly, the SIEPAC initiative illustrates that it is possible to create a relatively advanced regional electricity trading arrangement between countries that are at differing stages of internal market development.

125. Small national markets and poor market integration have been obstacles to the benefits of the economies of scale associated with the development of large-scale energy projects. The concept of a regional market was first discussed in 1987 and materialized with the SIEPAC initiative. SIEPAC consists of two interdependent projects, the development of a regional electricity market (MER) and the construction of a 1,800km power line that will interconnect the six Central American countries, thereby facilitating the interchange of electricity among them and opening the potential for trade with Mexico and Colombia. SIEPAC would also bring efficiency gains through integrated economic dispatch, shared reserve margins and exploitation of complementarities in demand and supply.

6.2. Regional interconnection system

126. The development of a regional power market in Central America is constrained, among other things, by the power flows allowed by the interconnection grid and by regulatory and institutional barriers (discussed later in section 9). The transmission capacity to make power interchanges between countries increases as new transmission links are commissioned (see Table 9). The Mexico-Guatemala interconnection, expected to be commissioned in 2009, would support 200 MW power flows from Mexico to Guatemala.

127. The Central American Electrical Interconnection System (SIEPAC) project, expected to be commissioned in 2010, would increase to 300 MW the capacity of power interchanges between most countries in the region. New transmission projects that are being considered would further increase the transmission capacity to develop a regional market. The second circuit of the SIEPAC project could increase trade capacity to 600 MW between countries

(450 MW between Costa Rica and Panama) and the Panama-Colombia DC link could provide a 300 MW capacity for power interchanges.

Table 9: Central America: Transmission Links

INTERCONEXIONES	GU-ES	GU-HO	ES-HO	HO-NI	NI-CR	CR-PA	MX-GU	CO-PA *
	N-S / S-N	N-S / S-N	N-S / S-N	N-S / S-N	N-S / S-N	N-S / S-N	N-S / S-N	N-S / S-N
Sistema Actual	67 / 44	0 / 0	125 / 101	42 / 54	48 / 78	39 / 0	0 / 0	0 / 0
México - Guatemala (Inicial)	67 / 44	0 / 0	125 / 101	42 / 54	48 / 78	39 / 0	200 / 70	0 / 0
Siepac 1er Circuito	300 / 300	300 / 300	300 / 300	300 / 300	300 / 300	90 / 300	200 / 70	0 / 0
México - Guatemala (Incr)	300 / 300	300 / 300	300 / 300	300 / 300	300 / 300	90 / 300	300 / 300	0 / 0
Siepac 2do Circuito (Contigencia dos circuitos)	600 / 600	596 / 600	450 / 350	300 / 350	330 / 350	300 / 300	300 / 300	0 / 0
Siepac 2do Circuito (Contigencia un circuito)	600 / 600	600 / 600	550 / 600	564 / 600	500 / 600	450 / 450	300 / 300	0 / 0
Colombia - Panamá	600 / 600	600 / 600	550 / 600	564 / 600	500 / 600	450 / 450	300 / 300	300 / 300

Source: *Estudio del segundo Circuito del proyecto SIEPAC como obra planificada y fecha óptima de entrada en operación*. SNC-Lavalin International Inc. October 2008

6.2.1. Existing regional interconnection systems

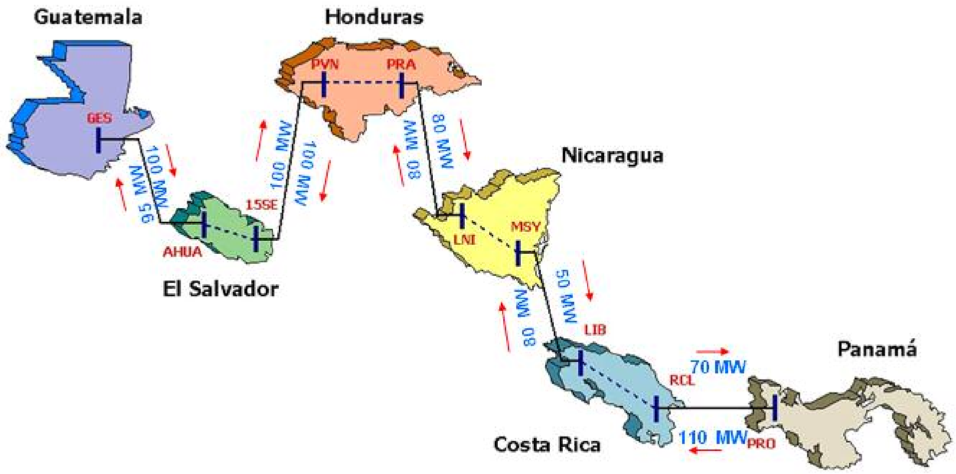
128. The first interconnection in the region was established in 1976 with the commissioning of a line connecting Honduras to Nicaragua. This was followed by connections between Nicaragua-Costa Rica in 1982, and Costa Rica-Panama and Guatemala-El Salvador in 1986. Until 2002 the region remained divided into two separate electrical areas with Guatemala and El Salvador connected to each other but isolated from the remaining four countries. Following the commissioning of a tie-line between El Salvador and Honduras, the transmission networks of all six countries are electrically interconnected (there is no direct interconnection between Guatemala and Honduras)[33].

129. Figure 8 illustrates the existing regional transmission grid, denominated RTR (Red de Transmisión Regional) as it was defined during the transition period up to the commissioning of the project SIEPAC (Sistema de Interconexión Eléctrica Paises de America Central). It consists of single 220 kV interconnection links connecting the power systems of neighbor countries, which today are considered without firm transportation capacity to support firm international electricity interchanges based on long-term

[33] Economic Consulting Associates (ECA). "Regional Power Sector Integration: SIEPAC Case Study", July 2009.

contracts. Current international electricity interchanges are agreed on the basis of emergency requirements or for short-term economic interchanges.

Figure 8: Regional Interconnection Grid, 2006



Source: *Integración Eléctrica: Restos y Oportunidades*, T. de la Torre, M. Dussan and others. 2008

6.2.2. The SIEPAC interconnection project

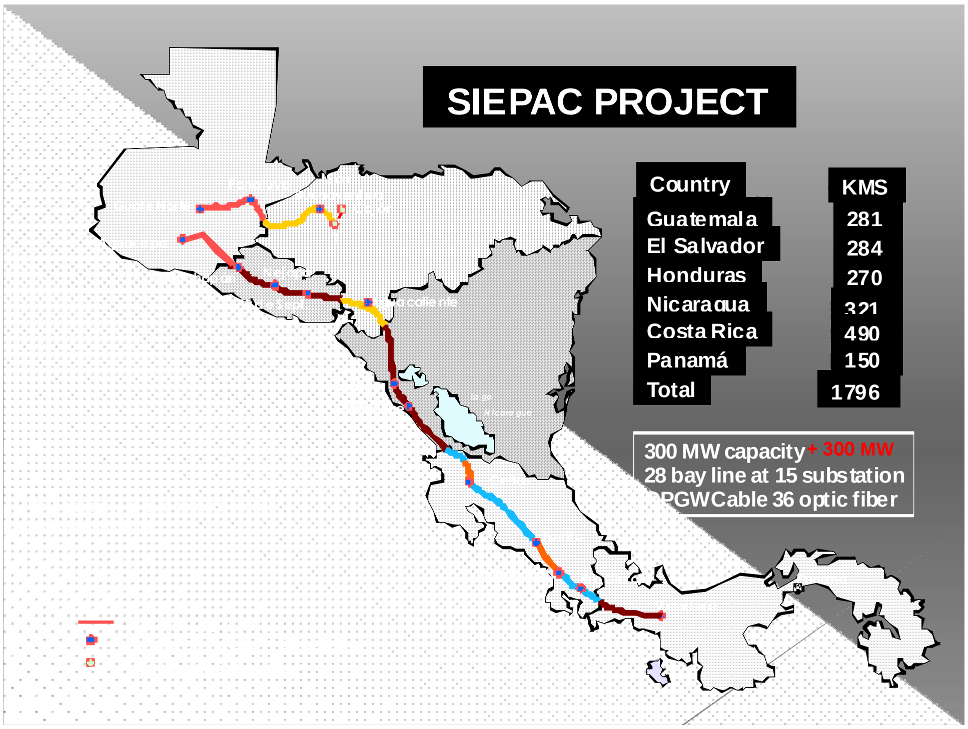
130. The Central American Electrical Interconnection System project is an initiative to create an integrated regional electricity market among the six Central American countries. It consists of a 1,800 km–long, 230 kV single-circuit transmission line[34], with 15 substations, comprising 20 transmission segments (see Figure 9). The project investment cost is estimated at about USD405 million, financed mainly by IDB (USD240 million), CABEI (USD100 million) and USD50 million of equity contributions from the 9 shareholders of the EPR[35] (the 6 Central American countries, ENDESA of Spain, ISA of Colombia and CFE of Mexico).

131. SIEPAC is part of a broader regional initiative under the Mesoamerica Project (formerly known as Plan Puebla-Panama, PPP). The Mesoamerica Project aims to develop and integrate the energy, communications and transport infrastructure across nine countries, including the six SIEPAC countries plus Mexico, Belize and Colombia. The PPP was proposed in 2001 and formally institutionalized in 2004. Although the SIEPAC line is contained within the Central America region, work on the interconnection with the Mexican system was commissioned in April 2009 and there are plans to strengthen the

[34] A fiber optic cable is also being installed with the transmission cable to strengthen the telecommunications infrastructure of the region (the "Mesoamerican Information Highway").
[35] The remaining 15 million have been financed by CAF loans

interconnection to support trade with Colombia (see section 8 for a complete description of the Mexico and Colombia interconnections).

Figure 9: SIEPAC Project



Source: EPR - Avance del proyecto SIEPAC-Presentación General del Proyecto-Agosto 2008

132. The stated objectives of the SIEPAC project are: (i) to improve security of supply by widening reserve margins, (ii) to reduce the problem of electricity rationing in capacity deficit countries (such as Nicaragua), (iii) to achieve improved operating efficiency and reduce generation fuel consumption, (iv) to introduce greater competition into the domestic markets, (v) to lower end-user electricity costs, (vi) to attract foreign investment to the region's energy sector, and (v) to contribute to the economic development of the region.

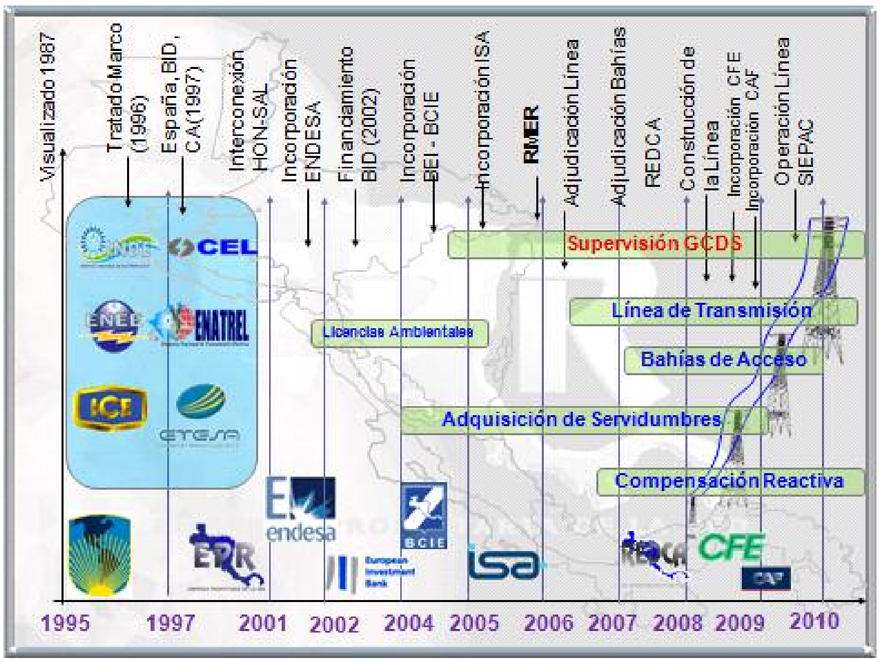
133. In addition, preliminary estimations show that SIEPAC will result in 1 million tons of avoided CO_2 equivalent per year.[36] This estimation is for the SIEPAC line with interconnections with Colombia and Mexico against the base case of no regional transmission expansion. The reduction will result from more efficient dispatch across the region as well as changes in the fuel mix.

---

[36] ENDESA, "Descripción del PDD del Proyecto SIEPAC", presentation, March 2007.

134. The saga of the SIEPAC project is summarized in Figure 10 (see Annex 7 for a complete timeline). The transmission company (*Empresa Propietaria de la Red* – EPR) was created in 1998, ENDESA joined in 2001, ISA in 2005 and CFE in 2008. Project financing by IDB was obtained in 2002. The main norms and regulations for the operation of the regional market (*Reglamento del Mercado Regional*—RMER) were adopted by the end of 2005.

Figure 10: History of the SIEPAC Project



Source: *EPR - Avance del proyecto SIEPAC*-General Project Presentation, august 2008

135. Main contracts for the construction of the transmission lines and acquisition of equipment and materials were awarded in 2006 and the construction started in 2008. A new telecommunication company, REDCA, responsible for the commercial operation of the optic fiber cable installed on the line, was created in 2007. According to a construction scheduled revised in October 2008, the transmission segment in Panama would be completed in September 2009, the segments in Guatemala and Honduras would be ready by December 2009 and in El Salvador and Nicaragua in March 2010. Construction of the transmission line in Costa Rica is delayed due to difficulties in obtaining rights of way. All segments would be ready by June 2010, except for segment 17, Palmar Norte- Parrita, which would be delayed at least until 2011 if rights of way are finally obtained.

136. In 1996 the six Central American countries signed the Framework Treaty for the Central American Electricity Market, ratified in 1998, which creates the regional electricity market (MER), based on the principles of competition, gradualism and reciprocity. The Treaty establishes that the regional market will include a spot market, based on regional economic generation dispatch, and a medium and long term contract market and that the Governments will establish adequate conditions for the future development of regional power plants.

137. The regional electricity market established in the Treaty and developed in the RMER (final MER regulations) is not an integrated regional electricity market, but a 7th market superimposed on the six national markets. This design takes into account the broad range of institutional development and capacity in the six national electricity sectors and seeks to allow the individual countries to develop their sectors at their own pace while at the same time enabling trade within the region. The points of connection between the MER and the national markets are the nodes of the RTR. As agreed in the Second Protocol, the national interconnection systems and lines that make possible the regional energy transfers will form part of the regional transmission grid (RTR) together with the SIEPAC transmission system.

138. The next sections describe in detail MER's legal framework and the main characteristics of the regional market.

6.3. MER's legal framework

6.3.1. Framework Treaties for the Central American Electricity Market

139. In 1996, the six Central American countries agreed to the creation of the MER through the Framework Treaty for the Central American Electricity Market, which was ratified by the Governments in 1998. The Treaty is based on the principles of competition in the electricity market, including non-discriminatory access to the transmission system, gradualism in the development of the market and expansion to include new participants, and reciprocity in the dealings between countries on the basis of mutually agreed rules. Art. 4 of the Treaty indicates that the MER will operate as a permanent activity of commercial international electricity transactions with short-term interchanges, based on economic generation dispatches in the participant countries, with regional economic criteria, and with mid and long-term electricity interchange contracts among the market agents. Article 9 of the Treaty indicates that the Governments will establish proper

conditions for the future development of regional power plants, aiming at an efficient regional market development.

140. To support the MER, the Treaty also created the regional regulatory commission CRIE[37] (*Comision Regional de Interconexión Eléctrica*), the regional system operator EOR[38] (*Ente Operador Regional*), and the company owner of the grid EPR (*Empresa Propietaria de la Red*). CRIE and EOR are outside of the jurisdiction of national courts as they were established as supra-national entities governed by international law through the Central American Court of Justice. CRIE's legal status, which creates a potentially powerful institution at the regional level, would indicate a serious commitment on the part of the national governments that have ceded authority to it via the Treaty[39].

141. The Treaty also established the scheme of protocols for future treaty adjustments and clarifications. The First Protocol was agreed in 1998 and consisted on several precisions and corrections to the text of the Treaty, such as: i) the EPR cannot have a single controlling partner, ii) the EOR directors are named by each government from representative agents, and iii) the controversies among governments are solved by arbitrage.

6.3.2. The Second Protocol for MER Treaty amendments

142. A Second Protocol with additional adjustments of the Framework Treaty for the MER was agreed in 2007. It has been ratified by five countries and is only waiting for the ratification of the Costa Rican Legislative Assembly. The objectives of this Protocol are: a) to complement the Treaty clauses adapting it to the MER development requirements, b) to define actions or omissions that would constitute failure of CRIE´s regulations and to establish the respective sanctions, and c) to establish regional regulation and operation charges to provide financing for the CRIE and the EOR. Also, this Protocol creates MER´s Board of Directors, composed of representatives of all the governments, and establishes its responsibilities. The next paragraphs summarize main adjustments to the MER introduced through the Second Protocol.

Agents and accounting separations

[37] CRIE was created in 2002 and is based in Guatemala
[38] EOR was created in 2001 and is based in El Salvador
[39] Economic Consulting Associates (ECA). "Regional Power Sector Integration: SIEPAC Case Study", July 2009.

143. Art. 3 ratifies that MER agents could be generation, transmission, distribution and commercialization companies as well as large consumers. All agents of the national markets, as ratified by the legislation of each country, are MER agents and they could participate in regional electricity trading[40]. As established in Art. 5, if a country permits the existence of companies with integrated activities, they must be separated in business units with independent accounting.

Transmission and charges

144. Art. 4 defines that national interconnection systems and lines that make possible the regional energy transfers are part of the regional transmission grid; Art. 5 establishes that regional transmission companies cannot participate in generation, distribution or commercialization activities and cannot be large consumers; and Art. 6 defines that the availability and use of the regional transmission grid charges will consider: variable transmission charges, the toll and the complementary charge.

Regulatory harmonization

145. Art. 12 agrees that the governments will perform the necessary actions to gradually harmonize the national with the regional regulations, permitting the normative coexistence of the regional and national markets for a harmonious MER functioning. Each country will define the gradualism for such regulatory harmonization.

Others

146. Other articles of this Second Protocol are mainly dedicated to establish the basic penalization regime for failure to comply with CRIE´s regulations, the related procedures and the corresponding sanctions. They provide CRIE with significant power to mandate specific national regulatory adjustments and to impose penalizations due to regional regulation failures. Also, regulatory and operational services charges to be paid by MER agents are established to support the operations of CRIE and EOR.

147. One of the main agreements included in the Second Protocol refers to the gradual regulatory harmonization for the implementation of the RMER (Art. 12). It is understood that this will allow the firm energy trading in the MER, implying that the contracted energy will have priority to supply the demand of the buyer in the country where it is located, instead of having priority to supply the demand of the country in which the seller is located. This basic concept will make it necessary to modify the national regulations which provide supply priority for national demand in most CA countries. This would be possible

[40] The RMER does not include specific regulations for regional generators, which should be developed by CRIE.

under the assumption that the MER Treaty is a supranational mandate, but this legal status should be properly assessed including the matter of gradualism for achieving the necessary regulatory harmonization.

6.3.3. MER specific regulations

148. MER operations are currently ruled by the transitory regulation, RTMER (*Reglamento Transitorio del MER*), which includes the market transitory rules for its operation and administration. These rules cover data base management, coordination of regional ancillary services, quality and reliability of service parameters, analysis and preparation of reports related to system disturbances, technical MER operations and electrical studies, MER commercial organization, settlement of international transactions and generation pre-dispatch coordination. The RTMER will be valid until the commissioning of the SIEPAC project (programmed for 2010). Then, the definitive market regulations, RMER (*Reglamento del MER*, a set of detailed market rules prepared in 2005), will be operative.

6.4. Regional electricity trade in the MER

149. The MER is a wholesale electricity market at the regional level whose organization and operation are based on the following premises: a) MER electricity transactions could be carried out as opportunity interchanges identified through a regional economic dispatch or by means of contracts between market agents; b) all MER agents, with the exception of the transmission agents, can purchase and sell electricity freely without discrimination, while the free transit of electricity is guaranteed by the MER member countries; c) MER generation agents can install power plants in any network of the member countries for commercialization of the energy produced at the regional level; d) MER agents have free access to the regional and national transmission networks that conform the RTR; and e) the MER is a market with its own rules, independent of the national markets of the member countries, in which transactions are made through the infrastructure of the RTR and the national networks. The points of connection between the MER and national markets are the nodes of the RTR.

150. As mentioned above, according to the general MER design, there are two main instances for international electricity trade in Central America: 1) the Regional Contract Market, and 2) the Opportunity Market. The main characteristics and rules associated to these commercial transactions are summarized in the sections below.

6.4.1. The Regional Contract Market

6.4.1.1. Objective

151. The terms, prices and other conditions in regional contracts will be freely agreed between the parts (agents from different countries), with a minimum duration of one day. The contracts must specify the hourly energy committed during the contract period and the flexibility conditions that could be applied to it.

152. These flexibility offers could also be used to manage transmission restrictions by reducing the committed energy and limiting it to the available transmission capacity, if necessary. Each national operator will daily inform the EOR of the hourly contractual interchanges associated to each regional contract in the nodes of the RTR. The Regional Regulation also establishes the coordination and administration requirements for transactions using the RTR.

153. The Regional Contract Market was designed with the objective of creating formal conditions and a regional administration to enable regional investments and expansion in generation and transmission infrastructure. Nevertheless, at the same time, it was deemed necessary that this market should allow and stimulate the maximization of the use of the available transmission and generation capacity through opportunity contracts. There are two types of contracts in the MER according to the firmness agreed for delivery of the contracted energy: (i) Firm Contracts, which establish priority of supply for the purchasing agent, and (ii) non Firm Contracts, which do not establish such provision for the purchasing agent. Firm Contracts must have associated transmission rights between the injection and retirement nodes.

6.4.1.2. Regional energy contracts during the transition phase

154. As per the RTMER, the regional energy contracts during the transition phase have been only non firm contracts that must comply with the national legal and regulatory framework. Today, the regional market contracts are all, therefore, contracts for import or export of electricity between agents represented by their respective national operators.

155. To meet the MER requirements such regional contract must indicate the hourly energy committed for the duration of the contract and the injection and ejection nodes. These contracts are not firm or financial, and their physical performance is subject to the

daily dispatch, based on injection and ejection bids. The parties must daily report the decremental bids required in the pre-dispatch phase to their national operators. Contracts are freely agreed between the parties and must comply with the respective national regulations. Those contracts are considered to be interruptible given: i) technical constraints, ii) quality and safety criteria, and iii) priority of supply of a national operator.

6.4.1.3. Regional Firm Energy Contracts after the transition phase

156. According to the RMER, after the transition phase, the objectives of the Regional Firm Energy Contracts will be:

- To give to each party (buyer and seller) security and obligations related to the agreed sales/purchases with agents located in another country of the region.
- To make possible the development of power plants at the regional scale.
- To promote long term interchanges of large volumes, permitting the expansion of the RTR.

157. In these contracts, the selling agent commits to the delivery of firm energy to the buyer in one or more nodes of the RTR, as required by the purchasing agent. The selling agent has to cover his commitment in each node with its own generation and/or purchases in the Regional Opportunity Market, and/or, if allowed by the corresponding national regulation, in the National Opportunity Market of the purchasing agent. By its characteristics, in general, this type of long term contracts will be associated to investments. Nevertheless, their terms of duration are subject to the decision of the parts since they are not governed by the regional regulations.

158. The Regional Firm-energy Contract establishes a supply priority different from which would arise from the physical location of the committed (seller) power plant. All the generation that is sold in a Regional Firm-energy Contract will be considered as regional generation. The demand of the buyer will enjoy priority of supply against the demand of the country where the seller is located. As a result, the contracted energy cannot be "firm" (with priority of supply) for the demand of the country in which the seller is physically located. Therefore, the local operator cannot interrupt the contracted delivery due to generation requirements in its national market.

159. CRIE, in coordination with the EOR, the regulatory bodies and the system operators and market administrators of each country, will calculate the amount of firm energy that can be committed in regional contracts, per appropriate periods of time for each country.

In order to establish the regional criteria for firm energy, CRIE will consider, among other factors, the generation capacity, the availability of power resources, the maximum demand of each national system, the regional and national reserve requirements, and the existing contracts.

160. This type of regional contracts does not operate yet[41], mainly due to the absence of an organized regional electricity trade environment (the RMER, which will be mandatory in 2010) and to the inexistence of firm transmission capacity among the national markets (the SIEPAC transmission system, to be commissioned in 2010). As discussed later, one of the contracting parties in a Firm Contract must own the transmission rights between the injection and the ejections nodes.

161. Finally, in order to guarantee efficiency and competition in the MER, each national system must permit the inclusion of the "regional" energy interchanges in its national market, using similar criteria in the economic dispatch, allowing for a transparent and non-discriminatory treatment. In countries with wholesale electricity markets, each of these regional contracts would then be part of a national contract. An adequate assessment should be carried out in every case to determine the effect of regional contracts on national prices.

6.4.1.4. Regional Non-Firm Energy Contracts

162. The objective of Regional Non-Firm Energy Contracts is to enable economic opportunity energy interchanges between agents, aiming at the maximization of their net income, and also to promote the development of the Regional Contract Market and maximize the use of the available transmission capacity. Short term selling/purchasing commitments with a minimum duration of a day are characteristic of these transactions that are daily agreed indicating the hourly energy interchange required for the following day. Being non-firm, these contracts are interruptible under specific conditions established for the MER.

---

[41] In December 2008 El Salvador Disco (CAESS) awarded) a firm 30 MW power and energy sell / purchase contract during 15 years, starting in January 2012, to the Guatemalan Genco (HIDRO XABCAL). This was the first long-term contract signed in the MER.

163. Non-Firm Contracts can be of two types: (i) Financials, which do not affect the regional pre-dispatch and count only for the conciliation of the transactions, and (ii) Physically Flexible, which are physical commitments of energy that can be made more flexible in the regional pre-dispatch by means of opportunity bids associated to the contracts; this type of contracts may also have maximum bids for variable transportation charges CVT (*Cargos Variables de Transporte*) associated

6.4.2. The Regional Opportunity Market

164. The Regional Opportunity Market makes it possible to obtain economic advantages from delivering exceeding generation from one country to another country, where it will supply a deficit or replace more expensive generation. This will happen based on the opportunities that the countries make available to the MER through their respective country system operators.

165. The objectives of these transactions in the Regional Opportunity Market are:

- To optimize the use of the resources available in the region, independently of the country in which they are located, within a common regulatory framework (an organized market of opportunity interchanges) based on competition.
- To promote the use of the installed generation capacity not committed in contracts and of the capacity of regional transmission, facilitating the recovery of investments.
- To enable an efficient coverage of the deflections that arise from the Regional Contract Market, reducing associated risks to contracts.
- To create an efficient mechanism to cover the deflections that arise, given quality and security or emergency criteria, in the real time programming and operation of the programmed interchanges.
- To create additional tools for risk coverage in the national electricity markets.

166. The transactions in the Regional Opportunity Market are of occasion and therefore interruptible by the national operator of the selling or buying country. The volume of transactions of opportunity will be limited by the capacity of transmission in each node of the RTR not occupied by the interchanges resulting from contractual commitments, considering quality and security criteria.

6.5. Firm energy contracts and transmission rights

167. A Regional Firm Contract relies on the availability of the necessary capacity of transmission to guarantee its firmness. In the MER, agents in Firm Energy Contracts must

have access to Transmission Rights. That is, Firm Regional Contracts are only celebrated when the required transmission capacity is available to ensure its fulfillment.

6.5.1. Transmission rights auctions and transmission expansion planning

168. The interchange of Transmission Rights (DT, *Derechos de Transmisión*) will be free if it does not lead to abuse of market power. CRIE will have the responsibility to supervise the DT, verifying that they will not affect free competition in the MER. In this sense, the RMER foresees the celebration of monthly auctions offering the DTs. In these auctions, the DTs will be assigned by month or by annual periods. CRIE will be able to authorize the assignation of the transmission rights for longer periods and to modify the frequency of the auctions. The EOR will carry out, for each auction, probabilistic projections of the nodal prices in the RTR for a two-year horizon[42], which will give the agents a reference on the prices of the DTs.

