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INSTITUTIONAL, REGULATORY AND COOPERATIVE FRAMEWORK MODEL FOR THE NILE BASIN POWER FORUM AND POWER TRADE

ANNEX 5: DELIVERABLE 5 – "ANALYSIS OF SPECIFIC REGIONAL MARKETS AND BEST PRACTISES IN PPAS"

Prepared for:

NILE BASIN INITIATIVE

" TO ACHIEVE SUSTAINABLE SOCIO-ECONOMIC DEVELOPMENT THROUGH THE EQUITABLE UTILIZATION OF, AND BENEFIT FROM, THE COMMON NILE BASIN WATER RESOURCES "

NILE BASIN INITIATIVE
Initiative du Bassin du Nil

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CONSULTANCY TO DEVELOP AN INSTITUTIONAL, REGULATORY AND COOPERATIVE FRAMEWORK MODEL FOR THE NILE BASIN POWER TRADE

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I LIST OF ACRONYMS

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AFC	Available Flowgate Capability
ARR	Auction Revenue Rights
BA	Balancing Authority
CAT	Curtailment Adjustment Tool (in SPP)
CEB	Communauté Electrique du Benin
CEM	Common Energy Market
CER	Certified Emission Reduction
CIE	Compagnie Ivoirienne d'Electricité
CIS	Commonwealth of Independent States
CoAG	Council of Australian Governments
CR	Congetion Rights (SIEPAC)
CRIE	Regional Regulatory Agency (SIEPAC)
CVT	Variable Transmission Charges (SIEPAC)
DAM	Day Ahead Market
ECOWAS	Economic Community of Western African States
EECI	Energie Electrique de la Côte d'Ivoire
EIS	Energy Imbalance Service
EOR	Independent system and market operator (SIEPAC)
EPC	Electricity Power Council (in CIS)
ESAA	Energy Supply Association of Australia
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission (US)
FTR	Financial Transmission Rights
GMS	Greater Mekong Sub Region
ICC	Information and Coordination Center (in WAPP)
ICE	Intercontinental Exchange (US)
ICT	Independent Coordinator of Transmission (SPP)
IDC	Interchange Distribution Calculator
IGA	Inter–Governmental Agreement on Power Trade in the Greater Mekong Sub–Region
IPP	Independent Power Producers/Project
IPSCIS	Interconnected Power System of Commonwealth of Independent States
JOA	Joint Operation Agreement
LIP	Locational Imbalance Prices (in SPP)
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LSE	Load Serving Entities
LTTR	Long Term Transmission Rights
MCE	Ministerial Council on Energy (Australia)
MER	Regional Electricity Market of SIEPAC
MISO	Mid-West Independent System Operator
MO	Market Operator
MOI	Memorandum Of interest
NBI	Nile Basin Initiative
NBPTF	Nile Basin Power Trade Framework
NE - ISO	New England Independent System Operator

NEM	National Electricity Market (Australia)
NEMMCO	National Electricity Market Management Company
NERC	National Electricity Reliability Council
NSI	Net Scheduled Interchange
OMVS	Organisation pour la Mise en Valeur du fleuve Sénégal
PAC	Participant Advisory Committee (Australia)
PJM	Regional Market of Pennsylvania, New Jersey and Maryland
PMU	Project Management Unit
PPA	Power Purchase Agreement
PRSG	Planned Reserve Sharing Group (in MISO)
PTC	Power Technical Committee
PTOA	Regional Power Trade Operating Agreement (in GMS)
RPM	Reliability Pricing Model in PJM
RPTCC	Regional Power Trade Coordination Committee (in GMS)
RPTP	Regional Power Trade Project
RRO	Regional Reliability Organization
RSC	Regional State Committee (in SPP)
RTEPP	Regional Transmission Expansion Planning Process in PJM
RTN	Regional Transmission Network (in GMS)
RTO	Regional Transmission Organization (US)
RTR	Regional Transmission Grid (SIEPAC)
SADC	Southern African Development Community
SADCC	Southern African Development Co-ordination Conference
SAP	Subsidiary Action Program
SAPP	Southern African Power Pool
SCED	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SERC	Southeastern Reliability Council (US)
SIEPAC	Central American Regional Electricity Market
SMD	Standard Market Design (NE-ISO)
SONABEL	Société Nationale Burkinabè d'Electricité
SPP	Southwest Power Pool
SRMC	Short Run Marginal Cost
STEM	Short Term Energy Market (in SAPP)
SVP	Shared Vision Program
TSO	Transmission System Operator
TUOS	Transmission Use of System
UES	Unified Energy System
UPS	Unified Power System (in CIS)
USSR	Union of Soviet Socialist Republics
VOLL	Value of Lost Load
VRA	Volta River Authority
WAPP	Western African Power Pool
WSPP	Western Systems Power Pool

Table 1: Acronyms

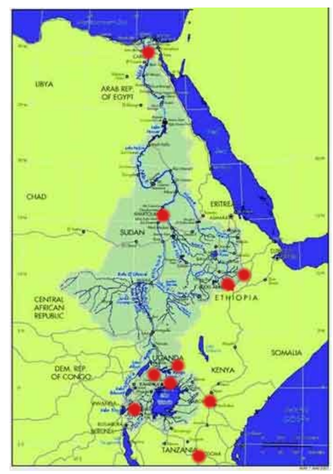
II FOREWORD

The purpose of this report, named "ANALYSIS OF SPECIFIC REGIONAL MARKETS AND BEST PRACTISES IN PPAS", is to present an in depth review of five regional power trade organisations and accepted best practises in PPAs according to international experience. The power trade organisations chosen are: Nord Pool, Great Mekong Sub Region, SIEPAC, SAPP and PJM.

This report is the Deliverable 5 and corresponds to Activity 5: "*Analysis of Specific Regional Markets and Best Practises in PPAs*" of the reviewed terms of reference of the project agreed during the inception mission in Dar es Salaam.

III BACKGROUND AND CONTEXT OF THIS PROJECT

The Nile Basin Initiative (NBI): Formally launched in February 1999 by the Council of Ministers of Water Affairs of the Nile Basin States, the NBI provides a forum for the countries of the Nile to move forward towards a cooperative process in order to reach tangible benefits in the Basin and build a solid foundation of trust and confidence.



The NBI has two primary areas:

1. Basin-wide projects - "Shared Vision Program" (SVP) to help create an enabling environment for action on the ground,

2. Sub-basin projects - "Subsidiary Action Program" (SAP) aimed at the delivery of actual development projects involving two or more countries.

The Regional Power Trade Project (RPTP) is one of the thematic projects to be implemented basin-wide, to help establish a foundation for trans-boundary regional cooperation and create an enabling environment conducive for investment and action on the ground, within an agreed basin-wide framework.

The RPTP aims to establish the institutional means to coordinate the development of regional power markets (such as a Power Pool) among the Nile Basin countries, through the creation of a power trade framework which can contribute to achieve poverty reduction including expanding access to reliable and low-cost power supply, in an environmentally sustainable manner.

The broad benefits envisaged from the NBI are poverty alleviation through improved, sustainable management and development of the shared Nile waters, and enhanced regional stability through increased cooperation and integration among the Nile states.

The project activities are coordinated by the Project Management Unit (PMU) at the regional level and by the PTC members at the country level. Activities include the establishment and operation of a power trade framework, the conduct of a comprehensive basin-wide analysis of long-term power supply, demand and trade opportunities, the identification of potential development projects within the NBI SAPs, the preparation of a public participation plan and stakeholder analysis, and the development of knowledge management tools. These activities are carried out through studies, consultations, workshops, seminars, and through other modalities, for which the project may seek assistance from national and regional research and training institutions, NGOs, consultants, and other public or private organizations from the Nile basin region.

The current project: “CONSULTANCY TO DEVELOP AN INSTITUTIONAL, REGULATORY AND COOPERATIVE FRAMEWORK MODEL FOR THE NILE BASIN POWER TRADE” falls within the RPTP framework. Among key project objectives are to:

1. Assist the RPTP and the NBI Power Technical Committee (PTC) in reviewing institutional arrangements adopted by regional power trade organisations, and submitting discussion papers to the RPTP, comparing and contrasting the different arrangements.

2. Conduct an information gathering tour so as to collect basic information of the countries in the region which will permit in the future develop recommendations and perform an informed decision making process.

3. Propose a model for developing Regional Power Trade at the Nile sub–basin and basin levels.

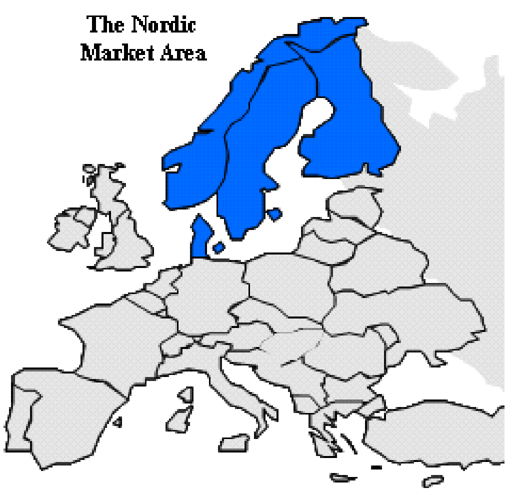
4. Draft Memoranda and legal documents as required.

IV NORD POOL

1. REGION COVERED BY THE INITIATIVE.

The following regional market is described in this document:

NORD POOL and the Nordic Area.



The Nordic market includes Finland, Sweden, Denmark and Norway. The total population of the area is 25 million.

The total annual generation is about 400 TWh, and the peak load is approximately 70.000 MW.

Figure 1: Nordic Area

2. BASIC CHARACTERIZATION OF THE REGION

2.1. *POPULATION, AREA, TOTAL CONSUMPTION, TOTAL GENERATION, AND GENERATION SPLIT*

Key information about the member states of NORDEL is presented in the next table:

Country	Population millions	Area in sq.km	Electric Consumption TWh	Electric Generation TWh
Norway	4.6	324,220	125.9 (2005)	137.9 (2005)
Finland	5.2	337,030	85.0 (2005)	67.9 (2005)
Denmark	5.4	43,094	35.7 (2005)	34.4 (2005)
Sweden	9.0	449,964	147.3 (2005)	154.7 (2005)

Table 2: Basic Data Nordic Area

In addition, Iceland is a member of NORDEL but no electrical links connects this country to other NORDEL members.

The remaining power generation in Denmark (19%) is from renewable sources, mostly wind. For all practical purposes the electrification level in the NORDEL is 100%.

2.2. AVAILABILITY OF NATURAL RESOURCES FOR GENERATION

The table below shows figures from the annual report of NORDEL, 2006 (www.nordel.org). Note that the totals include Iceland, which is a NORDEL member, but does not run its physical power trade on Nord Pool.

2006		Nordel area	Denmark	Finland	Norway	Sweden
Population	**(Mill)**	24.8	5.4	5.3	4,7	9.1
Consumption	**(TWh)**	405.4	36.4	90.1	122.6	146.4
Peak Load	**(GW)**	66.8	6.3	14.2	19.9	25.4
Generation	**(TWh)**	393.9	43.3	78.6	121.7	140.3
Hydro	**(%)**	51	0	14	98	44
Nuclear	**(%)**	22	0	28	0	46
Other Thermal	**(%)**	24	86	58	1	9
Wind power	**(%)**	3	13	0	1	1

Table 3: Power Sectors in Nordic Area

The hydro power potential in the Nordic had already been exhausted since many decades of the previous century. Relevant sources for generation now are gas and, in Finland, nuclear. It is expected that renewables will contribute to generation with an increasing share over the years to come, especially wind power.

2.3. OTHER GENERAL CHARACTERISTICS OF THE REGION THAT COULD BE RELEVANT FOR THE DESCRIPTION

- High trade activities both in contracts for dispatch and in derivatives based on the spot price as reference price.
- High demand side participation in both the bilateral and the spot market.
- Demand side bidding in the balancing markets and markets for capacity reserves.
- Full retail competition. Retail customers can have contracts where the price is a function of the spot price.
- The growing focus on the environment and the emissions, the trading of allowances and green certificates including CER (Certified Emission Reduction) certificates.
- Market coupling in Europe, forcing PXs to work together, having even mergers as a possible outcome.

- Trading of financial electricity contracts with reference from other electricity markets.

3. ROAD MAP FOR IMPLEMENTATION

3.1. THE BEGINNING OF THE REGIONAL INITIATIVE

The establishment of Nord pool and the Nordic power market was based on the following main objectives:

- The energy acts aimed at higher efficiency and better utilisation of the power resources. Introduction of competition and establishment of a power exchange with transparent price determination were considered as the tools required for meeting the objectives.
- The national TSOs were a result of the large national, vertically integrated electricity companies' unbundling.
- Integration into a Nordic market was carried out in order to achieve higher output from the total Nordic power resources, as well as a more appropriate market concentration without splitting large national generation companies.

Nord Pool was established first as a national Norwegian day-ahead market following the opening of the market in 1992. Later in 1996, 50% of the company was sold to the Swedish TSO, so Nord Pool could also serve as a day-ahead market for the Swedish national market. By 2000, all Nordic countries were integrated in one common power market.

Confidence in price determination is one of the most crucial elements in a competitive market. For both Norway, and later Sweden, and the other Nordic countries it was seen as **very urgent to get such a price formation/determination initialized.** This was the dominating driving force behind the development of the first international power exchange. The need for base load forward contracts, where positions in a power portfolio could easily be changed, led to the establishment of the Nord Pool forward financial contracts trade. Today this covers 5 years ahead of the current year.

3.2. WHO WAS INVOLVED AT THE BEGINNING?

The restructuring process started first in Norway. A national spot market in Norway had been in operation since 1971. This market was open for generators only. In 1992 this market opened to all customers. From the very beginning all major Norwegian generators were trading in the spot market.

Formulation of the overall rules and responsibilities in the Nordic market was carried out in committees and work groups with representatives from Nordic TSOs, generators and demand side participants.

Before the market opening in 1992, a close cooperation was already established among the large vertically integrated power companies in the Nordic Area, through the NORDEL organization. This was a solid foundation for further cooperation in the 1990s. However, the cooperation in NORDEL was reduced to a forum for the independent TSOs only, while the producers became competitors and focused on an efficient trading floor with transparency and liquidity at the forefront.

3.3. BASIS ON WHICH THE ORGANIZATION WAS ESTABLISHED

There are no specific intergovernmental agreements for the formation of a Scandinavian electricity market. The Nordic Council (http://www.norden.org/start/start.asp?lang=6) however, has been urging a closer cooperation in many fields in the Nordic Area (see link above).

There is a common code for grid operation between the TSOs, The Nordic Grid Code, which can be accessed at www.nordel.org.

In addition, the TSOs have entered into a business agreement concerning split ownership of the Nordic Power Exchange, Nord Pool ASA, www.nordpool.com, and also the Nordic Day Ahead spot Company, Nord Pool Spot ASA, www.nordpoolspot.com.

Finally, there is also a general participant agreement between the exchange and its members in the market, as well as an agreement between the exchange and the TSOs regulating the market's day to day operation, deadlines, gate closures, procedures etc.

3.4. EVOLUTION:

3.4.1. NEWCOMERS

Newcomers in the market are:

- Independent suppliers of the retail market,
- Increased participation by electricity intensive industry,
- Providers of market analysis services,
- Trade representatives and brokers,
- OTC market places.

3.4.2. RELEVANT MODIFICATIONS TO THE INITIAL SITUATION

The regulatory frameworks in the Nordic countries involve overall rules and principles only. Details are left to the companies to be determined, in communication with their respective customers.

The power exchange therefore, communicates with market participants from both the supply and demand side, in a market council. Similarly, the TSOs communicate in user groups with grid owners, generators and industry connected to the TSOs' network.

Changes in the details of the legal agreements and the incorporated rules that regulate market and grid operations and financial settlements in spot and in the balancing mechanism have been rather frequent. These changes are made efficiently, in communication with the market through the bodies mentioned above.

3.5. CURRENT SITUATION: MAIN ACHIEVEMENTS, MAIN CHALLENGES FACED TODAY

Nord Pool claims that liquidity is at the core. Today, after over 10 years of operating an international power exchange, the volume in the day-ahead market is over 70% of the electricity consumption in the Nordic area. This is a remarkable achievement, even in a global context.

The main challenge in the spot market is a further integration with the remaining European market.

Closer integration and harmonisation of real-time operation between the Nordic TSOs is also exigent.

Similarly, the volumes in electricity financial trade have reached acceptable levels for the short and medium term contract duration. The challenge remains for the long term contracts to reach acceptable volumes.

Also, it remains to be seen whether the market design provides sufficient incentives for long-term investments.

4. INSTITUTIONAL FRAMEWORK

4.1. INSTITUTIONS INVOLVED IN THE INITIATIVE

Prior to establishing the Nordic cooperation via NORDEL in 1963, each of the member countries had established their own electricity infrastructure and some cross border transmission lines were commissioned. Linked to NORDEL was also the Nordic Council which is a political institution promoting, both then and now, a more seamless and closer cooperation between the Nordic countries.

Of interest for the NBI should be the link between the political wing and the commercial and technological interests of the electricity industry in the Nordic area, and how this has promoted closer cooperation between these countries in many fields.

4.2. ROLES / OBJECTIVES OF THE INSTITUTIONS

The following is taken from NORD POOL SPOT AS: **www.nordpoolspot.com**

"Our objective/foundation

> The objectives of Nord Pool Spot AS is to organize, operate, and develop a market place for spot trade in electrical power in the Nordic countries, and also offer services in connection with this trade. The company can also own interests in other companies of the same or similar object or activities.

Our vision

- To be the leading power spot exchange in Europe. By *leading* we mean that we have:
  - Highest market share amongst non-mandatory exchanges
  - Best value-for-money fee structure
  - Best-in-class price calculations systems
  - Best-in-class customer services including product mix and information flow

Our mission

We add value to our customers by providing price transparency and quoting reliable prices

Our goals

- Provide price transparency at the Nordic power market
- Optimise the utilisation of grid capacities with the purpose to minimise price difference between price areas
- Promote a European spot market co-ordination center for market coupling purposes
- Quote reliable day-ahead and intra-day market prices which are the preferred price reference for forward energy contracts
- Offer a product mix adjusted to the requirement of the market
- Advise TSO's and energy authorities on development of the market
- Monitor the development of the growing interdependence between power and gas markets

"

4.3. COMMUNICATION AMONG THE INSTITUTIONS

Communication between the institutions is maintained in the following fora:

Nordel: The association of Nordic TSOs.

Market Council: A council established by power exchange with balanced representation of market participants from the demand and the supply side.

User Groups: Groups established by TSOs. The groups include representatives from companies connected to the networks of the respective TSOs.

Ownership of the power exchange by the TSOs maintains communication between TSOs and the power exchange.

The power exchange reports to the Norwegian regulator. The Nordic regulators meet to discuss common regional power market issues.