169. Long-term transmission expansion planning will be a responsibility of the EOR. The regional operator will have to identify extensions of the RTR that maximize the social benefits of injecting and ejecting agents, improve reliability at the regional level, and increase competition in the MER. Long-term planning will be made with a horizon of at least ten years, which may be extended by the EOR if deemed necessary. The long-term planning process should include information such as transmission expansion plans for each country and the indicative planning for generation.

6.5.2. Regional transmission charges

170. The CA Regional Transmission Service was conceived as a relative complex contract carrier power transportation service with transactions of Transmission Rights among specific RTR nodes applicable to acceptable power shipments for its owners, instead of as a common carrier service for MER agents. The conditions of access and use, quality of service, and tariffs were established as indicated in the RMER. The general design is described below.

6.5.2.1. General design included in the RMER

171. The methodology to define the charges for the use of the RTR , a nodal price scheme, was conceived with the objective of originating efficient economic signals. This system automatically calculates a monetary amount from the product of the difference of prices

[42] For this task, the EOR will use the simulation model of the MER, which is used for midterm planning studies of the RTR.

between two nodes of the RTR by the flow of energy transmitted in each hour and then adding it for each month. This amount is assigned to remunerate the regional transmission service, constituting the Tariff Revenue.

172. Considering the diversity of the current national regulations related to transmission charges, the methodology of nodal prices was established only for its application to the RTR. The cost attributable to the transmission losses due to the transactions in the MER will be covered within the methodology. Nevertheless, it is expected that the Tariff Revenue generated by the nodal prices scheme would not be enough to cover the average transmission costs since, due to the economies of scale in electricity transmission, under normal situations, the marginal costs are inferior to the average costs. Generally, this application allows covering in the order of 15 percent to 20 percent of the capital and operation and maintenance transmission costs. It was required then to complement the Tariff Revenue through tolls and complementary charges to suitably remunerate each of the investments (lines and substations) in this segment of the market.

173. As presented next, the remuneration of transmission in the MER is derived from a considerably complex and detailed scheme, which has the advantage that it would avoid potential disputes among the MER agents, while providing better economic signals to the market. However, this scheme may also pose a disadvantage due to the significant effort that the agents will have to dedicate to the understanding and to the economics of this segment of the market. This would imply higher costs and could potentially discourage the agents, a situation that might be avoided with a simpler transmission charging mechanism.

6.5.2.2. Transmission charges during the transition period (RTMER)

174. Annex 8 includes the description of the transmission charges currently applied in the MER during the transition phase. These consist essentially of variable transmission costs curves, CVT (*Costos Variables de Transmission*), associated to the national transmission systems, which are prepared weekly by each country, and operative tolls defined for each international link. This scheme is applied daily by solving an optimization dispatch problem for 14 nodes, 10 interconnectors and 4 CVT curves associated to the non-extreme interconnected countries.

6.5.2.3. Definitive transmission charges (RMER)

175. The detailed scheme for transmission charges included in the RMER (*Libro III: Transmisión*) is much more complex and has substituted the CVT curves by a detailed representation of the RTR and the determination of hourly nodal prices (implying losses and transmission congestions estimations). The operative tolls associated to the international links are eliminated and a methodology for the determination of the authorized regional transmission revenue, IAR (*Ingreso Anual Autorizado*), is established with a scheme of penalizations due to unavailability. The Tariff Regime of the RTR is made up of: a) the IAR transmission revenue that will be received by each Transmitting Agent; b) the Regional Transmission Charges paid by the agents, and c) the processes of conciliation, invoicing and liquidation of the regional transmission charges. Annex 9 summarizes this scheme.

7. Standardization of regional power contracts and processes

7.1. Introduction

176. In the six Central American countries, electricity markets were independently developed but interconnected among them. This allowed international electricity transactions, mainly to support emergency interchanges or for economic reasons when there was excess hydroelectric energy generation in some countries. Initially, minimum incidences of the interactions with the neighboring markets were expected, situation that would evolve gradually until the conformation of the regional electricity market (MER).

177. Future MER (*Mercado Eléctrico Regional*) development relies to a great extent in the implementation of adequate rules and practices for long-term firm energy international interchanges. Standard processes and terms are proposed to achieve improvements and higher efficiency in the Long-Term Firm Energy contracting process in Central America.

7.2. Rules for a "firm energy" regional concept

178. In the national wholesale markets operating in CA, Energy and Power are traded as main market products and security of supply is agreed by means of contracts that essentially compromise "firm" or "reliable" power availability (MW) required to supply consumers' peak demand (MW). However, in the MER, security of supply is governed by the concept of "firm energy" (MWh) to supply consumers' energy demand (MWh) and does not involve power transactions (MW). As an initial step for the standardization of Regional Firm Energy Contracts, it becomes necessary to regulate in detail the concept of "firm energy" in a way that is compatible with the concepts of firm power (or similar power related concepts) already established in the national markets.

179. In compliance with the concept of firm energy delivery, two types of contracts would be executed in the MER: a) Firm Contracts, establishing energy supply priority for the buyer; and b) Non Firm Contracts, which do not establish such supply priority. In a Regional Firm Energy Contract, the selling agent is committed to sell "firm energy" to the purchasing agent in the node of retirement of the RTR designated in the contract (in addition, one of the parts of the contract must hold the associated transmission rights between the injection and ejection nodes in the RTR).

180. The criteria to calculate the “firm energy” have not been regulated in detail yet. The RMER gives CRIE, the regional regulator, the mandate to define those criteria taking in consideration, among others, generation capacity factors, the availability of power resources, the maximum demand of each national system, the regional and national reserve requirements, and the existing national and regional contracts.

181. The amount of energy that an agent of the market can sell or buy in a Regional Firm Energy Contract will be limited by: i) the amount of “firm energy” authorized by the regulator of the country where the selling agent is located, based on the regional criteria established by CRIE; and ii) the transmission rights between the nodes of associated injection and retirement to the contract, owned by the part designated in the contract.

182. CRIE, in coordination with the EOR, the regulatory organizations and the system operators and market administrators of each country, will calculate the amount of “firm energy” that can be committed in regional contracts by each power plant, by appropriate time periods for each country.

7.3. Options for standardization of regional power contracts and processes

183. Additional aspects related to the standardization of Regional Firm Energy Contracts are discussed in this section. Its consideration and eventual introduction in the design of such contracts would mainly serve the purpose of improving the adaptation of the contracted patterns and conditions of the energy to be supplied by the producers with the demand requirements of the consumers. This would reduce the risks of additional costs to the buyers derived from energy transactions in the occasional markets.

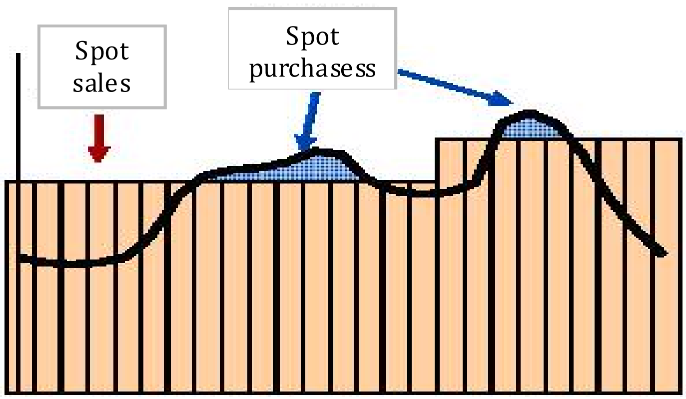
7.3.1. Contract types

184. In addition to the common agreements on the price and amount of firm energy that a contract would include, there are several types of contracts could be standardized for the Regional Market.

185. ***Pay as contracted***: Type of contract in which the buyer is committed to pay all the contracted energy at the contracted price each hour, irrespective of whether the energy is consumed or not. If the demand of the buyer is greater than the contracted energy, the difference is paid by the buyer at the cost of the occasional market. If the demand of the

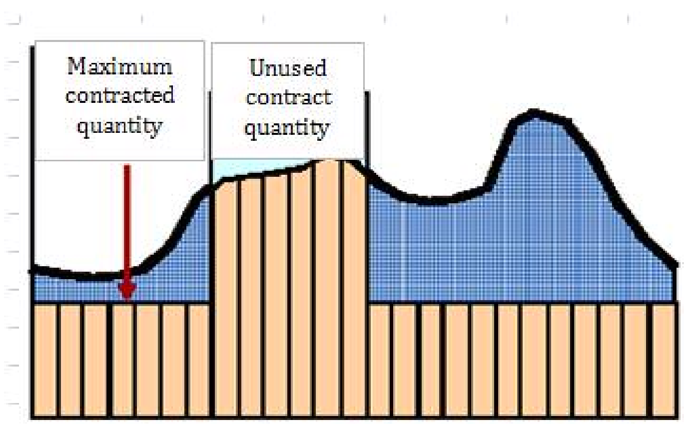
buyer is lower than the contracted energy, the difference is sold by the buyer to the occasional market at the spot price. This type of contract is illustrated in Figure 11.

Figure 11: Type of contract "Pay as contracted"



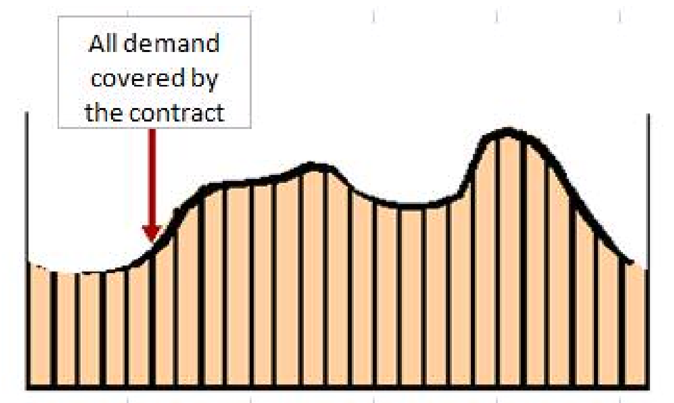
186. ***Pay as demanded***: Type of contract in which the buying agent only pays (at the contract price) the consumed energy each hour, as long as this one is lower or equal to its contracted quantity (upper limit). If consumption is above the contracted quantity, the buyer will pay the difference at the cost of the occasional market, as presented in Figure 12.

Figure 12: Type of contract "Pay as demanded"



187. ***Pay as demanded without cap***: Type of contract in which the buyer only pays (at the contract price and with demand risk assumed by the seller) its total demand less other contracts, as illustrated in Figure 13.

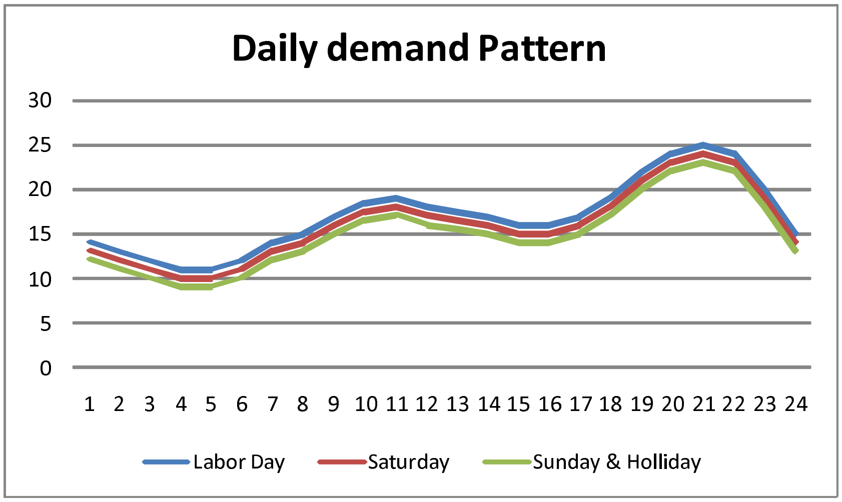
Figure 13: Type of contract "Pay as demanded without cap"



7.2.2. Load patterns

188. It would also be possible to standardize the daily load curves by type of day (working days, Saturdays, Sundays and holidays), establishing different contractual quantities for each type of day, as presented in Figure 14. This would increase the potential adaptation of contracted energy to the load pattern of buyers without losing contracting simplicity.

Figure 14: Daily demand pattern



Labor Day	Saturday	Sunday & Holiday
1 MWh	0.9 MWh	0.85 MWh

7.2.3. Standardization of contract clauses

189. Some CA countries have already introduced standard clauses which are divulged prior to the competitive tenders for long term power supply contracts with the objective of facilitating the contracting processes. Annex 4, sections 4.16 and 6.2 summarize standard contract clauses included in long term energy contracts in El Salvador and Panama, respectively. This type of standardization could also be adopted to support the contracting of MER international firm energy interchanges.

7.2.4. Institutionalization of competitive processes

190. To increase the firm energy volumes to be contracted to supply the demand in the MER through public tenders or auctions, several buyers may participate jointly. This would enable economies of scale as it would allow for the participation in such processes of producers that could develop generation plants of larger size. Annex 4, sections 4.1-4.15 and 6.1 summarize main steps applied in this type of public tenders for long-term energy contracting in El Salvador and Panama, respectively. Such procedures could be institutionalized to promote this type of competitive processes at the regional level, including the regulation of the voluntary (large consumers) and mandatory (distributors and traders with users at regulated tariffs) participations. This would require an active role of CRIE in the promotion and supervision of such activities, including the creation of a centralized process for the estimation of the total demand to be tendered or auctioned.

191. In addition, the international competitive processes for long term firm energy contracting could be institutionalized by introducing appropriate public tenders or auctions (for example auctions of the type "descendent clock") with pre-established schedules. This would improve and increase the efficiency of the competitive processes for long term energy contracting at the regional level, facilitating the future development of the MER.

8.

8. MER power trade with Mexico and Colombia

8.1. Status of the Mexico – Guatemala power interconnection

8.1.1. Origin and project development

192. The power interconnection Mexico - Guatemala was conceived within the Plan Puebla – Panama, agreed in 2001 to foster the development of the Central American countries and the Southern areas of Mexico. For the power sector, this plan includes: a) the development of the interconnection of the Central American power systems through the SIEPAC project, b) the Mexico – Guatemala power interconnection, and c) the Mexico – Belize power interconnection.

193. For the Mexico – Guatemala power interconnection, the two Governments, through SENER (the Energy Secretariat) of Mexico and MME (the Ministry of Mines and Energy) of Guatemala, subscribed in 2003 a Memorandum of Agreement to develop the project. This memorandum contains the basic project description, the proposed schedule for its construction, and the proposed financing scheme. It also assigns to CFE (*Comisión Federal de Electricidad*, México) and INDE (*Instituto Nacional de Electrificación*, Guatemala) the responsibility for the following two agreements, which were subscribed also with participation of CENACE (*Centro Nacional de Control de Energía*, México) and AMM (*Administrador del Mercado Mayorista*, Guatemala): i) Construction (studies, design, specifications and constructive phases) & Maintenance agreements subscribed among these two institutions, and ii) Operation (technical operative aspects of the interconnected systems and power dispatch) & Interchanges Administration (energy supply conditions, power transactions, guarantees and payments).

194. The Memorandum of Agreement also defined a professional team to assess the technical, regulatory and commercial barriers for the free trade of energy among the two countries and the design of the required solutions.

8.1.2. Description and financing

195. The power interconnection system Mexico – Guatemala was commissioned in April 2009. It consists of a 400 kV transmission line, 103 km long (70 percent in Guatemalan territory and 30 percent in Mexican territory), and associated substation expansions

(Tapachula in Mexico and Los Brillantes in Guatemala). Total transmission capacity is estimated at 200 MW from Mexico to Guatemala and 70MW in the opposite direction. Total project cost was US$ 55.8 million, from which USD 12 million were provided by CFE and USD 43.8 million were financed by Guatemala (USD 5.8 million by INDE and USD 37.5 million by a loan from the IADB).

8.1.3. Operation and maintenance agreement

196. The operation and maintenance agreement was subscribed in 2003 by CFE and INDE. This agreement includes the transmission interconnection components and the general operational and maintenance aspects. It also defines the interconnection point among the Mexican and Guatemalan systems and states that the transmission and ancillary services provided by the two parts will be governed by the regulations of each country.

197. It also states that each of the two participants will be responsible for the maintenance and inspection of its own components of the infrastructure, including telecommunications, control and metering, and for the installation and calibration of the protection systems, energy meters, and registers. This agreement also defines the responsibilities of the parts, the events of force majeure and other complementary aspects, and establishes the design of a coordination committee.

8.1.4. Operational coordination and interchanges administration agreement

198. A master operational coordination and power interchanges administration agreement was also subscribed in 2003 among AMM from Guatemala and CFE and CENAC from Mexico. The objective of this agreement is to establish the coordination mechanisms for the interconnected power systems operations in the two countries and the terms and conditions for the administration of the transactions of products (energy and power) and services (ancillary services and others) provided to the parts through the international interconnection system.

199. In regard to the operational coordination, the agreement establishes the following procedures: i) transaction programming, ii) real time operation coordination, c) communications, and d) metering and commercial transactions. Other complementary aspects are also included, such as technical description of components, force majeure, responsibilities, authorizations, etc.

8.1.5. Mexico – Guatemala power transactions

200. INDE has already contracted with CFE the purchase of 120 MW and it is expected that the remaining capacity of the line would be traded in the Guatemalan Opportunity Market. Also, if required, Guatemala could sell up to 70 MW to Mexico. The contract was subscribed in 2008 as a long-term firm energy purchase contract to import 120 MW of firm power and associated energy to Guatemala from the time of the commissioning date of the new interconnection link to April 2011. The basic prices agreed are: a) USD 4/kW-month for firm power, including generation and transmission charges, indexed to GDP inflation in United States, and b) USD 79.61/MWh (2009) and USD 73.26/MWh (2010-11) for associated energy, indexed with a formula including international prices for Bunker C and Natural Gas.

201. The firm power payment carries a "take or pay" commitment, while real energy imports will be the result of the economic dispatch operated by AMM in such a way that energy payments will correspond to real imported energy priced at agreed prices. Firm power conditions agreed state that imported power would be interrupted by CFE only under emergency conditions. The executed contract includes provisions for: a) daily energy interchanges programming coordinated by AMM & CENACE, b) the regulation of the interchanges by AMM, c) the delivery point, d) metering, and e) other complementary aspects.

8.1.6. MER harmonization with Mexican power market

202. The Mexico – Guatemala electricity trade agreements have advanced essentially as a bilateral relationship. They have been included within the Guatemalan electricity market regulations with this focus, which has been followed cautiously by other MER participants. In this order of ideas, the SIEPAC Executing Unit has promoted the inclusion of a first phase of the MER – Mexico harmonization within the Technical Cooperation CEAC-IADB.

203. This Technical Cooperation consists of a consultancy assessment to propose, for the MER and Mexico, the required regulatory harmonization, including the interfaces and adjustments in the legislation and regulation of each country, for a suitable interaction of the MER regulations and the regulation of the Mexican electricity market. Such harmonization would include the elimination of technical and commercial barriers.

8.2. Status of the Colombia – Panama power interconnection

204. Following the results to be obtained from the MER – Mexico regulatory harmonization task, a similar exercise would be done for the case of MER and the Colombian electricity market regulations in order to define the potential power interchanges and MER electricity trading through the future Panama – Colombia interconnection link. This project constitutes a step to interconnect the Andean Region and the Central American electricity markets. Its execution, accompanied by a harmonization process of the institutional, normative and regulatory electricity frameworks, will be the base to extend the international power interchanges among these two regions.

205. The project consists of the construction of a direct current power transmission line at 250 - 400 kV (HVDC) and with capacity of 300 MW and possible extension to 600 MW. Its length is 614 km, 340 km in Colombia and 274 km in Panama. Investment costs are estimated at USD 210 million, including the expansion of the Cerromatoso (Colombia) and Panama II (Panama) substations. The project counts with technical and environmental feasibility studies, developed within the frameworks established by the energy and environmental authorities of both countries. These studies have been financed by the Interamerican Development Bank (IADB) through non reimbursable Technical Cooperations.

206. Currently, ISA (the Colombian transmission company) and ETESA (the Panamanian transmission company) are advancing in the technical and environmental studies and project design, also using IADB financing under another non reimbursable Technical Cooperation. In addition, the regulators of both countries are advancing in the process of normative harmonization of their respective electricity market regulations. In this regard, a confidential study carried out by a Spanish consulting team was finished and an additional regulatory analysis is under way.

207. In order to develop this project, in April 2009, ISA and ETESA constituted, in Panama City and with equal participations, the binational company *Interconexión Eléctrica Colombia-Panama S.A.* (ICP). Prior to the constitution of this company, in August 2008, the presidents of both countries signed in Cartagena (Colombia) an Letter of Intent that provided the new dynamics to this project. This document was ratified in 2009 through an Agreement Protocol subscribed by the National Secretariat of Energy of

Panama and the Ministry of Mines and Energy of Colombia, aiming to develop and to implement the operative and commercial scheme that allows the international power interchange.

9.

9. Regulatory and institutional barriers to MER development

208. The SIEPAC initiative illustrates that it is possible to create a relatively advanced regional electricity trading arrangement between countries that are at differing stages of internal market development and have different types of electricity industry and institutional schemes. However, while the regional electricity market is in its current transition stage, the Central American governments and national regulators need to take some relevant decisions and actions to expedite the use of the transmission line and ensure that the region fully benefits from the potential offered by the new infrastructure and by the market architecture that have been under development for over a decade.

209. The major challenge faced by the regional market is how to exploit the potential offered by the transmission line and the MER regulatory and institutional framework by attracting energy projects of a regional scale (i.e. projects designed to serve the international market using the SIEPAC infrastructure). Achieving this goal will be a clear test of the options for long-term success of the market. For it to happen, the regulatory framework and the regional institutions must demonstrate their credibility to investors. In this sense, the early use and performance of the line will serve as a pilot in this process of trust-building.[43]

210. The MER general design provides a general framework that allows and promotes long-term firm power trade among Central American countries in order to facilitate the financing of economical regional generation plants. However, several barriers could arise for the accomplishment of such objectives. This section discusses the main barriers identified and proposes some options to address them.

211. **The asymmetry in the national markets can lead to a lack of reciprocity in the treatment of market agents.** There is a lack of reciprocity of the vertically integrated national electricity markets prevailing in two Central American countries (Costa Rica and Honduras) with the more open electricity markets already structured in the other four countries (Panama, Nicaragua, El Salvador and Guatemala). This is a source of asymmetry given that regional generators (and national generators in the last four countries) cannot

[43] Economic Consulting Associates (ECA). “Regional Power Sector Integration: SIEPAC Case Study”, July 2009.

directly contract electricity with potential distribution, commercialization and large consumers located in Honduras and Costa Rica. Also, potential regional generators located in these two countries would not have clear rules yet permitting them access to the national transmission grids. However, both ICE and ENEE will have the opportunity to sell to distribution and commercialization companies and large consumers in Panama, Nicaragua, El Salvador and Guatemala.

212. This could be essentially a political issue given that the National Congress of both countries is the ultimate instance to decide about the power sector restructuring. In particular, the Costa Rican Legislative Assembly has not ratified yet the Second Protocol, but there is a commitment at the President level to adopt it this year during the extraordinary sessions of the Assembly. Ratification of this Protocol has been difficult since the Costa Rican Government intended to remove some of ICE's attributions as the sole agent of Costa Rica in the MER, granting MINAET functions to define such responsibilities. For this reason, ICE blocked the adoption of this Protocol and is working with MINAET to present a consensus position.

213. To advance expeditiously in the solution of this lack of reciprocity and the asymmetry it creates, beyond the political factors, significant time and resources (technical and financial) would be required to implement the necessary electricity market reforms in Costa Rica and Honduras. In particular, these countries will have to develop clear rules for participation in the MER of agents other than ICE and ENEE (i.e. Independent Power Producers, since they are, as of today, the only additional agents in these two integrated markets), either through ENNE and ICE or directly if they were allowed to become MER agents. In the case of Costa Rica, any new national market agents resulting from the structural reform of the system that may be introduced through the new Electricity Law currently being discussed should be able to participate in the MER. In the case of Honduras, ENEE is likely to remain as the sole participating agent, at least in the medium term, since no significant reform of the sector is expected.

214. **Regulatory harmonization has to be completed in order to facilitate market operations**. There is a lack of harmonization of national and regional regulations at the operative and commercial levels. National electricity regulations must be harmonized with regional regulations in order to facilitate market operations and regional long-term firm power contracts between qualified agents. This issue should be solved in order to

implement the RMER (in substitution of the RTMER) and the appropriate interfaces so that MER regulations can harmoniously work with the corresponding regulations in each country.

215. The Executing Agency of the SIEPAC project is currently working on the harmonization of regional and national regulations and on the strengthening of the regional institutions (CRIE and EOR) with the support of an IDB-CEAC technical cooperation grant. The required tasks have been programmed in two stages: 1) the minimum regulatory harmonization necessary to allow the entrance in operation of the RMER instead of the RTMER; and 2) the remaining regulatory harmonization necessary to assure total interaction between the MER and the national markets when implementing the RMER in its final form. This process has suffered some delays due to the lack of interest of potential consultants.

216. **In most countries, domestic demand still has priority in case of power shortages, which creates a risk for firm contracts in the regional market**. In most countries, national laws, regulations and policies give supply priority or establish wholesale price controls in electricity supply to the domestic markets. For example: a) Honduras, Nicaragua and Panama explicitly established power supply priority for the local market (E.D 22-1998 Art. 30 in the case of Panamá), b) in Guatemala, in 2005, a resolution restricted energy exports, and c) in El Salvador and Nicaragua significant government interventions aiming to lower retail tariffs in their electricity markets manipulated the wholesale electricity prices jeopardizing potential energy imports. Also, the regulatory frameworks of all electricity markets foresee actions to guarantee local self sufficiency in electricity supply, such as: a) the generation – transmission expansion planning (centralized in Costa Rica and indicative in the other four countries), and b) the preferential treatment for the local markets of the long term firm energy contracts for the regulated markets (in Honduras, Nicaragua and Panama).

217. The way the regional market was designed would allow all SIEPAC members to benefit from the surplus of one country to cover deficits in another country, a win-win situation. However, to ensure that all countries benefit equally from the regional interconnection, the national supply priority in case of power shortages will have to be adjusted in the national markets according to the Second MER Protocol in order to permit the effectiveness of the firm energy contracts in the MER. In this regard, the Framework

Treaty, the Protocols and the associated regulations define the specific sanctions regime to apply in cases of non-compliance with the MER rules, as well as arbitration mechanisms for the solution of disputes. In any case, countries could still unilaterally decide to restrict exports in the event of national shortages. However, it is expected that the pressure exerted by the rest of the countries in the market and the threat of sanctions would acts as deterrents and minimize the risk of non-compliance with firm regional contracts.

218. **Price controls lead to misallocation of resources and can imperil the success of the regional market.** During the reform processes in the power sector, the stated objective was to achieve a situation where electricity would respond to normal supply and demand signals (as in the case of oil products), rather than to managed criteria which either distort the wholesale price or institute unsustainable subsidies. Unfortunately, regulatory authorities have not been resilient enough to resist political influence; changing the rules of the game by setting ceilings for market prices, and otherwise impeding true marginal costs to reflect on power sector transactions in the wholesale power markets.

219. During the last 4 years, countries in the region such as El Salvador and Nicaragua have introduced price controls in the spot market and generalized subsidies to mitigate the impact of high fuel prices on electricity tariffs. In the end these efforts have proved futile, with an enormous cost to the Government (as in Honduras and El Salvador) or to state power companies (as in Costa Rica and Guatemala). Moreover, the application of these practices in the future would reduce the opportunities for long term contracts and short-term transactions in the regional market. One of the challenges of interconnection and integration consists then of agreeing on common rules to avoid the misallocation of resources through arbitrary rulings of individual regulators.

220. Avoiding those kinds of errors calls first for increased support of national regulatory institutions. Some specific courses of action can be identified: (a) in Panama the regulator has proven to be a solid and responsible agency which has recently been reorganized, a process which is still ongoing and may have unforeseen consequences; (b) in Costa Rica the regulator has been at loggerheads with ICE, the major power company, with unfortunate consequences such as power blackouts, and a redefinition of responsibilities should take place in order to ensure a smoother institutional operation; (c) in Nicaragua the regulator has weak resources which require strengthening in order to effectively address numerous questions; (d) El Salvador has an effective and well-organized agency which is, however, subject to political influence, which has led it to put in place unsustainable and costly subsidies, and its organization and mission should be revisited; (e) Honduras has a weak and ineffective regulator with little influence over ENEE, the state power company, and a thorough review of its functions should be undertaken; (f) Guatemala's regulator has been effective in overseeing the market but its rulings have proven ineffective in attracting investment for developing native resources.