4.4. ORGANIZATIONAL CHART RESUMING THE RELATIONSHIP OF THE INSTITUTIONS

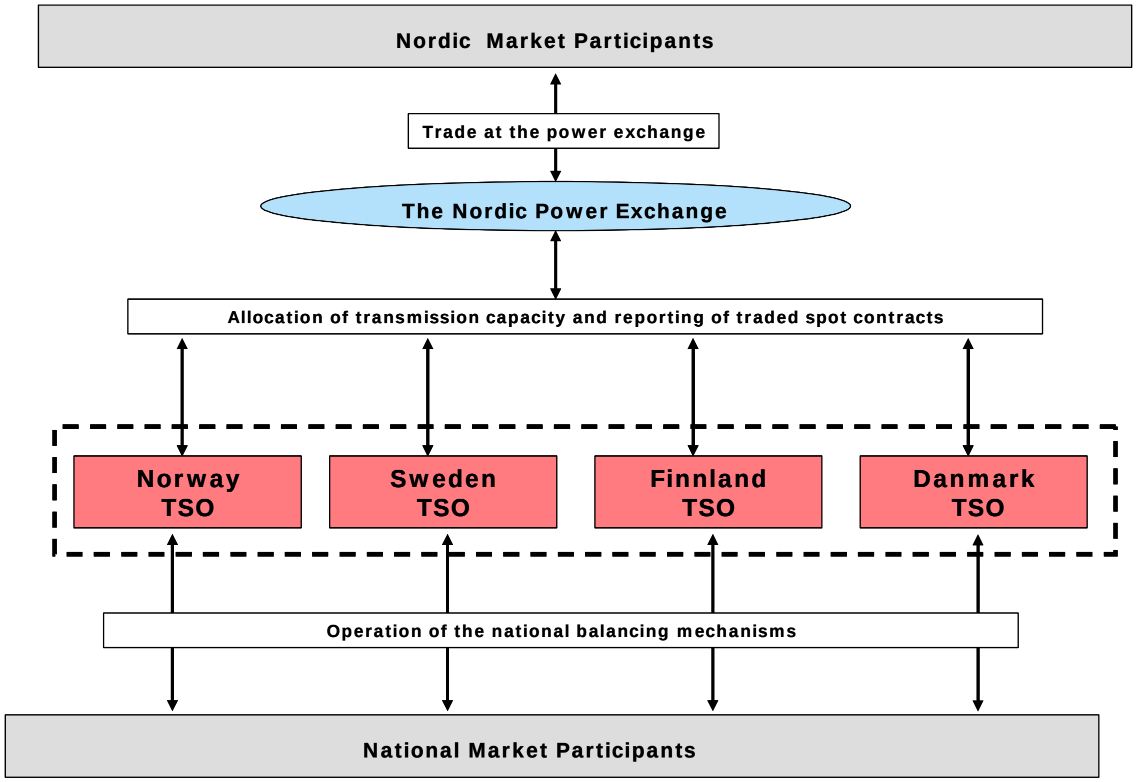


Figure 2: Organisation Chart of Stakeholders in Nordic Area

In the beginning the national TSOs operated the national balancing mechanisms towards their national participants with minimum integration. At present the cooperation has been further developed and is more integrated. The result is that the total system, in most cases, is now balanced by using only Norwegian and Swedish hydro power system recourses.

The TSOs cooperate in the decision for allocation of capacity to spot trade on interconnections. The power exchange applies this capacity in the trade system when zonal prices are calculated in case of congestion between the national zones.

The power exchange organises the trade in spot and report back to the respective TSOs on all trade schedules for dispatch.

The interface between the national TSOs is simple and well-defined. Harmonisation of procedures and methodologies between the countries involved is, therefore, reduced to the minimum.

4.5. GENERAL DESCRIPTION OF THE TRADING ARRANGEMENTS FOR THE REGION

In the Nordic area both bilateral and exchange trades have co-existed since the inception of the deregulated electricity market. This has facilitated an open competition between OTC and exchange trading, and resulted in a convergence of price levels, leading also to a standardization of types of contracts, the latter aiding in increasing market liquidity.

NORD POOL's approach has been to offer efficient and effective trading arrangements to the market participants.

This can be divided into 4 market areas:

- The physical day-ahead and intraday markets
- The financial market (forwards and futures)
- The balance (regulating power) market
- The ancillary service markets (reserves)

THE PHYSICAL DAY–AHEAD OR ELSPOT MARKET

On Elspot, hourly power contracts are traded daily for physical delivery in the next day's 24-hour period. The price calculation is based on the balance between bids and offers from all market participants – finding the intersection point between the market's supply and demand curves. This trading method is referred to as equilibrium point trading, auction trading, or simultaneous price setting. The price mechanism in Elspot adjusts the flow of power across the interconnectors – and also on certain connections within the Norwegian grid – to the available trading capacity given by the Nordic transmission system operators. Thus, Elspot is a common power market for the Nordic countries with an implicit capacity auction on the interconnectors between the bidding areas.

All participants who meet the requirements set by Nord Pool Spot are given access to the Elspot market. However, Elspot market participants must have a physical grid connection for power delivery or take-off in the area they want to trade in. Trading in Elspot requires signing a balance agreement with the TSO responsible in the Elspot area or areas with the physical grid connection.

Key features of the Nordic Elspot market concept:

- **Implicit auction**

  The Elspot concept is based on bids for purchase and sale of hourly contracts using three different bidding types: hourly bids, block bids and flexible hourly bids that cover some, or all of the 24 hours of the following day.

- **Grid congestion management**

  At the interconnections between the Nordic countries and within Norway, price mechanisms are used to relieve grid congestion (bottlenecks), by introducing different Elspot area prices. Within Sweden, Finland, and Denmark, grid congestion is managed by counter-trade purchases based on generators bids.

- **Area prices**

  The total geographic market is divided into bidding areas; these may become separate price areas if the contractual flow of power between bid areas exceeds the capacity allocated for Elspot contracts by the TSOs. When such grid congestion is developed, two or more area prices are created.

- **System price**

  The Elspot market's system price also denotes "the unconstrained market clearing price". This is because the system price is the price that balances sale and purchase in the exchange area, while not considering any transmission constraints. When there are actually no constraints between the bidding areas, area prices are all equal to system price.

The spot price of electricity reflects the marginal costs of production corresponding to the demand to be met. The spot price varies during the day, and during the year depending on the marginal unit cost being run on hydro, nuclear, coal or other resources. Nord Pool Spot's web site (www.nordpoolspot.com) shows current and historic prices.

THE INTRADAY MARKET – ELBAS

THE ELBAS MARKET PROVIDES CONTINUOUS POWER TRADING 24 HOURS A DAY, 7 DAYS A, WEEK COVERING INDIVIDUAL HOURS, UP TO ONE HOUR PRIOR TO DELIVERY. THE TRADED PRODUCTS ARE ONE-HOUR LONG POWER CONTRACTS.

The time span between the day's Elspot price-fixing and the actual delivery hour of the concluded contracts is quite long (36 hours at the most). As consumption and production situations change, a market player may be in a need of trading during these 36 hours.

The Elbas Market enables continuous trading with contracts, which leads to physical delivery for the hours that have been traded on the Elspot market and which are more than one hour from delivery. The Elbas market is open around the clock every day of the year.

The participants are power producers, distributors, industries and brokers. Today the Elbas market is open in Finland, Sweden and Eastern Denmark.

PRODUCT CHARACTERISTICS

The product characteristics of Elbas are quite simple. For each and every hour of the day one power hour contract is quoted. At 14:00 CET or when the deadline for filing complaints on the Elspot market is closed; the hour-contracts for the next day are opened for trade in the Elbas market areas Finland and Sweden. In Eastern Denmark the hour-contracts for the next day are opened at 17:00. The trade for a specific hour contract is closed one hour before its delivery.

THE BALANCING MARKET

Balancing Markets are operated by the TSOs. These markets are based on bids, including demand side bidding. Options for short term power reserves are traded in Norway.

Other services, such as compensation for reactive power, are based on negotiated agreements between TSOs and producers.

An inter-Nordic TSO agreement regulates the necessary co-operation between the TSOs.

THE FINANCIAL MARKETS

The financial market is a commercial centre where price securing contracts are traded.

In the following example, a retailer and a supplier have entered into a futures contract at a specific volume and a hedge price. The contract applies to one specific day, week, month, quarter or year. Since this is purely a financial contract, the power will have to be physically traded in the spot market before the retailer and the supplier settle the contract. Both parties involved in the contract have taken out a mutual insurance.

Supposing that the average system price for the period in question is higher than the hedging price, the wholesale market is obviously disadvantageous for the retailer. In this situation however, the supplier will compensate the retailer by paying him the difference between the average system price for the period in question and the hedging price multiplied by the volume.

Supposing now that the average system price for the period in question is lower than the system price, a low price on the wholesale market would obviously be disadvantageous for the supplier. In this case, the retailer will compensate the supplier by paying him the difference between the average system price for the period in question and the hedging price multiplied by the volume.

The contract is therefore settled by comparing the average system price for the specific period, with the hedge price in the contract. The difference in price is multiplied by the volume in the contract, and this amount of money is transferred among the parties. The retailer does not need to worry about the price. If it is higher than the system price, he will be compensated. On the contrary, if the price is lower than the system price, he will have to compensate the opposite party of the futures contract. A futures contract is therefore, not only a mutual insurance, but also a mutual obligation.

The two parties involved in the futures contract do not know each other's identity if the contract has been made via Nord Pool ASA's financial market. All settling of accounts takes place via Nord Pool Clearing. Furthermore, Nord Pool Clearing guarantees the settling of accounts by entering the contract if one of the parties cannot fulfil its obligations.

Funding of operational PX activities (for all markets): The PX incomes are based on fees: Fixed annual fee + volume fee per traded MWh. The fees are not related to the market prices of electricity or financial derivatives, only to the traded volumes.

4.6. MAIN REGULATIONS APPLIED

The overall rules in the national frameworks are very similar in the Nordic countries. They only include principles and, to a large extent, no details, while being in accordance with the European Community's directives. These directives are incorporated in all member states' legislation.

The set of operational agreements and the incorporated rules established by the TSOs and the power exchange in communication with the market are the same for all Nordic participants. There are no other special inter-Nordic market rules.

For system operations there is an inter-Nordic system operation agreement for the Nordic market. This is often referred to as the inter-Nordic grid code.

A collection of all the regulation for Nord Pool Spot as a regional power exchange can be viewed at www.nordpoolspot.com.

4.7. DISPUTE RESOLUTION

During the daily trade, market participants receive trade schedules for all 24 hours of the next day. The participants are given a short time to control the schedule and in case of mistakes they can complain to the power exchange. There are very few disputes and, if any, they are normally settled immediately.

If the dispute is not settled the first appeal is made to the regulator. The participant can forward the dispute further to the Ministry and, finally, it may end in the court.

4.8. SYSTEM EXPANSION PLANNING

The power exchange is not involved in any system planning. The TSOs, which are all state owned, are allocated the responsibility to maintain updated long term system expansion plans.

The plans shall be based on sceneries that include future changes in consumption, allocation plans for new generation capacities and required transmission capacity.

The TSOs maintain these plans in close communication with the respective regulators.

5. USE OF THE TRANSMISSION SYSTEM

5.1. PRINCIPLES FOR REMUNERATION OF THE TRANSMISSION SYSTEM

Main grid

In the Nordic area the main grid is divided into three different levels: the nationwide main grid (power supply "highways"), which transports electricity from one area of the country to another; regional grids (power supply "county roads"), which transport power from the main grid up to the local area's distribution grids; and the local distribution grids ("local roads"), which distribute the power over the last stretch to the consumers.

This arrangement allows a common pricing system for transmission services and provides all players with grid access on equal terms. The costs for leasing infrastructure have to be calculated in accordance with guidelines set by the regulatory authorities. Income derives from the charges paid by users for transmitting electricity via the grid.

In principle, costs and income should be balanced. If income exceeds costs, the surplus is deposited in accounts as a liability to main grid customers - and vice versa.

Point tariff system

The point tariff system is a type of "stamp system", where the producers pay a given price for the volume of power they contribute to the transport system. Correspondingly, the consumers pay a certain price for the volume of power they consume from the grid. The physical distance between the seller and the buyer who trade with each other in this area, is of no significance to the transport price.

This means for example, that a power company in Southern Norway can buy power from a producer in Northern Norway. Such a trade, of course, does not mean that the manufacture's power must be transported all the way from Northern to Southern Norway. The principle is simply that a producer somewhere must add a volume of power to the grid, corresponding to the volume consumed by the power company's customers.

Balance accounting

Whether the volume of the energy agreed between the producer and the power company is actually contributed or consumed, it is measured at the relevant points in the grid. The TSO's balance settlement compares the overall planned/agreed production from the individual producers and the overall consumption/withdrawal with the actual figures, and facilitates thus an open power market. The difference between the planned and actual consumption and production is calculated in regulating power bought and sold.

Transport price

The actual transport price is made up of several elements. Payment shall, in principle, be made in relation to the cost of one's use, and the payment is based on where (which point in the grid) one adds or consumes power, and how much.

The more the power added or consumed at one time, the more powerful the transport grid must be dimensioned. The lower the voltage level that the power is consumed at, the greater the number of step-down transformers that must be passed. The transport price varies somewhat geographically, as well: it is less expensive to bring power into the grid in areas with a high level of consumption, and it is less expensive to consume power in areas with a high level of production. This is because the physical transport of power is shorter, which means that less of the power grid's capacity is utilised. This is not related at all to where one buys the power from, or sells the power to, because power trading does not entail that the physical electrons move the same distance as the money.

5.2. MANAGEMENT OF CONGESTION

As a general observation, any infrastructure will be dimensioned in such a way that, from time to time, the service provided will not be matching the demand. This is evident from an economical point of view. Roads and streets may be congested at rush hours, flights sold out at peak holiday times and transmission lines for electricity might not be dimensioned to carry all the electricity demanded at certain times of peak loading.

Nord Pool has adopted for the Nordic area an implicit auction method to alleviate congested transmission lines, using a price mechanism only to regulate the flow of electricity within the transfer limits, set by the TSOs in the area.

In the day ahead market, prior to the day of operation the market's clearing price is calculated not considering any transmission capacity limits. This is the system price used as a reference for the financial market.

If at this price any of the major transmission links are congested, the price information contained in the day-ahead bids is used to find a price that limits the flow within the transfer limit.

Surplus power in one area will now flow (up to the set transfer limit) to neighbouring area(s).

This is illustrated at www.nordpoolspot.com with Nordic price areas. Due to a large surplus in Southern Norway (Aug 2007), the lines out of this area are congested, and as a result a very large price difference occurs between this surplus area and the rest of the Nordic region and Germany.

6. LESSONS LEARNT

- **Nord Pool** was at first established as a national power exchange in Norway. However, the objectives changed at an early stage towards developing a regional market for all the four interconnected Nordic countries. The model was appropriate for the formation of a regional Nordic market. The decentralised model reduced the need for harmonising the procedures and allowed the national markets to keep their own solutions in the balancing mechanisms, if required. The design has proved to be appropriate for establishing regional markets of independent states.

- Three of the TSOs involved in the market are fully owned by the state. All four TSOs have efficiently responded on political signals and, to a large extent, contributed to the successful development of the regional market.

- Nord Pool is a neutral and independent entity owned by the Nordic TSOs. Through the code of practice issued by the Norwegian Corporate Governance Board (UNES), Nord Pool is committed to clarify the roles between shareholders, Board of Directors and Executive Management. Nord Pool, as market operator, established a market council, while Statnett, as system operator, established user groups with balanced representation from generation and consumption. These councils and groups act as advisory bodies which address issues regarding market operation and the transmission and system operation. Ownership by neutral TSOs, the Code of Practice and the establishment of advisory bodies have all proved to ensure accountability, independency and efficient communication with market participants.

- The market concept is simple and easy to understand, and a low threshold with respect to costs which makes **a market entry very attractive for the consumer part of the demand side, too.**

- There is also **demand side** bidding in the real time markets and markets for short term reserve capacity within the Nordic area.

The generation companies signalled a preference for a decentralised market concept where generation planning and distribution of generation on units should be the companies' responsibility and not to be carried out by any centralised entity. Therefore, the wholesale market was designed with **self-dispatch** of spot contracts, and bilateral contracts and **centralised** dispatch in the real time markets based on bids from **generators**. These principles are considered to have contributed to a smooth stepwise development towards a regional market.

Initially, the driving force in the development of the market was NORDEL. NORDEL is a non-political association that has formed the cooperation within the Nordic power business based on rather wide frameworks from the respective Governments. When the restructuring process started to form a regional market, the procedures for operation of a competitive market were easy to implement with low level of political involvement.

There is large **demand side** participation both in the bilateral and the spot markets. Demand side participation here, means the participation where the end-users themselves procure the needed electricity in the market and respond on high prices by reduced purchase, if possible. The high demand side participation is mainly due to simplicity of the concept and low access costs to the spot market.

The presence of a noticeable and active **Market Surveillance** unit is assumed to have a considerable preventive impact against non-acceptable behaviour.

Traded volume for 2006 in the day-ahead market was 250 TWh, a market share of about 70% of the total consumption. The large market share indicates confidence in the price setting and in trading, in general. The large increase in volume in the last years is mainly due to changes in the use of spot market. Large companies operate with both their generation and sale units as independent business units towards the spot market. This indicates that the regional participants thrust the pricing mechanism at the spot market.

Market concentration within the total Nordic market is more appropriate than in several other regional and national markets. However, the transmission capacity is rather poor and the market may be considerably concentrated behind local congested areas. The regional market was formed to avoid market power being possessed by large national companies. However, in case of congestion the companies may have the same inappropriate market power as before restructuring.

The market was opened in a period with generation capacity surplus and rather high reservoir inflow. Wholesale prices dropped and investment in new capacity stopped. There is no capacity payment in the markets to stimulate investments in new generation capacity and there is no process initiated to implement such payment.

There have been periods of volatility in the day-ahead prices, which is always reflected in the forward market. High prices at some points have led to investments in additional generation, both gas power based in Norway and a new nuclear power project in Finland. This is truly a sign of a well functioning market when investments in new capacity are a result of a high price, in a market where supply can barely match demand. However, it is left to see whether the design is ensuring sufficient long term generation capacity.

Involvement of the regulator in market issues has been timely. In the wholesale market the Regulator has, to a large extent, limited regulation in practice for allocating responsibilities to key companies, such as a Power Exchange and a TSO. The commitment of these companies to establish procedures and a detailed methodology, in consultation with the market, have contributed towards reducing disputes and has ensured that **procedures and methods are accepted by the participants.**

The regulator has been more involved in metering and settlement, market information and procedures in the retail market. This involvement has to a large extent contributed to an **easy market access for small scale end-users and increased retail competition.**

V PJM

1. REGION COVERED BY THE INITIATIVE.

The regional solution described in this document is **PJM**.