46. **Increasing prices of electricity in exporting countries and availability of cheaper electricity in importing countries can spur opposition both from**

consumers and from existing generators. If MER energy trading is included in the national economic dispatches, prices may be higher in electricity exporting countries, while they would be lower in the importing countries. This is a necessary market rule to guarantee non-discrimination among the national markets (i.e. agents in an exporting national market will face the same spot price as for occasionally exported energy). However, this will not favor final consumers in the exporting countries or generators in the importing countries.

47. The effects of power interchanges in electricity prices should be further analyzed by CRIE in order to foresee appropriate mechanisms to address such effects. Those mechanisms should be designed on the basis that, for the regional market to work successfully, individual countries should have access to lower prices in other countries. In addition, governments of the interconnected countries should hold a strong position to avoid yielding to the pressure of generation lobbies, which can have strong interests in preventing cheaper generation from neighboring countries from entering their national markets. If those lobbies were to succeed, consumers in the importing countries would not be able to benefit from cheaper electricity prices.

221. **Lack of long-term transmission rights will hinder the signature of long-term contracts.** Regional long-term firm energy contracts for the development of new regional power plants would have to be agreed for periods of the order of 10 to15 years. However, this type of contracts needs to be supported by Transmission Rights that will be assigned through auctions, initially for short-term periods (one month) or at most for one year. The EOR will forecast nodal prices periodically for only 2-year horizons, while the transmission planning is expected to be done for 10-year horizons. These issues would have to be properly conciliated in order to support the regional long-term firm energy contracts associated to new regional power plants.

222. The RMER would have to be adjusted to provide longer terms for the transmission rights if, for example, the promoters and financers of new regional power plants perceive that the term for the assignation of these rights is too short (i.e. permitting longer transmission rights assignations to new regional power plants). However if the transmission activity were perceived more as a common-carrier than as a contract-carrier type, such requirement (i.e. short terms for the transmission rights) could be relaxed.

223. Also, given the considerable complexity of the regional transmission charges regulated in the RMER, developing comprehensive methodologies to support clear forecasts of such charges would be required. These forecasts would be based on the long term generation – transmission expansion planning and would provide adequate information to the agents on the expected prices of the transmission rights associated to the potential development of regional power plants. If such actions are not successful, future development of the MER would have to consider eventual simplifications in the scheme for regional transmission charges.

224. **Limited capacity and resources at CRIE, the regional regulator, make it vulnerable to national interests.** Addressing the more substantial harmonization problems would require additional analysis and the preparation of a strategy that uses a political economy approach. However, there is a lack of technical staff and computerized support in the CRIE and the commissioners meet only about four times a year. Under these circumstances, the role of CRIE could become very weak and face the risk of a situation in which national interests may prevail over the regional ones. It is evident that CRIE requires an urgent institutional reinforcement to foster an adequate preparation of the platform for the initial operations of MER.

225. Temporary financial resources would be needed until a more stabilized MER operation that provides stable financial resources to cover CRIE's operative budget is attained. The technical cooperation grant from the IDB mentioned above also includes among its activities direct support to the CRIE in the form of specialized consultants. However, it is estimated that additional support will be necessary to reinforce CRIE so that it can successfully carry out its regulatory activities.

226. Further activities might include: (i) support CRIE to regulate in detail the concept of "firm energy" associated to power plants in a compatible way with the concepts of "firm power" already established in the CA national markets, which is required to support reliability in the regional long-term firm energy interchanges; (ii) support CRIE in the standardization of the terms and clauses of long term regional firm energy contracts, taking into account the local regulations for firm power interchanges and the regional regulations and requirements of MER´s transmission rights, including the assessment of the adopted MER transmission regulations to foster regional electricity interchanges.; and (iii) assist CRIE and EOR to prepare a proposal for the institutionalization of regional

competitive processes and of mechanisms aiming at the consolidation of regional coordinated energy contractual electricity purchases by multiple agents.

227. **Bilateral agreements independent from the MER would restrict the benefits of the interconnections with Mexico and Colombia.** Guatemala - Mexico and Panama - Colombia are in the process of interconnecting their respective power systems, allowing for future bilateral international electricity interchanges. In both cases, bilateral agreements are being discussed and are advancing in their implementation. Apparently, Guatemala´s position is that power interchanges through the Guatemala – Mexico interconnection will be commercially agreed independently from the MER. In the case of the Colombia – Panama interconnection, a regulatory harmonization study recommended the existence of a common carrier and of free access type of use for this link. However, given its relatively high investment cost, the governments of both countries would have decided that its development would be at their promoter´s own risk, implying a contract carrier type of use for this link and, consequently, limiting the free access to agents not involved in its development. This could mean that MER agents could face barriers to access those international links as part of the RTR.

228. This issue would have to be analyzed in order to properly coordinate with MER regulations, which are interpreted as providing free access to those links, in order to avoid potential drawbacks in the development of the MER. In this sense, the SIEPAC Executing Unit has promoted the inclusion of a first phase of the MER – Mexico harmonization within the technical cooperation CEAC-IADB. This consists of a consultancy assessment to propose, for the MER and Mexico, the required regulatory harmonization. Such harmonization would include the elimination of technical and commercial barriers. Following the results of this assessment, a similar exercise would be done for the case of MER and the Colombian electricity market regulations, in order to define the potential power interchanges and MER electricity trading through the future Panama – Colombia interconnection link.

229. **Higher demand volumes would be required for the development of high capacity regional plants**. Local demand of the distributors, traders, and large consumers and associated competitive processes to purchase electricity is for relatively small volumes. Under current market conditions, it would be expected that individual long-term firm energy contracts would be of relatively minor volumes (i.e. associated to 50 MW

peak demands or lower). The development of the MER based on high capacity regional plants (i.e. with 150 MW of installed capacity or more) would require higher contracting volumes with agents that might be located in different countries.

230. Rules and competitive processes coordinating energy purchases with multiple agents will have to be implemented (or a more formal long term energy market). To increase the firm energy volumes to be contracted to supply the demand in the MER several buyers could participate jointly through public tenders. This would enable economies of scale as it would allow for the participation in such processes of producers that could develop generation plants of larger size. Such procedures could be institutionalized to promote this type of competitive processes at the regional level. This would require CRIE to play an active role, including the creation of a centralized process for the estimation of the total demand to be tendered or auctioned. Also, this is one of the aspects that should also be introduced in the regulatory harmonization of RMER with national regulations.

231.

10. Conclusions

232. The major challenge faced by the regional market is how to exploit the potential offered by the transmission line and the MER regulatory and institutional framework by attracting energy projects of a regional scale (i.e. projects designed to serve the international market using the SIEPAC infrastructure). Achieving this goal will be a clear test of the options for long-term success of the market. For it to happen, the regulatory framework and the regional institutions must demonstrate their credibility to investors. In this sense, the early use and performance of the line, which will be in operation in 2010, will serve as a pilot in this process of trust-building.44

233. **Development of the architecture of the Central America regional market has been slow but has advanced considerably; however, its success won't be evident until the market has been operational for some time.** The SIEPAC initiative illustrates that it is possible to create a relatively advanced regional electricity trading arrangement between countries that are at differing stages of internal market development and have different types of electricity industry and institutional schemes. However, while the regional electricity market is in its current transition stage, the Central American governments and national regulators need to make some relevant decisions and take actions to expedite the use of the transmission line and ensure that the region fully benefits from the potential offered by the new infrastructure and by the market architecture that have been under development for over a decade. As integration advances, competitive pressures in the electricity market are likely to lead "naturally", as in the case of Nord Pool, to ownership and structural changes in the sector, including some cross-ownership between countries and the entry of some foreign power companies[45].

234. **The performance of the regional market will also depend on the decisions taken by governments to strengthen their own national markets**. The region has been facing some difficulties in implementing the regional market, with a reduction in the volume of electricity exchanges in recent years. This regional market performance reflects to some extent the state of crises within some of the national power systems that have implemented short-lived measures, such as governments' imposition of restrictions on

[44] Economic Consulting Associates, 2009
[45] Carlson 1999

international energy transfers in an attempt to control internal tariffs in a context where generation reserves are low or nonexistent, and available national thermal generation is completely vulnerable to volatile oil prices. These factors can jeopardize the overall consolidation of the regional electricity market by further eroding national electricity markets.[46]

235. **The pursuit of self-sufficiency in an attempt to build stronger national markets is not necessarily detrimental to the development of a regional market.** Many governments have long viewed electricity as a strategic asset, which has traditionally led them to favor self-sufficiency, often through vertically integrated, state-controlled companies. [47] In Central America, national expansion plans prepared for the 2008-2020 period share a common characteristic, the reliance on local resources, i.e. an autarchic outlook regarding energy supplies. Nevertheless, self-sufficiency does not impede the development of the regional market. Countries could be self-sufficient but would always have opportunities to, for example, obtain cheaper power from imports. For instance, NORDEL[48] was based on the principle that each country would build enough generating capacity to be self-sufficient. Trading was meant to achieve optimal dispatch of a larger system-and investment in interconnection was generally based not on net exports but on expected savings from pooling available generating capacity[49].

236. **The consolidation of the MER's regulatory framework could benefit from additional short to medium term support to the regional institutions in the form of technical assistance.** Further activities might include: (i) support CRIE to regulate in detail the concept of "firm energy" associated to power plants in a compatible way with the concepts of "firm power" already established in the CA national markets, which is required to support reliability in the regional long-term firm energy interchanges; (ii) support CRIE in the standardization of the terms and clauses of long term regional firm energy contracts, taking into account the local regulations for firm power interchanges and the regional regulations and requirements of MER´s transmission rights, including the assessment of the adopted MER transmission regulations to foster regional electricity interchanges.; and (iii) assist CRIE and EOR to prepare a proposal for the

[46] USAID 2008

[47] Charpentier & Schenk 1995.

[48] This multicountry organization was founded in 1963 to promote cooperation among all power utilities of the Nordic countries (Denmark, Finland, Norway, and Sweden). NORDEL's original goal was to create and maintain conditions for efficient utilization of the interconnected national power grids of the Nordic countries to exchange hydro and thermal power. Nord Pool, the regional power pool, began to develop in 1992.

[49] Carlson 1999

institutionalization of regional competitive processes and of mechanisms aiming at the consolidation of regional coordinated energy contractual electricity purchases by multiple agents.

237. **The development of a regional plant with support from the IFIs could create the necessary incentives to overcome some of the existing regulatory barriers**. The process towards successful development of regional generation in the MER could follow two different paths. The first one would entail waiting for the complete definition of the market rules and the full implementation of the institutional arrangements before compromising large investments in generation. The second alternative would follow an opposite approach. It consists of the development, in the short-term, of a mid-sized regional generation plant with the participation of both private investors and national governments and the support from International Financial Institutions, which would need to develop new mechanisms to provide financing to a regional body. Such initiative would generate strong incentives for the different players in the market to find workable solutions to overcome the barriers arising from incomplete regulatory harmonization and unclear or not-fully developed MER rules.

238. **The interconnections with Mexico and Colombia could prove critical in overcoming the supply/demand imbalances in the region**. The interconnections Mexico-Guatemala and Colombia-Panama, if integrated with the regional transmission backbone, have the potential to provide enough power to address the precarious balance of supply and demand affecting all countries in the Central America region. These interconnections could eventually deliver the greatest benefits of power integration to the region, rather than the development of regional plants (e.g. medium to large-sized hydroelectric plants). For this and other reasons, a commonly agreed and carefully designed regional expansion strategy is urgently needed, so that existing human, technical, and financial resources are used in the most efficient way. This would also be a test to the rules of the regional market (RMER), which should prove their flexibility to accommodate to an evolving reality and benefit from the opportunities offered by an enlarged market.

Annex 1: Specialized agents in the Central American electricity markets

SPECIALIZED AGENTS IN CENTRAL AMERICAN ELECTRICITY MARKETS

			COSTA RICA		EL SALVADOR		GUATEMALA		HONDURAS		NICARAGUA		PANAMA
GENCOS	151	37		16		42		31		12		13	
		1	ICE	1	CEL	1	EGEE	1	ENEE	1	GECSA	1	AES Panamá
		1	CNFL	1	Duke	9	Ingenios	1	Lufussa	1	GEOSA	1	EGE-Fortuna
		1	La Joya	1	LaGeo	1	Duke E.I.G	1	Enersa	1	Hidrogesa	1	Egeminsa
		1	El General	1	Nejapa	1	Poliwatt	1	EMCE	1	Gemosa	1	ACP
		1	G.G.Ltd.	1	Inv.Ene	1	San José	1	Elcosa	1	EEC	1	PAN-AM
		1	Coopelesca	1	Textuf	1	PQPC	1	Zacapa	1	Monte Rosa	1	Pedregal
		1	P.E.S.A.	1	CESSA	6	Comegsa	1	Cahsa	1	CENSA	1	COPESA
		1	JASEC	1	Ing.Ang	1	Tampa	1	ELCATEX	1	NSEL	1	Edemet
		1	ESPH	1	CASSA	1	Renace	1	Nal Ing	1	Tipitapa	1	HidroPanama
		1	Movasa	1	Ing Cbñ	1	Duke E. C.	1	Esperan	1	PENSA	1	Arkapal
		1	Esperanza	1	Boreal	1	Amatex	1	Yojoa	1	Gesarsa	1	Candela
		1	S. Lorenzo	1	CECSA	1	Genor	1	Laeisz	1	ATDER	1	Egesa
		1	Volcán	1	EGI Hol	1	Sidegua	1	Cuyamapa			1	Semper
		1	Taboga	1	Sensuna	1	Orzunil	1	La Grecia				
		1	D. Julia	1	De Math	1	Secacao	1	Ampac				
		1	Platanar	1	GECSA	1	Tecnoguat	1	Gren Valle				
		1	Hidrozarca			1	Electrogen	1	AYSA				
		1	Don Pedro			1	Montecrist	1	Tres Valle				
		1	Rio Lajas			1	Pasabién	1	Río Blanco				
		1	El Viejo			1	Río Bobos	1	Azunosa				
		1	Aeroenergí			1	Calderas	1	Babilonia				
		1	Matamoros			1	S.Jerónimo	1	Cececapa				
		1	Zaret-R.Az			1	Coelsi	1	EDA				
		14	Otros			6	Otros	8	Otros				
TRANSCOS	8	1		1		3		1		1		1	
		1	ICE	1	Etesal	1	ETCEE	1	ENEE	1	Enatrel	1	ETESA
						1	Trelec						
						1	Duke E.I.T						
DISCOS	39	8		5		17		1		5		3	
		1	CNFL	1	CAESS	1	Deocsa	1	ENEE	1	Atder-BL	1	Edechi
		1	Coopealfar	1	CLESA	1	Deorsa			1	BluefieldS	1	Edemet
		1	Coopeguana	1	Delsur	1	EEGSA			1	Disnorte	1	Elektra
		1	Coopelesca	1	Deusem	14	EEM			1	Dissur		
		1	Coopesanto	1	EEO					1	Wiwilí		
		1	ESPH										
		1	ICE										
		1	JASEC										
TRADERS	25			11		14							
				1	CEL	1	CCEESA						
				1	ExcelergY	1	CECSA						
				1	Conec	1	Comegsa						
				1	LYNX	1	Duke E. C.						
				1	ORIGEM	1	MEL						
				1	Duke	1	Poliwatt						
				5	Otros	8	Otros						
LARGE CONS.	53			2		37		1		9		4	
				1	ANDA	1	C Progreso	1	Heco	1	Agricorp	1	Bpark
				1	Invinter	1	Olefinas			1	Cemex	1	Cempa
						1	IRTRA			1	CCN	1	Megadepot
						34	Otros			6	Otros	1	Ricama
TOTAL	276												

Source: CEPAL, 2007

Annex 2: Description of national wholesale electricity markets

1. COSTA RICA

In Costa Rica the provision of electricity services is mainly the responsibility of the Costa Rican Institute of Electricity (Instituto Costarricense de Electricidad [ICE]), a fully integrated company, but no competitive wholesale electricity market has yet been structured in this country. In Costa Rica's Electricity System, the ICE dispatches energy with a minimum cost criterion through a centralized process.

The ICE sells electricity in bulk to its subsidiary, the National Light and Power Company (Compañía Nacional de Luz and Fuerza [CNLF]) and to small municipal enterprises and cooperatives that operate in the country. For this purpose, it levies tariffs for the sale of bulk electricity, determined by the national regulatory agency (ARESEP) using a pricing methodology based on the cost of service. In addition, the ICE purchases electricity from several independent producers who have built small power stations using renewable energy, with energy purchase prices established mainly through competitive processes promoted by the ICE.

2. HONDURAS

The case of Honduras is similar to that of Costa Rica. The National Electricity Company (Empresa Nacional de Energía Eléctrica [ENEE]) is the integrated enterprise in charge of providing electricity services. The ENEE dispatches energy through a centralized process, using a minimum cost criterion, and no competitive wholesale electricity market has yet been structured in the country. The ENEE acquires part of its energy through PPAs (Power Purchase Agreements) from several independent producers who have built new power plants that were promoted and contracted by the ENEE.

3. NICARAGUA

3.1 Wholesale electricity market

The products that are purchased and sold in Nicaragua's Wholesale Energy Market (Mercado de Energía Mayorista de Nicaragua [MEMN]) are Energy and Power.[50] Consumer Agents and Producer Agents who conduct commercial operations participate in this market.

A Consumer Agent is considered to be: a) a Distributor who conducts marketing activities in his concession area; b) a Large-scale Consumer who purchases at wholesale level, by means of contracts and in the Spot Market; c) each Self-producer who purchases deficits; d)

[50] In addition, the following services are transacted in the MEMN: a) transmission service, remunerated through regulated tariffs in accordance with the Transmission Regulations, b) auxiliary services, with pre-established remuneration methodologies, and c) operational and dispatching service, and market administration, remunerated in accordance with the criteria and procedures in the Transmission Regulations.

an export contract in an international interconnection; i.e., another country's demand which corresponds to said contract and is represented by the local Market Agent who is the seller. The Consumer Agent's obligations and rights stemming from another country's demand associated with an export contract correspond to the local agent who is the seller under said contract.

A Production Agent is considered to be: a) a Generator; b) a Self-producer who sells surpluses; c) a Co-generator; d) an import contract in an international interconnection, i.e., another country's power generation which corresponds to said contract and is represented by the local Market Agent who is the purchaser. The Production Agent's obligations and rights in Nicaragua's Wholesale Market stemming from another country's power generation correspond to the local agent who is the purchaser under said contract.

Each Market Agent is authorized to conduct commercial operations in the Contract Market and in the Spot Market. Trading between the Spot Market and the short-term markets of other countries will be mediated and coordinated through the National Dispatch Center (CNDC) and the corresponding system operator and market administrator (OS&M) of the other country . A Wholesale Market company of another country may conduct operations in the Contract Market. This company will become an External Agent provided that it has a current import or export contract in the Contract Market, but it will not be authorized to operate directly in the Spot Market.

A Production Agent who is a Market Agent may: a) through contracts, purchase power and energy from another Production Agent in order to commercialize it in the Market; b) through contracts or in the Spot Market, sell power and/or energy of his own or contracted through third parties; c) through contracts or in the Spot Market, purchase the lacking power and energy with respect to his contractual commitments.

A Consumer Agent who is a Market Agent may conduct the following commercial operations related to energy and power: a) through contracts or in the Spot Market, purchase his demand for power and energy consumption; b) sell surplus power and energy (not required for his own consumption or that of his customers) in the Spot Market with respect to his contractual commitments; c) partially or fully sell contracts in which he is the purchaser, in the Contract Market. A Distributor will require the INE's prior authorization to verify that said transaction does not negatively affect the tariffs of the Distributor's customers.

3.2 Spot Market

The MEMN's Spot Market is based on the economic dispatch of power generation, which is defined as the administration of offered generation resources and of the available transmission capacity and international interconnections in order to meet the requirements of the demand for local electricity and in international interconnections, minimizing the associated supply cost under the priorities defined by the Quality and Safety Criteria.

Transactions in the Spot Market are those conducted on the hourly closing for energy and the daily closing for power, between generation and real consumption, and the commercial commitments made in the Contract Market. A country with hourly demand for spot exportation, i.e., outside of contracts, purchases energy from the Nicaraguan Spot Market, while a country with hourly supply for spot importation sells energy to that same market. Each hour, the diversion that arises between the scheduled exchange in an international interconnection and the real exchange will be called inadvertent energy and is valued at the Spot Market price until the MER Regulation begins operating and rules are established for its valuation and payment.

3.2.1 Energy transactions

Energy transactions in the Spot Market are conducted at the hourly price of energy, stemming from the short-term marginal cost of generation for an unrestricted condition. To calculate it, the CNDC utilizes the model with which it performs the daily economic dispatch and performs an Unrestricted Dispatch with the following characteristics: a) neither the transmission grid restrictions corresponding the design conditions nor restrictions due to Quality and Safety Criteria are included, b) the restrictions stemming from the distribution grid are not included, c) the operational restrictions of generating units are not included, d) the short-term reserve requirement is included; and e) the transmission grid is represented in order to take losses into account.

The hourly transactions of each Consumer Agent in the Spot Market are based on the following methodology: a) The energy purchased from Supply Contracts is totaled. b) If his real energy consumption is greater than the energy contributed by his Supply Contracts, the shortage is demanded in the Spot Market and will be purchased provided that such surplus exists. c) However, if his consumption is lower than the energy contracted, the surplus is offered in the Spot Market and it will be sold provided that there is demand to purchase it. For each Production Agent the following process is applied: a) His total energy is calculated as the sum of the generation of his dispatchable generation units (GGD), minus the energy he sells in Generation Contracts, plus the energy he purchases through Generation Contracts. b) The energy committed by contracts is totaled as the sum of energy to be delivered to Supply Contracts. c) If total energy is less than the energy committed for sale in contracts, the shortage is demanded in the Sport Market and it will be purchased provided that such surplus exists. d) If instead total energy is greater than the energy committed for sale in contracts, the surplus is allocated as supply to be sold in the Spot Market.

3.2.2 Power transactions

The daily power requirement of each Consumer Agent stems from his participation in the system's Maximum Demand for Generation that is recorded that day during the period of maximum demand. A Consumer Agent is obliged to purchase the power required for his participation in this system's Maximum Demand for Generation through the Contract Market and the Spot Market. Each day, the power requirement of each Production Agent stems from his commitments to sell power in the Contract Market.

The closing of daily power deficits and surpluses is conducted in the Spot Market. For this purpose, on a daily basis each Market Agent provides the CNDC with the prices at which he is willing to sell power if the next day he has a power surplus. Each Distribution Agent is obliged to submit to the CNDC bids for all of his contracted power in bulk representing the power of each of his contracts, with the corresponding price offered for such contract. The CNDC must establish the shortlist of bids for power and the price of power in the Spot Market is the price of the highest accepted bid.

In the Spot Market, power sellers are agents who ended up with a daily surplus of power at the prices they informed the previous day in their bid for the sale of surpluses. Each agent with power deficits becomes a debtor for the power purchased in the Spot Market at the corresponding price, and each agent with a supply of surpluses accepted in the Spot Market becomes eligible for the power sold, valued at the price of power in the Spot Market.

Before the end of each year, the CNDC must determine and inform agents about the Reference Price of Power.[51]

3.3 Contract Market

The MEMN operates with methodologies to coordinate the provision of information and restrictions related to the contracts agreed by Market Agents, whether internal or import/export contracts.

3.3.1 Power and energy commitments

Any contract that sells power should identify its per-day power commitment. Therefore, a power commitment for an interval of less than one day cannot be expressed in a contract, and the period of effectiveness of a contract that sells power should be at least one day. In addition, any contract that sells energy should identify its commitment in per-hour energy. The information needed to determine the amount of energy contracted each hour and/or the amount of power contracted each day should be clearly provided. With the objective of providing transparency to the administration of the Spot Market, this information should be open and accessible to agents.

3.3.2 Classification

[51] Thus, the CNDC uses the following procedure: a) The fixed cost representative of a peak unit is calculated to cover periods of maximum demand requirements, in accordance with the conditions and needs existing in Nicaragua. A peak unit is understood as a quick-starting generating unit whose operational flexibility makes it possible to monitor demand. b) The annual portion associated with said cost is calculated with the discount rate defined for the tariff scheme, considering a useful life of 15 years. C) The annual portion resulting in a percentage of unavailability for reliability is calculated. This percentage will be between 5% and 15% and is initially defined as 10%. The percentage may be modified at the CNDC's request, with the corresponding justification, and with the INE's authorization. D) Revenue above its variable costs that said unit could recover through energy sales in the Spot Market is deducted. E) The remaining fixed cost is obtained, expressed in a monetary unit per MW per day.

Contracts will be classified according to their duration in the long, medium and short terms. A long-term contract is considered to be one whose period of effectiveness is no less than 6 months. A medium-term contract is considered to have a period of effectiveness between 7 days and 6 months. A short-term contract is considered to be one with a period of effectiveness of less than 7 days. Short-term contracts will be differentiated in scheduled and emergency contracts. A contract is in emergency status when: a) it is required by a Production Agent due to unscheduled or unforeseen unavailability in one or more of his units, and b) it is an import or export contract that is required when conditions are modified due to unforeseen unavailability or emergencies the day before.

Contract information should be provided to the CNDC with enough lead time for it to be able to properly carry out its duties. The local agent will provide data on import and export contracts (quantities, time periods and prices) to the CNDC within the prescribed periods. If in any hour during the real operation the contract does not perform as the physical exchange scheduled in the international interconnection, for the administration of MEMN's the value corresponding to the operation's reality will be considered as the scheduled value of the contract for that hour.

If from the data provided for International Transactions through contracts the exchange in an international interconnection turns out to be greater than the maximum allowed (due to technical restrictions and/or Quality and Safety Criteria), for the exchange of import or export contracts, short-term contracts would be limited first, then medium term, and finally long term, until the resulting total exchange in the international interconnection exceeds the maximum allowed.

4. EL SALVADOR

4.1 Wholesale energy market

4.1.1 General definition

In El Salvador the electricity products that are traded are Power and Energy;[52] the Wholesale Energy Market (Mercado Mayorista de Energía [MME]) is composed of the Contract Market (Mercado de Contratos [MC]) and the System's Regulatory Market (Mercado Regulador del Sistema [MRS]) in which generating operators and marketers participate. The Transactions Unit (Unidad de Transacciones [UT]) operates the MRS and uses the MC for its scheduled dispatching, in which all operators directly connected to the transmission system may participate, including marketers. The UT is responsible for the scheduled dispatching of energy among generators, distributors and final consumers connected to the system.

[52] In addition, the secondary market or Auxiliary Services Market also operates. Its objective is to provide the commercial and competitive means for PMs to fulfill their mandatory quality and safety requirements as stipulated in the market regulations. The following are traded in this market: primary spinning reserve, automatic control of generation, reactive power, zero-voltage start-up, and cold reserve. Charges for transmission, system operation, auxiliary services and other similar charges must be reported separately by the generator to the UT, for subsequent transfer to consumers directly and without a surcharge through tariffs.

When congestion is detected in the transmission system, the UT creates as many MRS as needed to maintain the safety and stability of the system. The price differences among the abovementioned MRS will give rise to the charging of fees for congestion; the corresponding revenue is distributed among the system users according to the method established by the Office of the General Superintendent of Electricity and Telecommunications (Superintendencia General de Electricidad y Telecomunicaciones [SIGET]).

4.1.2 Dispatching

Regulations have been in place since 2006, whereby, until the necessary conditions exist to ensure competition in the prices offered to the MRS, the UT will be governed by by-laws that favor bid performances similar to those of a competitive market, according to the methodology established in the Regulation of the General Electricity Law (Ley General de Electricidad). This Regulation which will be based upon marginal production costs, fixed and investment costs. In the case of hydroelectric plants, it will be based on the value of replacing water. For these purposes, the market condition will be established jointly by the General Superintendent of Electricity and Telecommunications and the Superintendent of Competition through an Agreement based on internationally accepted indexes that measure competitiveness in electricity markets.

The UT must plan and coordinate the dispatching of generating units and the operation of the transmission infrastructure with the objective of meeting demand at the expected minimum cost of operation and rationing, subject to compliance with service quality and safety standards.

The units must be dispatched according to their respective variable operating costs. In the case of thermoelectric and geothermal units, these costs will be determined in terms of fuel costs, as the case may be, as well as other operating costs that may vary according to the amount of energy produced. For the case of hydroelectric plants with reservoirs, for purposes of dispatching, variable operating costs will be understood as those determined by the replacement cost or opportunity cost of water, determined by the UT. For the case of hydroelectric plants without reservoirs, these will be dispatched according to the availability of energy with the objective of minimizing the system's operating cost.

For dispatching purposes, imports will be treated as thermoelectric units with variable operating costs equal to the price of imported energy, and exports as an additional demand. The unit cost of rationing will be represented by means of Forced Rationing Units, in terms of the percentage of rationed energy.

4.3 Contract Market

The objective of the rules for the MC is to establish the general characteristics of contracting and the characteristics of bilateral transactions that may stem from contracts.

The objective of the rules for Scheduled Dispatching (Despacho Programado [DP]) is to: a) define the procedures to be carried out by each Market Participant (Participante en el Mercado [PM]) to inform the UT about bilateral energy transactions stemming from the Contract Market; and b) define the procedures under which the UT will conduct the Scheduled Dispatching.

Each PM is free to select its commercial strategy for purchasing and selling and to decide which transactions to conduct in the MC, with conditions and prices freely agreed between the parties. In order to participate in the MC, the PMs are obliged to provide auxiliary services corresponding to their transactions and must provide daily information to the UT on the bilateral transactions stemming from their contracts.

Each Generator must provide daily information to the UT each day, together with its bilateral transactions, on the injection in each Generation Unit (Grupo Generador [GGP]) that it owns, allocated as losses associated with the injection that said GGP makes through bilateral transactions.

Bilateral transactions that stem from the daily information provided by MPs to the UT are a commitment to inject into the grid and withdraw from the grid, respectively, by the selling party and the purchasing party. The UT will conduct the predispatching, taking into account the bilateral transactions about which the PMs have informed, and will administer diversions when necessary.

4.3.1 Bilateral injection transactions

Each PM must inform the UT about its bilateral injection transactions, identifying the PM that receives the energy. In a bilateral injection transaction, the delivering party, when informing about such a bilateral transaction, could include the following as an injection: a) that corresponding to a GGP that it owns, in which case the injection node will be that corresponding to said GGP; b) the energy received in bilateral international transactions, in which case the injection node will be the node of the corresponding interconnection line, in the national system. If in a bilateral injection transaction more than one node is indicated, it is necessary to indicate the energy to be injected, with details about each injection node, and each bilateral withdrawal node will have the right to a proportion of the injection from each injection node.

4.3.2 Bilateral withdrawal transactions

Each PM must inform the UT about its bilateral withdrawal transactions, identifying the PM that delivers it. In a bilateral withdrawal transaction, the receiving party may include in its statement, as delivery points, its own nodes and/or those of the delivering party. If the total energy to be withdrawn from the grid in a bilateral transaction corresponds to more than one node of withdrawal from the grid, it is necessary to detail the energy to be withdrawn in each node, and each injection node will have the right to a proportion of the withdrawal in each withdrawal node.

4.3.3 Bilateral transfer transactions

Each PM must inform the UT about its bilateral transfer transactions, identifying both the PM that delivers the energy and the PM that receives the energy. In a bilateral transfer transaction, the PM that provides the information should include the following: a) the energy to be received, with details about each reception node; b) the energy to be withdrawn in each withdrawal node; c) the energy received or delivered in bilateral international transactions, in which case the injection or withdrawal node will be the node of the corresponding interconnection line, in the national system.

The objective of the rules for spot bids is to establish the procedures under which PMs will provide the UT with their commercial bids associated with the flexibility of their injection capacity and their withdrawal requirements, as well as the way in which the UT will administer short-term markets.

4.3.4 Appraisal of contract diversions

The scheduled dispatching for each period is based on electricity purchase-sale transactions agreed in the MC. Operators are obliged to provide monthly information to the UT and the SIGET on the prices and other financial and technical conditions agreed in transactions conducted in the MC. They must also submit to the UT price bids due to increases or decreases with regard to the agreed amounts of energy. The UT operates the MRS in order to maintain a balance at all times between electricity supply and demand based on these bids. Those generators who do not have energy sale contracts participate in the MRS, and their scheduled dispatching is considered to be equal to zero.

Each participant's diversions with regard to scheduled dispatching are assessed at the prices stemming from the MRS's operation, as follows: a) the distributor or end-user whose consumption differs from that scheduled will be credited or charged at the MRS price of each node in which he had scheduled consumption; b) the generator whose plant generates more or less than the amount scheduled will be credited based on the MRS price of the node corresponding to such plant or charged based on the cost of the energy needed to replace the non-delivered energy; and c) when a plant generates less than the amount scheduled due to transmission grid defects that limit its capacity to deliver to the system, the UT will charge the transmitter who is responsible for the defect for the value of replacing the non-delivered energy.

4.3 Spot Market

4.3.1 Operation

Each PM must provide daily spot injection and/or withdrawal bids. Optionally, a spot bid may be reported as valid for a period of more than one day. The UT will organize the spot bids it receives each day, in order to include them in the database of the Market Administration System (Sistema de Administración del Mercado [SAM]) and will use them to conduct the predispatching and administration of the operation in real time the next day. Through spot bids, each Generator should inform the UT about his injection bid and the associated flexibility. A spot bid for the injection of a GGP must include for each period defined a maximum amount of bidded energy and two or more blocks of bidded energy, with a price for each block and with the following characteristics: a) an initial block that corresponds to the minimum bidded injection, b) one or more blocks, each with accumulated energy greater than that of the previous block and less than or equal to the maximum bidded energy. The bidded price should be equal to or monotonously increasing between one block and the next. Spot injection bids will also be used by the UT to adjust the injections informed in one or more of its bilateral transactions in terms of the prices that arise in the predispatching and the MRS. In this case, the predispatching and administration of the MRS will reduce the injection in the bilateral transaction when it is more economical to cover the commitment with MRS purchases.

Through spot withdrawal bids, each PM that withdraws energy from the grid will inform the UT about its withdrawal requirement and the associated flexibility. The real withdrawal of a PM will be the result of bilateral transactions and spot bids.

4.3.2 Price of energy

The energy transaction price in the MRS is established as being equal to the system's marginal operating cost, plus charges for transmission, system operation, auxiliary services and other legal charges. The marginal operating cost is understood as the cost of supplying one additional kilowatt-hour of demand in this interval. In cases of rationing, the marginal cost will be equal to the unit cost of the corresponding Forced Rationing Unit (Unidad de Racionamiento Forzado [URF]).

Energy transactions are conducted for each market interval. Each MRS will have a price. The UT will calculate the price of energy, taking into account existing restrictions, including congestion conditions, losses, auxiliary service requirements, and spot bids, including the spot bid for forced rationing (URF). The UT calculates the ex post prices of the MRS, with real data on energy injected into and energy withdrawn from the grid. The calculation will take into account the existing restrictions in real-time operation. Price formation does not include: a) prices bidded for generation that is mandatory; b) prices bidded for generation with non-compliance regarding the injection required by the UT; c) prices bidded for demand with non-compliance regarding the reduction in energy to be withdrawn from the grid required by the UT; and d) energy of units under generation testing.

4.4 Power transactions

Each generating system connected to the electricity system is annually assigned a firm capacity determined by the UT with the following criteria: a) the firm capacity of a unit is that power that a generating unit or plant is able to inject into the system with high probability in the electricity system; b) the firm capacity of a hydroelectric plant will depend on hydrological uncertainty, forced unavailability and its maintenance; c) the firm capacity of a thermal or geothermal unit will depend on the availability of fuel or steam, its rate of forced unavailability, and its scheduled maintenance; d) the firm capacity of a non-conventional generating unit, such as wind, solar, co-generation, etc., will depend on the uncertainty of its primary resource; e) the capacity of a generating unit to be used in the calculation of firm capacity may not be greater than the maximum capacity it can inject into the system for stability reasons; and f) the firm capacities of all units should be adjusted proportionately so that the sum of such firm capacities is equal to maximum demand during hours of maximum requirement for the power generating plant. Maximum demand will be understood as the net hourly maximum generation plus imports and minus exports.

Marketing operations give rise to firm capacity transactions, which will be determined annually by the UT through a firm capacity evaluation that takes the following into consideration: a) generators whose capacity committed in contracts in the control period is less than the sum of recognized firm capacities in their generating units will be considered sellers of firm capacity due to the difference between both values; otherwise they will be considered purchasers; b) operators, distributors, clients or marketers whose power demand in the control period is less than the firm capacity committed in contracts during the same hours will be considered sellers of firm capacity due to the difference between both values; otherwise they will be considered purchasers; and c) for marketers, the power demand in the control period will correspond to the committed capacity to be supplied in contracts during the same period.

The price for assessing firm capacity transactions stemming from the annual evaluation mentioned above will be known as charges for capacity and will be determined as being equal to the annualized per-kilowatt investment cost plus the fixed operating cost of an efficient unit that provides backup power and additional capacity in the system control period, expanded in a reserve margin and in a loss factor corresponding to hours of peak demand. The capacity charge and the formula to adjust it will be determined and updated every five years by the SIGET.[53]

4.5 Marketing and contracts

4.5.1 Marketing activity

[53] For this purpose, the investment costs, fixed operating costs and the useful life of the most economic machinery for peak power and back-up services, considering the size, location, and technical and economic characteristics suited to the electricity system's reality, will be determined by means of a study contracted by the SIGET with a specialized consulting company. To calculate the annual portion of the investment, the SIGET will use a representative discount rate for generation activities in El Salvador, which will be determined on the basis of a study contracted with a specialized consultant. In no case will this discount rate be lower than that established in the General Electricity Law for the transmission and distribution sectors. The reserve margin will be no lower than 10% and no higher than 20%.

For purposes of the market and marketing activity, the following definitions are stipulated: a) Supply Contract: the agreement under which a marketer is obliged to deliver to the end-user at a determined point, continuous or periodic electricity for a determined or undetermined period, at a price and under conditions that are fixed or to be fixed; b) Supply Contract: the agreement under which a national or foreign generator or marketer is obliged to deliver to a market, at a determined point, continuous or periodic electricity during a determined or undetermined period; and c) Distribution Contract: the agreement under which a distributor is obliged to permit the use of his grids by a marketer or generator to supply electricity to marketers or end-users connected to the distribution grid, or in the case of a generator connected to the distribution grid, the conveyance of electricity to high-voltage grids.

MME marketers may conduct the following activities: a) sign electricity provision and supply contracts, transmission contracts and distribution contracts; b) buy and sell electricity in low-voltage grids; and c) buy and sell electricity in the wholesale market.

The prices and conditions of supply contracts signed by marketers may be equal to or different from those contained in the Tariff Specifications approved by the SIGET for distributors who operate as marketers in the areas where their grids are located. End-users, in accordance with the provisions of the General Electricity Law, may choose the marketer with whom they will contract the provision of electricity.

4.5 Contract conditions

4.5.1 Transmission and distribution contracts

Generators connected to the transmission system must at all times have valid transmission contracts. Generators who have electricity provision contracts with end-users should be registered in the SIGET as marketers. Marketers should have distribution contracts with each of the operators of the grids used to supply electricity. Distribution contracts should stipulate the way in which the marketer will pay the distributor for the energy consumed by end-users, in excess of the amount contracted. The methods for setting fees for the use of transmission and distribution systems are established by the SIGET.

4.5.2 Supply contracts

The prices and conditions of energy supply contracts between operators will be limited only by the willingness of the parties and by the Law, and to improve them the intervention of third parties will not be necessary. The electricity sales and purchase transactions that distributors report to the UT for scheduled dispatching should include transactions corresponding to marketers with whom they have signed distribution contracts. For these purposes, marketers must provide timely information to the distributor on the amounts of energy and power that have been agreed with end-users for each dispatch period.

5. GUATEMALA

The key regulations that govern Guatemala's Wholesale Electricity Market (Mercado Mayorista de Electricidad [MM]) are contained in Decree 939 of the Congress of the Republic (General Electricity Law), in its Regulation, in the Wholesale Market Administrator (Administrador del Mercado Mayorista [AMM]) Rules , including Government Agreements Nos. 68-2007 and 69-2007 and AMM Resolutions 157-10 and 300-01.

5.1 Wholesale electricity market

The products that are purchased and sold in Guatemala's MM are power and electricity.[54] Transactions are conducted through: a) A Spot Market, with an hourly price calculated on the basis of the short-term marginal cost; b) a Futures Market, for contracts between Agents or Large-scale Users, with periods, quantities and prices freely agreed between the parties; and c) a market for daily and monthly Power Diversion Transactions. In the latter, the following are liquidated: differences between the available power and the Firm Power of Participating Producers, and the differences between the Effective Firm Demand of each Distributor, Large-scale User or Exporter and their effectively contracted Firm Demand, evaluated at the Reference Price of Power.

Agents and Large-scale Users of the Wholesale Market (MM) may conduct import or export transactions, as the case may be, with the Regional Electricity Market (Mercado Eléctrico Regional [MER]) or with any other market or country with which the Interconnected National System is connected. In order to conduct short-term export transactions, the exporter must have power contracts with an Efficient Firm Supply that is not committed in contracts to cover Firm Demand or Power Reserves; using the same power to back short-term exports and Firm Demands is considered a serious offense.

An MM participant who conducts an import or export transaction is directly responsible to the AMM for the payment of fees resulting from such a transaction. The importation is considered generation that is added to the MM, and the corresponding fees must be paid. Exportation is considered an additional demand that is added to the MM at the supply node and the corresponding fees must be paid. An import transaction corresponds to additional production stemming from generation that does not belong to the MM; this import generation is economically dispatched in the MM according to the Variable Cost of such importation.

5.2 Spot Market

5.2.1 Economic dispatch

The Spot Market is based on a price determined hourly as the marginal cost resulting from Economic Dispatch, which consists of determining the dispatch program for available supply, making it possible to meet the demand foreseen hourly in the MM, minimizing the

[54] Electricity conveyance services and complementary services are also provided.

total cost of the operation. Dispatching should consider the demand to be met as that corresponding to Participating Consumers and should consider the supply to be dispatched as that corresponding to Participating Producers. The AMM conducts the dispatching without considering mandatory minimum energy purchase conditions or any other type of contractual condition that restricts dispatching, which are taken into account solely for purposes of liquidating transactions in the Futures Market.

For hydroelectric plant dispatching, the AMM calculates the value of water based on information sent by agents; for thermal plants, it calculates the variable costs of fuels and O&M with the methodology and information stated. Importers also state the amount of energy and power offered and the methodology for calculating the corresponding variable cost.

5.2.2 Transactions by generators

All the energy exchanged is sold and purchased in the Spot Market. In this market, a generating agent sells his energy dispatched in his own node and evaluated at the price corresponding to that node. To comply with his supply contracts, he acquires the required energy in the Spot Market and at the price of his purchasers' nodes. The supply contract is interpreted as if each hour the generator must deliver the contracted energy in the exchange node, charging the agreed price, regardless of the real requirement of the demand of the person with whom he signed the contract or the generation actually conducted by the seller.

Each hour, the AMM monitors the differences between its generation and the sum of the power delivered by its contracts, and calculates the assessment of these differences. The participant may be a creditor or debtor in the Spot Market, depending on whether or not the integration of the amounts corresponding to hourly discrepancies throughout the month is positive or negative.

5.2.3 Transactions by consumers

A Participating Consumer purchases in the Spot Market the energy corresponding to his hourly demand, valued at the consumption node. The supply contract is interpreted as if each hour the Participating Consumer must purchase in the market the power and energy of each one of his contracts, regardless of what his own demand requires.

To monitor the differences regarding a Participating Consumer's supply contracts and to calculate his purchases and sales in the MM, the AMM considers the contracted total hourly power to be the sum of the hourly power of the load curves that are representative of his contracts or to be the missing demand. If the Participating Consumer possesses power contracts with a purchase option, the purchase option will be considered exercised if the generator has also been dispatched.

Each hour, the AMM monitors the differences between its own demand and the sum of the power delivered by its Supply Contracts, and calculates the assessment of these differences.

The participant may be a creditor or debtor in the Spot Market, depending on whether or not the integration of the amounts corresponding to hourly discrepancies throughout the month is positive or negative.

5.3 Futures Market

5.3.1 General aspects

A Futures Market is that which is constituted by contracts between Agents or Large-scale Users of the Wholesale Market (Mercado Mayorista [MM]), with prices, quantities and duration agreed between the parties. It is formed by existing contracts to which their own terms are applied (i.e., dispatch of minimum contracted quantities), as stated in the AMM Regulations, and by subsequently signed contracts. In this market, contracts can be agreed upon, either to guarantee the provision of a certain demand for power and energy, to have the backing of a power reserve, or to have power that allows the firm demand of Participating Consumers to be met.

Possessing a contract in the Futures Market also implies operating in the Spot Market to trade surpluses and deficits between what is dispatched or consumed and what is contracted.

5.3.2 Long-term contracts

a. General aspects

MM Generators may sign Futures Market Contracts with MM agents (Distributors, Marketers or other Generators), and Large-scale Participating Users, with conditions, time frames, quantities and prices agreed among the parties. They may also conduct International Transactions with companies from other countries, complying with established regulations.

b. Types of contracts

i) Contracts for differences with load curve

In this type of contract, the parties stipulate a contracted power value to meet Firm Demand at all times during the contract period, which may not exceed the seller's Efficient Firm Supply not committed in other contracts. Furthermore, the Participating Producer commits to supply an energy demand, defined as an hourly demand curve throughout the contract's period of effectiveness, to a Participating Consumer. The energy of the hourly curve will be assigned to the contract's purchaser and deducted from its seller. The seller may be supported by contracting power in order to fulfill his commitment. The hourly demand curve may be established by the Participating Producer either through his own generation or by purchasing the deficit in the Spot Market if the necessary surplus exists. This means that a Production Agent has no obligation to generate the energy committed in the contract.

ii) Contracts for power without associated energy

In this type of contract, the parties stipulate a contracted power value to meet Firm Demand at all times during the contract period, which may not exceed the Efficient Firm Supply of the seller that is not committed in other contracts. The MM's Participating Consumer may purchase the energy demanded in the Spot Market.

iii) Contracts with Energy Purchase Option

In this type of contract, the parties establish a contracted power value to meet Firm Demand at all times during the contract period, which may not exceed the Efficient Firm Supply of the seller that is not committed in other contracts. Moreover, the Participating Producer sells to a Participating Consumer an amount of hourly energy according to the following: the parties stipulate an Energy Purchase Option Price; if the Opportunity Price of Energy is lower than the Option Price, no energy stemming from the contract is assigned. Otherwise, the Participating Producer sells, using his own energy or that purchased in the Spot Market, the hourly energy informed by the parties, which may not exceed the value of the contracted power.

iv) Contracts on differences due to a deficit in demand

In this type of contract, the parties stipulate a contracted power value to meet Firm Demand at all times throughout the contract period, which may not exceed the seller's Efficient Firm Demand that is not committed in other contracts. Moreover, the Production Agent agrees to deliver, at the agreed price, all the energy demanded by the purchaser that is not supplied by other contracts, up to the amount of power committed.

v) Existing Contracts

These are the contracts to which Article 40 of the AMM Regulations refers; they will be administered in accordance with the contractual conditions about which AMM is informed.

vi) Contracts for generated energy

In this type of contract a Generating Agent, whose generating units have not been assigned an Efficient Firm Supply, sells to a Participating Consumer all the energy he can generate in the MM. With this type of contract, he only sells energy for which there is no commitment of power to meet Firm Demand.

vii) Backup Contracts

Backup Power Contracts (or Backup Contracts, for short) mean that the machinery of a generator will be made available to the purchaser of the Efficient Firm Supply, to be used by the contractor under present conditions (for example, a deficit in the MM) to meet his own requirements. This type of contract will allow generators who have supply contracts in the Futures Market with non-compliance penalty clauses to have a backup for their supply commitments.

A Backup Contract between a Generator and an MM agent must specify: a) its period of effectiveness; b) the identification of the Generator's machinery that is committed as a Reserve; c) the total firm supply committed to this machinery: a value that varies over the period considered may be indicated, and a payment formula ($/MW) for this capacity may be made available; d) a condition for its use, i.e., the condition by which the machinery is considered to be generating for the Backup Contract, if it is dispatched; e) a formula of payment for the energy generated when the contracted capacity is summoned to produce; and f) penalties, if any, if the committed energy is not available at the moment it is required.

Those Generators contracted as a reserve must inform the AMM about signed contracts (prices, period of effectiveness, reserve power, summons clause, etc.). A machine hired as a reserve will participate in the MM's dispatching and will only generate when dispatched by the AMM. Once dispatched, its energy may only be commercialized in the Spot Market if it is not summoned by its Backup Contract. Once summoned, it must deliver to the contract the energy generated stemming from the dispatching up to the amount of power committed, in accordance with contract conditions, and therefore this energy will not be commercialized in the Spot Market.

The commitment will be considered established specifically with the machinery indicated, and each month the Generator will cover the corresponding charge for the power made available under the contract, whether or not summoned, provided that it has the committed availability in such machinery; it may not purchase the deficit from the MM. When summoned, it will also charge for the energy generated under the contract.

viii) Power Guarantee Contracts

Participating Producers may sign contracts for the purchase of reserve power to back their own commitments for selling power to Distributors, Large-scale Users, Participants, marketers or other generators. In this type of contract a Participating Producer sells to another Participating Producer a certain amount of power during the contract period. The seller must back this commitment with an Efficient Firm Supply not committed in other contracts or used to back exports. The power contracted by the Participating Producer will be added to his Efficient Firm Supply, to be commercialized in the Wholesale Market.

5.4 Power diversion transactions

The Peak Power Price in the MM is calculated by AMM as the marginal cost of the investment for a unit of peak generation. This price corresponds to the Power Reference Price (Precio de Referencia de la Potencia [PRP]), which is used for Power Diversion Transactions.

The AMM determines the Effective Firm Demand of each Distributor or Large-scale User. The difference between the Effective Firm Demand and the Firm Demand that the Distributor or Large-scale User has covered with contracts, is liquidated monthly as a charge or credit, as the case may be, through a Power Diversion Transaction that is calculated with the PRP. The monthly value resulting from these power diversions is distributed on a prorated basis between Participating Producers and Consumers with positive monthly power surpluses.

For this purpose, the AMM annually calculates the Efficient Firm Supply of each generating unit or plant of the MM. The Efficient Firm Supply related to International Transactions is established on the basis of the contract's firmness, in the understanding that such contract covers at least the current year, has a supply guarantee, availability, and the committed power and the methodology to calculate the variable cost are defined.

The Efficient Firm Supply is calculated in terms of the Firm Supply and the economic efficiency of each power plant with respect to the range of power plants installed in the Interconnected National System or in accordance with the characteristics of the power generation unit related to the corresponding International Transaction.

6. PANAMA

The key regulations that govern Panama's Wholesale Electricity Market (Mercado Mayorista de Electricidad [MME]) are contained in the Commercial Regulations, which were established in accordance with the guidelines contained in Law 6 of 1997 (Regulatory and Institutional Framework for the Provision of Public Electricity Services), in the amendments to it, introduced by Law 10 of 1998 and in Executive Decree No. 22 of 1998 (which regulates Law No. 6 of 1997).

6.1 Wholesale electricity market

The Commercial Regulations of the MME in Panama state that the products purchased and sold are energy and power,[55] which are traded in: a) a Spot Market, and b) a bilateral Futures Contract Market, between market agents. Market participants are: Participating Consumers[56], who represent electricity consumption and who also include companies that commercialize another country's consumption, which they purchase in Panama's MME, linking through international interconnections; and Participating Producers,[57] who

---

[55] The services provided are: transmission service, auxiliary grid services, and integrated operational service and commercial administration, assigned to the National Dispatch Center (CND) of the transmission company.

[56] Participating Consumers are: a) Large-scale Customers who opt to purchase directly at wholesale level in the market; b) Distributors, conducting the marketing activities of their customers or Large-scale Customers within or outside their concession zone. c) self-generators and co-generators located in the Republic of Panama who purchase deficits; d) Companies that market another country's consumption, who purchase in Panama's Wholesale Market, connecting through international interconnections.

[57] Participating Producers are: a) generators located in the Republic of Panama; b) self-generators and co-generators located in the Republic of Panama who sell surpluses; c) distributors when they sell their own surplus generation to third parties, either in the Contract Market or in the Spot Market, and services that the CND administers, under the restrictions

represent electricity generation, including companies that commercialize another country's consumption and sell in Panama's MME through international interconnections. The regulation stipulates that market agents will have access to the transmission grids owned by the Electricity Transmission Company (Empresa de Transmisión Eléctrica [ETESA]) at regulated tariffs and under non-discriminatory conditions.

6.2 Spot Market

The Spot Market is where hourly, short-term commercial transactions are conducted, making it possible to assess the surpluses and deficits that arise as a consequence of the differences between contractual commitments and the reality of consumption and generation. The price of energy in the Spot Market stems from the short-term marginal cost of generation. The CND calculates it with an economic dispatch without restrictions of the transmission and distribution grid, known as price dispatching. Importation participates in the formation of the price of energy in the Spot Market as additional generation in the international interconnection, while exportation participates as a demand.

Energy transactions and the price calculation in the Spot Market are conducted on an hourly basis. The energy price is calculated with the ex post price dispatching, using the same procedures and models as for pre-dispatching, but also using the real available supply (available generation, real supply of self-generators and supply from international interconnections) and registered demand. The CND must calculate the energy price with the variable cost applicable to the dispatching of the final bid required for the price dispatching in order to meet demand. For the variable costs of thermal plants, their fuel and O&M costs are used. For the variable costs of hydroelectric plants, economic opportunity values of water are used; these are calculated by means of modeling basins and reservoirs and using the technical characteristics of their hydroelectric plants. To consider import bids, the bidded price of importation in the interconnection is used, which for the case of contracts will be that declared to the CND by the National Participant, and for the case of spot importation it will be that informed by the EOR.

In the Spot Market, the CND acts as an intermediary in spot importation and exportation operations.

6.3 Contract Market

6.3.1 General aspects

The Contract Market is where medium- or long-term commercial transactions are conducted between participants for the purchase/sale of energy and/or power with periods, quantities, conditions and prices agreed between the parties. The purchase by Participating Consumers with the supply guarantee detailed below in Section IV is made through the Contract Market.

---

and requirements stated in these Commercial Regulations; d) Companies that market another country's generation, which they sell in Panama's Wholesale Market through international interconnections.

Power transactions are conducted in the Contract Market and through power compensations. Participating Producers may sell, either through contracts or in the Spot Market, power and/or energy of their own or contracted from third parties, and may purchase, through contracts or in the Spot Market, the power and/or energy deficit with regard to their contractual commitments. The same rights apply to the Distributor when he is considered a Participating Producer by selling surpluses of his own generation to third parties.

Participating Consumers may purchase, through contracts or in the Spot Market, their demand for power and energy consumption, and may sell surplus energy and power (not required for their own consumption or that of their clients) in the Spot Market and in the daily power compensations. Participating Consumers who serve users at regulated prices have the obligation to sign long-term energy and power purchase contracts to ensure the supply to their customers, under the terms presented in Section III. Purchasing Participants include Large-scale Customers who have the option to freely negotiate the terms and conditions of energy supply with other market agents, or to make use of the terms and conditions established for customers in the regulated market, corresponding to the level of tension at which energy is supplied.[58]

6.3.2 Long-term contracts

a. General characteristics

Contracts between National Participants may not establish a physical bilateral exchange that alters the dispatch,[59] unlike import and export contracts which must establish the physical commitment for exchange in the interconnection. A Participating Producer may sell power and energy by means of contracts, provided he has the generation to back them, either with generating units that belong to him or generation contracted from another Participating Producer. Each Participant must inform the CND about the prices and basic information needed for the operational and commercial administration of contracts, which are reported to the market in general.

b. Operational and commercial conditions

Each contract must include a clause in which the parties agree that they accept MME's Commercial Regulations and their modifications. Each contract must include a clause in which the Participating Producer agrees to operate in accordance with CND instructions that stem from centralized economic dispatch and from integrated operation, according to the rules and procedures that are defined in the Operating Regulations. He must also indicate that he commits his contribution to auxiliary services for the quality of service

[58] Cooperatives, commercial centers, buildings, users' associations, housing, recreational and similar complexes may be considered Large-scale Customers.