PJM Interconnection is a regional transmission organization (RTO) operating the wholesale electricity market in all or parts of the states of Pennsylvania, New Jersey, Maryland, Delaware, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Tennessee, Virginia, West Virginia and the District of Columbia. The map below shows the PJM area among other RTOs and ISOs (from www.ferc.gov):

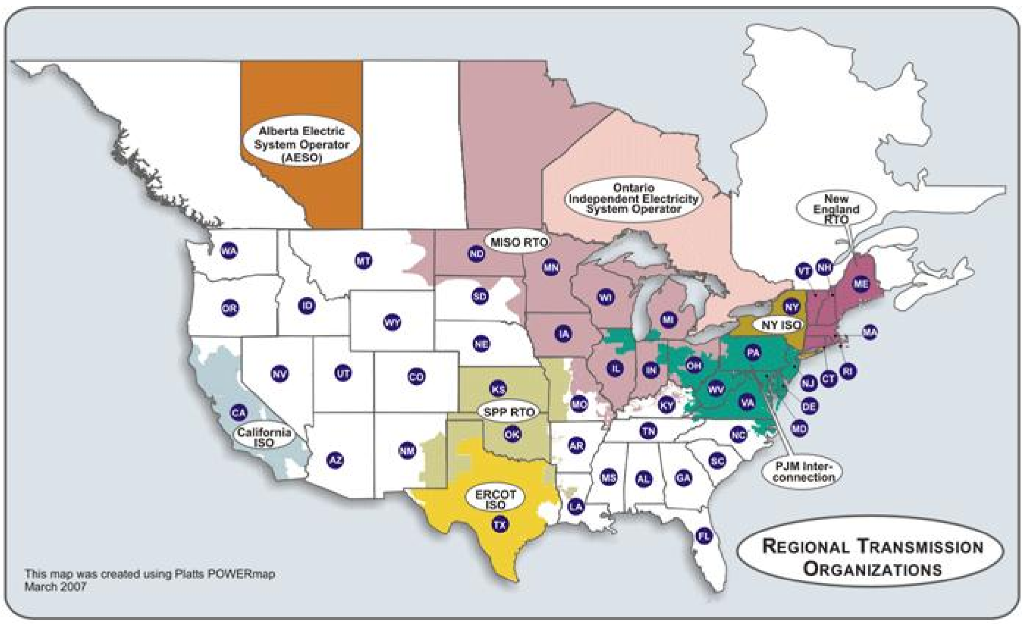


Figure 3: PJM Area

2. BASIC CHARACTERIZATION OF THE REGION

(Source: www.pjm.org/about/overview.html)

Generating Units	**1271**
Generating Capacity	**164,905 MW (2006)**
Peak Load	**144,796 MW (Aug. 2, 2006)**
Annual Energy	**729 TWh**
Area sq. miles	**164,634**
Miles of transmission	**56,250**

Population served	**51 million**
States	**13 + Washington D.C.**
Members	**450+**
Transmission Customers	**100+**
Real time SPOT market share of total electricity	**35%**
Price determination method	**Locational Marginal Prices (LMP)**

Table 4: PJM – Region Characteristics

2.1. ELECTRIFICATION LEVEL

The electrification level in the PJM area is 100%.

2.2. AVAILABILITY OF NATURAL RESOURCES FOR GENERATION

The energy delivered in 2006 was approximately 700 TWh, representing more than 20% of the US electric energy consumption.

The generation capacity in the PJM RTO area (2006) adds to a total of 165 GW. The shares of different fuel types are:

Fuel type	(%)
Coal	41 %
Nuclear	19 %
Natural gas & other	27 %
Oil	9 %
Hydro	5 %
Other	1 %

Table 5: PJM Generation by Fuel Type

According to FERC's State of the markets report (2004), almost all electric energy in 2003 was generated from hydro, wind, nuclear and coal. The gas-fired capacity of 18% represented 2% of the net generation.

2.3. OTHER RELEVANT CHARACTERISTICS OF THE REGION

The formation of RTOs is voluntary, and there are four RTOs operating in North America:

- PJM Interconnection (PJM)
- Midwest Independent Transmission System Operator (MISO)
- ISO New England Inc. (ISO-NE),
- Southwest Power Pool (SPP)

There are also eight ISOs operating in North America:

- Alberta Electric System Operator (AESO)
- California ISO (CAISO)

- Electric Reliability Council of Texas (ERCOT)
- Florida Reliability Coordinating Council (FRCC)
- ISO New England (ISONE)
- Midwest ISO (MISO)
- New York ISO (NYISO)
- Independent Electricity System Operator (IESO, of Ontario, Canada)

The PJM wholesale markets (day-ahead and real-time) have a market share of around 1/3, the remaining 2/3 being traded bilaterally.

3. ROAD MAP FOR IMPLEMENTATION

3.1. INITIAL STEPS OF THE REGIONAL INITIATIVE

PJM was established on 16 September 1927 as the “PNJ Interconnection”. Three utilities formed the world’s first power pool, signing the PA-NJ agreement. A 376 km transmission ring connected the three utilities in 1936 (the Pennsylvania / New Jersey Interconnection, 220 kV). The objective of the power pool was to share their electric loads, and to receive power from a huge new hydro-electric plant at Conowingo, Md. Meeting power demands in Philadelphia were a primary goal.

Additional utilities joined in 1956, 1965 and 1981. Throughout this time, PJM was operated by a department of one member utility. In 1956 the system was renamed the “PJM Interconnection”.

PJM began its transition to an independent, neutral organization in 1993 when the PJM Interconnection Association was formed to administer the power pool. In 1997, PJM became a fully independent organization. At that time, membership was opened to non-utilities, and an independent Board of Managers was elected. In 1997, PJM opened its first bid-based energy market. Later that year the Federal Energy Regulatory Commission (FERC) approved PJM as the nation’s first fully functioning independent system operator (ISO). ISOs operate, but do not own, transmission systems in order to provide open access to the grid for non-utility users.

In 1998, PJM went from a single market clearing price (MCP) to locational market price (LMP). Approximately 1300 pricing points constitute the LMP model.

Later, the FERC encouraged the formation of RTOs to operate the transmission system in multi-state areas and to advance the development of competitive wholesale power markets. PJM became the first fully functioning RTO of USA in 2001.

In 2002, PJM integrated Allegheny Power’s five-state transmission system into the PJM system. On May 1st, 2004, PJM integrated Commonwealth Edison (ComEd) into the PJM system. This addition increased PJM's scope by 20%, making PJM the largest transmission grid operator in the world.

3.2. UTILITIES INVOLVED IN THE BEGINNING

The three utilities founded by PJM were Philadelphia Electric, Pennsylvania Power & Light, and Public Service Electric & Gas of New Jersey.

3.3. BASIS FOR THE ORGANIZATION

The PA-NJ agreement was signed by three utilities in 1927.

The role assumed as federally regulated RTO in 2002 was approved by FERC. The formation of RTOs is voluntary to promote efficiency in wholesale electricity markets and the lowest price possible for reliable service (www.ferc.gov). The minimum characteristics for an RTO are

- Independence
- Scope and Regional Configuration
- Operational Authority
- Short-term Reliability.

The minimum functions of an RTO are:

- Tariff Administration and Design
- Congestion Management
- Parallel Path Flow
- Ancillary Services
- OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
- Market Monitoring
- Planning and Expansion
- Interregional Coordination.

3.4. EVOLUTION:

3.4.1. RELEVANT MODIFICATIONS TO INITIAL AGREEMENTS / RULES

PJM grew in steps, from being a power pool of three utilities in 1927, to include 5 utilities in 1956, 6 in 1966, 8 in 1981. The operation of the competitive wholesale electricity market started in 1997, when PJM was approved as Independent System Operator (ISO) by FERC, and non-utilities were accepted as members. Since 2002, PJM is a federally regulated RTO. The inclusion of the transmission system of Allegheny Energy in 2002 was a recent major expansion. PJM has doubled in size with new areas since 2002.

The relevant and recent modifications to the initial agreements are outlined by the FERC's orders and proposals:

- Energy Policy Act (1992): FERC was authorized to open the electricity transmission.
- FERC Orders 888/889 (1996): Required non-discriminatory open grid access.
- FERC Order 2000 (1999): Regional, multi-state RTOs should be responsible

for operation and control of the transmission lines owned by local utilities.

- SMD NOPR (2002): Proposed Standard Market Design was not approved.
- Energy Policy Act (2005): FERC is given additional responsibilities.
- FERC Order 890, The OATT reform: Open Access Transmission Tariffs to mitigate transmission market power.

3.5. CURRENT SITUATION: MAIN ACHIEVEMENTS, MAIN CHALLENGES FACED TODAY

Achievements:

- PJM focuses on reliability in the 2006 Annual Report (www.pjm.org), a year that saw three all-time high peak loads during a two-week period. The annual peak was 8% higher than year before. The peak increased by 24,000 between 2004 and 2006.
- The demand-side response during the day of the peak record lowered the total electricity cost of the day by $230 million.
- Generator availability improved from 81.1% in 1994 to 86.2% in 2004 (percentage of hours in a year that a generating unit is available for operation at full capacity).
- From 1998 to 2006, 11,000 MW of net generation were added. In the comparable period prior to the opening of the competitive wholesale market about 2,200 MW were added.
- Demand response programs have provided electricity consumers an option to participate in wholesale markets by curtailing their electricity use during peak periods when the wholesale prices are high.

Challenges:

- PJM faces a growing need for energy. The capacity requirement for 2020 is estimated to 220,000 MW, calling for 55,000 MW of new generation and demand response.
- Environmental pressure calls for focus on renewable energy and demand response.
- Rising fuel costs cause higher retail prices, which may challenge the structure of wholesale markets.

4. INSTITUTIONAL FRAMEWORK

4.1. INSTITUTIONS INVOLVED IN THE INITIATIVE (AT REGIONAL AND NATIONAL LEVEL)

The formation of an RTO for operation of the transmission and the wholesale electricity market is voluntary, and involves the RTO itself, i.e. PJM, and the federal regulating entity, FERC.

The operation of the market also involves 400+ members, along with the grid owners. Legal agreements define the relationships between PJM and:

- FERC
- The grid owners
- The members
- NERC (North American Electric Reliability Corporation), for security standards and information exchange.

4.2. ROLES / OBJECTIVES OF THE INSTITUTIONS

PJM Interconnection's mission is:

"Ensuring the reliability of the electric grid and the effective operation of the wholesale electricity markets."

4.3. RELATIONSHIP AMONG THE INSTITUTIONS OF THE INITIATIVE

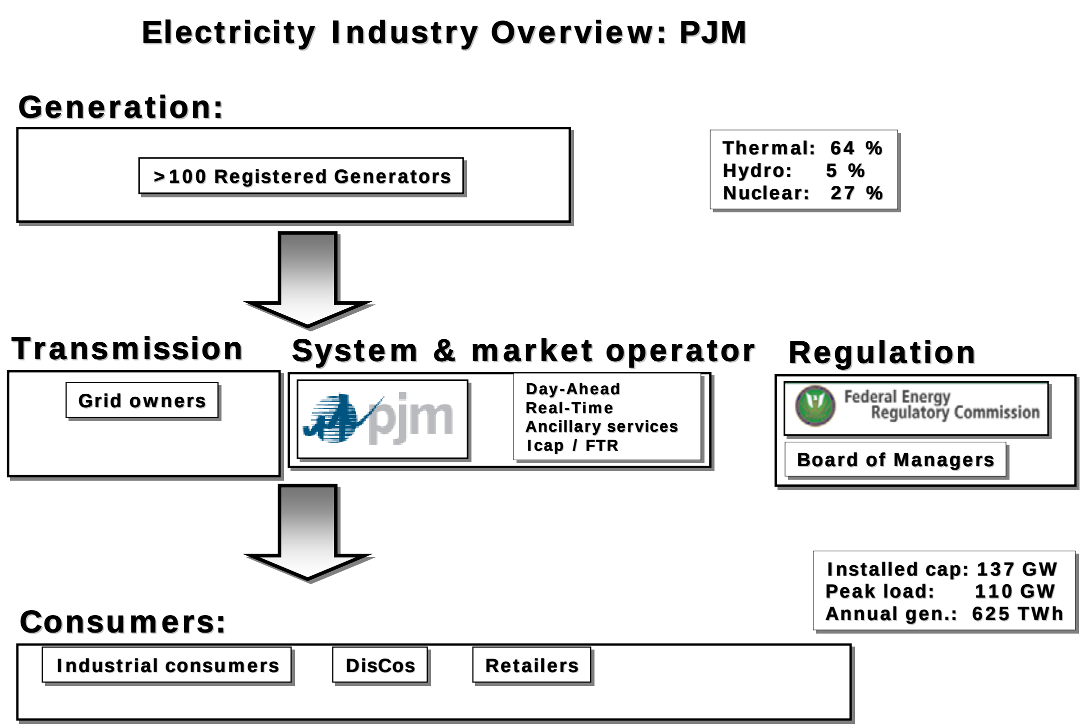


Figure 4: PJM – Electricity Industry Overview

5. REGULATORY FRAMEWORK

5.1. *GENERAL DESCRIPTION OF THE TRADING ARRANGEMENTS OR "HOW TRADE IS PERFORMED" IN THE REGION*

The following is a summary of how PJM markets operate.

Energy

PJM coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. In its role as market operator, PJM balances the needs of suppliers, wholesale customers and other market participants, and monitors market activities to ensure open, fair and equitable access.

PJM's Energy Market operates much like a stock exchange, with market participants establishing a price for electricity by matching supply and demand. The market uses locational marginal pricing that reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, energy cannot flow freely to certain locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal price (LMP) is higher in those locations.

The Energy Market consists of **Day-Ahead** and **Real-Time** markets.

- The **Day-Ahead Market** is a forward market in which hourly locational marginal prices (LMPs) are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.

- The **Real-Time Market** is a **spot** market in which current **LMPs are calculated at five-minute intervals** based on actual grid operating conditions and are published on the PJM Web site. **PJM settles transactions hourly** and issues invoices to market participants monthly.

Both the day-ahead and the real-time markets apply Locational Marginal Pricing based on an algorithm called Security Constrained Unit Commitment (SCUC), integrated with the computer system for supervision and control of the transmission grid. This system includes telemetered data from nearly 74,000 points on the grid, and the real-time market manages prices for 1300 grid points every 5 minutes.

Financial Transmission Rights

PJM also operates a market for financial transmission rights (FTRs) to assist market participants in hedging price risk when delivering energy on the grid. FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly energy-price differences across a transmission path in the Day-Ahead Market.

The FTRs provide a hedging mechanism that can be traded separately from transmission service. This gives all market participants the ability to gain price certainty when delivering energy across PJM.

Market participants can obtain FTRs in three ways:

- They can bid for them in PJM's annual auction, in which FTRs for the system's entire transmission capability are available.

- They can bid for them in the monthly auctions at which leftover FTRs are sold in the PJM's Markets

- They can buy them in the secondary market in a transaction with another market participant.

Market participants can manage their FTR portfolios by using the eFTR tool. Participants use eFTR to post their FTRs for bilateral trading, as well as to participate in the scheduled monthly FTR auctions.

Ancillary Services

Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers.

PJM currently operates two markets for ancillary services – **regulation** and **spinning reserve**.

Regulation service corrects for short-term changes in electricity use that might affect the power system's stability. It helps match generation and load and adjusts generation output to maintain the desired frequency. Load-serving entities (LSEs) can meet their obligation to provide regulation to the grid by using their own generation, by purchasing the required regulation under contract with another party. or by buying it in the regulation market.

Spinning reserve service supplies electricity if the grid has an unexpected need for more power, on short notice. The power output of generating units supplying spinning reserve can be increased quickly to supply the needed energy for balancing supply and demand. LSEs can meet their obligation to provide spinning reserve to the grid by using their own generation, by purchasing the required spinning reserve under contract with another party or by buying it on the spinning reserve market.

Capacity Credits

Each LSE in PJM must own or acquire capacity resources to meet its unforced capacity obligation. An LSE can acquire capacity resources by entering into bilateral arrangements, or by participating in the Capacity Credit Market.

The Capacity Credit Market is intended to provide a transparent, market-based mechanism for LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The market provides a means to balance the supply and demand for capacity, which are not met through bilateral transactions or self-supply.

The market consists of daily, monthly and multi-monthly (interval, remainder of interval and yearly) markets. The daily market permits LSEs to match capacity resources with short-term shifts in retail load. The monthly and multi-monthly markets provide mechanisms to match long-term obligations with capacity resources.

The market uses a closed, uniform-price auction format. Confidential buy bids and sell offers are submitted to PJM via the eCapacity system. Buyers indicate the maximum amount of unforced credits requested (in megawatts) and the maximum price (in dollars per megawatt-day) they are willing to pay for those credits. Sellers indicate the maximum amount of unforced capacity credits offered, and the minimum they are willing to accept for those credits.

Buy bids and sell offers are matched to satisfy the maximum number of buy bid requests at the lowest possible sell offer price. The last sell offer to be matched with a buy bid sets the market's clearing price. All credits purchased or sold through the market are traded at this market clearing price.

The market is illustrated in the figure below:

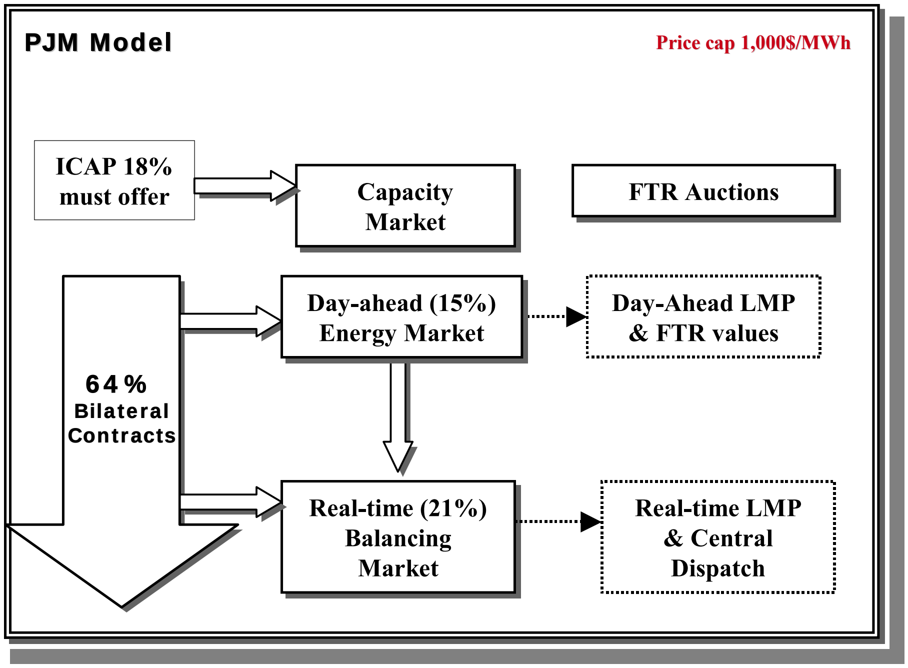


Figure 5: PJM – Trading Model

5.2. *MAIN REGULATIONS APPLIED*

PJM is an RTO regulated by the **Federal Energy Regulatory Commission (FERC)**. FERC is an independent regulatory agency within the United States Department of Energy. FERC is independent of the Department of Energy (DOE), but the latter may intervene just like any other party in FERC's proceedings. Regulatory Events:

Energy Policy Act (1992):

- FERC was authorized to open the electricity transmission.

FERC Orders 888/889 (1996):

- Requires non-discriminatory open access
- Utilities must file tariffs and accept service
- General tariff for ancillary services
- Unbundling of transmission, generation, and marketing
- Electronic (internet) same-time information system (OASIS)
- Recovery of Stranded Costs

FERC Order 2000 (1999):

- Transmission-utilities encouraged to turn operational control of their high-voltage power lines over to independent entities called Regional Transmission Organizations (RTO's)
- RTOs were intended to be large, independent
- Utilities maintain ownership of grid assets and derive revenue from grid use.