[59] Participants must keep in mind that, if a contract includes mandatory minimum purchase conditions (take or pay), these will not be taken into account in the load dispatching conducted by the CND.

required for the safe operation of the grid, in accordance with current quality criteria in the integrated operation.

A Participating Producer may sell to Participating Consumers, through contracts, up to his Maximum Power for Consumer Commitments, which is calculated as the sum of the effective power of the plants he owns, minus the power sold through Backup Contracts to other Participating Producers, plus the power purchased through Backup Contracts from other Participating Producers.

A Participating Producer may sell to other Participating Producers, through contracts, up to his Maximum Power for Producer Commitments, which is calculated as the sum of the effective power of the plants he owns, minus the power sold through Supply Contracts to Participating Consumers.

The contracts may not establish a bilateral physical commitment that mandates a certain amount of generation within the Republic of Panama. The energy that each plant produces will be the result of dispatching and real operation, and thus will be independent from the existence of contracts or the lack thereof.

Participants should include the following basic contract information: a) Identification of the purchaser and the seller, b) Period of contract effectiveness, c) Type of contract, d) Delivery and withdrawal points, e) Power and/or energy contracted during the period of effectiveness. The power contracted for each day of contract effectiveness should be identified, as well as the energy contracted for each hour of contract effectiveness, in accordance with the terms and characteristics defined in these Commercial Regulations, f) If there is more than one purchaser, the amounts of energy and/or power that correspond to each or the formula to distribute the total energy and/or power contracted between each of the purchasers, g) If one of the parties assumes the transmission charges of the other party, h) A clause that indicates the parties' acceptance that the contract and the associated generation will be administered in accordance with the current operating rules in the Operating Regulations, the Commercial Regulations and Methodologies that are in effect.

With the exceptions that are applied to long-term import and export contracts, the time frames for providing information on a contract and the period in which the CND must respond regarding its authorization may not be longer than those stated in the regulation. Participants are obliged to inform the CND each time that they agree on modifications to any of the contract data. This notification must identify the modified data and the new value in effect.

c. Types of contracts

There are two types of contracts in the Contract Market: a) Supply Contract, for the sale of energy and/or power from a Participating Producer to Participating Consumers, and b) Backup Contracts, for the sale of energy and power from one Participating Producer to another Participating Producer. Depending on the parties' location, two types of contracts are defined: a) National contracts, in which both parties are National Participants, and b) Import and export contracts, in which one party is a National Participant, who produces or consumes in Panama, the other party is a Foreign Participant who produces or consumes in another country, and the exchange is conducted through one or more international interconnections (the requirements that these contracts must meet are presented in Annex 6 – Section 6).

c.1 Supply contracts

The seller of supply contracts must be a Participating Producer, including a Distributor authorized as a Participating Producer who may sell his own firm generation. The purchaser must be Purchasing Participant (Distributor or Large-scale Client).

c.1.1 Conditions for contracting power

A Supply Contract that contracts Long-term Firm Power may define a contracted amount of power that is variable throughout the contract's period of effectiveness. The contract must clearly identify the power contracted for each day of contract effectiveness and one or more delivery points. A Participating Producer who sells power under a Supply Contract assumes the commitment that the installed contracted power exists, with adequate maintenance to meet the availability requirements agreed in the contract. The same obligation applies to a Distributor authorized as a Participating Producer when he sells Firm Power that he has generated, under Supply Contracts.

A Supply Contract that contracts power must have an agreed remuneration for power based on a scheme of availability for the contracted power, and may also include a scheme of rewards and penalties. The power pricing formula, availability, and rewards or penalties may vary throughout the contract period. A Supply Contract that stipulates energy commitments must contain an agreement on a pricing scheme for such energy, and may vary throughout the contract period or in terms of parameters agreed in the contract.

In a Supply Contract the Participating Producer commits Long-term Firm Power; the contract may stipulate a target availability requirement. The Participating Consumer agrees to pay for each MW of firm power contracted that meets the target availability, regardless of whether or not power is actually generated. The contract may divide the year into one or more periods, to give a different economic weight to the power under different conditions, and may differentiate periods by season of the year and/or by type of day and/or by hour of the day.

The Participating Consumer who is the purchaser acquires the right to use the power that is contracted, and may sell spot power when he has surpluses with regard to its provision, through power compensations. The contracting of power with associated energy establishes the priority for use by the Participating Consumer who purchases it. Under a condition of rationing, the contract becomes a physical commitment and the CND must assign the energy associated with the contracted power to the purchaser's supply.

As an option, a power contract may include maximum price insurance for energy. In this case, the contract must indicate the energy price at which such an option is activated. Each hour in which the price in the Spot Market exceeds the energy price stipulated in the contract, the option is activated and the Participant who is the seller will pay a compensation to the Participant who is the purchaser, equal to the hourly energy corresponding to the contracted power, estimated by the difference between the price in the Spot Market and the price of energy in the contract.

c.1.2 Conditions for contracting energy

The contracting of energy makes it possible to stabilize or define the future price of energy, but it does not impose restrictions or obligations on the physical operation. The seller assumes a commitment to deliver energy, but not an obligation for his own production. The purchaser assumes a commitment to pay for a block of energy, with the priority of using it for his own consumption and selling spot surpluses.

The contract should clearly identify the energy contracted for each hour of contract effectiveness, under the characteristics and terms that these Commercial Regulations stipulate.

A Supply Contract that stipulates energy commitments will be administered in accordance with the procedure regarding differences as defined in the Commercial Regulations. Supply Contracts must contain an agreement on and the identification of one or more energy or power delivery points. If energy transmission charges exist, the CND should consider that in a Supply Contract the seller assumes the transmission charges associated with the energy contracted from its point of connection to the grid, to delivery points, and the purchaser assumes the associated transmission charges, if any, from the delivery points to his consumption node, unless the parties include in the contract a different agreement for associated transmission charges, of which they must inform the CND.

c.2 Backup Contracts

Both the purchaser and the seller of a Backup Contract must be a Participating Producer, including the case of a Distributor authorized as a Participating Producer who sells through own-generation contracts.

By means of this transaction, the Participating Producer who sells under a Backup Contract assumes the commitment that the installed contracted power exists, with adequate maintenance to meet the availability requirements agreed in the contract. For commercial administration, the CND should consider that the power committed in a Backup Contract belongs to the Participating Producer who is the purchaser of the power, which he may use to sell in the Market and/or as a reserve to back up the obligations assumed in those Supply Contracts in which he is the seller.

A Participating Producer may sell to other Participating Producers his power surpluses, understood as the power that is not committed for sale in contracts or contributes to the long-term reserve service. The Backup Contract should define the contracted power and the delivery node(s). The amount of contracted power may vary throughout the contract's period of effectiveness. The contract should clearly identify the power contracted for each day of the contract's effectiveness.

For energy, the contract commitment is that the seller will deliver to the Participating Producer (purchaser) the energy generated by the contracted power. The contract may include an option for energy, establishing a condition under which the purchase of the generated energy is activated (is summoned).

The CND must consider that the Producer who purchases, assumes the associated transmission charges, if any, except if the parties state in the contract and inform the CND about another type of agreement with regard to transmission charges.

Annex 3: Description of long term purchase obligations

1. COSTA RICA

In Costa Rica there is still no formal separation of distribution activities and existing distribution companies, other than the ICE, purchase energy in bulk without a long-term contract, but with the responsibility for supply basically assumed by the ICE.

2. HONDURAS

In Honduras there is still no formal separation of distribution activities and distribution companies do not operate in the country.

3. NICARAGUA

In Nicaragua, distributors are obliged to have electricity purchase contracts with generators located within the country or with generators located in another country through import contracts. As of December 1 of each year, there should be contracts covering 80% of expected demand for the following year and 60% of expected demand for the subsequent year. The distributor will be temporarily exempt from this obligation if there are no offers in the bidding process that qualify as an efficient purchase transferrable to tariffs. Each distributor's obligation to contract is calculated by subtracting his own generation that is committed for coverage from forecasts of energy consumption and participation in the Power Demand for Forecasted Total Generation. The INE will authorize the distributor, during a transitional period, to purchase the non-contracted deficit in the Spot Market while conducting a new bidding process.

Large-scale Consumers must meet at least a percentage of their forecasted demand through contracts, so that their coverage is no less than the minimum between the mandatory percentage for distributors to contract and 50%. In terms of the market's evolution, the INE may reduce this percentage.

The Supply Guarantee Obligation is calculated for each Market Agent, using the energy and power forecasts indicated in the Demand Forecasts Report. Each Distribution Agent is required to provide information to the CNDC on a yearly basis, along with demand forecasts for the Demand Forecasts Report, on his own generation that is committed for his Supply Guarantee Obligation, indicating whether this corresponds to the coverage of Large-scale Consumers with whom he has contracts or to coverage for the rest of his customers.

4. EL SALVADOR

Distributors in El Salvador are obliged to sign long-term contracts through processes of free competition, for no less than 50% of the demand for maximum power and its associated energy. Based on the evolution of demand and of the supply of electricity in the wholesale electricity market, the SIGET may recommend increasing the contract percentage.

The form of supply to be contracted by the distributor will be standardized so that each contract will be characterized by an amount of power or capacity to be contracted in the control period of the electricity system's firm capacity and the associated energy to be supplied. The contract's associated energy will be equal, each hour, to the amount resulting from applying to the average hourly demand measured during that hour a percentage equal to that which represents the contracted capacity in relation to the distributor's maximum annual demand estimated during the control period of the electricity system's firm capacity.

With the objective of stabilizing the average price of energy in their respective contract portfolios, distributors should diversify the volumes and deadlines of the contracts that form them. For this purpose, each time the distributor signs a long-term contract, it should not exceed 25% of the energy demand supplied by the distributor, taking into consideration the composition of the supply for such demand according to its forecast for the year in which the respective supply begins. If this percentage is exceeded, contracting should be separated into two or more contracts that fulfill the condition indicated and whose period will be scheduled in different years, also considering the expiration of current contracts.

5. GUATEMALA

In Guatemala, distributors must have a power contract that allows them to meet, with Efficient Firm Supply, their firm demand requirements in order to serve their customers. In the case of Large-scale Users with representation, the Marketer with whom they have signed the Commercialization Contract will be responsible for meeting, with an Efficient Firm Supply, the Firm Demand of each Large-scale User for the current year and the subsequent year. These contracts must belong to the Futures Market and be in effect in order to meet Firm Demand during the current year and the subsequent year.

In the case of a Marketer, his demand to be contracted is calculated as the sum of the firm demands of the Large-scale Users that he commercializes. A Marketer may sign Commercialization Contracts with Large-scale Users, with the objective of assuming all the commercial responsibilities of these Large-scale Users in dealings with the AMM. In the case of Large-scale Users with Representation, the Marketer with whom they have signed the Commercialization Contract will be responsible, during the current year and the subsequent year, for meeting the Firm Demand of these Large-scale Users. In this case, the Firm Demand to be contracted by the Marketer will be the sum of the Firm Demands of Large-scale Users with representation.

The Efficient Firm Supply purchased or represented by the Marketer will be used to meet the Firm Demand of his Large-scale Users with representation. The Marketer should have sufficient Efficient Firm Supply, represented or contracted, to meet all the Firm Demand requirements of all his clients. If the Marketer has surpluses of Efficient Firm Supply, he may commercialize them in the MM or sell them in the power diversion market.

Distributors purchase their needed energy that is not supplied by contracts in the MM at the opportunity price of energy in the Spot Market. The forecasted demand to be purchased at the spot price is calculated for each distributor each hour, deducting from the power demand the sum of the representative load for that hour in his Supply Contracts, with the exception of those without associated energy. For Participating Large-scale Users and Marketers, the demand not covered by contracts is purchased in the Spot Market at the spot price of energy.

6. PANAMA

Panama's MME operates with Supply Guarantee Obligations, which consist of each distributor's supply commitment to the clients he serves, at regulated tariffs. The distributor is obliged to have, in advance, long-term firm power that is committed to cover the participation of his regulated clients in the maximum demand for the system's forecasted generation, and to set the cost of supplying the energy foreseen for his regulated clients.

Each distributor must comply with this obligation by means of: a) his own generation, committed in accordance with the criteria and procedures that are stipulated in the Commercial Regulations; b) purchases in the Contract Market, in accordance with his obligation to contract, which stems from the rules and procedures stipulated in the Commercial Regulations and by the Regulatory Agency. In other words, the coverage of a distributor's obligation to guarantee supply may be performed with long-term Firm Power Contracts resulting from processes of free competition and with his own committed generation.

On the other hand, a Large-scale Client who is a Participating Consumer is free to determine his commercial strategy for contracting, according to the purchasing needs and conditions he desires. Two or more Large-scale Customers may join to add demand and purchase through the same contract. In this case, the CND should assign the energy and/or power resulting from such contracting between/among Large-scale Customers in proportion to their participation in the total contract.

The Supply Contract is the commercial tool with which the distributor fulfills his obligation to contract, in accordance with the rules defined in the Commercial Regulations and the rules that the National Public Services Authority (Autoridad Nacional de Servicios Públicos [ASEP]) establishes in this regard. He may establish: a) a commitment exclusively for power; b) a commitment exclusively for energy, or c) a commitment for power and energy. The contracting of power through a Supply Contract is a long-term reserve of Firm Power with an availability commitment, dedicated, in the case of deficits, especially to cover the supply of the Participating Consumer(s) who is/are the purchaser.

In the case of the contracting of Firm Power with associated energy, the purchaser is obliged to acquire the Required Associated Energy (Energía Asociada Requerida [EAR]) contracted; this is calculated hourly as the fraction of Total Measured Energy (E) delivered to meet the purchaser's total demand, resulting from dividing the Maximum Demand for Generation (Potencia Firme Contratada [PFC]) by the Maximum Demand for Generation (Demanda Máxima de Generación [DMG]), excluding the Reliability Reserve (Reserva de Confiabilidad [R]), according to the following formula:

$$EAR = (PFC/(DMG - R)) \times E$$

In the case of contracting only energy, it shall be contracted based on the Equivalent Power (Potencia Equivalente [PE]) which results in energy associated with the required energy, according to the following formula:

$$EAR = (PE/(DMG - R)) \times E$$

The purchaser's rights and obligations with respect to the contracted power and energy are as follows:

- He must purchase the contracted amounts even if he does not require them to meet his real demand.
- He must pay for the total hourly energy contracted.
- He must pay for the total Contracted Power and, in case of deficits, he acquires the right to assign them, as a priority, to meet his demand.
- He must pay the transmission charges corresponding to the portion of his demand covered by the contract.

The seller's obligations and rights with regard to contracted power and energy are as follows:

- He is obliged to sell to the distributor the contracted amounts at agreed prices.
- He is obliged to supply the amounts of energy contracted, and may fulfill the commitments with his own generation or that purchased from third parties in the MER or in any other market, assuming the corresponding costs.
- He is obliged to supply the amounts of Contracted Firm Power, and may fulfill this commitment with his own generation or that purchased from third parties in the MER or in any other market, assuming the corresponding costs.
- He will take responsibility for the corresponding transmission charges, in accordance with ASEP regulations.
- He is obliged to keep the committed generating units in service, unless he has additional units or contracts that guarantee him the contracted supply.

Annex 4: Description of mechanisms for competitive power contracting

1. COSTA RICA

Costa Rica does not have distribution companies.

2. HONDURAS

Honduras does not have distribution companies.

3. NICARAGUA

Nicaragua does not have regulated competitive bidding processes.

4. EL SALVADOR

The MME has the necessary regulations to conduct processes of free competition with regard to the bidding procedure through which distributors issue bidding invitations for the contracting of energy and power supply, according to the magnitude, timeliness and periods established in the bidding documents and at a price specified by the bidder.

In summary, the bidding invitation will be such that the signing of contracts which refer to a supply for a period exceeding five years must be conducted no less than three and no more five years in advance of the date when the supply begins. For contracts whose supply period is less than or equal to five years, the signing of the contract must be at least three months prior to the date when the supply begins.

The base price of power that governs each Supply Contract will correspond, at each point of supply, to the capacity charge existing in the MRS on the bidding date. If no capacity charge is in effect in the MRS, the base price of power that governs each Supply Contract will be defined by the SIGET, so that it reflects the unit cost of capital and the fixed operation and maintenance costs of an efficient unit in order to provide backup and additional capacity during the system's control period.

In each bid, participants should offer a single base price of energy. The SIGET, through an agreement, may establish a base price ceiling for energy, which will be calculated, depending on the contracts' periods of effectiveness, by taking into account the cost of developing efficient generating units and the expected energy prices in the MRS, stabilized. The price ceilings will be confidential in order to ensure competition in the bidding processes.

In order to expedite these processes, the following procedure was regulated.

4.1 Demand forecasts

Distributors must inform the SIGET on an annual basis about their energy and capacity forecasts for the following 5 years, as well as the annual portions thereof, covered by long-term contracts, signed under existing free competition procedures. The distributors should make this same information available electronically to the public.

4.2 Conduction of the free competition process

Free competition processes must be conducted by each distributor on an individual basis for his own supply. Distributors will also be responsible for awarding the corresponding contracts, subject to the SIGET's authorization. Distributors may join together and bid in the same free competition process on all demands subject to bidding. In this case, distributors may designate one of them to conduct the process. However, in this case, the award of the corresponding contract to each Distributor is an individual responsibility, subject to the SIGET's authorization.

4.3. Bidding documents

Bidding documents will be prepared by each distributor and for each free competition process to be conducted; these must comply with stipulations in the law, its regulation and contracting rules. The bidding documents must be approved by the SIGET, subject to consultation with the office of the Superintendent of Competition, and must contain at least the following: a) the bidding invitation; b) the detailed description of the service that is being contracted; c) instructions to participants or bidders on the bidding procedure and deadlines; d) the economic background data established using a base price ceiling for energy, power price, indexing formulas for base prices of power and energy, and price indexes to be used in the energy indexing formula. The value of the base price ceiling of energy will be recorded in the Registry assigned to the SIGET and is confidential; e) the period of the contract subject to bidding; f) the date, place and time of the submission and opening of bids; g) the bid evaluation criteria; h) the form or format to be used for submitting bids; i) the guarantees considered; and j) the corresponding contract model.

4.4 Bidders

All generating or marketing companies that conduct transactions in the MME may participate as bidders in the free competition process. Potential national or international generators who, if awarded the contract, guarantee the start-up of operations in the periods stipulated in the bidding documents, may also participate. According to the conditions that the MER presents, the SIGET may authorize the participation of generating and marketing companies that operate in this market, provided that they meet the firm contract requirements for international marketing operations in accordance with the regulation effective in it. In any case, and in compliance with the principle of reciprocity to which Article 3 of the MER's Framework Treaty refers, only bidders from those countries in the region that allow the participation of Salvadoran agents under conditions equal to those of local bidders, may participate.

4.5 Minimum requirements for bidders

The bidding documents should stipulate the minimum requirements to be met by bidders in order to become potential winners of the bidding. These requirements should be stipulated in terms of technical, legal, financial and commercial capacity, and should refer exclusively to the bidders' capacity to satisfactorily fulfill the bid for supply under the terms agreed in the respective Supply Contract. The bidding documents may not include discrimination or preferences of any sort, with the exception of those that the current regulation specifically states in this regard. Likewise, distributors may propose in the documents the establishment of guarantees to commit the payment of contracted supplies, in which case they should specify the costs that the existence of such guarantees would cause them. These should be approved by the SIGET and the costs for the distributor will be considered part of the administration costs to which the following section refers.

4.6 Administrative costs of the free competition process

All costs stemming from the administration of free competition processes will be assumed by the distribution companies. For tariff purposes, the efficient costs of administering long-term contracts will be recognized; these will be transferred to the tariff terms of the distributors' clients.

4.7 Other aspects

Contractual rules contain the detailed regulation of the various phases and aspects of the process, i.e.: a) approval of bidding documents, b) prior publication of bidding documents; c) call for bids, d) bidding timetable, e) participants' observations, f) communications between the distributor and participants, and g) subdividing of the supply to be contracted.

4.8. Form of supply to be contracted

The form of supply contracts will be standardized.

4.9 Applicable price of power and bidded price of energy

The base price of energy that governs the Supply Contract will correspond, at each supply point, to the capacity charge existing in the MRS at the time of the bidding. If no capacity charge exists in the MRS, the base price of power that will govern each Supply Contract will be that defined by the SIGET. In each alternative amount of supply requested, participants should offer a single base price of energy. The SIGET may establish a base price ceiling for energy, which will be calculated depending on the periods of contract effectiveness, taking into account the cost of developing efficient generating units and the expected energy prices in the MRS, stabilized. If the SIGET exercises this authority, the bidding documents should explicitly state that the ongoing bidding process is subject to the existence of a base price ceiling; however, its value will be recorded in the Registry assigned to the SIGET and will remain confidential until the bids are opened. If a base price ceiling for energy has been established, those bids that present a base price of energy higher than the ceiling indicated will not be considered valid.

4.10. Indexing mechanism, additional charges and economic indicators

The mechanism for indexing the price of power will be defined by the SIGET and stated in the bidding documents. Depending on what the SIGET stipulates, the mechanism for adjusting the price of energy may be defined in the bidding documents or the participant may be asked to propose it in his bid.

The bidding documents must express that, during the period of contract effectiveness and for purposes of invoicing the contracted supply, generators should add to the indexed prices of energy the charge for the use of the transmission system, the system's operation, auxiliary services and similar charges that may be transferred to users, if these charges stem from the application of the regulation that governs these matters during the contract period.

The SIGET will stipulate a defined set of economic indicators, on the basis of which the indexing formulas presented by bidders should be designed. These indicators will correspond to national or international indicators that reflect the prices of inputs for generation, as well as the variation of the key general parameters of the economy.

4.11 Date of the start and end of supply in contracts

The starting date of the supply in contracts with a period greater than 5 years may not be prior to 36 months or later than 60 months from the date when the contract is signed. The maximum duration of the contract will be 15 years from the date when the supply begins. The starting date of the supply in contracts with a duration of less than or equal to 5 years may not be prior to 3 months from the date when the contract is signed.

4.12 Subdividing and scaling of contracts

In order to stabilize the average price of energy, within the respective contract portfolios, distributors should diversify the volumes and expiration periods of the contracts that compose them. For this purpose, each time that the distributor signs a long-term contract, such contract should not exceed 25% of the energy demand supplied by the distributor.

4.13 Submission and opening of bids

Bids should be submitted in a sealed envelope on the date, in the place and at the time stated in the bidding documents. The bid opening ceremony will be public and take place on the date, in the place and at the time so specified in the bidding documents.

4.14 Validity and guarantee of bids

Bids should be valid for at least 65 working days from the date of bid opening. The bidding documents will require the submission of a guarantee to hold the bid, for an amount to be stated in said bidding documents, and which should be valid for 20 working days in addition to the bids' period of validity.

4.15 Evaluation and awarding of bids

The evaluation of each offer in the bidding process will be conducted, considering only the base price bidded for energy. The distributor should prepare all possible combinations that make it possible to cover the total supply bidded, and the combination with the lowest cost according to the prices and indexing mechanisms offered should be selected. The period that the distributor will have to evaluate the bids and award the corresponding contract(s) may be no more than 20 working days from the date when bids are opened. The contract award should be approved by the SIGET and published. The signing of the corresponding contract(s) should take place within 15 working days following the date when the award is communicated.

4.16 Contract model

The bidding documents should include an annex to the contract model that contains: a) the identification of the parties; b) the contract's period of effectiveness; c) the commitment to supply power in the firm capacity control period, as well as the acceptance to deliver the energy commitment; d) the price formula and remuneration scheme; e) the form of payment; f) the supply points; g) the procedures for measuring and invoicing; h) the parties' commitment to accept the existing legal rules and regulations; i) the compensation that the supplier will pay in the case of a deficit in the committed energy; j) the guarantees to be required from the bidder; k) the guarantees to be shown by the distributor in the case of non-compliance in payments, provided that the SIGET approves the existence of such guarantees; l) the conditions for finalizing the contract; m) the procedure for making modifications and limitations, as well as their causes. In any case, these modifications should be approved by the SIGET before they are implemented, and may not refer to changes in the prices or in the conditions for delivering the supply; n) the individualization and specification of documents attached to the contract; o) the jurisdiction; p) the mechanism for conflict resolution or arbitration; and p) the grounds for force majeure or unforeseeable circumstances in accordance with common law.

4.17 Complementary aspects

All contracts awarded through the free competition procedures will be public and must be recorded by the contracting party in the Registry assigned to the SIGET. Contracts awarded through the free competition procedure may be fully or partially transferred to other operators by mutual agreement between the contracting parties. This transfer should be approved by the SIGET before it takes effect.

5. GUATEMALA

In Guatemala the aim is to promote the addition of new power generation through long-term contracts signed by distributors who provide Final Distribution Services with generators in charge of developing new generating plants.

For this purpose, distributors must conduct an open bidding process to contract the supply that guarantees their power and electricity requirements, for a maximum period of fifteen years. The bidding should be conducted at least five years prior to the start of the supply to be contracted, and the National Electricity Commission (Comisión Nacional de Energía Eléctrica [CNEE]), when necessary, may reduce this period. Taking into account the needs of distributors and the indicative Generating Expansion Plan prepared by the AMM, the CNEE prepares the terms of reference that the define the criteria to be met by distributors in order to prepare the documents for the open bidding process so that the processes of acquiring power and energy can be carried out. The bidding documents that the distributor prepares must be submitted to the CNEE for approval; the CNEE will decide on their merit or lack thereof within the following thirty calendar days. Once the bidding documents are approved, the distributor should issue an invitation for open bidding in a maximum period of ninety calendar days.

The deadline for the submission of bids should be no less than six months or more than twelve, and the contracting must be done within three months of the award date. The contract period should include two phases: the first as a construction phase, and the second as a commercial operation phase, which should not exceed a maximum period of fifteen years.

When, stemming from the contracts signed as a result of the biddings established in this article, there are power and energy surpluses, these may be marketed by contracting distributors in the Wholesale Market or in the Regional Market. The period of contracts stemming from Public Bidding Processes, conducted by distribution companies that provide Final Distribution Services, may not be extended for any reason.

6. PANAMA

Distribution Agents who operate in Panama must inform the CND in writing about the portion of their own generation that they propose to commit in order to cover the supply guarantee of their regulated customers and the corresponding period, and must also provide demand forecast data for the preparation of the Indicative Report on Demands. The period for committing one's own generation must cover at least the 12 months of the following year. The distributor must contract (is obliged to contract) the obligation to supply his regulated clients which is not covered by his own committed generation. The obligation to contract will be conducted in the Contract Market through processes of free competition, as stated in the Law and the rules and procedures that regulate the ASEP.

6.1 Bidding procedures

The bidding procedures typically approved by the ASEP include the following clauses: A. General Information (Call for Bids, Purchaser, Partial Bid, Prequalification, Bidders, Firm Power, Availability of Firm Power and/or Energy, B. Contents (Sections, Notifications and Consultations, Amendments), C. Bid Preparation (Cost, Language, Documents that form the bid, Forms, Alternative Bids, Prices, Currency, General Documents, Documents that support the power and/or energy capacity, Basic requirement for participation, Period of Validity, Bid Bond, Format and Signature), D. Submission and Opening of Bids (Timetable, Information Meeting, Submission, Deadline, Late Bids, Withdrawal and Modification, Opening of Bids), E. Evaluation of Bids (Confidentiality, Clarifications, Compliance, Differences and Errors, Preliminary Examination, Examination of Terms and Conditions, Preference for power generating technology, Evaluation, Comparison, Conflicts of Interest, Rights of Purchaser), F. Special Conditions (Power and Energy requested, Withdrawal and Delivery Points, Calculation of Associated Energy, Obligation of the Parties, Economic Evaluation, Price Indexing, Connection Points, Transmission and Distribution Costs, Specification of Measurement Equipment, Penalties), and G. Awarding of Contract (Criteria, Rights of the Purchaser, Notification of Award, Period, Signature and Performance Bond).