Proposed Standard Market Design (Notice of Proposed Rulemaking, 31/7 - 2002): The Standard Market Design (SMD) proposal from FERC met strong regional opposition, and was not implemented as intended. However, the proposal is worth mentioning, and its intentions are reflected in the RTO regulation. SMD Goals: To Create Efficient Markets with Clear Rules:

- Eliminate discrimination in the use of transmission
- Establish Standardized, Flexible Transmission Service
- Open & Transparent Spot Markets
- Level Playing Field in Wholesale Power Markets
- Price Signals that provide appropriate incentives for investment in Transmission, Generation, & Demand Response
- Protect against the exercise of Market Power

SMD Measures:

- Single, non-discriminatory open access transmission tariff
- Independent Transmission Providers (ITPs)
- Interaction of Spot Markets and Bilateral Contracts
- Locational Marginal Pricing and Congestion Management
- Market Power Mitigation and Monitoring
- Long-Term Resource Adequacy

A FERC whitepaper of April 28, 2003 identified eight requirements for wholesale electric markets:

1. Regional Independent Grid Operation,
2. Regional Transmission Planning Process,
3. Fair Cost Allocation for Existing and New Transmission,
4. Market Monitoring and Market Power Mitigation,
5. Spot Markets to Meet Customers' Real-Time Energy Needs,
6. Transparency and Efficiency in Congestion Management,
7. Firm Transmission Rights,
8. Resource Adequacy Approaches.

In an August 2003 technical conference with FERC, PJM reported that it would comply with all eight elements of FERC's SMD.

The opposition against the SMD proposal was particularly strong in Southern and Northwest states, and the criticism included (neaap.ncat.org/journal/Spring03/fercsmd.htm):

- High complexity in the rulemaking
- Scepticism towards deregulated markets after the Californian crisis, and the

Enron collapse

- Fear of higher power rates.

Energy Policy Act (2005): The new 2005 **Energy Policy Act** expanded FERC's authority to impose mandatory reliability standards on the bulk transmission system and to impose penalties on entities that manipulate the electricity and natural gas markets. The 2005 Energy Policy Act gave FERC additional responsibilities as outlined in FERC's Top Priorities and updated Strategic Plan.

FERC Order 890, The OATT reform (2007, reform to orders 888 and 889).

FERC vs. **NERC**: Only electric utilities that are located within the United States fall under FERC authority, but a larger organization called the **North American Electric Reliability Corporation (NERC)** overlays the entire FERC footprint and also includes a Mexican utility and several Canadian utilities. The North American Electric Reliability Corporation (NERC) is a non-profit corporation based in Princeton, NJ. It was formed on March 28th, 2006, succeeding the North American Electric Reliability Council which was formed in 1968 by the electric utility industry to promote the reliability and adequacy of power supply in North America. NERC's mission states that it is to "ensure that the bulk electric system in North America is reliable, adequate and secure". NERC's major responsibilities include defining standards for power system operation, monitoring and enforcing compliance with those standards.

FERC’s rules applied to RTOs and ISOs are summarized in the FERC RTO-ISO Handbook:

1. Governance
2. Section 205 Filing Rights
3. Exit Rights
4. Market Monitoring Units (MMU)
    - Independence
    - Responsibilities and Authority
    - Market Power Mitigation
    - Relationship to State Commissions
    - Information Sharing. What is Permitted?
5. Markets Operated by ISO/RTO and Pricing
    - Day-Ahead Market
    - Real-Time Market / Spot Market
    - Treatment of RMR Units
    - Congestion Management
    - Rate Design / Pricing
6. Reliability
7. Treatment of Existing Contracts
8. Reporting Requirements

9. Treatment of Non-Public Utility RTO/ISO members, including exit rights
10. Information Sharing by RTO/ISOs (What is permitted?)
11. Demand Response Programs / Requirements
12. Control Areas
13. Treatment of transmission vs. distribution or non-pool transmission
14. Interconnection (Compliance with Order No. 2003)
15. System Planning Process
16. Creditworthiness

5.3. RESOLUTION OF DISPUTES

The procedures for resolution of disputes in PJM are described in the Third Revised Rate Schedule FERC No. 24 , SCHEDULE 5: PJM DISPUTE RESOLUTION PROCEDURES (http://www.pjm.com/committees/working-groups/rppwg/downloads/20070730-item-01c-dispute-procedures.pdf), with the intention to establish common and uniform procedures for resolving disputes arising under the Related PJM Agreements. This document describes two phases of the process:

- Negotiation and mediation
- Arbitration

For each of these phases, the procedures define, inter alia:

- When the process is required
- How to initiate
- Selection of mediator/arbitrator
- Work procedures
- Enforcement
- Confidentiality and compulsory disclosure
- Timetable
- Allocation of costs

5.4. PLANNING FOR SYSTEM EXPANSION:

PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additions to the grid are needed to ensure reliability and the successful operation of the wholesale markets.

The regional plan is the end result of a continuing process to make necessary transmission improvements. Transmission upgrades keep the system in compliance with reliability standards. These standards ensure that the system continues to deliver electricity throughout the region, which covers 13 states and the District of Columbia. The improvements also accommodate the interconnection of new generating projects.

The decision to build a new electric generating plant or a transmission line is significant, since these construction projects are costly, time-consuming and subject to numerous regulatory approvals. At the same time, decisions to add generation or transmission resources cannot be made in a vacuum because these projects affect the grid’s overall operation and its ability to reliably deliver power to customers.

The RTEP process evaluates proposed transmission upgrades, generation interconnections and demand-side projects to make sure that compliance with reliability criteria is maintained. The process also includes a mechanism to mandate necessary grid improvements. PJM’s planning process began in 1997; its first regional plan was approved in August 2000. The process accommodates not only expansion projects proposed by transmission owners, typically electric utilities, but also merchant generation and transmission projects that are financed by private investors instead of utilities.

PJM's review process ensures that all interested parties, including state regulatory agencies, have an active role in planning for future electricity supply and reliability needs. As part of the RTEP process, projects are reviewed by the PJM Board. Once a project is approved by the board, it is incorporated into the plan. The RTEP process determines the need for, and benefits of, a transmission project; it does not review or approve a transmission line’s siting. That is the responsibility of the affected states.

Under PJM agreements, transmission owners are obligated to build transmission projects that are needed to maintain reliability standards, and which are approved by the board.

The board approved the RTO’s first 15-year regional plan in June 2006. The board authorized the construction of $1.3 billion in electric transmission upgrades by 2011, including a 240-mile, 500-kilovolt transmission line from south-western Pennsylvania to Virginia. These upgrades will ensure reliability through 2011 and are expected to reduce congestion by $200 million to $300 million a year. (Congestion – heavy use of the transmission system in an area – causes the price of electricity to rise in that area because the lowest priced electricity cannot flow there freely).

6. USE OF THE TRANSMISSION SYSTEM

6.1. REMUNERATION OF THE TRANSMISSION SYSTEMS (PRINCIPLES)

(Source: The FERC RTO-ISO Handbook, section “Rate Design / Pricing”)

PJM has a zonal rate design for transmission service. PJM’s zonal, license plate rate design for existing transmission facilities is considered for replacement, preferably with the postage stamp rates recommended by FERC’s staff, where the charges would be fixed, regardless of the distance that the energy travels, pending FERC’s decision.

Through and out rates between PJM and MISO were eliminated as of December 1st, 2004, and replaced with a new long-term transmission pricing structure that eliminates seams throughout those regions.

In response to the FERC’s request that the Midwest ISO and PJM (along with their transmission owners) develop a proposal for allocating to the customers in each RTO the cost of new transmission facilities that are built in one RTO, but provide benefits to customers in the other RTO, the Midwest ISO and PJM have established a proposal where the cross-border cost allocation is based on a joint RTO load flow model that identifies project beneficiaries following cost causation.

The framework for the RTO grid’s tariffs is set by the regulator, and the latest development is described below:

(Sources: FERC News Release on the OATT Reform, February 15, 2007, http://www.ferc.gov/news/news-releases/2007/2007-1/02-15-07-E-1.asp, and FERC OATT Fact Sheet, http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf).

After the FERC's Order No. 2000 in 1999, transmission providers were seen to have retained the incentive and ability to discriminate against third-party users of their transmission systems. The OATT Reform mitigates the transmission market power. It is designed to:

1. Strengthen the *pro forma* open-access transmission tariff, or OATT, to ensure that it achieves its original purpose of remedying undue discrimination,

2. Provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement,

3. Increase transparency in the rules applicable to planning and use of the transmission system.

The final rule will:

- Increase non-discriminatory access to the grid by eliminating the wide discretion that transmission providers have in calculating available transfer capability.

- Increase the ability of customers to access new generating resources by requiring an open, transparent and coordinated transmission planning process.

- Increase efficient utilization of transmission by eliminating artificial barriers to use of the grid.

- Facilitate the use of, and access to, clean energy resources, such as wind power.

- Strengthen compliance and enforcement efforts.

The reforms in the rule include:

- **CONSISTENCY IN THE CALCULATION OF AVAILABLE TRANSFER CAPABILITY**. Calculating Available Transfer Capability (ATC) is one of the "most critical functions under the pro forma OATT because it determines whether transmission customers can access alternative power supplies," the Commission (i.e. FERC) said, in providing for more consistent calculation of ATC. The rule requires public utilities, working through the North American Electric Reliability Corp., to develop consistent ATC calculation methodologies and to publish those methodologies to increase transparency.

- **COORDINATED, OPEN TRANSMISSION PLANNING PROCESS**. Each transmission provider's planning process must meet nine specified planning principles: coordination; openness; transparency; information exchange; comparability; dispute resolution; regional coordination; economic planning studies and cost allocation.

- **TRANSMISSION PRICING REFORMS**. The rule reforms the pricing of energy and generator imbalances to require such charges to be related to the cost of correcting the imbalance, to encourage efficient scheduling behaviour and to exempt intermittent generators, such as wind power producers, from higher imbalance charges in recognition of the special circumstances presented by such resources.

- **NON-RATE TERMS AND CONDITIONS**. The Commission adopts a conditional firm component to long-term point-to-point service, addressing situations in which firm service can be provided for most, but not all, hours of the requested time period. The rule also reforms the existing requirements for redispatch service, to ensure that the requirements are of greater use to transmission customers and more consistent with reliable planning and operation of the system.

6.2. MANAGEMENT OF CONGESTION

(Sources: PJM fact sheet "Congestion", "FERC State of the markets report 2004", and the FERC RTO-ISO Handbook).

Heavy use of the electricity grid produces congestion, a situation in which the lowest-priced electricity can't flow freely to a specific area.

PJM Interconnection's locational marginal pricing (LMP) system takes account of congestion in determining electricity prices. It reflects the value of the energy at the specific location and time it is delivered.

- When the lowest-priced electricity can reach all locations, prices are the same across the entire PJM grid.
- When there is heavy use of the transmission system, the lowest-priced energy cannot flow freely to some locations. In this case, more-expensive but advantageously located electricity is ordered to meet that demand. As a result, the locational marginal prices are higher on the receiving end of the congestion and lower on the sending end.

Congestion generally raises the LMP in the receiving area of the congestion and lowers the LMP in the sending area. Operating conditions such as generation patterns, load levels and transmission outages can cause congestion and result in LMP changes.

LMPs send price signals that identify congestion and encourage new transmission facilities, new generation or demand-response initiatives in areas where congestion is common.

<u>Transmission Congestion Charges</u> - When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses, PJM will calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer. The basis for such charges will be the differences in the Locational Marginal Prices between points of delivery and points of receipt.

<u>Transmission Congestion Credits</u> (TCCs) - With certain limitations, each holder of a Financial Transmission Right will receive as a TCC a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

Market participants have the opportunity to request that transmission owners to accelerate or reschedule transmission outages that either (1) cause significant congestion, or (2) impact generation owners when related to their generation interconnections. This change allows generation owners and other market participants to avoid or reduce unhedged transmission congestion when the costs of accelerating or rescheduling an outage are less than the congestion costs would be if the outage preceded as originally scheduled. PJM's provisions apply to both planned and forced outages.

<u>Financial Transmission Rights</u> (FTRs) - TCCs will be calculated based on the FTRs held at the time of the constrained hour. FTRs are defined from a point of receipt/injection to a

point of delivery/withdrawal.

7. KEY LESSONS LEARNED FROM THE PJM MARKET AREA

Establishment of the PJM markets was based on much the same principles as the European markets. Whereas the European electricity market co-operation involves independent nations, PJM includes merging of federal states markets. Differences and similarities can be seen in these tasks and design approaches. PJM operations include both market and system operation.

PJM operates an advanced flow based operational model of Locational Marginal Pricing (LMP) that requires an advanced infrastructure, both regarding organisation and technical equipment attached to grid, generation and control/dispatch facilities. The model implies a centralised dispatch and national companies must delegate authority to a central entity that operates the market. This also implies, to a larger extent, political consensus. Mainly due to high complexity and not so transparent price determination methodology, acceptance has been slow.

PJM has succeeded in establishing a wholesale electricity market over several federal states, and in continued expansion to new territories and utilities. The PJM's success has inspired ERCOT of Texas to adapt to a similar nodal (LMP) market model, and the ERCOT's change is in progress. However, in Europe the nodal model has gained little support (except in Russia and most recently the Single Electricity Market – or SEM - for the island of Ireland), possibly due to the resistance against central dispatch in international market co-operation.

PJM has proven high system reliability under peak conditions, possibly enabled by the central, security constrained dispatch.

PJM has seen an increase in the generation capacity of 11,000 MW, or 7%, since 1998, indicating that price signals provide incentives for investment.

Demand response programs have provided electricity consumers with an option to participate in the wholesale markets by curtailing their electricity use during peak periods when the wholesale prices are high. Considerable savings have been achieved in peak conditions.

Since the market model includes integrated systems for market operation and system operation, and considerable amounts of real-time data, a harmonisation of methodology and procedures across the borders are required more than in other concepts.

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- Demand Response

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VI SAPP

1. COUNTRIES COVERED BY THE INITIATIVE

SAPP is a cooperation between 12 southern African countries, where trading applications and procedures to be implemented shortly are based on the **NORD POOL** regime for the Nordic area in Europe, which includes Finland, Sweden, Denmark and Norway with a total population of about 25 millions.

Country	Utility	Installed Capacity MW	Maximum Demand MW	MD Growth %	Sales GWh	Sales Growth %	Number of Customers	Number of Employees	Generation Sent Out GWh	Net Imports GWh	Net Exports GWh	Transmission System losses %	Revenue US$ Million
Angola	ENE	745	397	9	1,843	12.7	143,937	4,250	2,649	0	0	25	87.94
Botswana	BPC	132	434	7.96	2583.7	7.5	152,744	2,091	977	2,006.50	0	10.96	121.8
DRC	SNEL	2,442	1012	2.53	4,656	13	360,329	6,268	6,904	0	1,800.00	6.3	149.2
Lesotho	LEC	72	90	0	354	12	46,173	439	446	8	11	20	25.6
Malawi	ESCOM	285	242	6.5	970	4	135,000	2,400	1,177	0	0	19	5.319
Mozambique	EDM	233	285	7.1	1,308	11.8	338,597	2,969	147.418	1,501	1,496	5	110.9
Namibia	NamPower	393	491	6.51	2,976	6.5	3,403	891	1,660	1,703.0	0	8	169
South Africa	ESKOM	42,011	33,461	-2.2	207,921	0.8	3,758,569	29,697	221,985	8,730	13,107	8.9	5,388,000
Swaziland	SEB	51	172	1	852.8	2.5	48,500	667	103.5	916.8	0	16	59.7
Tanzania	TANESCO	839	531	4.3	2,549	10.3	550,863	4857	3674	43	0	24	188
Zambia	ZESCO	1,732	1,330	2.8	8,457	3.1	297,000	3,814	8,884	0	69	3.6	217.6
Zimbabwe	ZESA	1,975	2,066	-0.1	10,480	3.5	559,766	5,928	9,391	2,666	255.5	12.6	29.463

Table 6: SAPP – Characterisation of the Area

1.1. ELECTRIFICATION LEVEL

The electrification level for the SAPP members varies a great deal; the table below shows electrification for SAPP members, where the vast differences between these countries are clearly illustrated. A similar disparity can be observed among NBI countries, and this must weigh heavily on choosing approaches to, and design of, road maps for a design of electricity for implementation.

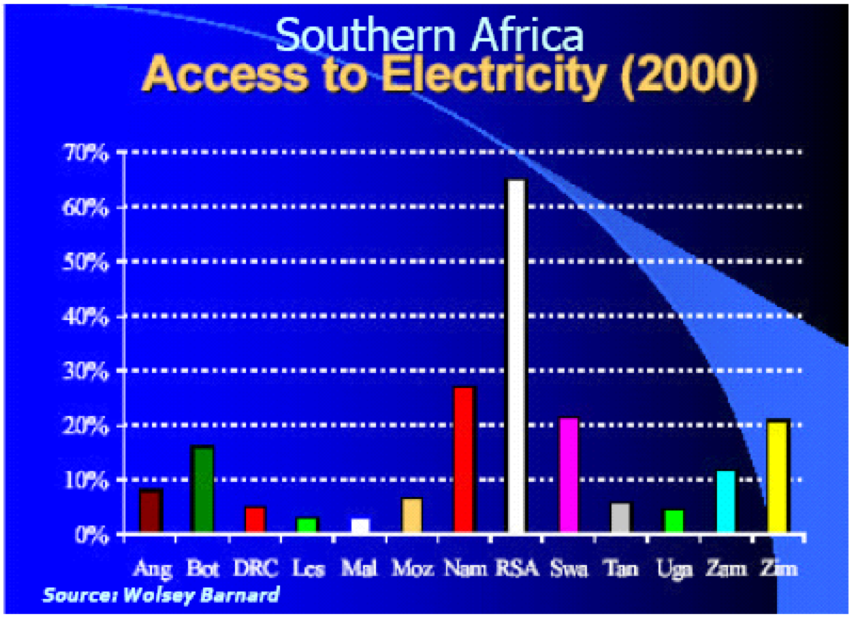

Figure 6: SAPP – Electrification Level of Countries

1.2. AVAILABILITY OF NATURAL RESOURCES FOR GENERATION

SAPP

In the SAPP region the main hydro resources in the interconnected system are in the countries DRC, Zambia, Zimbabwe and Mozambique.

In South Africa the major part of the generation is based on coal and on one nuclear power plant. Zimbabwe has also a significant part of its generation based on coal.

Generally, this area has the main hydro resources in north and thermal generation in south. The main part of the population is in the south, so the structure is similar to that of the Nordic area.

Leap forwards might be possible with new cross border connections being established.

2. ROAD MAP FOR IMPLEMENTATION

2.1. HOW WAS THE INSTITUTION INITIATED

SAPP: The Southern African Power Pool (SAPP) has come a long way in establishing a competitive electricity market for the Southern African region. In the early 1960's, only a few participants were involved in the market, which typically consisted in governmental to governmental bilateral agreements. As the interconnections expanded, more participants entered the market. The main drawbacks at that time were transmission tariffs and electricity pricing. It was difficult to get third party access and this prevented meaningful trading from taking place between countries.

In 1995, the north-south interconnector was commissioned and this paved the way for increased energy trading between the predominantly northern hydro networks and the southern thermal systems. In 2001, the SAPP started the short-term energy market (STEM). The STEM market was viewed as a first step towards the development of a regional competitive electricity market. In the STEM market energy is traded a day-ahead. STEM is a firm energy market, though bilateral contracts take precedence over STEM contracts on the transmission lines.

The Southern African Power Pool was created in August 1995 at the Southern African Development Community (SADC) summit held in Johannesburg, South Africa, when member governments of the SADC, excluding Mauritius, signed an Inter-Governmental Memorandum of Understanding for the formation of an electricity power pool in the region under the name of the Southern African Power Pool (SAPP). The SAPP is now an association of twelve member countries represented by their respective electric power utilities organised through SADC.

2.2. WHO WAS INVOLVED AT THE BEGINNING

There were 12 countries within the SADC that were involved from the beginning. From those, 9 countries were connected in a synchronous network, and they were called Operating Members.

Those countries were: DRC, Zambia, Zimbabwe, Botswana, Mozambique, Swaziland, Lesotho, Namibia and South Africa.

Angola, Malawi and Tanzania are also members of SAPP but are not yet connected to the synchronous grid.

2.3. BASIS ON WHICH THE ORGANIZATION WAS ESTABLISHED

The **SAPP** is governed by four agreements:

- The Inter-Governmental Memorandum of Understanding which enabled the establishment of SAPP;
- The Inter-Utility Memorandum of Understanding, which established the SAPP's basic management and operating principles;
- The Agreement Between Operating Members which established the specific rules of operation and pricing;
- The Operating Guidelines, which provide standards and operating guidelines.

In case of inconsistency, the first document has precedence over the second document; the second document over the third, and the third over the fourth. No other document can be construed as governing the establishment and administration of the SAPP.

The MOUs have been recently revised to allow for new members to join the SAPP. There is still some practical work to be done, but the preparation is ongoing.

2.4. CURRENT SITUATION: MAIN ACHIEVEMENTS, MAIN CHALLENGES FACED TODAY

The main challenge in the SAPP area at present is the power balance. The generation has problems meeting the peak load in several countries, partly because generation is not available. Some of the generation is old and needs maintenance and some of the generation has not sufficient supply of fuel.

SAPP has a lot of ongoing work to prioritise investment projects for new generation and new interconnectors.

SAPP has now a structure that makes this coordination possible and the work in all SAPP committees is doing well.

3. INSTITUTIONAL FRAMEWORK

3.1. INSTITUTIONS INVOLVED IN THE INITIATIVE

The institutions involved in the practical work are the national utilities from the participating countries. The members of the SAPP executive committee, management committees and other committees are elected from those utilities.

The association of regulators in SAPP are more and more involved in the work in SAPP and are normally participating in the SAPP meetings held twice a year.

3.2. ROLES / OBJECTIVES OF THE INSTITUTION

The **objective** of the SAPP is to provide reliable and economical electricity supply to the consumers of each of the SAPP Members, consistent with reasonable utilisation of natural resources and effect on the environment. The SAPP coordinates the planning and operation of the electric power system among member utilities, and provides a forum for regional solutions to electric energy problems.

Based on the current SAPP Inter-Governmental Memorandum of Understanding, the general arrangement for electricity trading in SAPP is for the national power utilities to engage into long-term and short-term bilateral contracts for the sourcing and consumption of electrical energy. The intergovernmental agreements and the bilateral contracts between the utilities form the basis and foundation for cross border electrical energy trading in the SAPP. The routine activities that follow include scheduling, settlements, monitoring of the quality of supply and detailed investigations are conducted into inadvertent energy flows and major power system faults and disturbances. The energy prices for the bilateral contracts are negotiated between the buyer and the seller. The pricing structure for bilateral contracts is diverse with some contracts having capacity rates and energy rates which takes cognisance of the time of use, peak or off peak. Other contracts have flat energy rates.

SAPP also coordinates projects for analysing different issues within SAPP. Examples of such projects are the project for Day Ahead Market, the project for Ancillary Service Management and the POOL Review.

SAPP publish monthly reports for the activities within SAPP and annual reports.

The structured communication takes place within SAPP’s organised committees that have regular meetings.

Other communication normally goes by e-mail and by the reports published by SAPP.

4. REGULATORY FRAMEWORK

4.1. GENERAL DESCRIPTION OF THE TRADING ARRANGEMENTS

Bilateral trade

The main part of the trade is in bilateral contracts between SAPP members. The parties of the contracts pay wheeling fees according to agreements within SAPP, but SAPP is not involved in the negotiations of contracts. SAPP is informed on the quantities traded.

THE STEM (short-term energy market)

This market is ongoing until the Day Ahead Market is started, probably late 2007.

The goal of a standard market design is to establish an efficient and robustly competitive wholesale electricity marketplace for the benefit of the consumers. This could be achieved through the development of consistent market mechanisms and efficient price signals for the procurement and reliable transmission of electricity, combined with the assurance of fair and open access to the transmission system. Bilateral contracts provide for the assurance of security of supply but are not flexible to accommodate varying demand profiles and varying prices. To further explore the benefits thereof, the sourcing and scheduling of electrical energy closer to the time of dispatch, the short-term energy market (STEM), was designed to specifically mimic a real time dispatch.

The primary objective of the STEM is to offer attractive energy economy through competition.

STEM's financial settlement periods are much shorter than bilateral contracts. STEM is viewed as a first step towards the development of a competitive market for the SADC region.

The main trade in STEM is in contracts for next day delivery. The matching of contracts is performed by distributing all offers among all bidders willing to pay the offer price or higher. The contracts end in bilateral contracts between the participants and can be handled as bilateral contracts regarding management of wheeling and losses.

THE SAPP COMPETITIVE MARKET

Since January 2004, SAPP has been developing a competitive electricity market for the SADC region. The proposed market is a day-ahead market based on the following principles:

i. *Market type* - The SAPP day-ahead market is an auction type of a market where the participants would bid for all 24 hours of the next day or a future day.
ii. *Bidding* - In bidding for one specific hour the participants would submit several price/volume pairs defining a bid profile, and may submit both purchase and sale bids. The bids can be of two types: Single hour bids and Block bids.
iv. *Bid areas* - There will be multiple bid areas in the market with configurable transmission capacities between them.
v. *Price calculation* - At a defined time, the market would close for bidding and the Market Clearing Price (MCP) would then be calculated. The MCP is the price where there is a balance between supply and demand without taking transmission system constraints into consideration. This unconstrained MCP can be used as a reference for derivatives trade.
vi. *Congestion Management* - The calculated contract flow between the bid areas will be computed and compared with available transmission capacity for spot trade. In case of detected congestions, congestion management by market splitting will be performed, and local area prices will be calculated. This will secure that the available transmission capacity is fully utilized when needed.
vii. *Auction results* - The results of the auction will be submitted to participants. The participants will receive the area prices with their associated volume, in accordance with their bid. The auction results will also be published at an aggregated level.

viii. *Currency of trade* - The trading platform will be configured to support multiple currencies.

The trading timeline for the proposed SAPP competitive electricity market is shown in the following table.

TRADING TIMELINE FOR THE SAPP DAY-AHEAD MARKET

TIME	ACTIVITY
09:30	Usage of bilateral contracts registered by participants. Calculation of available transmission capacity is performed. Opening of the market for delivery day X.
10:30	Market is closed for delivery day X.
11:00	Price calculation.
12:00	Distribution of prices and schedules
12:30	Participants receive information on prices and schedules.
13:00	Deadline for complaints.
14:00	A report on contracted volume per balance Party is sent to System Operators.
24.00	Delivery starts for day-ahead contracts for hour-1.

Table 7: SAPP Day Ahead Market

In the present STEM market there is a Book of Rules that describes the trading and settlement rules.

During the preparation work for the new SAPP DAM, a participant agreement and a SAPP DAM Book of Rules are being developed.

The agreements for DAM will be handled in a SAPP meeting in the beginning of September 2007. If they are approved, the work with implementation of the SAPP DAM can continue.

The agreements are handled in the Market Development sub committee, then in the Operative committee, and finally in the Executive committee.

4.2. DISPUTE RESOLUTION

The Management Committee shall endeavour to resolve and settle the matter in dispute according to Article 20 in the SAPP Revised Inter-Utility Memorandum of Understanding, dated April 24th, 2007.

Article 23 in the SAPP Revised Inter-Utility Memorandum of Understanding, dated April 24th, 2007 defines how confidentiality should be handled within SAPP.

4.3. SYSTEM EXPANSION PLANNING:

SAPP has developed a pool plan for SAPP. This plan is under revision now. SAPP has a Planning Sub Committee handling coordination of plans from the different participating countries, and making a priority list of projects in transmission and generation that will have the highest value for the regional system.

5. USE OF THE TRANSMISSION SYSTEM

5.1. PRINCIPLES FOR REMUNERATION OF THE TRANSMISSION SYSTEMS

The transmission systems are normally a part of the national vertically integrated utility. They cover the costs for the national grid. For transmission of bilateral countries between neighbouring countries there have been no extra tariff for wheeling, but wheeling through a third party's network has been paid for, according to a published wheeling fee.

Since SAPP is preparing for competitive market solutions, there is an ongoing project proposing new regime for transmission pricing and loss compensation. The proposed solution is based on the principle of point of connection tariff, but so far limited to one reference node per country.

5.2. MANAGEMENT OF CONGESTION

As a general observation, any infrastructure will be dimensioned in such a way that, from time to time, the service provided will not be matching the demand. This is evident from an economic point of view. Roads and streets might be congested at rush hours, flights sold out at peak holiday times and transmission lines for electricity might not be dimensioned to carry all the electricity demanded at certain times of peak loading.

The system operators calculate the physical transmission capacity between the countries. Long-term bilateral contracts are then given priority and subtracted from the transmission capacity. The difference is available for short-term trade.

In the STEM trade the matching of contracts take this available capacity into account.

In the new DAM trade system the nomination of use of bilateral contracts will be collected every morning of a trading day. Then, the available transmission capacity will be calculated and stored in the trading system database.

Once the DAM bids are matched the flow between areas will be compared with the available capacity. If congestions are detected, "market splitting" will be performed in the same way as described for the Nordic system.

6. LESSONS LEARNT

SAPP was established to increase the utilisation of power resources in the Southern African Region through increased trade on interconnections.

In the first phase it was very important to establish rules on how to regulate the cooperation with reference to technical - and system security issues.

Later on, it was focused upon short term trading and STEM was introduced.

SAPP has focused on introducing more marked based systems and the necessary changes that need to be made to facilitate this development.

Focus is not put on the retail market and competition within the respective national markets involved, but on the regional wholesale market. It is the belief of SAPP that when a regional competitive electricity market is established in the SADC region, the market will provide price indicators for investors and other players to participate. This is a better pricing mechanism for electricity in a competitive environment. The creation of a competitive market in the region would optimise the use of regional resources, enable the determination of the correct price of electricity in the pool and will send signals for investments and real time utilization of existing assets; transmission, generation and consumption. The market will also enable the demand side to respond to the market's price signals.

Lessons from the SAPP market area

In SAPP, several independent nations cooperate having as main objective to increase the use of power resources through efficient utilisation of transmission capacity on interconnections. Demand side participation and retail competition are not a priority.

Trade on interconnections has always been carried out based on different procedures for price determination, transmission and transit. These procedures involve cash flows. Experience shows that the parties involved fear that changes will reduce their income.

Therefore, a simple system is recommended, allowing for a stepwise development starting at first with the international wholesale market and, to a large extent, allowing for national procedures in system and grid operations. Stepwise, the integration can be developed further when the infrastructure is prepared to meet the required changes.

System services and balancing mechanism could, at least in a transition period, continue with a minimum of international harmonisation.

The trade system can be implemented with the present infrastructure regarding metering and control facilities and data acquisition system.

Meetings and seminars on market simulation of trade in the new market have been successful. Simulation of market prices based on different market scenarios is experienced to be one of the most important activities in the planning period, to reduce uncertainty by decision makers and achieve consensus prior to implementation of new procedures and rules.

VII CENTRAL AMERICAN REGIONAL MARKET - SIEPAC

1. COUNTRIES COVERED BY THE INITIATIVE

The Central American regional electricity market currently consists of six countries: El Salvador, Guatemala, Honduras, Nicaragua, Costa Rica and Panama. Another country in the region, Belize, is not yet integrated to the regional electricity market.

Figure 7: SIEPAC Geographical Area

Central America is home to some of the world's poorest and most densely populated countries. Over half of the region's population lives in rural areas, and as many as two-thirds survive on less than US$2 per day. Agriculture and manufacturing for export constitute the major components of many Central American economies.

2. BASIC CHARACTERISTICS OF THE REGION

The following table shows the most relevant economic and demographic indicators of the Central American countries.

Country	Population 2006	GDP per Capita 2006 (PPP)	Peak Load 2006	Energy Consumed 2006	Electrification Level 2006
	Millions	USD	MW	GWh	%
Guatemala	12.7	5,000	1017	6070	95
El Salvador	6.9	4,900	881	5194	99 U / 61 R
Honduras	7.5	3,100	1088	5947	67

Country	Population 2006	GDP per Capita 2006 (PPP)	Peak Load 2006	Energy Consumed 2006	Electrification Level 2006
Nicaragua	5.7	3,100	565	2869	73 U / 30 R
Costa Rica	4.1	12,500	1800	6824	100 U / 97 R
Panama	3.2	8,200	1024	5696	81

U: Urban; R: Rural

Table 8: SIEPAC – Countries' Basic Characteristics

The region does not have any special energy sources, has very little oil and practically no natural gas reservoirs. It has some geothermal energy potential, and indeed there are some developments in this field, the available scale is however, small.

The composition of the installed capacity is as follows:

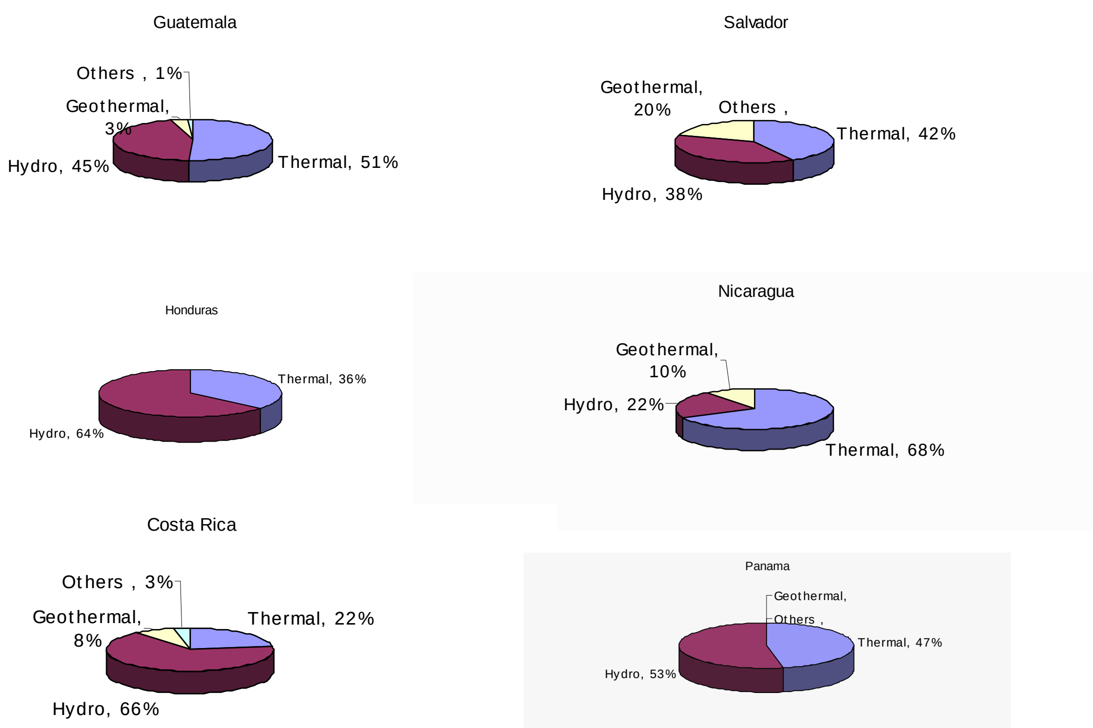

Figure 8: Composition of Installed Capacity in SIEPAC Region

Central American countries rely heavily on imported petroleum and indigenous hydropower to meet domestic energy demand. Imported petroleum comes primarily from Venezuela and Mexico, under the terms of the San Jose Pact and the Caracas Energy Agreement. The region consumes no natural gas and very little coal (only in a 120 MW power plant in Guatemala). Historically, hydroelectric power has dominated Central America's electricity sector. However, since opening up the market to foreign investors in the middle and late 1990s, the use of thermal generation has increased rapidly.

The big energy potential in the region lies in the neighbouring countries at both ends of the region: Mexico and Colombia. Both countries are very rich in terms of oil and hydro resources.

In December 1999, Guatemala and Mexico signed an agreement to construct a natural gas pipeline from Ciudad Pemex (Pemex City), in southern Mexico, to the southern Guatemalan city of Escuintla. The approximately 500 Km pipeline would follow the path of an existing oil pipeline in Guatemala's Peten jungle region (northeast of Guatemala), and the gas would be used for both industry and electricity generation. Initial demand is estimated to be about 40 million cubic feet per day (MMcf/d). The pipeline could eventually be extended to the borders of Honduras and Salvador, and possibly Nicaragua and Costa Rica. It can also be part of a wider Central America gas pipeline network.

Another project that has been analyzed the past few years is to import oil through a pipeline from Colombia to Panama and Costa Rica. However, the project is currently not advancing.

Another energy potential in the region is LNG. Not far away from the region is Trinidad and Tobago, one of the big LNG producers in the world. For many years the construction of a big gas fired plant located in Honduras (El Cajon) has been under analysis and feasibility studies.This project consists of an 800 MW combined cycle plant in Honduras, with a gasification plant, port facilities for unloading the LNG and transmission lines to export the energy to El Salvador and Guatemala.

These last energy potentials however, in order to be economically feasible, require a scale which largely exceeds the size of each of the countries' markets, being the only way to materialize any of them, the markets' integration as SIEPAC proposes.

3. COUNTRY'S INSTITUTIONAL FRAMEWORKS

3.1. National Market Structure and Private Sector Participation

From 1996 to 2000, four countries restructured their electricity sectors: Guatemala, El Salvador, Nicaragua and Panama. Reforms included: (1) the creation of wholesale competitive markets; (2) the privatization of the distribution and generation (partial) sectors; and, (3) the creation of Independent Regulatory Agencies and System Operators.

Honduras and Costa Rica did not reform their electricity sectors, but both countries accepted Independent Power Producers, signing contracts with the state-owned utility companies.

The next table summarizes the most relevant issues of the electricity sector's organization in the region.