6.2 Typical content of contracts

The energy and power supply contracts signed by distributors in Panama typically contain the following General Conditions: Definitions, Contract Documents, Interpretation, Language, Association in Participation (Consortium or Association), Notifications and Notices, Applicable Law, Conflict Resolution, Contract Objective, Duration – Periods – Penalties, Contracted Firm Power – Required Associated Energy, Prices, Forms of Payment – Penalties, Payment of Transmission and Distribution Fees, Taxes and Duties, Performance Bond, Copyright, Non-confidentiality of Information, Patent and Licensing Rights, Limitation of Responsibility, Force Majeure or Unforeseeable Circumstances, Amendments, Termination, Assignment.

They also contain Special Conditions, consisting of: Purchaser, Required Associated Energy Formula, Guaranteed Firm Power (if applicable), Address for notifications, Modality of supply, Period of supply, Penalties for delay in date of the start of supply, Contracted power, Committed power generation units, Modality of power, Power delivery points, Energy delivery points, Price of firm power and adjustment formula, Price of required associated energy and adjustment formula, Penalty for deficits in power delivery, Penalty for deficits in energy delivery, Bank transfer data, Performance bond, Payment guarantee, Period of non-compliance of contracted power, Termination notice by the Purchaser, Period of non-compliance in payment, Termination note by the Seller.

Annex 5: Contracting in the wholesale electricity markets

1. COSTA RICA

Costa Rica does not have a wholesale electricity market.

2. HONDURAS

Does not have.

Honduras does not have a wholesale electricity market.

3. NICARAGUA

3.1 General characteristics

A contract establishes conditions and prices for the future purchase of energy and/or power. Two or more Consumer Agents may join together to aggregate demand and purchase through the same contract. The Consumer Agent who is the purchaser of a contract may agree to fully or partially transfer said contract to another agent. Each Production Agent may agree on: a) the purchase through energy and/or power contracts of machinery owned by another Production Agent; b) the sale of energy and/or power through internal contracts to a Consumer Agent; c) the sale of energy and/or power through export contracts to an External Agent. The transmission charges corresponding to each agent will be independent from their contracts. However, one of the parties may agree in a contract to take responsibility for part or all of the other party's transmission charges.

3.2 Types of contracts

In the Contract Market, two types of contracts are differentiated, depending on the parties involved: a) Supply Contracts, in which a Production Agent and one or more Consumer Agents agree on the purchase/sale of energy and/or power; b) Generation Contracts, in which agreement is reached between one Production Agent and another Production Agent, or between a Consumer Agent (purchaser) and a Production Agent (seller) on the purchase/sale of generated energy and available power.

3.3 Pre-existing contracts

A pre-existing contract is considered to be any contract in effect on the date of effectiveness of the present Operating Regulations. Pre-existing contracts must be registered in the INE and information on them must be provided to the CNDC. A pre-existing contract will only be authorized to belong to the Contract Market if it does not include clauses on the mandatory payment of minimum energy (take or pay) or any type of restriction that keeps it from being considered dispatchable. The CNDC must commercially administer any pre-existing contract that does not belong to the Contract Market as if the generation belonged to the purchaser. In this case, the resulting responsibilities and rights for this generation as a Production Agent correspond to the Market Agent who is the purchaser.

3.4 Requirements and restrictions

The following requirements and restrictions are applicable to all contracts: a) An internal contract may not establish a commitment for physical bilateral exchange that alters economic dispatch. b) The energy that each plant produces will be a result of dispatching, Quality and Safety Criteria and requirements in the real operation. c) Contracts must include a clause in which both parties state their acceptance of the economic outcome associated with the contract that stems from the rules defined in the Operating Regulations, as well as their acceptance of the CNDC's instructions stemming from compliance with the procedures defined in the Operating Regulations. d) Any Supply or Generation Contract or Generation in which the purchasing party consists of two or more Consumer Agents should identify, for each agent who purchases, the share corresponding to him in the total purchase of the contract.

3.5 Interaction with the Spot Market

In the administration of the Spot Market, the CNDC should respect contracts, implementing non-discriminatory treatment between internal contracts and import or export contracts. For internal contracts, the differences that arise for each agent, between contractual commitments and real operation will be administered by the CNDC in the Spot Market. In the Spot Market, the CNDC should administer the differences for a Contract, whether internal or import, in which the purchasing party consists of two or more Consumer Agents, allocating the energy and/or power resulting from such contracting between the purchasing Consumer Agents, according to their share as defined in the contract.

3.6 Backing of contracts

A Production Agent may sell power and energy through contracts, provided that he has sufficient generation to back them up, either with generating units that belong to him or generation that he contracts from another Production Agent. The maximum contractable power that a Production Agent may sell through Supply Contracts is calculated as the sum of: a) the Maximum Guaranteeable Power of the plants he owns, whose value is determined as stipulated in the Regulation; b) minus the total power sold to another Production Agent through Generation Contracts; c) plus the total power purchased from another Production Agent through Generation Contracts. The maximum contractable power that a Production Agent may sell through Generation Contracts is the sum of the Maximum Guaranteeable Power of the plants he owns minus the power committed in Supply Contracts. The energy that a Production Agent may sell through contracts is that associated with his maximum contractable power.

A Production Agent must have maximum contractable power that is more than or equal to that committed as sold power in his contracts, as stated in this Regulation. Thus, he should take the necessary measures with regard to keeping the units that he owns in service, and/or install new generating plants and units, and/or carry out Generation Contracts.

3.7 Supply contracts

The purchasing party of a Supply Contract must be one or more Consumer Agents, and the seller must be a Production Agent. A Supply Contract may establish: a) a commitment exclusively for the availability of power; b) a commitment exclusively for the delivery of energy; or c) a commitment for the availability of power and the delivery of energy.

A Supply Contract must contain an agreement and an identification of the delivery point(s), which may be one or more, and indicate the power and/or energy commitment in each of these points. The contract may differentiate periods during its period of effectiveness, such as season of the year, and/or type of day, and/or hour of the day, and establish different commitments and/or prices for each period.

The commitment for power availability and/or energy delivery may define quantities that vary throughout the contract period. If the contract establishes the purchase/sale of energy, it must identify the commitment as hourly blocks of energy for which the CNDC can conduct the administration of the parties in the Spot Market. This commitment may be expressed as a percentage of consumption, as fixed quantities, or any other modality that allows the CNDC to determine, hour by hour, the energy commitment associated with the contract.

Contracting energy allows both parties to stabilize or define the future price of energy, but it does not authorize imposing restrictions or obligations on dispatching or the physical operation of the system. The seller assumes a commitment to deliver energy but not an obligation to do so with his own generation, and thus the seller may fulfill his commitment with his own generation and/or purchases from other contracts and/or purchases in the Spot Market. The purchaser assumes a commitment to pay for the blocks of energy contracted and may sell surpluses in the Spot Market.

In a Supply Contract that includes the purchase/sale of power, the Production Agent/seller assumes the commitment of having the maximum contractable power that such contract authorizes, and of fulfilling the availability requirements agreed in the contract through the availability of his own generation and/or purchases of power in other contracts and/or purchases in the Spot Market. The purchaser agrees to pay for the available contracted power, regardless of whether or not he generates such power.

The Consumer Agent who is the purchaser of a Supply Contract with the purchase/sale of power acquires the right to use the power that he contracts, for his own requirements or to sell it in the Spot Market when he has surpluses with respect to the requirements of his demand.

The contracting of power and energy through a Supply Contract assigns supply priority for the purchaser insofar as the seller can fulfill the commitment with his own generation. In case of deficits in the supply that lead to forced rationing, the CNDC will administer each Supply Contract for energy and power as if a physical commitment were established between both parties and the purchaser will not find that the part of his supply that is covered by the contract is affected.

Each Supply Contract should define the delivery nodes. The seller assumes the associated transmission risks, if any, from his node of connection to the grid to each node of delivery under the contract, and the purchaser assumes the associated transmission risks, if any, from the node of delivery under the contract to his nodes of consumption.

3.8 Generation contracts

In a Generation Contract, a Production Agent may purchase power with associated energy from another Production Agent to sell it in the market and/or to back up the Supply Contracts in which he is the seller. In a Generation Contract, a Consumer Agent may purchase power with associated energy from another Production Agent for his own supply, and may sell surpluses, if any, in the Spot Market. The Generation Contract must establish the delivery node(s) and the contracted power in each. Said power commitment may vary throughout the contract period. Each Generation Contract should define the delivery nodes. The seller assumes the associated transmission risks, if any, from his node of connection to the grid to each delivery node under the contract.

3.9 Power for reliability

Each Consumer Agent must purchase power for reliability based on the requirement forecasted in the latest available Report on Demand Forecasts. A percentage of this power must be purchased in advance in the Contract Market as a Supply Guarantee Obligation.

3.10 Contract duration

Contracts will be classified by their long-, medium- and short-term durations. A long-term contract has a period of no less than 6 months. A medium-term contract has a period from 7 days to 6 months. A short-term contract has a period of less than 7 days.

3.11 Current contracts

The following table summarizes contracts in effect as of March 2009.

NICARAGUA: CONTRACTS IN EFFECT AS OF MARCH 2009

COMPRADOR	VENDEDOR	TIPO	INICIO	FIN	AÑO	ENERGÍA CONTRATADA	POTENCIA CONTRATADA	COMENTARIOS
DISSUR	GEOSA	GENERACIÓN	10/1/2000	1/31/2009	2000	28%	23.00 MW	PLAZO DE REGISTRO Y RECONOCIMIENTO POR PARTE DEL INE VENCIÓ EL 31 DE ENERO DEL 2009. INE EXTENDIÓ SU REGISTRO HASTA EL 28 DE FEBRERO DEL 2009
					2001			
					2002	22%		
					2003	20%	25.00 MW	
					2004			
					2005		30.00 MW	
					2006	17%		
					2007	11%	26.00 MW	
					2008	8%	22.00 MW	
					2009	25%	45.00 MW	
DISNORTE	GEOSA	GENERACIÓN	10/1/2000	1/31/2009	2000	28%	23.00 MW	PLAZO DE REGISTRO Y RECONOCIMIENTO POR PARTE DEL INE VENCIÓ EL 31 DE ENERO DEL 2009. INE EXTENDIÓ SU REGISTRO HASTA EL 28 DE FEBRERO DEL 2009
					2001			
					2002	22%		
					2003	20%	25.00 MW	
					2004			
					2005		30.00 MW	
					2006	17%		
					2007	11%	26.00 MW	
					2008	8%	22.00 MW	
					2009	25%	45.00 MW	
DISSUR	GEOSA	SUMINISTRO	10/1/2000	9/30/2005	2000	PUNTA: 20.00 MWh MADRUGADA 5.00 MWh RESTO 10.00 MWh	15.00 MW	
					2001			
					2002	PUNTA: 20.00 MWh MADRUGADA 10.00 MWh RESTO 20.00 MWh	15.00 MW	
					2003			
					2004			
					2005			
DISNORTE	GEOSA	SUMINISTRO	10/1/2000	9/30/2005	2000	PUNTA: 20.00 MWh MADRUGADA 5.00 MWh RESTO 10.00 MWh	15.00 MW	
					2001			
					2002	PUNTA: 20.00 MWh MADRUGADA 10.00 MWh RESTO 20.00 MWh	15.00 MW	
					2003			
					2004			
					2005			
DISSUR	GECSA	GENERACIÓN (PMGA 3, PHCh 1 y 2, PCG 1, 2 y 3)	10/1/2000	1/31/2009	2000	50.00%	19.10 MW	LAS NUEVAS UNIDADES INSTALADAS POR GECSA EN NICARAGUA SE AGREGARÁN A LA FÓRMULA DE ENERGÍA COMPROMETIDA DE ACUERDO A LO ESTABLECIDO EN EL CONTRATO. PLAZO DE REGISTRO Y RECONOCIMIENTO POR PARTE DEL INE VENCIÓ EL 31 DE ENERO DEL 2009
					2001			
					2002	40.00%		
					2003	35.00%		
					2004		17.19 MW	
					2005		15.28 MW	
					2006	30.00%	13.37 MW	
					2007	20.00%	11.46 MW	
					2008	15.00%	9.55 MW	
					2009			
DISNORTE	GECSA	GENERACIÓN (PMGA 3, PHCh 1 y 2, PCG 1, 2 y 3)	10/1/2000	1/31/2009	2000	50.00%	19.10 MW	LAS NUEVAS UNIDADES INSTALADAS POR GECSA EN NICARAGUA SE AGREGARÁN A LA FÓRMULA DE ENERGÍA COMPROMETIDA DE ACUERDO A LO ESTABLECIDO EN EL CONTRATO. PLAZO DE REGISTRO Y RECONOCIMIENTO POR PARTE DEL INE VENCIÓ EL 31 DE ENERO DEL 2009
					2001			
					2002	40.00%		
					2003	35.00%		
					2004		17.19 MW	
					2005		15.28 MW	
					2006	30.00%	13.37 MW	
					2007	20.00%	11.46 MW	
					2008	15.00%	9.55 MW	
					2009			
DISSUR	GECSA	SUMINISTRO 1 (PMGA 4 y 5, PLB 1 y 2)	10/1/2000	9/30/2005	2000	PUNTA: 7.50 MWh MADRUGADA 5.00 MWh RESTO 7.50 MWh	5.00 MW	
					2001			
					2002			
					2003			
					2004			
					2005			
DISNORTE	GECSA	SUMINISTRO 1 (PMGA 4 y 5, PLB 1 y 2)	10/1/2000	9/30/2005	2000	PUNTA: 7.50 MWh MADRUGADA 5.00 MWh RESTO 7.50 MWh	5.00 MW	
					2001			
					2002			
					2003			
					2004			
					2005			

4. EL SALVADOR

Each Supply Contract is characterized by a capacity to be contracted in the control period of the electricity system's firm capacity (period of maximum demand) and the associated energy to be supplied. The contract's associated energy will be equal, at each hour and at each supply node, to the amount resulting from applying to the average hourly demand measured at that hour and at that node, a percentage equal to that which represents the contracted capacity in relation to the integrated maximum annual demand of the distributor in the firm capacity control period.

For these purposes, the Transactions Unit (Unidad de Transacciones [UT]) will determine for each distributor the proportionate form factors which, multiplied by the contracted capacity indicated, determine the hourly energy associated with the respective contract. These form factors will be determined by the UT using historical background and may be based on consumption recorded during sample days and months. The form factors will be reviewed and updated by the UT once a year, taking into consideration the changes observed in the form of consumption.

The differences between the contracted energy and the energy actually consumed, will be settled in the MRS. Likewise, the difference between the distributor's total contracted capacity and the real maximum capacity demanded in the firm capacity control period will be acquired or sold by the distributor in the MRS. Thus, the distributor's capacity to pay in each contract will be equal to the capacity specified in such contract. Each supply alternative must be clearly specified in the bidding documents, with consideration given at least to: a) the specification of the capacity to be contracted in the firm capacity control period, stated in MW and in an integrated manner for all supply points; b) the specification of total maximum demand in the firm capacity control period, integrated for all supply points; c) for reference purposes, the specification of the annual energy to be contracted and its distribution throughout the year. For this purpose, the monthly and hourly form factors corresponding to the calendar year immediately preceding the year in which the bidding documents are issued will be specified and integrated for all supply points.

Participants may not offer the supply in a form that is different from the manner stated previously; in particular, they may not: i) offer amounts of power different from those specified in the supply alternatives stated in the bidding documents; ii) specify energy supplies that determine a different distribution of energy over time; and iii) condition the supply to the technical or production characteristics of generation units.

The contract's energy price and its indexing will be that obtained in the contract bidding for each energy supply point. The base price of power that governs the Supply Contract will correspond, at each supply point, to the capacity charge existing in the MRS at the time of the bidding by which the contract was made.

The volumes of energy corresponding to contracts in effect in 2009 are summarized below:

Energy Demand in the Contract Market, 2009 (GWh)

EMPRESA	Enero	Febrero	Marzo
AES CLESA & Cia S. en C. de C.V.	13.1	16.5	18.2
Administración Nacional de Acueductos y Alcantarillados (ANDA)	28.4	25.6	28.1
CAESS S.A. de C.V.	37.9	47.1	52
Cemento de El Salvador S.A. de C.V.	0.2	0.2	0.2
Comisión Ejecutiva Hidroeléctrica del Rio Lempa (COM)	0.3	0.3	0.3
DELSUR S.A. de C.V.	66.3	41.9	47.4
Deusem S.A. de C.V.	1	1.6	1.7
EDESAL S.A. DE C.V.			0.4
EEO S.A. de C.V.	5.1	7.9	8.7
Excelergy S.A. de C.V.	13.1	11	12.1
Mercados Electricos S.A. de C.V.	0.2	0.1	0.5

Source: UT

5. GUATEMALA

5.1 Contractual conditions

5.1.1 General aspects

For a contract to be recognized as an MM Futures Market contract, it should: a) identify the seller and purchaser of the contract; b) establish the restriction on maximum energy to be sold by contracts; c) establish the period of effectiveness; d) correspond to a type of Futures Market contract; e) ensure that the seller has Efficient Firm Demand that is not committed and is sufficient to cover the acquired power commitment; f) not include clauses on the mandatory minimum purchase of energy, understood as a generator's obligation to supply a contract with his own generation, independent of the economic dispatch (with the exception of contracts signed prior to the issuance of the General Electricity Law). The AMM may not accept contracts in which the generator's units must be dispatched based on criteria that are different from the scheduling of the operation conducted by the AMM; g) not include clauses that limit the parties' right to sell surpluses; h) establish an Option Price for the purchase of energy in the case of a contract with an Energy Purchase Option; i) the parties must complete all the information required in the contract sheet that the AMM makes available to MM Participants.

The Participating Producer—the seller—in a contract must have his own or contracted Efficient Firm Supply to cover Firm Demand; this supply must not be committed in other contracts or exports, and must be sufficient to cover the power committed in the contract.

Those Participating Producers who have not signed contracts with Participating Consumers for the full amount of their Efficient Firm Supply may sell the portion not committed in contracts to other Participating Producers who need to cover their firm power needs.

There are no restrictions regarding the duration of contracts, which may be freely defined between the parties. Contracts are considered to be agreed at a point called the Exchange Node in which the price is defined.

5.1.2 Maximum generation to be sold under contracts

The maximum generation to be sold under contracts reflects the production capacity of a Production Agent or a Marketer of generation with which he can back up his sales contracts in the Futures Market. In the case of a hydroelectric plant, the plant's firm energy and Efficient Firm Supply are applicable to each as the maximum power and energy subject to contracting. In the case of a thermal plant or machine, the Efficient Firm Supply of the plants and machines commercialized is considered. Consequently, each is eligible for the total efficient firm supply of the machine or plant as the maximum power subject to contracting.

A Generator or Marketer of generation may sell through contracts only the power that can be produced with the Efficient Firm Demand he has available (plus that which he has acquired through contracts minus his sales commitments) and consequently can back up. The maximum power subject to contracting is the result of the sum of the Efficient Firm Demand of his commercialized machines and/or plants plus that which he has contracted from other generators minus that which he has committed through contracts. The maximum energy subject to contracting in the Futures Market corresponding to a hydroelectric plant is limited by a value of its firm energy. It is calculated in accordance with the determination of each plant's Efficient Firm Supply. The monthly firm supply of each of the MM's hydroelectric generators is calculated as the sum of the firm energy of its commercialized hydroelectric plants. The generator may sign contracts provided he does not exceed this value.

5.1.3 Supply contracts

In supply contracts, except those corresponding to the modality of power without associated energy, Generator "k" commits the provision of energy to a Consumer Agent. To cover this energy, he may use:

a) his own generation (PPROPIAk), understood as the energy generated by his machinery (PGENk), the machinery ("kk") of other generators with whom he has signed Backup Contracts and who have been summoned by such contracts (PGENkk), and the energy imported through firm contracts by the generator (PGENimp);

$$PPROPIAk = PGENk + \Sigma_{kk} PGENkk + PGENimp$$

b) energy purchased in the Spot Market, if his own generation is insufficient due to dispatching or the lack of his own availability and/or that of his machinery contracted as a reserve.

A commitment to provide energy may be indicated, depending on the type of contract, in three different ways: a) an hourly curve, b) an amount of power to be supplied and an option price for the purchase of energy (when the Spot Market price exceeds the exercise price, the seller must supply the power with his own generation or with energy purchased in the Spot Market, and when the Spot Market price is lower than the exercise price, there is no energy provision stemming from the contract), and c) a commitment to meet the non-contracted demand of a Consumer Agent.

Generators must inform the AMM within the deadlines indicated in the signed supply contracts, indicating the necessary data for their commercial and operational coordination, including: the corresponding Consumer Agent; the period of effectiveness, the contract modality, the contracted demand to be met, power, and when necessary the load curve; the exchange node, when necessary, the exercise price, and supply prices and guarantees and possible adjustment formulas.

5.1.5 List of existing contracts

The following table summarizes the list of contracts existing in Guatemala's MM during 2008 (contracts with distributors, large-scale clients, and for export supply).

GUATEMALA: SUPPLY CONTRACTS IN 2008

INFORME DE TRANSACCIONES ECONÓMICAS 06-2009
VERSIÓN REVISADA
PERIODO DEL 1 AL 30 DE JUNIO DEL 2009
COSTOS DIFERENCIALES DE LOS CONTRATOS EXISTENTES

	Agente o Participante	Costo Diferencial Mensual		
		Abonos	Cargos	Resultado Neto
		US$	US$	US$
1	AGENCIAS J. I. COHEN	-	(501.58)	(501.58)
2	ALIMENTOS INDUSTRIALES SANTA LUCIA, S. A.	-	(660.95)	(660.95)
3	CARNES PROCESADAS, S. A.	-	(2,204.32)	(2,204.32)
4	CENTRAL COMERCIALIZADORA DE ENERGIA ELECTRICA, S.A.	-	(67,749.36)	(67,749.36)
5	COMERCIALIZADORA DE ELECTRICIDAD CENTROAMERICANA, S.A.	-	(46,984.97)	(46,984.97)
6	COMERCIALIZADORA ELECTRICA DE GUATEMALA, S. A.	-	(872,226.58)	(872,226.58)
7	COMERCIALIZADORA ELÉCTRICA DEL SUR, S. A.	-	(13,916.09)	(13,916.09)
8	COMERCIALIZADORA ELECTRONOVA S. A.	-	(279,494.45)	(279,494.45)
9	COMERCIALIZADORA GUATEMALTECA MAYORISTA DE ELECTRICIDAD, S. A.	-	(56,967.52)	(56,967.52)
10	COMPAÑIA BANANERA GUATEMALTECA INDEPENDIENTE, S. A. (FINCAS)	-	(3,637.34)	(3,637.34)
11	COMPAÑIA BANANERA GUATEMALTECA INDEPENDIENTE, S. A. (MUELLES)	-	(11,350.43)	(11,350.43)
12	CONTRATACIONES ELECTRICAS, S. A. (PC)	-	(28,859.86)	(28,859.86)
13	DISTRIBUIDORA DE ELECTRICIDAD DE OCCIDENTE, S. A. (CONSUMO TARIFA SOCIAL)	-	(440,737.08)	(440,737.08)
14	DISTRIBUIDORA DE ELECTRICIDAD DE OCCIDENTE, S.A. (CONSUMO TARIFA NO SOCIAL)	-	(497,577.86)	(497,577.86)
15	DISTRIBUIDORA DE ELECTRICIDAD DE ORIENTE, S. A. (CONSUMO TARIFA SOCIAL)	-	(286,212.70)	(286,212.70)
16	DISTRIBUIDORA DE ELECTRICIDAD DE ORIENTE, S.A. (CONSUMO TARIFA NO SOCIAL)	-	(446,983.73)	(446,983.73)
17	DUKE ENERGY INTERNATIONAL GUATEMALA Y CIA. S.C.A. (GRAN USUARIO)	-	(246.62)	(246.62)
18	ECONOENERGÍA, S. A.	-	(19,607.96)	(19,607.96)
19	EMPRESA DE GENERACION DE ENERGIA ELECTRICA DEL INDE (DEMANDA EEM)	-	(320,254.96)	(320,254.96)
20	EMPRESA DE COMERCIALIZACION DE ENERGIA ELECTRICA DEL INDE	-	(87,931.59)	(87,931.59)
21	EMPRESA ELECTRICA DE GUATEMALA, S. A. (CONSUMO TARIFA NO SOCIAL)	6,236,533.37	(1,705,562.15)	4,530,971.22
22	EMPRESA ELECTRICA DE GUATEMALA, S. A. (CONSUMO TARIFA SOCIAL)	-	(626,275.75)	(626,275.75)
23	EMPRESA MUNICIPAL RURAL DE ELECTRICIDAD DE PLAYA GRANDE	-	(3,115.07)	(3,115.07)
24	EMPRESA PORTUARIA NACIONAL SANTO TOMAS DE CASTILLA	-	(14,359.12)	(14,359.12)
25	EXCELERGY, S. A.	-	(102,804.96)	(102,804.96)
26	FRIGORIFICOS DE GUATEMALA, S. A. (F-48101)	-	(7,524.95)	(7,524.95)
27	FRIGORIFICOS DE GUATEMALA, S. A. (I-78014)	-	(13,286.35)	(13,286.35)
28	FRIGORIFICOS DE GUATEMALA, S. A. (J-38887)	-	(777.32)	(777.32)
29	FRIGORIFICOS DE GUATEMALA, S. A. (J-38718)	-	(308.67)	(308.67)
30	FRIGORIFICOS DE GUATEMALA, S. A. (J-38874)	-	(597.28)	(597.28)
31	FRIGORIFICOS DE GUATEMALA, S. A. (J-38894)	-	(436.18)	(436.18)
32	FRIGORIFICOS DE GUATEMALA, S. A. (J-38928)	-	(1,377.16)	(1,377.16)
33	FRIGORIFICOS DE GUATEMALA, S. A. (J-39010)	-	(327.94)	(327.94)
34	FRIGORIFICOS DE GUATEMALA, S. A. (J-39078)	-	(130.30)	(130.30)
35	FRIGORIFICOS DE GUATEMALA, S. A. (J-39182)	-	(2,150.51)	(2,150.51)
36	FRIGORIFICOS DE GUATEMALA, S. A. (K-22771)	-	(712.91)	(712.91)
37	FRIGORIFICOS DE GUATEMALA, S. A. (T-61028)	-	(400.99)	(400.99)
38	GALERIAS REFORMA, S. A.	-	(574.63)	(574.63)
39	GEOCONSA ENERGY, S.A.	-	(81,322.74)	(81,322.74)
40	GLOBAL CEMENT, S. A.	-	(16,596.30)	(16,596.30)
41	GUATEMALA DE MOLDEADOS, S. A.	-	(2,674.08)	(2,674.08)
42	INSTITUTO DE RECREACION DE LOS TRABAJADORES	-	(10,320.98)	(10,320.98)
43	INSTITUTO NACIONAL DE ELECTRIFICACION (EDIFICIO INDE)	-	(1,574.06)	(1,574.06)
44	INVERSIONES PELICANO, S. A.	-	(711.05)	(711.05)
45	MAYORISTAS DE ELECTRICIDAD, S.A.	-	(100,019.79)	(100,019.79)
46	OLEFINAS, S. A.	-	(14,389.81)	(14,389.81)
47	PASTEURIZADORA FOREMOST DAIRIES DE GUATEMALA, S. A.	-	(2,890.33)	(2,890.33)
48	PUMA ENERGY GUATEMALA, S. A.	-	(323.22)	(323.22)
49	RAFIAS Y EMPAQUES DEL ISTMO, S. A.	-	(3,696.15)	(3,696.15)
50	RECURSOS GEOTERMICOS, S.A.	-	(28,018.46)	(28,018.46)
51	ROGAZU, S. A.	-	(3,809.65)	(3,809.65)
52	TABLEROS DE FIBRA DE MADERA EL ALTO, S. A.	-	(3,891.41)	(3,891.41)
53	TEJIDOS CORPORATIVOS, S. A.	-	(2,346.82)	(2,346.82)
54	TELEFONICA INTERNATIONAL WHOLESALE SERVICES GUATEMALA, S. A.	-	(516.48)	(516.48)
	TOTALES	**6,236,533.37**	**(6,236,533.37)**	**0.00**

6. PANAMA

6.1 Contractual conditions

The energy and power contracts signed by distributors in Panama typically contain the General Conditions and Special Conditions summarized in Section 6.2 of Annex 4.

6.2 Compilation of existing contracts

The following is a summary of the power and energy supply contracts in effect in Panama's MME during 2008. Note that the largest amounts of power contracted at individual level were around 80 MW.

PANAMA: SUPPLY CONTRACTS IN EFFECT IN 2008

VENDEDOR	COMPRADOR	No. DE CONTRATO	INICIO	FIN	POTENCIA CONTRATADA (MW)
ACP	EDEMET	No. 12-06	01/01/2007	31/12/2008	20.00
ACP	EDEMET	No. 01-07	01/03/2007	31/12/2008	(***)
ACP	ELEKTRA	No. DME-001-07	01/03/2007	31/12/2008	(***)
AES	ELEKTRA	No.03-99	03/11//2003	11/02/2013	48.72
AES	ELEKTRA	No. DME-002-07	01/08/2007	31/12/2008	(***)
AES	ELEKTRA	No. DME-003-04	01/01/2006	31/12/2008	
			2006		20.00
			2007		40.00
			2008		60.00
AES	EDEMET	No.10-04	01/01/2005	31/12/2008	
			2005		1.00
			2006		20.00
			2007		66.00
			2008		66.00
AES	EDEMET	No.02-99	03/11//2003	11/02/2013	62.78
AES	EDEMET	No. 02-07	01/08/2007	31/12/2008	(***)
FORTUNA	EDEMET	No. 08-04	01/01/2005	31/12/2008	
			2005		0.00
			2006		73.00
			2007		79.00
			2008		77.00
FORTUNA	EDEMET	No. 14-04	01/01/2005	31/12/2008	
			2005		100 (ene. a jun.) jul 115 ago 119 sep-oct 112 nov 115 dic 112
			2006		110
			2007		35
			2008		74
FORTUNA	EDEMET	No. 13-06	01/01/2007	31/12/2009	
			2007		10 (ene -jun) 0.1 (jul) 5 (ago) 10 (sep - dic)
			2008		5.00
			2009		10.00
FORTUNA	EDEMET	No. 03-07	01/03/2007	31/12/2008	(***)
FORTUNA	EDECHI	No. 09-04	01/01/2005	31/12/2008	
			2005		10 (ene. a jun.) 0 (jul. a dic.)
			2006		77.00
			2007		71.00
			2008		73.00

VENDEDOR	COMPRADOR	No. DE CONTRATO	INICIO	FIN	POTENCIA CONTRATADA (MW)
FORTUNA	ELEKTRA	No. DME-019-06	01/01/2007	31/12/2009	
			2007		25 (ene - jun) 0 (jul) 10 (ago) 25 (sep -dic)
			2008		5.00
			2009		15.00
FORTUNA	ELEKTRA	No. DME-003-07	01/03/2007	31/12/2008	(""")
PEDREGAL	ELEKTRA	No. DME-004-05	01/01/2006	31/12/2008	30.00
PEDREGAL	ELEKTRA	No. DME-006-05	01/01/2006	31/12/2008	
			2006		12.00
			2007		5.00
			2008		15.00
PEDREGAL	ELEKTRA	No. DME-012-06	01/01/2007	31/12/2009	
			2007		10 (ene - abr) 1 (may - jul) 10 (ago - dic)
			2008		1
			2009		1
COPESA	EDEMET	No. 011-05	01/01/2006	31/12/2008	35.00
BLM	ELEKTRA	No. DME-004-07	01/03/2007	31/12/2008	(""")
BLM	ELEKTRA	No. DME-001-02	01/01/2005	31/12/2008	80.00
BLM	EDEMET	No. 21-06	01/01/2007	30/09/2008	82.50
BLM	EDEMET	No. 04-07	01/03/2007	31/12/2008	(""")
PAN-AM	ELEKTRA	No. DME-005-05	01/01/2006	31/12/2008	60.00
PAN-AM	ELEKTRA	No. DME-009-06	01/01/2007	31/12/2010	
			2007-2008		16.00
			2009-2010		45.00
INV. BALBOA	EDEMET	No. 09-07	04/08/2008	31/12/2008	22.03 ("""")
INV. BALBOA	EDECHI	No. 06-07	04/08/2008	31/12/2008	2.87 ("""")
INV. BALBOA	ELEKTRA	DME-006-07	01/08/2008	31/12/2008	16.6 ("""")
TERMICA CARIBE	EDEMET	No. 01-08	01/08/2008	31/12/2009	10.00

(""") Contratos de Energía
("""") Entran en vigencia durante el año 2008

Annex 6: Description of national regulations for international transactions

1. COSTA RICA

In the short and medium terms, it is expected that the international exchange transactions in these two countries will be conducted exclusively with the ICE as the sole national purchaser and seller of electricity and in accordance with the regulations agreed for the MER.

2. HONDURAS

The case of Honduras is similar to Costa Rica's. In this case, ENEE is in charge of the international marketing of electricity.

3. NICARAGUA

3.1 General aspects

The CNDC is responsible for conducting the operational and commercial coordination of international interconnections in Nicaragua with the System Operator and Market Operator (Operador del Sistema y Administrador del Mercado [OS&M]) responsible for the operational coordination and commercial administration of each international interconnection. The CNDC will conduct the coordination through the Regional Operating Agency (Ente Operador Regional [EOR]) and/or the OS&Ms in accordance with the rule agreed in this regard. For the commercial coordination of import and export operations as well as to make compatible the regulatory and time frame differences between Nicaragua's Wholesale Market and each Wholesale Market with which it is interconnected, an agreement must be reached on the coordination of International Transactions. This agreement should respect the criteria and procedures defined in the MEMN's rules.

3.2 Import and export contracts

Import and export contracts must establish a physical exchange commitment in one or more international interconnections. Because an import or export contract demands the fulfillment of requirements in both markets involved, to authorize it the CNDC will consider it as an authorization that is in process until the agent who is the local party under the contract presents proof of the authorization to the other market. Import and export contacts must fulfill the same requirements as those of internal contracts, as well as the requirements for this type of contract defined in the current legislation and rules in each country involved. All charges that arise in the market as a consequence of an import or export contract, including transmission charges, auxiliary services and losses, will be assigned as the payment responsibility of the Market Agent who is the local party under the contract.

The sharing of commercial information for the administration of import and export contracts in the market must be channeled by the local party under the contract.

Coordination in international interconnections will be conducted between the CNDC and the corresponding country's OS&M. The CNDC must assign the charges or credits that arise within the market as the result of an import or export contract to the local party of said contract.

An import contract will be administered as an obligation of the seller to inject the contractual commitment into the international interconnection. The purchaser may not cover it through purchases in Nicaragua's Spot Market. For the agent who is the local purchaser, differences will be administered in the Spot Market. An export contract will be administered as an obligation for the purchaser to withdraw the contractual commitment from the international interconnection, and in accordance with the dispatching, the local seller may be able to meet this commitment through purchases in the Spot Market.

3.3 International spot transactions

Bids for spot transactions with interconnected countries must be exchanged between the CNDC and the OS&M of each country, with the same periods and administrative procedures as Market Agents' offers for generation and flexible demand in the Spot Market. The CNDC must model the spot import as a generator located in the interconnection node with power and/or energy equal to the spot export offered. If the payment of charges associated with the import is applicable (for example, charges for the use of the transmission grid or a charge for losses), these must be added by the CNDC to the price offered in the international interconnection to obtain the price offered in the Spot Market. Optionally, the other country's OS&M may require it to offer directly in the Spot Market and include in the offered price the charges to be paid in Nicaragua's Wholesale Market. The CNDC must model the spot export like a Large-scale Consumer located in the interconnection node, with an amount of power and/or energy equal to the spot export offered or required. If the payment of charges for the export conducted is applicable, these must be added by the CND to the Spot Market price in order to obtain the price considered as offered in the interconnection node.

The CNDC may only mediate in the purchase and sale of electricity from third parties in spot import and export activities in the Spot Market. The CNDC must provide this service in a neutral, transparent manner, and this service must not result in a profit or loss for the CNDC, in accordance with the procedures defined in the Operating Regulations, in representation of: a) Spot Market purchases in the case of a spot import; b) Spot Market sellers in the case of a spot export.

The CNDC will seek to maintain the control and compensation of exchanges in international interconnections so that the net balance at the end of the month is zero. The CNDC must consider the discrepancies between the scheduled exchange in international interconnections, also known as inadvertent energy, as purchasing or selling, as the case may be, in the Spot Market, and will be remunerated at the price of energy in the Spot Market, minus discounts corresponding to charges to be paid, such as transmission tariffs and charges for losses. Until agreement is reached on a different treatment at regional level, the resulting amount will be assigned as a regulation under the Automatic Generation Control (AGC) at the cost of the auxiliary service of the spinning reserve.

4. EL SALVADOR

The UT is responsible for conducting the operational and commercial coordination of electricity imports and exports. The UT will consider the Regional Operating Agency (Ente Operador Regional [EOR]) to be the regional counterpart for coordinating electricity import and export transactions. For the coordination of import and export operations, the UT will use the Regional Electricity Market Regulation approved by the CRIE for such purposes.

4.1 General aspects

Operators and end-users may sign contracts whose objective is to provide energy and services with agencies located outside the country. Transactions conducted under such contracts must be subject to legal provisions and be coordinated through the agency responsible for dispatching in the country where said agencies are located. The dispatching costs incurred by the UT to conduct International Transactions will be covered by the national operators or end-users who participate in them, and will be based on the MRS prices in the respective node. Prior to the signing of international interconnection agreements, the SIGET's opinion must be heard.

Each PM who conducts an export in an international interconnection will be considered an end-user in the international interconnection node, and should provide the same information as that indicated for an end-user, considering the export requirement as a demand. Each PM who conducts an import in an international interconnection will be considered a generating plant that injects into the international interconnection node, and should provide the same information as that indicated for a Generator, considering the anticipated import as generation.

4.2 Import and export contracts

The UT will administer the bilateral transactions corresponding to import and export contracts, as stipulated in the regulation of the regional electricity market coordinated by the EOR. Each import or export contract must be reported to the UT as a bilateral transaction; this information will be provided to the UT by the national PM and confirmed by the foreign PM to the UT through the EOR. The information to be submitted, besides that required from all PMs, will include the following: a) the identification of the foreign PM; b) the identification of the national PM; c) type of operation (import or export); d) the notification that the bilateral transactions reported by said national PM are considered proper, with respect to energy for injection or withdrawal, as the case may be, in the international connection for the foreign PM, and the period of validity of said notification.

Each import contract will be considered as a generator located in the international interconnection node. The national PM must keep in mind that his transaction will be subject to the associated charges stemming from the importation, as stated in the sector's legislation. Each export contract will be considered as a withdrawal (end-user) located in the international interconnection node. The national PM must keep in mind that his transaction will be subject to the associated charges stemming from the exportation, as stated in the sector's legislation.

The UT is responsible for providing information on bilateral transactions and spot bids for import or export operations to the corresponding interconnected country's COP, in accordance with agreed protocols on data sharing. In the agreed protocols on data sharing, the UT will include the deadlines, means and formats for sharing the import and export information that the PM provides in each country. In particular, agreement should be reached on the procedure to be used to verify the compatibility of the information provided in each country with regard to the same import or export operation. The reported bilateral transactions will be valid in accordance with the same procedures as those corresponding to local participants.

All International Transactions will be subject to the same conditions as those of the national market, except when an international agreement between the relevant authorities specifies different or special conditions. Charges or credits that arise within the market as a result of bilateral international interconnections will be assigned to the national PM.

4.3 Spot imports and exports

Offers for spot transactions with interconnected countries will be shared by the UT and the operator in each country. Spot import and export offers must comply with the same deadlines and procedures and be administered with the same methodologies as the spot offers of national PMs.

Each spot import offered will be considered as a Generator located in the international interconnection node, without bilateral transactions, and with a spot offer of injection in the international interconnection node that corresponds to spot import offered. The remuneration of imports will be carried out by applying the same rules as those for national PMs, according to the prices offered, the block of power dispatched, and considering the charges associated with said imports.

Each spot export will be considered as a withdrawal (end-user) located in the international interconnection node, without bilateral transactions, and with a spot offer of consumption in said interconnection node equal to the required spot export. The bidder must keep in mind that, if the export is accepted, the UT will assign him the responsibility of paying the charges associated with said export operation.

The UT and each COP will share information on spot bids for importation and exportation. The UT will reach agreement with the COP of each interconnected country on the protocol for sharing such information, so that it is provided in a timely and proper manner. The charges and credits stemming from exports or imports to the MRS will be deducted or added to the amount resulting from the international sale or purchase. The net balance will be paid by the UT to the COP so that said agency can pay it as required in that country's transactions.

4.4 Interruptibility of international exchanges

El Salvador's regulation indicates that the UT will administer bilateral transactions corresponding to import and export contracts, as stated in the regulation of the regional electricity market coordinated by the EOR, which ensures the viability of carrying out long-term firm contracts, not interruptible by the UT in case of national market requirements.

5. GUATEMALA

5.1 General aspects

Electricity import and export transactions may be conducted between the MM Participants and MER Agents belonging to other countries, in accordance with existing legislation and regulations. To ensure the transparency of such transactions, it is necessary to establish minimum conditions of reciprocity and symmetry between the MM and the MER; these are: a) Generation market and Economic Dispatch of bids based on a Spot Market with free access by all MM Participants under conditions of competitiveness; b) open access to the remaining transport capacity; c) non-discriminatory conditions for MER requestors and bidders. Participants in the MM and the OS/OM of other countries with which the Guatemalan system is interconnected (i.e., Mexico) may conduct electricity import and export transactions, in accordance with existing legislation and regulations, taking into account the bilateral agreement approved for this purpose.

Long-term import and export transactions may be conducted through Firm Contracts, taking into account the gradual approach established in the AMM Regulation, as well as through short-term contracts by means of Non-Firm Contracts and spot energy transactions.

5.2 Agents

Importer. An importer is an MM Participant who conducts import activities in accordance with the following: a) a Distributor who imports electricity through Firm Contracts signed according to the bidding documents approved by the CNEE to supply end-users; b) a Generator who imports electricity to back up his sales contracts in the MM; c) a Marketer who imports electricity to market it in MM, d) a Large-scale Participating User who imports electricity for his own consumption through contracts.

Exporter. An exporter is an MM Generator or Marketer who conducts export activities in accordance with the following: a) a Generator or Marketer who conducts short-term export transactions, for which he must have an Efficient Firm Supply not committed in contracts, exports or in the provision of Complementary Services; b) a Generator or Marketer who conducts export transactions through Firm Contracts, for which he must have an Efficient Firm Supply to meet Firm Demand, not committed in contracts, exports, or in the provision of Complementary Services; c) a Distributor who conducts short-term export transactions when, stemming from signed contracts, he has energy and power services.

AMM. In addition, the AMM may export or import electricity in the case of deficit or emergency in the countries that are interconnected with the National Interconnected System (Sistema Nacional de Interconexción [SNI]), in accordance with the agreements that govern the MER or the agreements with other countries with which the SNI is interconnected.

5.3 Types of transactions

The following types of import and export transactions may be conducted: a) Short-term Transactions: import and export transactions conducted through Non-firm Contracts and spot energy transactions; b) Firm Transactions: long-term import and export transactions conducted through Firm Contracts.

5.3.1 Exports

An export transaction, either with the MER Spot Market, with the MER Futures Market, or with other countries to which the SNI is interconnected, does not signify a priority for the dispatching of the seller's power but rather an additional demand that is added to the MM to be covered by dispatching. A generating unit committed in an export contract participates in the MM's dispatching and only generates the amount dispatched by the AMM. An MM Generator or Marketer who exports should have Efficient Firm Supply and cover the energy supply requirements associated with said export with his own generation or with purchases in the MM Spot Market.

The exporter may not sell the power committed in export transactions within the MM, but may sell the spot energy that is dispatched and produced by such power when the contract does not convoke it and the exporter ends up with a surplus available for the MM.

5.3.2 Imports

Once considered within the dispatching program and confirmed by the EOR or by another country to which the SNI is interconnected, the import supply is treated as physical compliance in the corresponding node. If during real-time operations any of these supplies turns out to be outside the range of Economic Dispatch, because of the existence of more economical generation that has not been summoned, the import supply will be treated as forced generation, and will be remunerated at the Variable Cost of said supply in the corresponding node. If a short-term import is dispatched, the energy is assigned to the purchaser under the contract to meet his demand. However, because these are non-firm imports, the purchaser may not cover his Firm Demand requirements. If there is a surplus between imported energy and demand, the latter will be considered sold in the MM Spot Market.

In the case of International Transactions through Firm Contracts for which Efficient Firm Supply has been recognized to meet Firm Demand, it may be used by the contract's purchaser to meet his Firm Demand. The generation of short-term imports will not be subject to remuneration for Power Diversions.

6. PANAMA

6.1 General aspects

The MME's Commercial Regulations state that market agents may conduct energy purchase and sale operations with other countries through long-term contracts or through short-term operations. The Regulatory Agency and the National Dispatch Center must be informed about long-term contracts. Market Agents may conduct energy and power purchases in the Spot Market to meet their commitments. The National Dispatch Center will assign priority to supply the national market. Consequently, a Market Agent may export energy and power, provided that he has such energy and power available and these are not committed to other Market Agents and are not required by the National Dispatch Center to serve the national market.

The international market currently comprises the following energy transaction options:

- Spot export: a spot export operation, outside of contracts, that is conducted in the Spot Market.
- Non-firm export: an export operation that does not correspond to a long-term firm contract.
- Spot import: a spot import operation, outside of contracts, that is conducted in the Spot Market.
- Non-firm import: an import operation that does not correspond to a long-term firm contract.

Once the SIEPAC system is launched, the regulation of the international market should also include options for the importation and exportation of firm energy. One aspect to be coordinated and reconciled by the MME and the MER is the treatment of the concept of power as a product of tradable electricity.

In Panama, the CND has the responsibility of conducting the commercial coordination of import and export operations and must coordinate the physical and commercial operation with the EOR and the OS&M of each country, in accordance with the international rules and the procedures agreed on this matter. For the commercial coordination of these transactions, the CND must establish protocols for sharing commercial information and coordinating the operation with the EOR and the OS&M of each interconnected country.

6.2 Import and export contracts

Import and export contracts must comply with the requirements defined for the Contract Market, and will be administered according to the same procedures as those of national contracts, with the exception of the differences stated in the Commercial Regulations. For the authorization of an import or export contract, the CND should verify the following: a) It meets all requirements indicated in the Commercial Regulations. b) There is available capacity in the international interconnections in which the exchange will be conducted, taking into account the capacity already allocated to long-term contracts. The CND should detail the deadlines and procedure for the submission of information on import and export contracts, for its authorization, the monitoring of free capacity in international interconnections and for the administration and notification of interruptions or reductions in an exchange committed in an authorized import or export contract. The sharing of commercial information for the administration of import and export contracts must be channeled among the CND, the EOR and the OS&M of the corresponding country.

The CND must assign the charges or credits that arise as a result of an import contract within the Panamanian market, whether the Spot Market or power compensations (for power importation contracts) or losses or service for the use of the transmission grid, to the National Participant who is the purchaser. For an export contract, these must be assigned to the National Participant who is the seller.

a. Long-term contracts

An import or export contract will be considered long term if it meets the following requirements: a) information has been reported to the Regulatory Agency and the CND at least thirty days prior to its start; and b) it has an established commitment for the amounts of energy to be delivered or received, or a firm power commitment for a period of no more than twelve months. The authorization for a long-term export contract requires the fulfillment of requisites concerning the safety of national market supply as defined in the present Commercial Regulations.

A short-term import or export contract will be considered a spot commitment. In the administration of capacity in international interconnections, the energy required by a long-term contract will have priority over the energy required by a short-term contract, taking into account that the former corresponds to a firm long-term commitment and the latter to a short-term spot commitment.

b. Import contracts

For the energy and/or power contracted, the company of another country that sells through an import contract must fulfill the procedures and deadlines defined for a National Producer, plus the special requirements defined for import contracts. The Commercial Regulations for producers are understood as including foreign companies with regard to the energy they inject or the power the commit in international interconnections. A Participant who submits an import contract with the purchase of power from another country should include in said contract's clauses the manner in which the CND can verify the availability of such power. This manner may include the participation of the other country's OS&M or of the EOR, when said agency is operational and has in place the means and regulations to perform these functions. The CND must not authorize a power importation contract if this requirement is not met and verified.

c. Export contracts

A National Participant may sell energy and/or power through export contracts, provided that: a) he has this energy and/or power available and it is not committed in other contracts or in the Long-term Reserve Service; b) he fulfills the requirements defined in the Commercial Regulations, and c) this energy and/or power is not required by the National Dispatch Center to supply the national market. For the energy and/or power contracted, the company of another country that purchases through an export contract must comply with procedures and deadlines defined for a Participating National Consumer. The Commercial Regulations that apply to a Participating Consumer are understood as including foreign companies that take energy and/or power in international interconnections.

To fulfill the requirement of priority for supplying the national market, the Participating Producer, i.e., the seller of a long-term export contract, must submit to the CND a Study of Long-term Supply Security in order to demonstrate that the long-term contract will not affect the security of long-term supply to the national market. Using a methodology, the CND will establish the details on the procedures, data and format of the Study of Long-term Supply Security.

To meet the requirement of priority for supplying the national market, the CND should administer short-term export contracts according to the interruptibility criteria stipulated in the Commercial Regulations. The energy or power required by the CND to supply the national market is understood as that required: a) in an authorized long-term contract, for the conditions envisaged in the Study of Long-Term Supply Security, according to the criteria stipulated in the present Commercial Regulations; and b) in a short-term contract, for the conditions envisaged under the advance notification deadlines indicated in the criteria for the administration of the interruptibility of export contracts.

6.3 Spot imports and exports

Offers and requirements for spot transactions with interconnected countries must be exchanged between the CND and the EOR, and correspond to spot exchanges. Spot imports and exports are understood as those that take place between the Spot Market of the Republic of Panama and the Spot Market of another country, or if this type of market does not exist in the other country, the economic dispatch of the other country’s electricity system.

The CND must model the spot import as a generator with a GGC located in the interconnection node with an amount of power and/or energy equal to the spot import offered, and the spot export as a Large-scale Client who purchases in the Wholesale Market located in the interconnection node, with an amount of power and/or energy equal to the required spot export.

The CND must calculate the charges or credits that arise as the result of importation in the Spot Market and deduct or add them to the amount resulting from the sale of imported energy in the Spot Market. The CND must pay the net balance to the EOR so that said agency can pay it accordingly in each country.

6.4 Interruptibility of international exchanges

The CND is authorized to interrupt an exchange in an international interconnection, even if it stems from a contract, if the system's security requires it, to avoid its total or partial collapse, as stipulated in Article 30 of Executive Decree No. 22 dated June 19, 1998. In the case of problems of quality or reliability, the safety of supply or economic dispatch requirements, the CND is authorized to interrupt a Spot Market exchange in an international interconnection, even if this exchange stems from a contract, if the quality of the system so requires in order to avoid its total or partial collapse.

The CND is authorized to interrupt an export in an international interconnection in case of a deficit in supply or for the operational reserve needed in accordance with current Quality and Safety Criteria, only if the exchanges do not correspond to authorized long-term export contracts.

In the case of economic dispatch requirements, the CND is authorized to interrupt international exchanges under short-term contracts, as follows: a) in the weekly scheduling, if it is a short-term contract with an advance notification of no less than one week or a spot import or export (with the Spot Market); b) in the daily predispatching, if it corresponds to a short-term contract with an advance notification of no less than three days; and c) in real-time operations and in the case of redispatching, if it corresponds to a short-term contract with an advance notification of no less than two days. Any spot import or export must first have been interrupted.

When the exportation in an international interconnection must be reduced but not completely interrupted, the CND should administer the interruptibility of exchanges in the international interconnection according to the following priority: a) first, reduce or interrupt the non-contract export, i.e., the spot import or export (in the Spot Market); b) next, as needed, interrupt or reduce exchanges through short-term contracts, in the given order of advance notification, i.e., first interrupting contracts about whose exchange the CND was informed with the least advance notification, followed by those with the most advance notification.

Annex 7: Chronology of regional power integration in Central America[60]

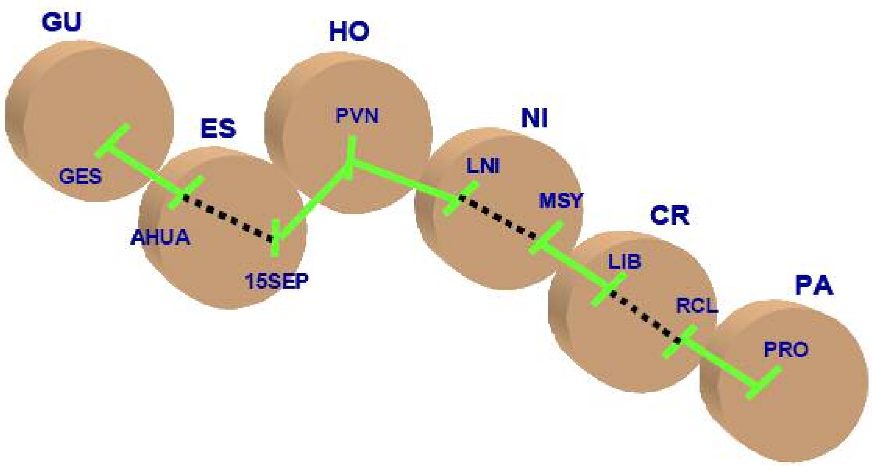
Year	Event
1976	First interconnection in the region built between Honduras and Nicaragua
1979	The governments and state utilities of the six countries agree to create the **Central American Electrification Council (CEAC)**.
1989	CEAC is formally established following ratification of its Constituent Agreement
1990	Costa Rica is the first country in the region to begin reform of its electricity sector. Establishes a single buyer model. Guatemala follows in 1991.
1993	**Protocol Treaty on Economic Integration of Central America** agreed to at summit of Central American Presidents
1996	Peace Accords signed in Guatemala ending the internal conflicts that began there in 1960. Conflicts had also ended in Nicaragua (1988) and El Salvador (1992).
	Guatemala implements a cost-based pool. All six countries have now reformed at least to the stage of introducing a single buyer.
	The six countries sign the **Marco Treaty of the Electrical Market of Central America**
	Technical studies support the construction of a 230kV regional transmission line
1997	IADB and the Government of Spain approve loans to the SIEPAC project
1998	**Marco Treaty ratified**
	Economic-Technical study of SIEPAC carried out
1999	**Marco treaty comes into effect**
	Regional transmission line company (EPR) incorporated
2000	**MER design approved** by six governments following two-year development process
	Regional electricity market regulator (CRIE) established
	Nicaragua launches its wholesale electricity market
2001	**Regional electricity system and market operator (EOR)** established
	IADB loan package reformulated to include concessionary loans to Honduras and Nicaragua
	Interconexión Eléctrica S.A. (ISA) of Colombia becomes eighth shareholder in EPR
	Plan Puebla-Panama (PPP) proposed by Mexico to support regional development and integration
2002	New tie-line between Guatemala and El Salvador completes interconnection of all six countries. However, transfer capacities remain limited

[60] From the report by Economic Consulting Associates (ECA): “Regional Power Sector Integration: SIEPAC Case Study”, July 2009.

Year	Event
	Transitional Regulations for the Regional Electricity Market (MER) finalised by CRIE and signed by the governments
	MER begins operation under transition code
2003	Environmental Impact Assessments for the SIEPAC line completed for each of the six countries
2004	A geological and geotechnical study and ground classification are carried out for the route
	Plan Puebla-Panama institutionalised
2005	Transitional MER regulations replaced by updated code approved by CRIE
	Central American Free Trade Agreement (CAFTA) signed into US law
2006	**Construction of the SIEPAC transmission line begins**
	Construction begins on the strengthened interconnection between Mexico and Guatemala
2008	Initially planned completion date for SIEPAC line missed. Completion now expected in 2010
	Plan Puebla-Panama changes its name to the Mesoamerican Integration and Development Project (**'The Mesoamerican Project'**)
	The state-owned Mexican utility, Comisión Federal de Electricidad (CFE), becomes the ninth shareholder
2009	La Corporación Andina de Fomento (CAF) signs a loan agreement with EPR

Annex 8: Transmission charges during the transition period (RTMER)

Transactions related to contracts pay a Transmission Charge composed by a Variable Transmission Charges (CVT´s) plus Operative Tolls associated to the contracted power interchanges through the RTR. This charge is calculated for each hour as the hourly contracted power interchange valued at the difference of the nodal prices in the injection and extraction nodes, considering the following transmission scheme.