			Private Sector Participation		
Country	Reforms	Wholesale Market	Distribution	Generation	Transmission
Guatemala	Yes	Yes	All	Yes (60%)	No
El Salvador	Yes	Yes	All	Yes (50%)	No
Honduras	Partial	No	No	Yes (35%)	No

			Private Sector Participation		
Country	Reforms	Wholesale Market	Distribution	Generation	Transmission
Nicaragua	Yes	Yes	All	Yes (75%)	No
Costa Rica	No	No	No	No	No
Panama	Yes	Yes	All	All	No

Table 9: Power Sectors Organisation in SIEPAC Area

3.2. NATIONAL INSTITUTIONAL ARRANGEMENT

The principal institutions acting in each country are:

Country	Policies	Regulator	System Operator and Market Administrator
Guatemala	MEM (Ministry)	CNEE (Energy National Commission)	AMM (Wholesale Market Administrator) Independent
El Salvador	MARN (Ministry)	SIGET (Energy and Telecomm)	UT (Transactions Unit) Independent
Honduras	SERNA (Secretary of Natural Resources)		ENEE (National Utility)
Nicaragua	CNE (National Energy Commission)	INE (National Institute for Energy)	CNDC (National Dispatch Center) Transmission company
Costa Rica	MINAE (Ministry)	ARESEP (Regulatory Authority for Public Services)	ICE (Utility)
Panama	COPE (Energy Policies Commission)	ERSEP (Regulatory Entity for Public Services)	CND (National Dispatch Center) Transmission Company

Table 10: Main Institutions in SIEPAC Countries

4. REGIONAL MARKET BACKGROUND

In the early 1990's, the Spanish Utility ENDESA, with the full support of the Spanish

Government, started the promotion of the construction of a power line linking the six Central American countries, as part of the many activities organized between Spain and Latin American countries to celebrate the fifth centennial since the discovery of America. This promotion included a big financial support for this initiative, comprising grants and soft loans from the Spanish Government.

Based on that initiative, during a period of some years there was an intense negotiation process between that Spanish utility, the Spanish Government and all the Central American countries' governments, through which the implementation of that initiative was rounded.

As part of those negotiations, it was concluded that the development of such an investment needed to be complemented with the development of a regional power market organizing the transactions among the countries and allowing maximum usage of the new infrastructure to be built.

Another relevant issue in this process was that the Inter-American Development Bank (IADB) was invited to join the initiative. The IADB contributed with additional financial support and was nominated as a trustee of the Spanish funds.

On December 30th, 1996, in Guatemala City, the six Central American republic presidents signed a Treaty. This Treaty was partially modified through a protocol that also was signed by all presidents, in Panama City, on July 11th 1997.

This Treaty and its protocol, were ratified by all national parliaments in 1998, and became mandatory for all participating countries.

The whole Treaty and its Protocol #1 is included in Appendix 1 to this section, provided that it is very illustrative to see all the details included in both documents. The main institutional issues addressed in them, are:

1. The development of a regional transmission system (SIEPAC) that will reinforce the existing interconnection among the countries in the region. The project consists of 1.830 Km of 230 kV line, connecting 16 substations, some of them existing and some new.

2. For this reason, the Countries agreed to create a special purpose company to develop this infrastructure: the EPR (Empresa Propietaria de la Red: the network owner company). It was formally created on February 1999 with the six participant countries as its shareholders. One year later, the Spanish utility ENDESA became shareholder of the company.

3. The creation of a regional electricity market (MER) in Central America in the future. The MER was the environment for all market participants of the six countries, to trade energy, coordinated by a regional system and market operator (EOR).

4. The creation of the CRIE (Comisión Regional de Integración Eléctrica, regional commission for electrical integration), with jurisdictional powers to deal with the cross border electricity transactions among the market participants.

5. The custody of this Treaty was entrusted to SICA[1].

5. REGIONAL MARKET OBJECTIVES

SIEPAC has two main objectives:

(i) the gradual formation and consolidation of a regional electricity market through the creation and establishment of the appropriate legal, institutional, and technical

[1] SICA is the System for the Central American Integration and was created on December 13th, 1991. Its main objective is the creation of a juridical and political framework for all aspects and levels of integration, such as economic, social, cultural, politic, environmental, allowing to visualize that integration as integral for the region.

mechanisms to promote private sector participation, especially in the development of additional generating capacity; and

(ii) the development of an electric interconnection infrastructure (230 kV transmission lines with a capacity of 300 MW with the corresponding substations) to facilitate trading of electric power among the agents of the regional electricity market.

6. EXPECTED BENEFITS

The expected benefits to be obtained through the creation of this regional trading system complemented by the infrastructures development are the following:

1. Development of larger power plants with lower unit costs and benefits stemming from economies of scale.
2. Economic benefits to be obtained from coordinating the operation among the six countries' systems, taking advantage of the diversity in the region's electricity supply sources, while reducing operating costs.
3. Taking advantage of the peak demand variations in the different countries, minimising the reserve and expansion needs in interconnected systems.
4. Assistance to any country with rationing problems, which economically translates into lower failure costs and less unsaved energy.
5. Greater reliability in the systems' operation and greater security in meeting demand.

7. REGIONAL INSTITUTIONAL ARRANGEMENTS

As already mentioned, there are four key regional institutions/organizations dealing with both, the development of SIEPAC and its operation and functioning:

- Comisión Regional de Interconexión Eléctrica - CRIE (Regional Regulatory Commission)
- Ente Operador Regional (EOR)
- Empresa Propietaria de la Red (EPR) (Owner Company of the Line)
- Consejo de Electrificación de América Central - CEAC

7.1. CRIE (REGIONAL REGULATORY COMMISSION)

CRIE: MER's Regulatory Commission	
Location	It is located in Guatemala and started functioning in 2000.
Features	It has its own registration with capacity in International Public Rights. It has enough jurisdictional power to: deal with judicial and extra-judicial acts; to contract on its own; and to organize and run its own operation as necessary to comply with the responsibilities assigned to it by the Treaty, both, inside the Territory of Guatemala, or in any of the signatory countries, observing the principles of satisfying the

	public interest, non discrimination, free competence and publicity of its acts.
Composition	One Commissioner per member country, designated by each Government, for five years, which can be renewed. It also has a technical and administrative structure.
Resources	Charges paid by the market participants, special funds contributed by the member countries' Governments and the amounts of penalties and economic sanctions.
Objectives	• Enforce the compliance of the Treaty, Protocols, Regulations and other complementary regulatory instruments. • Foster and promote market development and consolidations, as well as its transparency and well functioning. • Promote competition among market participants.
Functions	• Regulate MER's functioning. • Guarantee fair competition and non discriminatory conditions for all participants. • Propitiate market development, both at its initial stages and in its evolution. • Grant authorizations to market participants to enter and trade in the regional market. • Provide measures to avoid or minimize power market dominant positions. • Impose sanctions as established in the protocols and MER's Regulations, for non compliance with the Treaty, or regulations or procedures. • Approve Regional Transmission Tariffs. • Settle disputes between market participants. • Approve EOR's fees. • Evaluate market evolution. • Request audited accounting information to the business units (of those vertically integrated utilities acting as market participants). • Coordinate with the national regulatory agencies, the regulatory measures required for the proper development, functioning and evolution of the Regional Market.

Table 11: CRIE Characteristics

7.2. EOR: REGIONAL SYSTEM AND MARKET OPERATOR

EOR: MER's System and Market Operator	
Background	Created by Article 18 of the Treaty.
Location	It is located in El Salvador and started functioning in 2002 (temporarily subcontracting this role with the local market

	administrator) and definitely as from June 2006, when the EOR was definitely settled in this country.
Features	It has its own registration with capacity in International Public Rights. It has enough jurisdictional power to deal with judicial and extra-judicial acts, to contracts on its own and to organize and run its own operation as necessary to comply with the responsibilities assigned to it by the Treaty, both, inside the Territory of El Salvador or in any of the signatory countries, observing the principles of satisfying the public interest, non discrimination, free competence and publicity of its acts.
Composition	Two representatives per member country, designated by each System and Market Operator. It also has a technical and administrative structure.
Resources	Funds required for operating EOR shall come from service charges for operating the system paid by the Market agents, economic sanctions, and interest from commercial transactions, donations and transfers from public or international organizations, based on a budget approved by the CRIE.
Objectives & Functions	• Propose the operating procedures for the Market and the use of the regional transmission networks to REIC. • Ensure that the operation and regional delivery of energy is carried out using financial criteria, so that it may attain suitable security, quality and reliability standards. • Carry out commercial management of transactions between Market agents. • Support the Market's development process by supplying information. • Devise an expansion plan indicative of regional transmission and generation, foreseeing the establishment of regional reserve margins and put it at the disposal of the Market agents.

Table 12: EOR Characteristics

7.3. EPR: OWNER COMPANY OF THE LINE

EPR: Owner Company of the Line	
Background	Created by Article 15 and 16 of the Treaty. The commercial name is Empresa Propietaria de la Linea, S.A. (owner company of the line, ltd).
Location	It was originally created in Panama, in 1998. Its headquarter was located in Costa Rica in 2002.
Features	It has its own registration under the private company's law. It has enough jurisdictional power to deal with judicial and extra-judicial acts, to contract on its own and to organize and run its own operation as necessary to comply with the responsibilities assigned to it by the Treaty, both, inside the Territory of El Salvador or in any of the signatory countries, observing the principles of satisfying the public

	interest, non discrimination, free competence and publicity of its acts
Shareholders	• Costa Rica: Instituto Costarricense de Electricidad (ICE) and Compañía Nacional de Fuerza y Luz de Costa Rica (CNFL) • El Salvador: Comisión Ejecutiva Hidroeléctrica del Río Lempa (CEL) y la Empresa Transmisora de El Salvador (ETESAL) • Guatemala: Instituto Nacional de Electrificación de Guatemala (INDE) • Honduras: Empresa Nacional de Energía Eléctrica de Honduras (ENEE) • Nicaragua: Empresa Nacional de Transmisión Eléctrica de Nicaragua (ENTRESA) • Panama: Empresa de Transmisión Eléctrica S.A. de Panamá (ETESA) • Spain: ENDESA Internacional de España • Colombia: Grupo Empresarial ISA de Colombia
Resources	Remuneration for the availability and use of the regional networks paid by the Market agents in accordance with the methodology approved by CRIE.
Mission	Develop, design, finance, build and maintain the first interconnection system in Central America. Also manage the SIEPAC infrastructure in a competitive manner, with reliability and quality, and in harmony with the environment and social responsibility. In the future, to care about the increasing transmission capacity needs.

Table 13: EPR Characteristics

7.4. CEAC: CENTRAL AMERICAN ELECTRIFICATION COUNCIL

CEAC, the Central American Electrification Council, has the overall coordination role for the SIEPAC project.

This function has been developed mainly through two organizational instruments:

- Grupo Director (Directing Group), integrated by representatives of all member countries. During the initial steps of the creation of SIEPAC, this group made most of the decisions regarding the institutional development, general design approval and hiring services for the upcoming works.

- Unidad Ejecutora (Management Unit). This unit has been, since the very beginning of the SIEPAC project, the executive cell in charge of its daily issues, with a permanent staff of about 5 to 10 people, depending on the project's different stages. It is located in Costa Rica, and will go off once the implementation phase comes to an end.

7.5. RELATIONSHIPS BETWEEN THE INSTITUTIONS

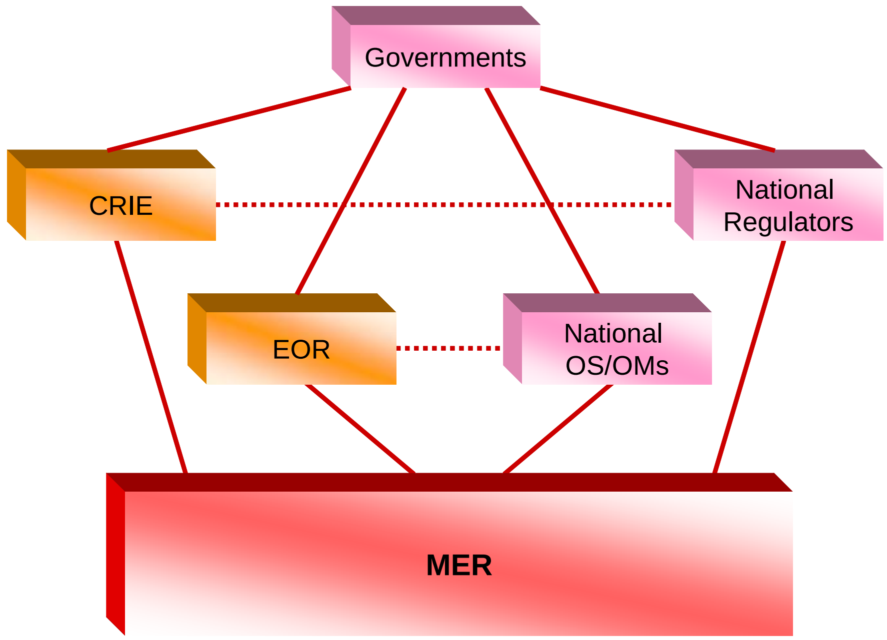

Figure 9: SIEPAC – Relationship Between Institutions

7.6. MOST IMPORTANT REGIONAL MARKET IMPLEMENTATION MILESTONES

Since the signing of the Treaty, the following steps have been undertaken:

- Year 2000: Completion of the regional market's general design.
- Year 2000: Launch of the Regional Regulatory Agency (CRIE).
- Year 2001: Launch of the Regional system operator (EOR).
- Year 2002: CRIE approved the transitory code for operation of the MER; MER started operations.
- Year 2002: The six countries get interconnected with the commissioning of the 230 kV line linking Honduras with El Salvador, connection of the six countries' grids.
- Year 2002-2004: Development of the final version of market and transmission codes and the organization of CRIE and EOR.
- Year 2005: CRIE approved the MER Regulation (RMER).

8. REGULATION OF THE MER

The regional market regulation was developed in three main phases:

- **General Design**, establishing all regulations required and proposing the guidelines for their detailed development, ensuring consistency and fulfillment of the general objectives for the regional market.
- **The RT-MER: Transitory Regulation for the MER.**
- **The R-MER: Regulation of the MER**, including specific regulations, including mainly the Transmission Code and the Settlement Code.

8.1. General Design

The mot relevant dispositions of the General Design are:

- MER constitutes the seventh market, superposed with the existing markets in the six countries.
- Market participants of the six countries are automatically considered market participants in the MER, and are allowed to participate in it.
- Countries can preserve local regulations, with the necessary changes for compatibility with regional codes.
- The Regional Transmission Grid (RTR), which is defined as where international trade occurs and is monitored by the EOR. The RTR is formed by existing interconnections between countries; parts of the existing country grids, the SIEPAC project. Future expansions of transmission capacity reinforcing it for cross border trading will also be considered part of the RTR, and planned and risk expansions of the RTR.
- Ex-ante and ex-post prices will be set in each node of the RTR, taking into consideration losses and congestion (see clarifications below).
- Day ahead spot market and real time balance.
- The rules for transmission access, establishing basically open access to the available RTR transmission capacity, applying specific rules for its determination.
- Firm contracts, which are contracts physically dispatched when requested by the parties (the selling party must deliver the agreed amounts at the node where the transactions were agreed).
- Parties of firm contracts must obtain Congestion Rights (CR) between the injection and withdrawal nodes.
- The EOR must organize periodic auctions of CR where market participants will be able to purchase CR required for having firm cross-border contracts.
- Transmission Use of System Charges (TUOS) will have three components:
    - √ Variable costs, associated to losses and congestion
    - √ Toll, based on actual flows in the lines
    - √ Complementary charge: the part of the regulated revenues requirements of transmission companies not collected through toll and variable costs.
- At the final stage of the market development, RTR's expansions will be centrally planned by the EOR. Until then there is no centralized planning, being each country responsible for its own expansion planning process.
- Market participants' parties are allowed to build their own transmission facilities. Sponsors of this type of expansions will receive the CRs corresponding to the new facilities, and may get the right to perceive a toll.

8.2. Transitory Regulation for the MER (RT-MER)

The most important features of the RT-MER are:

8.2.1. DAY-AHEAD DISPATCH: A JOINT ENERGY AND TRANSMISSION AUCTION

An hourly day-ahead energy and transmission dispatch is currently in operation in Central America for international electricity trade transactions. The dispatch mechanism allows market participants (generators, distributors, eligible large customers) to submit energy-only bids and offers and requests for point-to-point transmission services; while the charges for transmission services are calculated through a regulated procedure.

There is a hierarchical process, where market participants inform the national MSO, which informs the EOR. Information presented to national MSO depends on each country's internal regulations. The national MSO presents information to the EOR on offers and bids for the day-ahead market and on bilateral contracts.

In a spot market that is based on nodal prices, the price of energy and the price of the transmission services are closely bound. The difference in the price of energy between two nodes is equivalent to the price of "using" the transmission service, i.e. the variable transmission charges or CVTs[2].

Before commissioning the connecting line between El Salvador and Honduras (230 kV) in early 2002, Guatemala and El Salvador formed the Northern subsystem while Honduras, Nicaragua, Costa Rica and Panama formed the Southern subsystem.

Guatemala and El Salvador exchanged energy at their common border. Honduras, Nicaragua, Costa Rica and Panama, in addition to the trade between neighbouring countries at the common border, reached an agreement on a methodology for the establishment of "wheeling" charges - i.e. to determine the charges for the transmission services provided to international transactions in which neither the seller nor the buyer is located in the "wheeled" sub-system (that providing the transmission service). This represented an important step in the integration process.

The wheeling charges were simply the difference of short-run marginal costs at the border substations (SRMC extraction – SRMC injection), i.e. the CVTs. A regional working group used to meet regularly to carry out calculations of the CVTs for "wheeling" transactions - per season (wet/dry), demand level (peak/off-peak), level and direction of wheeling. The CVT curves ($/MWh vs. MWh) measure the expected impact of a pass-through transaction on the transited system (Nicaragua and Costa Rica). If CVT < 0.0 then CVT = 0.0; i.e. if a given pass-through transaction reduces the losses of the transited system, the transaction receives no compensation, and makes no payment.

The Transitory Code (RT MER) includes a day-ahead dispatch that can be seen as a "natural" extension of previous practices in the Southern subsystem since it continues using the CVT curves (now for El Salvador and Honduras – potentially transit systems, in addition to Nicaragua and Costa Rica).

The RT MER allows energy-only bids (demand) and offers (supply), i.e. the opportunity market, as well as transmission services bids (demand). The supply curves for transmission services are "regulated", i.e. the charges for transmission services are evaluated as: CVTs + operative toll (for the tie-lines only). The basic contracts in the RT MER are: (1) financial, considered in the net settlement and with no impact on the dispatch other than through bids and offers to the opportunity market; (2) physical flexible, which are requests for transmission services between two nodes and a maximum price that the bidder is willing to pay for the requested transmission services; and (3) physical flexible, where the bidder may replace his injection (or part of it) by purchases in the opportunity market (at a specified maximum price).

Although the scheme has been an in-house development in the region, similar ideas are

[2] CVTs – Costos Variables de Transmisión (variable transmission costs).

being applied or proposed in other markets, e.g. option (2) has recently been introduced at PJM and a very similar scheme has been proposed to auction the tie-lines' transmission capacity in Europe.

For the opportunity market, the algorithm "matches" supplies and demands, taking into account payments to "wheeled" countries (CVTs + operative toll). The opportunity market "competes" for the transmission services with the demands for the "pure" wheeling services associated to contracts. The EOR does not have information on the prices of these contracts, solely the prices that the agents are willing to pay for the wheeling services, balanced injection/extraction in pairs.

EOR settles all the cross border transactions. It informs each national OS/MO, which informs THEIR market participants.

The EOR identifies the non-fulfilment of the country, based on total deviations between scheduled and realized cross-border flows. Deviations are billed to each OS/MO. The OS/MO identifies the market participants' deviations, based on ordered and realized generation-consumption. The OS/MO bills to market participant the deviations between ordered and realized generation/consumption.

Non fulfilments are considered deviations, and the responsible considered trading such deviation in the spot market. There is a particular regime for deviations during regional emergencies.

8.2.2. Operative Toll

In the final regulation of the MER the application of a non-operative toll is being considered, i.e. independent of the transactions that occur in the MER. In the RT-MER though, an operative toll is being used, i.e. applicable to the transactions that occurs in the MER. The toll ($/MWh) is applied only to the energy transmitted through the tie lines between the countries. The operative toll's values are approved by the CRIE and are part of a RT-MER's appendix. The operative toll causes a dead weight loss but its impact on transactions does not seem to be important.

8.2.3. The Regional Dispatch

The total charges for the transmission services is then the sum of the CVTs plus the operative toll, i.e. the resulting curve of total charges ($/MWh vs. MWh) is a curve displaced upwards with respect to the CVTs curve.

The CVT curves are calculated weekly ex-ante by the EOR through simulations of the wheeling system's economic dispatch (isolated dispatch). The CVT curves are evaluated at discrete points characterized by the demand period (e.g. peak / off-peak), magnitude (0, 20, 40, 60 and 80 MWh) and direction of the wheeling service (North to South / South to North), modelling the whole transmission system, i.e. from border to border. The CVT ($/MWh) is the difference of marginal costs between the nodes of retirement and injection. The CVTs are thus "anchored" to the wheeling systems' prices estimated from expected average conditions, which causes some inaccuracies. Additionally, if CVTs < 0.0, then CVTs = 0.0, which causes some inefficiencies.

8.2.4. Calculation of hourly nodal prices

The nodal price at node k (ρk) is defined as the incremental cost incurred to satisfy a marginal increase in the demand of energy at such node k; i.e. ρk is the increase in the total cost incurred (generation and transmission) to satisfy a marginal increase in the demand at node k, maintaining the optimality and feasibility conditions (taking into account the necessary adjustments so that the re-dispatch continues being optimal and feasible).

The hourly nodal prices ρk´s are a by-product of the MER's dispatch (24 hourly dispatch), which is subject to nodal balances, offers limits and transmission limits, where:

- If transaction i is an extraction request (demand), the price (positive) will be the maximum price that the bidder is willing to pay for the purchase of energy from the MER.
- If transaction i is an injection offer, the price (negative) will be the minimum price that the bidder is willing to receive for the sale of energy to the MER.
- If transaction i is a request for transmission services between two nodes, the price (positive) will be the maximum price that the bidder is willing to pay for the requested transmission services.

8.2.5. RT-MER Summary

The next Figure shows in a schematic way how the transitory code functions.

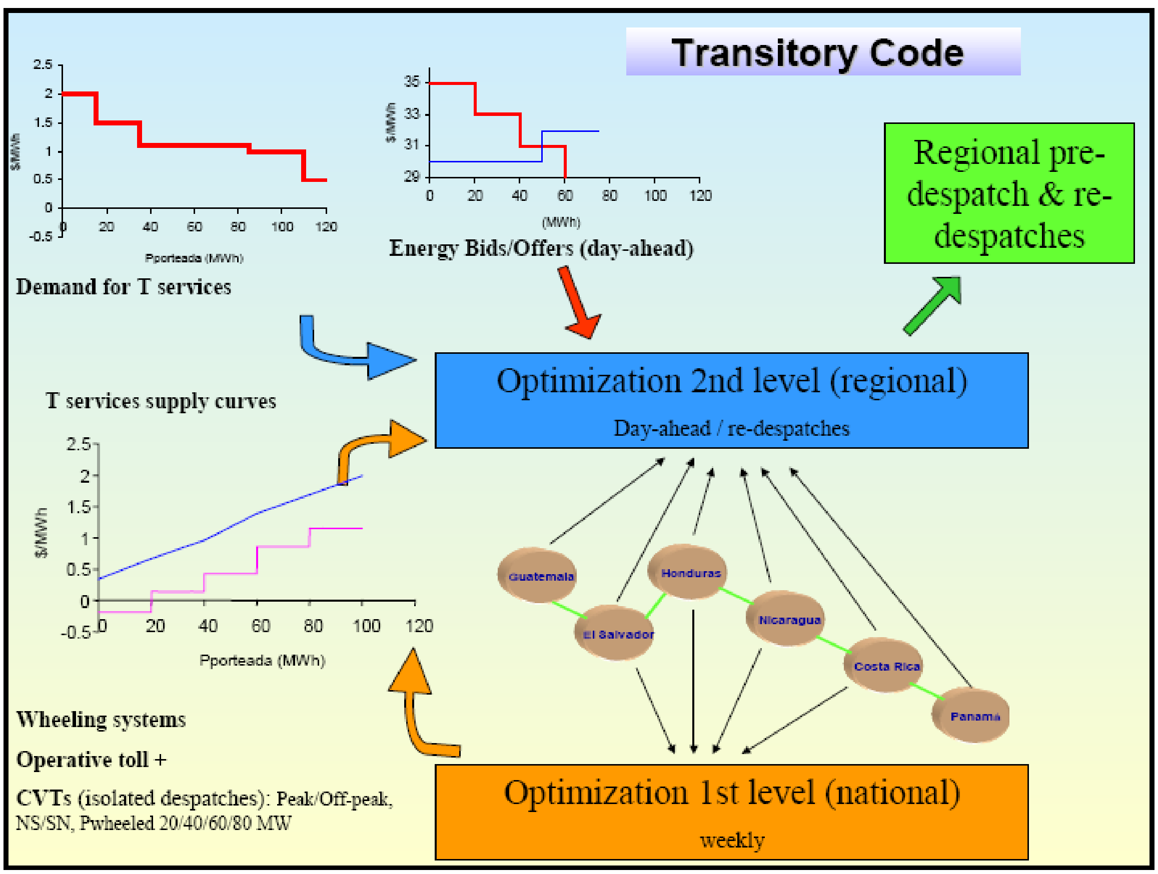

Figure 10: SIEPAC – Transitory Code Functions

8.3. THE MER'S FINAL REGULATION: R-MER

It is based on the Treaty and the MER's General Design, and is composed of five Books[3]:

- Book I – General Aspects.
- Book II – Technical and Commercial Operation.
- Book III – Transmission.
- Book IV – Sanctions and Disputes.
- Book V – Transitory Dispositions.

The body in charge of the MER's regulation approval and amendment is the CRIE.

The MER's operation is hierarchical, with a centralized dispatch of the transmission capacity and a centralized dispatch of energy.

The first level of this hierarchical operation is occupied by the EOR, and the second level is occupied by the national System and Market Operators (OS/MO).

The products that are commercialized in the MER are:

- Hourly energy
- Transmission services
- Ancillary services
- MER's Operation and Administration Services.

These products are traded in two different markets:

- Contract Regional Market
- Opportunity (short term) Regional Market

The Regional Transmission Grid is integrated by all national Transmission lines that may significantly influence the regional exchanges. These lines will be subject to national and regional regulation, and its technical and commercial operation coordination will be in charge of the EOR.

The RTR expansions could be of two kinds:

- Risk Expansions, which will be able to be undertaken by market participants to their own risks, receiving in exchange the Transmission Rights on the new transmission capacity
- Planned Expansion, carried out based on the so called Regional Transmission Expansion System (SPTR).

Transmission tariffs are based on three components:

- Transmission Variable Charges that include marginal looses costs and congestion costs.
- Toll, based on actual flows in the lines.
- Complementary Charge, associated only to costs of expansions decided through the Regional Transmission and Generation Planning System.

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[3] See Appendix 2 to this section for content details

8.4. EXCHANGES RESULTS IN 2006

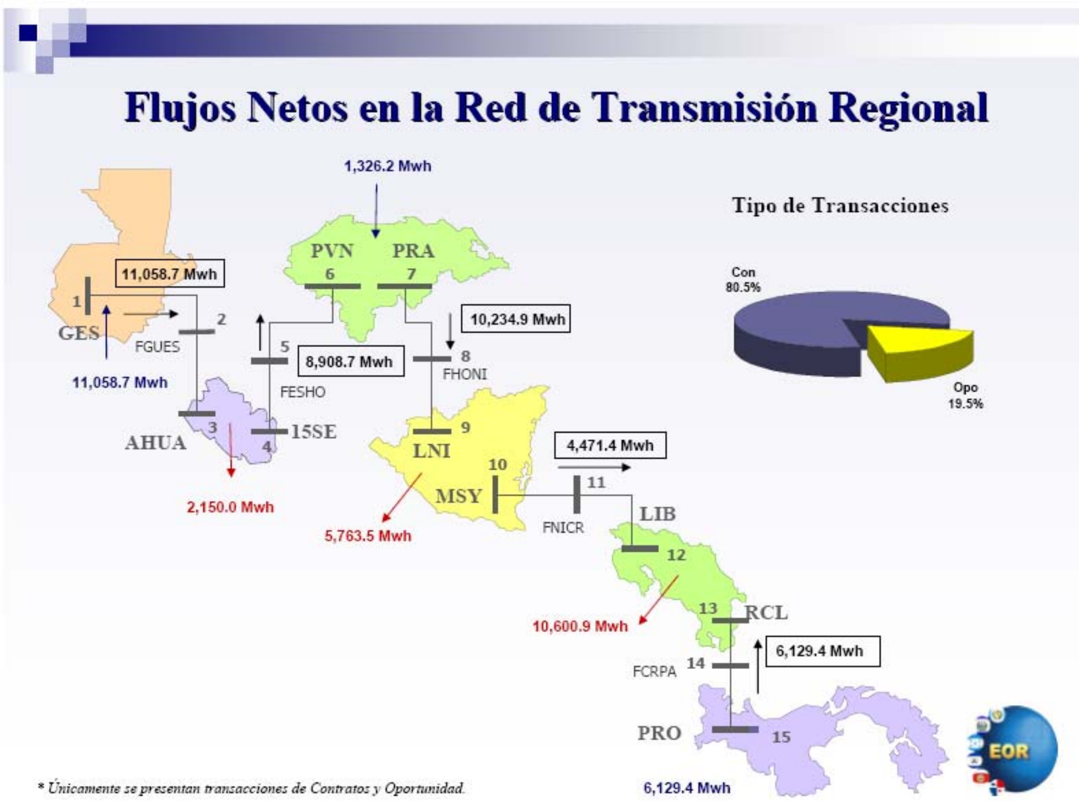

Figure 11: SIEPAC Exchanges in 2006

9. REGIONAL TRANSMISSION PROJECT

The next diagram shows SIEPAC's transmission line project.

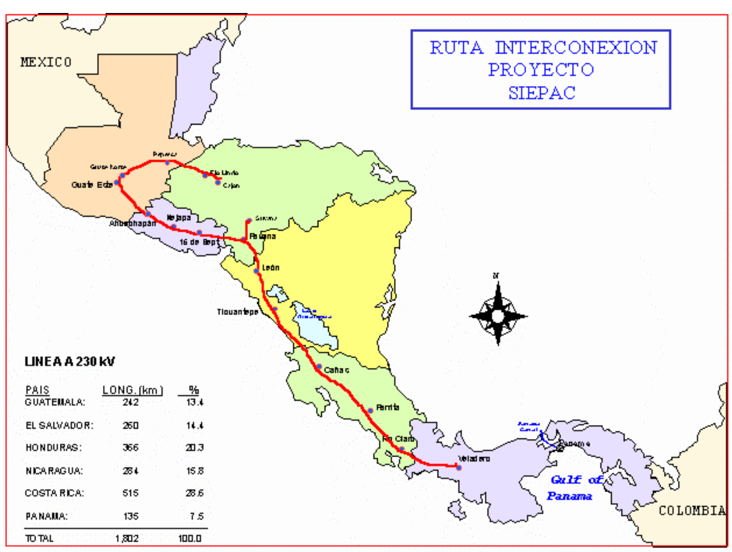

Figure 12: SIEPAC Transmission Line

10. LEARNINGS

It is not necessary to have an (almost) uniform regulatory framework for developing a regional market. In Central America there are four countries that have transformed and deregulated their electricity sectors, while two maintain their organization unchanged.

The countries that deregulated the sectors have different regulatory frameworks, with some important differences. One of the countries that did not deregulate, has an important participation of IPPs in its generation sector.

The solution of creating a regional market (the seventh market), with its own rules and institutions, with interfaces with the countries' markets is a pragmatic and realistic solution that allows the development of transactions.

The limited capacity of existing interconnections was not an obstacle. Nowadays the transactions between agents of different countries saturated several of the existing interconnections.

VIII SIEPAC - APPENDIXES

1. APPENDIX 1. THE TREATY AND ITS PROTOCOL

ADOPTION OF THE CENTRAL AMERICAN ELECTRICITY MARKET FRAMEWORK TREATY AND ITS PROTOCOL

ARTICLE 1. - The Central American Electricity Market Framework Treaty, signed in the city of Guatemala on 30 December 1996; in addition to its Protocol, signed in the city of Panamá on 11 July 1997, are hereby approved in each of their parts. The texts are as follows:

CENTRAL AMERICAN ELECTRICITY MARKET FRAMEWORK TREATY

The Governments of the Republic of Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama, hereinafter the "Parties",

CONSIDERING that, within the framework of the Central American Integration System (SICA), the States of the region have demonstrated their desire to initiate a gradual electricity integration process by developing a competitive regional electricity market, using transmission lines interconnecting their national grids and by promoting regional generation projects;

AWARE that a regional electricity market, underpinned by the interconnectivity of the countries' electricity systems, fosters the development of an electricity industry of benefit to all its inhabitants;

SECURE IN THE KNOWLEDGE that consolidating the regional electricity market will enable increased electricity transactions and will satisfy efficiently the needs of sustainable development in the region, within a framework of respect and protection for the environment;

TAKING INTO ACCOUNT that the Presidents of the six countries of Central America, at the fifteenth, sixteenth and seventeenth Summits, stated that the leading priority was to spur on realization of the project known as the Electrical Interconnection System for the Countries of Central America (SIEPAC);

Have agreed to sign this Central American Electricity Market Framework Treaty, which shall be governed by the following:

OBJECTIVE OF THE TREATY:

Article 1. - The objective of this Treaty is to establish and gradually expand a competitive regional Electricity Market, hereinafter the "Market", based on reciprocal non-discriminatory treatment that will contribute to sustainable regional development within a framework of respect and protection for the environment.

PURPOSE OF THE TREATY:

Article 2. - The purpose of the Treaty is to:

(a) Establish the rights and obligations of the Parties.

(b) Establish conditions for growth within the regional Electricity Market, which shall supply in a timely and sustainable manner the electricity required for economic and social development.

(c) Stimulate greater and more competitive private participation in the electricity sector.

(d) Boost the interconnecting infrastructure necessary for developing the regional Electricity Market.

(e) Establish the conditions necessary for attaining acceptable levels of quality, reliability and security in supplying electricity in the region.

(f) Establish objective, transparent and non-discriminatory rules for regulating the operation of the regional electricity market and relations between the participating Market agents, in addition to establishing the appropriate regional bodies in order to attain these objectives.

(g) Ensure that the benefits derived from the regional electricity market reach all the inhabitants of the countries in the region.

PRINCIPLES GOVERNING THE TREATY:

Article 3. - The Treaty shall be governed by the principles of competition, progression and reciprocity, which are defined thus:

Competition:

Freedom to develop service provision activities based on objective, transparent and non-discriminatory rules.

Progression:

Foresight in the progressive development of the Market by having new participants join, progressively increasing coordinated operations, developing interconnected networks and strengthening regional bodies.

Reciprocity:

The right of each State to apply to another State the same regulations and standards that the State temporarily applies in accordance with the principle of progression.

THE REGIONAL ELECTRICITY MARKET:

Article 4. - The Market shall operate as a permanent activity of commercial electricity transactions, with short-term exchanges arising from the delivery of electricity with regional financial criteria and by the use of medium- and long-term contracts among the Market agents. The Market should develop gradually from an initially limited situation towards a broader, more open and competitive situation, underpinned by the existing and future infrastructure at the national and regional levels.

Article 5.- The Market's activities shall be undertaken by its agents, who could include companies generating, transmitting, distributing and marketing electricity; as well as major consumers. Market agents shall be able to purchase and sell electricity freely and without any form of discrimination. Nevertheless, when a country's legislation allows the same company to undertake two or more activities supplying electrical services or designates a sole company to undertake transactions in the Market, these companies shall establish separate business units enabling a clear identification of the costs of each activity. Participation of agents in the Market shall be governed by the rules contained in this Treaty, its protocols and regulations.

Article 6. - The Parties shall endeavour for the Market to become increasingly competitive by undertaking joint analyses at least every two years, based on recommendations made by the Regional Electrical Interconnection Commission (CRIE), a regional body established under Article 18 of this Treaty.

REGIONAL ELECTRICITY GENERATION:

Article 7. - Electrical transactions in the Market shall be carried out by generators of electrical systems designated as Market agents.

Article 8. - Power stations may be installed in any member country, complying with the requirements of each country's legislation.

Article 9. - Parties shall generate favourable conditions for the development of regional power plants, consistent with the efficient development of the regional Market.

Article 10. - The Regional Operating Entity (EOR), a regional body established under Article 18 of this Treaty, in coordination with the national electricity delivery bodies, shall coordinate operation of the electricity systems based on financial criteria.

REGIONAL TRANSMISSION:

Article 11. - Regional transmission shall be considered as the cross-border flow of energy between countries, enabling Market transactions by means of existing high-voltage networks and those that shall be built in the future.

Article 12. - Market agents shall freely access regional and national transmission networks. Charges for the use and availability of regional networks shall be approved by CRIE and charges for the use and availability of national networks shall be approved by the national regulatory body, which shall not practice discrimination in its use regionally.

Article 13. - The regional transmission companies shall have the transmission or transport of electricity as their sole purpose.

Article 14. - Remuneration for the availability and use of the regional networks shall be covered by the Market agents in accordance with the methodology approved by CRIE.

Article 15. - Each Government shall designate a public body in their country to participate in a publicly or privately funded company, with a view to developing, designing, financing, constructing and maintaining the first regional transmission system interconnecting the electricity systems of the six countries. This company, known as the Owner Company of the Network (EPR), shall be governed by private law and shall have legal domicile in a Central American country.

Article 16. - In accordance with the legal procedures of each country, each Government shall grant whatever respective permits, authorizations and concessions are necessary for EPR to construct and operate the first regional interconnection system. This shall have a lifetime of up to 30 years and is renewable.

Article 17. - In accordance with the legal procedures of each country, each Government agrees to grant EPR or other regional transmission companies whatever authorizations, permits or concessions are necessary for future expansions of the regional transmission networks.

REGIONAL BODIES:

Article 18. - In order to obtain improved and more effective compliance with the purposes of this Treaty and to organize relations between the Market agents, the Regional Electrical Interconnection Commission (CRIE) and the Regional Operating Entity (EOR) are established as regional bodies.