A. Operative Tolls

The Operative Tolls are only applied to the international interconnection lines and are calculated by EOR according the historical use of such links. Next table summarizes current Operative Tolls.

OPERATIVE TOLLS

País	Peajes Operativos de la RTR (NS/SN)		
	De	Hasta	$/Mwh
Guatemala	MOY	FGUES	0.14
El Salvador	FGUES	AHUA	0.11
El Salvador	15SE	FESHO	0.59
Honduras	FESHO	PVN	0.30
Honduras	PRA	FHONI	0.06
Nicaragua	FHONI	LNI	0.21
Nicaragua	AMY	FNICR	0.11
Costa Rica	FNICR	LIB	0.28
Costa Rica	RCL	FCRPA	0.13
Panamá	FCRPA	PRO	0.00

Source: www.enteoperador.org/PeajesOperativos_RTR.jsp

B. Nodal prices

The hourly nodal prices are determined using the CVT´s estimated weekly by the EOR. Negative values of the CVT´s are considered zero. The nodal Price in node k (ρk) is defined as the incremental cost associated to a marginal demand supply increment in such node k, and are obtained through the following optimal dispatch process in the MER.

Maximize

∑ (Transaction Price I x Power Flow i) **-** ∑ Transmission Costs k(fk)

Subject to:

- Nodal balance equations
- Limits of the bids
- Transmission constraints

Were:

- Transaction Price i : bid Price i ($/MWh).
- Power Flow i: Power accepted from bid i (extraction, injection or transmission service)
- Transmission cost k(fk): transmission cost of link k, defined as the CVT curves for the national systems or the Operative Tolls for the international interconnections.

The application of this process is equivalent to an “optimal dispatch” (or transportation problem) of individual injection or ejection bids (associated to opportunity power interchanges) or “by pairs” (requirements of transportation services associated to contracts). With this formulation the determination of the prices for power transmission among the six CA countries is solved by an optimization problem of:

- 15 nodes (10 substations at 230 kV and 5 frontiers).

- 14 links (5x2 sections of international interconnections with marginal power losses and Operative Tolls and 4 national systems with CVT curves for El Salvador, Honduras, Nicaragua y Costa Rica).

Annex 9: Transmission charges (RMER)

The Regional Transmission Charges are the Variable Transmission Charge CVT (*Cargo Variable de Transmisión*), the Toll and the Complementary Charge. The CVT is paid implicitly in the Market of Regional Opportunity or explicitly in the Regional Contract Market. The Toll and the Complementary Charge conform the Charge for the regional transmission grid CURTR (*Cargo por Uso de la RTR*).

To calculate the CURTRs, the EOR will determine the revenues to be collected IR (*Ingresos a Recolectar*) for each installation in each semester in the following way:

IR = IAR/2 + (SCF-SCE) - CVTn – IVDT

Where:
SCF – SCE: Net of compensation accounts for each installation
CVTn: 6-month revenues associated to CVT´s less associated transmission payments
IVDT: 6-month revenues associated to sales of transmission rights (DT)

For the calculation of the CURTR and the CVT, the net flow of energy in an element of the RTR each national market will be obtained by means of the superposition of the flows caused by the global national transaction and of the flows caused by the global MER transaction.
The Tolls will be estimated from the IAR´s multiplied by the relation between the net flow in the element and its operational transmission capacity and taking into account the allocation of the responsibility of the regional Toll payment in each element of the RTR based on its use to the global transaction of each National Market and to the global transaction of the MER.
The Complementary Charges will be also estimated from the IAR´s multiplied by the difference of the operational transmission capacity less the net flow, divided between the operational transmission capacity and taking into account cost allocations determined for each element of the RTR (considering the methodology of dominant flow) based on the transactions in each National Market and the transactions in the MER.

Appendix 1: Electricity interconnections and power pools

Objectives of a power pool

1. The search for a more reliable and secure electricity supply has been the determining factor in the decision to build power system interconnections and to enter into inter-utility electricity exchange agreements among neighboring countries around the world. Development experience and operation of power pools in Europe and the United States indicate that the power pooling arrangements have, for the most part, evolved from simple interconnections between neighboring utilities to support each other in case of emergencies into more sophisticated formal legal entities with differing responsibilities in system operation and power market regulation.[61]

2. **Five main types of exchanges can take place between interconnected partners**: (i) firm energy sales (i.e. a continuous exchange of base load energy, which may include slight variations provided for in the contract, as well as interruptible power); (ii) backup exchanges for emergency support; (iii) marginal exchanges of spinning reserves; (iv) occasional exchanges, in which no guarantee of capacity is given; and (v) compensation exchanges made in kind.[62]

3. Once deployed, the operation of cross-border interconnection facilities opens up numerous opportunities for national power utilities to exchange a range of energy services that are germane to the delivery of reliable electricity supply at minimum cost, including the following: (a) lowering of generation capacity reserve requirements, (b) ability to achieve scale economies, (c) opportunity to interchange economic energy, (d) increased load and fuel diversity, (e) opportunities for sale of surplus firm energy, and (f) emergency support on major break downs.[63]

4. **The objectives of power pooling can differ between developed and developing countries**. In developed countries, where power systems cover almost the entire population, a recent objective of most power pools is to reduce capital and operating costs by capturing the benefits of competition in generation and in fuel supply, as well as to reduce costs, plan regionally, and enhance the reliability of service and security of supply. Under competition, generators typically have the option of entering their supply units into a competitive "pool" that establishes a dispatch merit order based on the bids they have

[61] ECA 2004
[62] Charpentier & Schenk 1995
[63] World Bank 2008

received. As for developing countries, the early strategic emphasis of the power pool's institutional design is on enhancing the region's power sector investment environment, rather than necessarily unleashing competition in those power markets from the start. With an appropriate and flexible institutional design at the outset, a regional power pool can gradually develop its governance, regulatory structures and technical rules as competition becomes more desirable and feasible.[64]

5. In a developing country context, as is the case of the Central America Regional Electricity Market (MER), the creation of a regional power pool by a group of smaller market economies can reduce the risks and help the pool match supply and demand more efficiently. The existence of a pool enhances a project developer's ability to finance and construct power generating facilities that are closer to available energy sources situated in smaller market economies, and utilizing cleaner and sustainable energy resources. A pool can make the development of a country's or sub-region's capital-intensive power projects more attractive to both domestic and international investors and lenders, reducing risks by creating a broader demand pool of utilities/off-takers for the production of proposed generating facilities.

Benefits of power pools

6. General benefits derived from power pooling include: (i) increasingly efficiency supply to meet the regional demand; (ii) increased opportunities for development of larger scale projects; (iii) enhanced competition; (iv) increased market liquidity; and (v) reduced power supply risks. The result would benefit all consumers in the region by lowering prices and improving power supply quality and safety and would eventually result in a reduced environmental impact due to power development.[65]

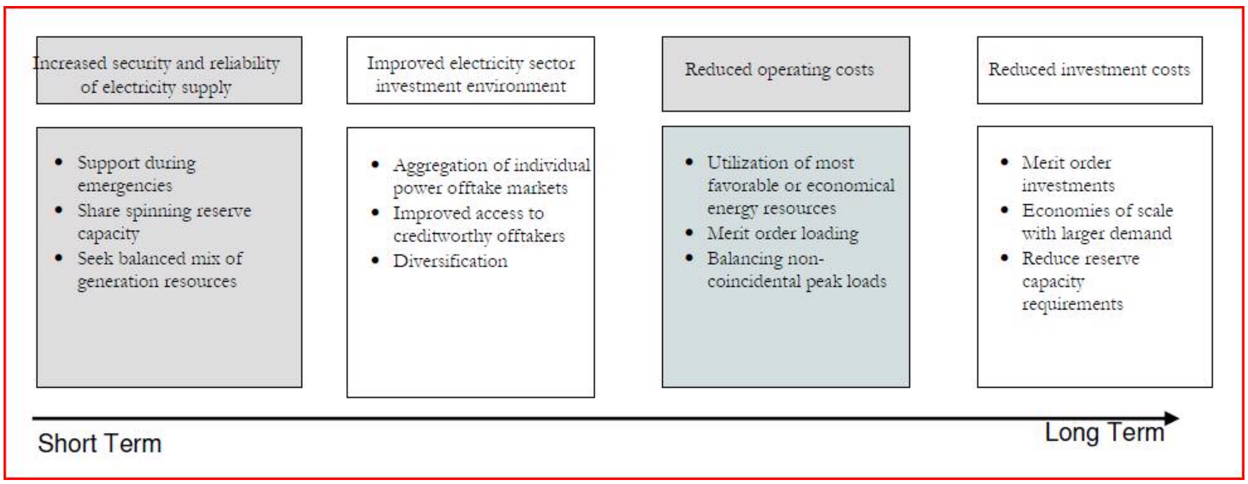
7. **Benefits of power pools would be gradually realized by the member countries as the regional market evolves (see Figure below).** In the short to medium term, the two main benefits of power pools are: (1) increased security and reliability of electricity supply through (1.i) providing mutual support during emergencies through short-term, non-firm power exchanges, (1.ii) sharing spinning reserve capacity on the interconnected system, and (1.iii) seeking a balanced generation mix involving hydro; and (2) improved electricity sector investment environment thanks to (2.i) aggregation of individual power off-take markets and improved access to multiple off-takers, which allows project developer to access multiple markets using more efficient technologies, (2.ii)

[64] USAID 2008
[65] ESMAP 2001

diversification of individual country risks, and (2.iii) improved creditworthiness of individual projects.[66]

8. In the medium to long term, the main benefits would be: (1) reduced operating costs from (1.i) using the most favorable or economic energy resources, particularly through the integration and coordination of hydropower and thermal systems, which reduces operating costs through increased hydropower generation in off-peak periods, (1.ii) merit order loading to obtain operational benefits in the case of central dispatching, and (1.iii) balancing non-coincidental peak loads; and (2) reduced investment costs in the long term through integrated planning on a multi-system basis (2.i) economies of scale, (2.ii) reduced total reserve requirements, (2.iii) reduced or postponed investments in new peak power capacity in thermal systems, and (2.iv) reduced investment in the hydro system due to the possibility of importing electricity from neighboring systems during a dry year.[67]

Figure: Core benefits of power pools



Source: USAID 2008

9. **Benefits derive from the multiplication of energy interchanges.** The benefits accruing from cross-border interconnection facilities, once built and put into operation, derive primarily from the multiplication of energy exchanges among national power utilities. In economic terms, such growth in cross-border energy exchanges should increase until the marginal benefits from displacing more expensive capacity and/or from additional sales equal the marginal cost of transmission across the interconnected

[66] USAID 2008
[67] USAID 2008

networks. The same applies to expansion of an interconnection, for which costs of new generation and transmission must be taken into account.[68]

Main requirements for the creation of a successful power pool

10. **Common and flexible legal regulatory framework**. A critical success factor in creating regional power pools is the extent to which governments and the operators of their respective national power grids are able to define a common legal and regulatory framework to facilitate achievement of regional objectives. Once consensus is achieved on putting place a common legal and regulatory framework, another critical success factor is to maintain flexibility in the setting up of a viable, multi-country, organizational structure to leverage the individual and collective capabilities of the system operators to (a) plan for and implement cross-border interconnection facilities, (b) harmonize the operational rules of practice for their interconnected national power grids, and (c) put in place a transparent, fair, and viable commercial framework for cross-border trading in energy services.[69]

11. **Harmonized commercial rules**. Regardless of whether cross-border trade takes place on the basis of cooperative or competitive frameworks, it is important for a clear, transparent, and harmonized set of "Commercial Rules of Practice" to be put in place and adhered to by the interconnected national power utilities, with the following aims: (a) set the commercial framework within which energy exchanges will be conducted, (b) agree on pricing principles, (c) oversee and settle transactions, (d) agree and enforce technical standards for metering, and (e) arbitrate between and among power utilities. Deployment of such commercial rules of practice also requires introduction of measures to enhance capabilities of the system operators.[70]

Types of power pools

12. **Power pools evolve over time**. Power pools worldwide have evolved over time from simple interconnections between neighboring utilities that support each other in emergencies to more sophisticated formal legal entities with differing responsibilities in system operation and power market regulation. In fact, many power pools have arrangements that are designed to evolve over time from pure bilateral agreements between neighboring countries to more competitive pools as integrated power systems develop.[71]

---

[68] World Bank 2008
[69] World Bank 2008
[70] World Bank 2008
[71] USAID 2008

13. An example of such evolution is Nord Pool[72]. Before the move to the international pool, the power sectors of Norway, Sweden, and Finland all had an oligopoly structure, with dominant state-owned enterprises that also controlled the national grids and with differences in structure, ownership and regulation. The smooth transition to the world's first international power market happened thanks in large part to the long tradition of cross-border bilateral trade and cooperation and the existence of cross-border transmission structures.[73]

14. The four main models of power pools could be regarded as four phases in a continuum: (i) interconnection of electricity systems, an arrangement in which participants must meet fairly simple requirements such as building an interconnection and define an arrangement by which they agree to support the neighboring country, region or utility during emergencies; (ii) loose pool, in which power exchanges which are defined contractually through bilateral power purchase agreements occur continuously, requiring coordinated dispatch between the countries, regions or utilities involved; (iii) tight pools, in which a centralized least-cost merit order dispatch takes the place of the coordinated dispatch, leading to a high level of complexity that requires substantial investment for IT systems and an advanced level of harmonization of regulatory frameworks; and (iv) new pools, in which dispatching is not based on costs, but rather on the bid price of each generator (i.e. on a competitive basis), which means "open access"[74] of the market, at least at the wholesale level.[75]

[72] The Nord Pool power pool began to develop in 1992 when a power exchange was established in Norway. When Sweden opened its electricity market, on January 1996, Nord Pool became the first international power exchange in the world.
[73] Carlson 1999
[74] One the most successful open access pools in operation today is right next to the Central America region, in Colombia. Colombia exchanges electricity on a daily auction basis with Venezuela and Ecuador. The Colombian regulator has implemented a scheme that does not interfere or distort considerably domestic prices and benefits nationals of both exchanging countries (i.e. importer and exporter) taking advantage of the complementary seasonal hydrological and weather conditions.
[75] ECA 2004

Appendix 2: SDDP model description and basis used for the CA market simulations

A. SDDP model summarized description

SDDP is a hydrothermal dispatch model with representation of the transmission network used for short, medium and long term operation studies. It uses the stochastic dual dynamic programming, developed by PSR, to estimate the future opportunity cost function of stored water in hydroelectric power plants. Because of this feature, it is not necessary to enumerate the combinations of reservoirs levels, which allows the determination of the stochastic optimal solution for systems with a large number of hydro plants, such as the Central American interconnected power systems.

The model calculates the least-cost stochastic operating policy of a hydrothermal system, taking into account the following aspects: a) operational details of hydro plants (water balance, limits on storage and turbined outflow, spillage, filtration etc.); b) detailed thermal plant modeling (unit commitment, "take or pay" fuel contracts, concave and convex efficiency curves, fuel consumption constraints, multiple fuels etc.); c) representation of spot markets and supply contracts; d) hydrological uncertainty: it is possible to use stochastic inflow models that represent the system hydrological characteristics (seasonality, time and space dependence, severe droughts etc.) and the effect of specific climatic phenomena such as the El Niño; e) detailed transmission network: Kirchhoff laws, limits on power flows in each circuit, losses, security constraints, export and import limits for electrical areas etc; f) load variation per load level and per bus, with monthly or weekly stages (medium or long term studies) or hourly levels (short term studies).

Besides the least-cost operating policy, the SDDP model calculates several economical indexes and operative results, among others: a) operative statistics: hydro and thermal generation, thermal operation costs, energy interchanges, fuel consumption, deficit risks and energy not supplied; b) short run marginal costs (spot prices) for each interconnected market; c) marginal capacity benefits (i.e. measure of the operational benefit of reinforcing the installed capacity of a thermal plant, the turbine limit of a hydro plant or the storage capacity of a reservoir). All detailed results of the SDDP model are written to *. csv format files. These files are managed by a graphic interface (the GRAF program) which produces Excel files with the desired results.

B. Main data used

Main data used in the simulations were obtained from XM Company included in "Documento de Supuestos para los Análisis Energéticos de Febrero 2009. Gerencia Centro Nacional de Despacho. Dirección Planeación de la Operación. Febrero 10 de 2009. XM. Colombia (www.xm.com.co)".

B.1 Demand forecasts

The next table summarizes the demand forecasts used in the simulations.

CENTRAL AMERICAN COUNTRIES: POWER DEMAND FORECASTS

	PANAMA		COSTA RICA		HONDURAS	
Año	TWh/año	%	TWh/año	%	TWh/año	%
2008	6.6951		9.5621		6.7467	
2009	7.3421	9.7	10.0430	5.0	7.1626	6.2
2010	7.7289	5.3	10.5559	5.1	7.5355	5.2
2011	8.2007	6.1	11.0828	5.0	7.9375	5.3
2012	8.6697	5.7	11.6357	5.0	8.3335	5.0
2013	9.1397	5.4	12.2186	5.0	8.7895	5.5
2014	9.6117	5.2	12.8345	5.0	9.2574	5.3
2015	10.0917	5.0	13.4843	5.1	9.7373	5.2
2016	10.6007	5.0	14.1762	5.1	10.2303	5.1
2017	11.1368	5.1	14.9091	5.2	10.7332	4.9
2018	11.6998	5.1	15.6819	5.2	11.2482	4.8
2019	12.2888	5.0	16.4998	5.2	11.7751	4.7
	NICARAGUA		EL SALVADOR		GUATEMALA	
Año	TWh/año	%	TWh/año	%	TWh/año	%
2008	3.1776		5.5991		8.3558	
2009	3.3496	5.4	5.8401	4.3	8.8978	6.5
2010	3.5226	5.2	6.0911	4.3	9.1926	3.3
2011	3.6795	4.5	6.3531	4.3	9.7496	6.1
2012	3.8435	4.5	6.6261	4.3	10.3116	5.8
2013	4.0165	4.5	6.9111	4.3	10.8786	5.5
2014	4.2014	4.6	7.2081	4.3	11.4505	5.3
2015	4.3974	4.7	7.5181	4.3	12.0125	4.9
2016	4.5964	4.5	7.8411	4.3	12.5795	4.7
2017	4.8104	4.7	8.1781	4.3	13.1686	4.7
2018	5.0403	4.8	8.5301	4.3	13.7796	4.6
2019	5.2753	4.7	8.8971	4.3	14.4146	4.6

Source: XM (ETESA, October, 2008. Mean scenario)

B.2 Generation expansion programs

Generation expansion programs used for each country are presented next.

CENTRAL AMERICAN COUNTRIES: GENERATION EXPANSION PROGRAMS

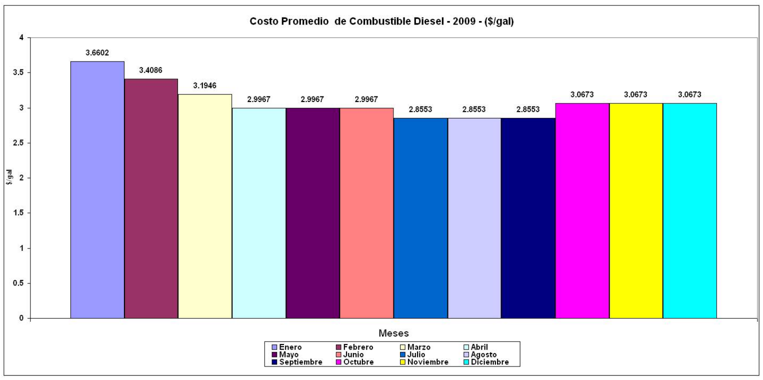
	PANAMA		COSTA RICA		NICARAGUA	
	PLANTA	MW	PLANTA	MW	NICARAGUA	MW
2009	Tcativa(Ene)	43.5	EolBOT(Ene)	25	E AMAYO(ene)	40
			Pocosol(ene)	26	ALBANISA4(mar)	80
	CC_tcol(Jun)	130	INGEN_BUN(Abr)	38	PMANAG_U3(Jul)	-43
			El_Encant(oct)	8	MMV 44 (ago)	44
			INGENIOS(Dic)	42		
2010	Blmcarbon(Ene)	120	EolBOT(Ene)	25		
	BLM123(Ret-Ene)	-120	Pirris(Ago)	128		
	Mendre(Ene)	20	MMV GARAB(Sep)	200	PTIZATE1(dic)	-10
	Bjo Mina(Ene)	52	ALQUILER(Sep)	-200	PTIZATE2 (dic)	33
					PTIZATE3(dic)	33
2011	Chan I (Abr)	213	GEO PAILA(May)	70		
		10			LARREYNAG (sep)	17
	Baitun(Abr)	86	Toro3(Ago)	50	PANTASMA(sep	17
	Gulaca(Nov)	26				
2012	Los Anile(Mar)	36	COLIMA(Ene)	-14		
	Chiriquí(Sep)	56	MOIN_MT(Ene)	-26		
	Pando(Sep)	32	EolProy1(Ene)	20	CB100(dic)	100
	Mon Lirio(Sep)	52	COL NEW(Ene)	30	PGEHOYOI(dic)	40
2013	El Alto(Ene)	60	EolProy1(ene)	30	BOBOKE(ene)	70
	Bonyic(Ene)	30	EolProy2(Ene)	100	PBRISA_U1	-24
			EolProy3(Ene)	100	PBRISA_U2	-38
			Bot-Proy(ene)	150	SALTO Y-Y(sep)	25
2014			Reventazo(ene)	300		
					TUMARIN(may)	160
2015	Tab II(ene)	35	S ANT NEW (Ene)	34	MMV100a(ene)	100
			S ANT(ene)	-34	MMV100b(ene)	100
2016	Sindigo(ene)	10	BARRANC(ene)	-36	VALENTIN(ene)	28
			BARR NEW(ene)	36		
			Diquís(ene)	622		
2017					CORRIE LI(ene)	40
					MMV100c(ene)	100
					MMV100d(ene)	100
2018	CB250a(ene)	250			PIED FINA	42
2019	B. Blanco(Ene)	20	CCLNG500a	500	EL CARMEN(ene)	60
2020					CCDS150a(ene)	150
					CB150(ene)	150
2021	CB250b(ene)	250				
2022			CCLNG500b	500		

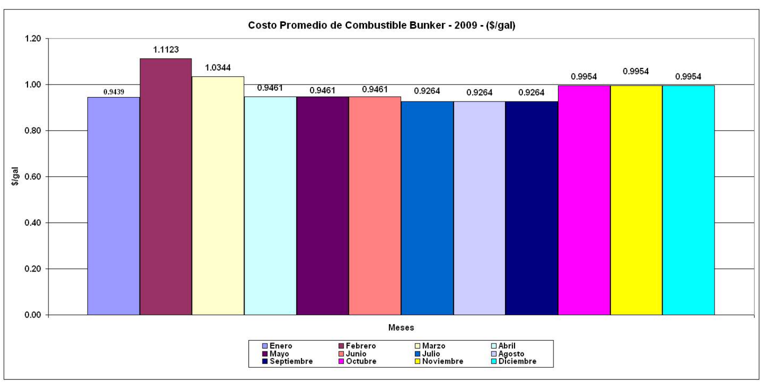
	HONDURAS		EL SALVADOR		GUATEMALA	
	PLANTA	MW	PLANTA	MW	PLANTA	MW
2009	Biomasa(ene)	93	TALNIQUE(may)	50	CALD3b-B(ene)	22
	Alsthom (mar)	27			CALD3c-B(ene)	11
	Sulzer(may)	30			GESSA-B (ene)	35
	Ceiba(sep)	-24				
	ENVAS MOT(oct)	33	TERMOPUER(nov)	75		
	CECSA MOT(oct)	50				
2010	Biomasa(ene)	11	SONSONATE(ene)	20	ESC2-V(ene)	-24
	Elcosa(jun)	-80	OZATLAN(ene)	50	ESC3_V(ene)	200
	Lufussa1(dic)	-40			DUKE-C(ene)	80
					TECUAMBU(ene)	44
					STAROSA-C(ene)	100
2011	CECSA(ene)	150	CHAPARRAL(ene)	66	XACBAL(ene)	94
	ENVASA(ene	100	05-Nov(ene)	64	RENACE(ene)	163
	Biomasa(ene)	100	AES F(ene)	250		
	CECSA MOT (oct)	-33				
	ENVAS MOT(oct)	-50				
2012	CB60(ene)	60	CERRON GD(ene)	86	CB275(ene)	275
	Alsthom(ene)	-27				
	Sulzer(ene)	-30				
2013			CUTUCO(ene)	525		
2014					SERCHIL(ene)	145
2015	Patuca2A(ene)	150	CIMARRON(ene)	261		
	Tornillit(ene)	160				
	Llanitos(ene)	98				
	Puert ENE(ene)	-10				
	Puert MEX(ene)	-16				
2016	Tablon(ene)	20				
	Jicatuyo(ene)	173				
2017					CB250a(ene)	250
	Lufu3-210(dic)	-210				
	CB100(dic)	100				
2018	Enersa(ene)	-15	MMV100a(ene)	100		
	MDMV 2(ene)	500				
2019	CB300a(ene)	300			CB500(ene)	500
	Emce2(abr)	-55				
	Lufussa2(may)	-77				
2020			MMV100b(ene)	100		
2021	Amp-ENERS(ene)	-15			CB250c(ene)	250
	Enersa(ene)	-200				
	CB200(ene)	200				

Source: XM (ETESA, October, 2008)

B.3 Fuel prices

Fuel Oil # 2 (Diesel) and Fuel Oil # 6 (Bunker) prices, main drivers of marginal costs and electricity prices in Central America, were updated according to forecasts done by CND (ETESA) in Panama for the last three quarters of 2009 (based on EIA short term forecasts). Those price levels (USD 2.97/Gal for Diesel and USD 0.97/Gal for Bunker C) were assumed to remain stable for 2010 – 2016. The next graphs illustrate the monthly fuel oil and diesel prices forecasts used by ETESA in the Panamanian market for 2009.





Source: "INFORME MENSUAL DE OPERACIONES". ETESA, CND. Marzo de 2009

C. Additional aspects

The simulations were done in two phases: a) the first phase consisted on an optimization phase which permitted to obtain the evaluation of the opportunity cost of stored water in each main reservoir used for hydroelectric generation, this was done individually for each electricity system in each country; and b) the second phase consisted in the simulation of the operation of the interconnected systems (minimum cost dispatch) subject to the previously determined hydrothermal optimal operative policies (governed by the opportunity cost of stored water) and considering energy economical interchanges among the different systems. Both phases were done on monthly basis and considering monthly demand representation in five blocks.

In the simulation, a variable transmission charge of USD 7.5/MWh was used in each one of the international interconnections. This was estimated based on USD 430 million of SIEPAC investment cost, 10% discount rate, 4% of investment as annual operation and maintenance cost, 290 MW as average available capacity in each international link and 55% load factor (implying a maximum of 8,200 GWh/year for international interchanges). Additional transmission revenues would be recovered through fixed transmission charges.

The interconnected systems operations were simulated under 100 monthly equally likely synthetically generated hydrological sequences, representative of the inflows used for hydropower generation, internally generated by the SDDP model (preserving the statistical parameters associated to the historical series) and results obtained were processed to obtain annual average values.

Sources

Carlsson, L. (1999). "International Power Trade - The Nordic Power Pool." Viewpoint **171**.
Charpentier, J. P. and S. K. (1995). "International Power Interconnections. Moving from electricity exchange to competitive trade." Viewpoint **42**.
Economic Commission for Africa (ECA) (2004). Assessment of Power-pooling Arrangements in Africa.
Economic Consulting Associates (2009). "Regional Power Sector Integration: SIEPAC Case Study".
ESMAP (2001). Regional Electricity Markets Interconnections - Phase I. Identification of Issues for the Development of Regional Power Markets in South America. Technical Paper.
USAID (2008). Sub-Saharan Africa's Power Pools: Development Framework. White Paper.
World Bank (2008). Building Regional Power Pools: A Toolkit.