THE REGIONAL ELECTRICAL INTERCONNECTION COMMISSION:

Article 19. - CRIE is the regulatory body for the regional market, with independent legal personality and capacity in international public law applicable to the Parties. It shall be domiciled in one of the countries of Central America, to be defined by the Parties. Its lifetime shall be that of this Treaty.

Article 20. - CRIE possesses sufficient legal capacity to act judicially and extra-judicially and to undertake all acts, contracts and operations necessary or advisable to comply with its purpose, both within and outside the territory of the signatory parties to the Treaty, while respecting the principles that satisfy public interest, in addition to equality, free competition and openness.

Article 21. - In order to comply with its objectives and functions, CRIE shall comprise one commissioner for each member country, appointed by the respective Government for a period of five years, which may be renewed. CRIE shall possess whatever technical and administrative structure it requires.

Article 22. - The general objectives of CRIE are to:

(a) Enforce this Treaty and its protocols, regulations and other additional instruments.

(b) Endeavour to develop and consolidate the Market, in addition to ensuring its transparency and efficient operation.

(c) Foster competition among Market agents.

Article 23. - CRIE is competent to, *inter alia*:

(a) Regulate the Market's operation by issuing the necessary regulations.

(b) Take whatever general and specific measures are necessary for ensuring competitive and non-discriminatory conditions in the Market.

(c) Adopt decisions to spur development of the Market, ensuring its initial operation and its gradual development towards a more competitive situation.

(d) Approve the physical and financial delivery regulations, as proposed by EOR.

(e) Regulate aspects concerning regional transmission and generation.

(f) Resolve authorizations established by the Treaty, in accordance with its regulations.

(g) Adopt measures seeking to avoid any abuse of a dominant position in the Market by any agent.

(h) Impose those sanctions established by the protocols concerning non-compliance with the Treaty's provisions regulations.

(i) Approve the tariffs for the use of the regional transmission system in accordance with the corresponding regulations.

(j) Resolve conflicts between Market agents arising from the application of this Treaty.

(k) Authorize companies to act as Market agents.

(l) Approve the operational service costs of the system provided by EOR according to the corresponding regulation.

(m) Assess the development of the Market periodically and propose to the Parties whatever measures it deems advisable in order to move forward in consolidating the Market.

(n) Request audited accounting data from the business units established under Article 5.

(o) Coordinate, in conjunction with the national regulatory bodies, the measures necessary for the Market to operate efficiently.

Article 24.- Funds required for operating CRIE shall come from regulations and other charges borne by the Market agents, government contributions, economic sanctions, interest from commercial transactions, donations and transfers from public or international organizations, funds or resources earmarked by laws and regulations, and goods or rights acquired, whether in return for payment or free of charge.

The mechanism to determine the cost of regulation and auditing shall be established in the corresponding protocol.

THE REGIONAL OPERATING BODY:

Article 25. - EOR is the operating body of the regional Market, with independent legal personality and capacity in international public law applicable to the Parties. It shall be domiciled in one of the countries of Central America, to be defined by the Parties and its lifetime shall be that of this Treaty.

Article 26. - EOR possesses sufficient legal capacity to acquire rights and contract obligations, act judicially and extra-judicially and to undertake all acts, contracts and operations necessary or advisable to comply with its purpose, both within and outside the territory of the signatory parties to the Treaty, respecting the principles that satisfy public interest in addition to equality, free competition and openness.

Article 27. - In order to comply with its objectives and functions, EOR shall be directed by a Board of Directors comprising two Directors per Party, appointed by their respective Government or proposed by the Market agents of each country for a period of five years. Governments, by protocol to this Treaty, shall be able to implement another structure for the board of directors if they deem it advisable. EOR shall have whatever administrative and technical structure it requires.

Article 28. - The principal objectives and functions of EOR are to:

(a) Propose the operating procedures for the Market and the use of the regional transmission networks to CRIE.

(b) Ensure that the operation and regional delivery of energy is carried out using financial criteria, so that it may attain suitable security, quality and reliability standards.

(c) Carry out commercial management of transactions between Market agents.

(d) Support the Market's development process by supplying information.

(e) Devise an expansion plan indicative of regional transmission and generation, foreseeing the establishment of regional reserve margins and put it at the disposal of the Market agents.

Article 29.- Funds required for operating EOR shall come from service charges for operating the system and other charges borne by the Market agents, economic sanctions, interest from commercial transactions, donations and transfers from public or international organizations, funds or resources earmarked by laws and regulations, and goods or rights acquired, whether in return for payment or free of charge.

AUTHORIZATIONS:

Article 30. - Public bodies from member countries involved in generating, distributing and commercializing electricity are authorized to:

(a) Become Market agents;

(b) Purchase and sell electricity on a short-term basis under Market regulations; and

(c) Sign long-term energy trade contracts in the Market by means of a procurement procedure; all in accordance with Article 5.

Article 31. - Public bodies from member countries involved in generating, distributing and commercializing electricity are authorized to:

(a) Purchase on the international market whatever fuels are necessary for generating electricity.

(b) Purchase shares in the corporation constructing the first regional interconnection line. To such an effect, contributions can be made in cash and not in non-monetary forms, such as land, easement rights, designs or topography.

(c) Sign contracts to ensure payment for remuneration of the regional transmission networks.

(d) Pay the charges corresponding to the habitual operation of the regional bodies established by this Treaty.

COMMITMENTS OF THE GOVERNMENTS:

Article 32. - The Governments:

(a) Guarantee the free transit or circulation of electricity through their respective territories, for themselves or for third countries of the region, subject only to the conditions established in this Treaty, its protocols and regulations.

(b) Declare whatever electrical infrastructure works are necessary for the activities of the regional electricity market to be of public interest.

(c) Exempt those taxes on transit, import and export of electricity between their countries, which discriminate between Market transactions.

DISPUTE RESOLUTION:

Article 33. - The Market agents shall endeavour to reach agreement on the interpretation and application of this Treaty and shall strive to find a mutually satisfactory solution to any dispute that could affect its operation.

Article 34. - Disputes arising among Market agents that cannot be resolved through negotiation shall be referred to CRIE for final resolution.

Article 35.- Disputes arising between Governments concerning the interpretation and application of the Treaty that are not resolved by negotiation shall be referred for arbitration, at the request of one or the other Party in dispute, to the Central American Court of Justice or another body agreed upon by the Parties for final resolution.

PROTOCOLS:

Article 36. - In order to facilitate compliance and due application of the provisions contained within this Treaty, the Parties shall endorse the necessary protocols, which shall be framed in the principles, purposes and other provisions of this Treaty.

PRIVILEGES AND IMMUNITIES:

Article 37. - CRIE and EOR officials shall enjoy, within the territory of the Market member countries, the privileges and immunities accorded by concluding a protocol, without prejudice to the Headquarters Agreement for Regional Bodies established in this Treaty.

VALIDITY, RATIFICATION, ACCESSION, REGISTRATION AND TERMINATION:

Article 38. - This Treaty shall be subject to ratification and shall remain open for accession by other American States.

The Secretary General of the Central American Integration System (SG-SICA) shall be the depositary of the instruments referred to in the previous paragraph.

This Treaty shall be open-ended and shall enter into force eight days after the date on which the second instrument of ratification is deposited. For each Party that ratifies this Treaty or accedes to it after the second instrument of ratification has been deposited, the Treaty shall enter into force eight days after the State has deposited its instrument of ratification or accession.

The Secretary General of SICA, as depositary of the Treaty, shall send registered copies to the Ministry of Foreign Affairs of each member country, who it shall immediately notify when each one of the instruments of ratification is deposited.

When this Treaty enters into force, the Secretary General of SICA shall send a registered copy to the Secretariat of the United Nations, so that it may be registered pursuant to Article 102 of the Charter of the United Nations.

This Treaty may be terminated by any of the Parties by means of written notification to the Secretary General of the Central American Integration System, with ten years' prior notice, following the tenth year that it has been in force.

Article 39. - For this Treaty to be updated, it may be revised at the request of two of its member countries.

COPIES:

Article 40. - This Treaty has been signed in six equally authentic copies.

TRANSITIONAL ARRANGEMENTS:

FIRST. - The first protocol shall be signed within the three months subsequent to the Treaty entering into force.

SECOND. - CRIE shall be established within the six months subsequent to the Treaty entering into force, and EOR within the twelve months.

THIRD.- Temporarily, whilst EOR is being established, an electricity interconnection committee, comprising representatives of the electricity companies responsible for national delivery, shall coordinate operation of the interconnected systems, for which the Parties, through the bodies that they designate, shall provide the necessary support and resources.

PROTOCOL TO THE CENTRAL AMERICAN ELECTRICITY MARKET FRAMEWORK TREATY

The Republics of Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama, hereinafter "the Parties",

TAKING INTO ACCOUNT that the Presidents, meeting in Tegucigalpa, Honduras on 28 January 1997, instructed the Coordinating Council of the Central American Electrical Interconnection System (SIEPAC) to analyse the text of the Central American Electricity Market Framework Treaty, signed on 30 December 1996 in Guatemala;

CONSIDERING that the Coordinating Council of the Central American Electrical Interconnection System (SIEPAC), at its eighth meeting held from 6 to 7 February 1997 in the Republic of Panama, analysed the said Treaty and recommended the modifications necessary to facilitate its interpretation and application;

Have agreed to sign this Protocol:

Article 1. - Article 4 shall read as follows:

"Article 4. - The market shall operate as a permanent activity of commercial electricity transactions, with short-term exchanges, arising from delivery of energy using regional economic criteria and by medium- and long-term contracts among the Market agents. The market must develop gradually from an initially limited situation towards a broader, more open and competitive situation, underpinned by the existing and future infrastructure at the national and regional levels."

Article 2. - Article 15 shall read as follows:

"Article 15. - Each Government shall designate a public body from their country to participate in a publicly or privately funded company, with a view to developing, designing, financing, constructing and maintaining the first regional transmission system interconnecting the electricity systems of the six countries. Its constitutional social pact shall ensure that no member may possess a percentage of shares giving them majority control of the company. This company, known as Owner Company of the Network (EPR), shall be governed by private law and shall have legal domicile in a Central American country."

Article 3. - Article 16 shall read as follows:

"Article 16. - In accordance with the legal procedures of each country, each Government shall grant whatever respective permission, authorization and concession necessary to EPR to construct and operate the first regional interconnection system. This shall have a lifetime of up to 30 years and is renewable."

Article 4. - Article 27 shall read as follows:

"Article 27. - In order to comply with its objectives and functions, EOR shall be directed by a Board of Directors comprising two Directors per Party, appointed by their respective Government or proposed by the Market agents of each country for a period of five years. Governments, by protocol to this Treaty, shall regulate the structure of the Board of Directors. EOR shall have the administrative and technical structure that it requires."

Article 5. - Article 29 shall read as follows:

"Article 29. - The resources required for operation of EOR shall come from service charges for operating the system approved by CRIE and other charges borne by the Market agents, economic sanctions, commercial management interests, donations and transfers from public or international bodies, funds or resources earmarked by laws and regulations, and goods or rights acquired, whether in return for payment or free of charge."

Article 6. - Article 35 shall read as follows:

"Article 35. - Disputes arising between Governments concerning the interpretation and application of the Treaty that are not resolved by negotiation shall be subject to arbitration."

Article 7. - The Second Transitional Arrangement shall read as follows:

"Second. - CRIE shall be established within the six months subsequent to the Treaty entering into force, and EOR within the twelve months."

Article 8. - This Protocol shall be subject to ratification and shall remain open for accession by other American States.

Article 9. - The Secretary General of the Central American Integration System shall be the depositary of this Protocol and shall send registered copies to the Ministry of Foreign Affairs of each member country, who it shall immediately notify when each one of the instruments of ratification or accession is deposited.

Article 10. - This Protocol shall enter into force eight days after the date on which the second instrument of ratification is deposited. For States who ratify or accede after that date, it shall enter into force eight days after the instrument of ratification or accession is deposited.

Article 11. - Any of the Parties to this Protocol shall be able to terminate it at the same time as terminate the Treaty by means of written notification to the depositary, with ten years' notice after the tenth year of being in force.

Article 12. - When this Protocol enters into force, the Secretary General of the Central American Integration System shall send a registered copy to the Secretariat of the United Nations, so that it may be registered pursuant to Article 102 of the Charter of the United Nations.

ARTICLE 2.- The obligations and rights of Costa Rica as a Contracting Party, in addition to the functions of Market agents corresponding to domestic law, are assigned to the Costa Rican Electrical Institute, which has been entrusted with the rational development of sources producing physical energy that the nation possesses and the planning of the national electricity system.

ARTICLE 3. - The Costa Rican Electrical Institute is hereby authorized to participate as a shareholder in the owner company of the Central American electricity network.

Applicable as from date of publication.

2. APPENDIX 2. R-MER BOOKS' DETAIL CONTENTS

Book I: General Aspects

- **Glossary**
  - Definitions
  - Terminology
  - Objectives
  - Structure
  - RMER Purpose and Application
  - Interpretation
  - RMER Administration
- **Information**
  - Confidentiality
  - Report to Regional entities
  - Regional Data Base
- **Market Participants**
  - Market Participants
  - Rights and Obligations
  - Requirements for Trading in the MER
  - Requirements to stop Trading in the MER
  - Participants Suspension and Disable
  - Participant Registry
  - Market Fees

Book II. Technical and Commercial Operation

- **Commercial Operation**
  - General organization
  - Contract Regional Market. Features and Organization
  - Opportunity Regional Market. Features and Organization
  - Nodal prices system
  - Ancillary Services
  - Regional Transmission Services
  - Other Services
  - Guarantees
  - Commercial Data Base
- **Invoicing**
  - Commercial Metering System
  - Post-dispatch
  - Trading and charges Conciliation
  - Timing and Information obligations (pre- and post-dispatch)
  - Regional Economic Transactions Document
  - Invoicing
  - Conciliations and invoicing review and dispute resolution
  - Payments
  - Payment Guarantees
- **Technical Operation**
  - Hierarchical Operation
  - Regional Data Base
  - Telecommunications, Information Exchange and Operation Supervision
  - Audits to the EOR
- **Operational Planning**
  - Operational Security
  - Medium term operational Planning
  - Operational Criteria
  - Simulation Software
  - Information
  - Reporting
- **Regional Pre-dispatch**
  - Opportunity Bids and Contractual Commitments
  - Flexibility Bids associated to non firm contacts
  - Ancillary Services Bids
  - Invalid Bids and Contracts
  - Pre-dispatch Optimization Model

  - Ex-ante Nodal prices calculation
  - Pre-dispatch Coordination Timetable
  - Coordination between EOR and National OS/OMS
  - Pre-dispatch Operative Security Evaluation
  - Pre-dispatch Guarantees Validation
  - Pre-dispatch Publication
  - Real Time Deviations (programmed vs. actual operation)

Book III: Transmission

- **The Regional Transmission Grid (RTR)**
  - Installations that are part of the RTR
  - Methodology to Identify the Installations that are part of the RTR
- **Obligations & Rights Related to the Regional Transmission Service**
  - Transmitter's Obligation and Rights
  - Market Participants Obligations and Rights
- **Open Access Coordination**
  - RTR Installations Capacity
  - Power Injecting Market Participants Access to the RTR
  - Power Extracting Market Participants Access to the RTR
  - Procedures to request Access to the RTR
  - Connection Authorization Contract
- **RTR Operative and Technical Coordination**
  - Regional Information Requirements
  - Operative Security Studies
  - Real Time Operation Criteria
  - Contingency Plans
  - Event Report, Availability Report and Operative Reports
  - Inspections, tests and Audits
  - Maintenance Schedule and New RTR Installations Commissioning
- **Transmission Quality of Service Regime**
  - Objectives
  - Unavailability Compensations
  - Compensations Regime
  - Quality of Service Regime Gradual Application
- **Ancillary Services**
  - Technical Requirements
- **Transmission Rights**
  - RTR Transmission Rights
  - Transmission Rights Auctions Organization
  - Transmission Rights Auctions Development
  - Ways of Payments
  - Payments to Transmitters
  - Simultaneous Feasibility Test
  - Changes in the RTR
  - Congestion Fees Calculation
  - Transmission Rights Calculation and Payment
  - Transmission Rights Auctions Prices Projections
  - Firm Contracts Reductions and Associated Firm Transmission Rights
  - Market Power Monitoring
- **RTR Tariff Regime**
  - Transmitters Authorized Revenues
  - Regional Transmission Charges
  - Transmission Charges Assigning Methodology Among Transmitters
- **Regional Transmission and Generation Planning System (SPTR)**
  - Long Term Planning Scope
  - Medium Term Planning Scope
  - Concepts to be Observed by the SPTR
  - Regional Planning
  - Procedures and Methodologies
  - Demand Projection
  - On-Supplied Energy Costs
  - Planning Software Tools
  - Coordination with National System Expansions
- **RTR Expansions**
  - Approval of SPTR Expansions

  - Approval of Risk Expansions
  - Transmission Expansions Implementation
- **Payment System**
  - Compensation Accounts
  - Transmission Service Conciliation, Invoicing and Payments
- **Expansion Design Criteria**
  - Requirements
- **Public and Private Spaces affected to the RTR**
  - Requirements
- **Environmental Considerations**
- **Quality, Security and Performance Design Criteria for RTR Installations**
- **Required Studies for Risk Transmission Expansions**

<u>Book IV. Sanctions And Disputes</u>

- **Sanctions and Dispute Resolution**
  - Regional Regulation Compliance
  - Sanctions Regime
  - Fines and Sanctions
  - Anticompetitive Practices and Monitoring
  - Fines and Sanctions Catalogue
  - Dispute Resolution
  - Conciliation and Arbitrage
  - Administrative Recourses
- **Supervision and Market Monitoring**
  - Market Monitoring
  - Market Monitoring Group
  - Investigations
  - Information Divulgation
  - CRIE Attributions

<u>Book V: Transitory Dispositions</u>

- Transmitters Authorization
- Regional Transmission and Generation Planning System (SPTR)
- Non-Supplied Energy Costs
- Transmission Rights Auctions Organization
- EOR's Additional Responsibilities
- Quality, Security and Performance Criteria
- Quality or Service objectives

IX GREAT MEKONG SUB REGION

1. AREA COVERED BY THE INITIATIVE.

The Great Mekong Sub Region (GMS) is a very heterogeneous area which comprises the following countries: Cambodia, the Yunnan Province of China, Lao PDR, Myanmar, Thailand and Vietnam.

This area is shown in the following map.

Figure 13: GMS Area

2. CHARACTERIZATION OF THE REGION

2.1. BASIC INDICATORS

The differences of the countries are in size, in development, in their power systems, etc. The next table shows some basic indicators which illustrate basic characteristics of the countries pertaining to this region. In the case of China, indicators correspond to the whole country and not exclusively to the Province of Yunnan.

REGION CHARACTERISATION						
	Cambodia	China	Lao PDR	Myanmar	Thailand	Vietnam
Population (million hab)	14,0	1322,0	6,5	47,4	65,1	85,3
Area (sq km)	176.520	9.597.000	230.800	657.740	511.770	325.360
Peak (MW)	370	391.420	691	1.930	24.805	9.029
Peak Load per capita (watt/hab)	26	296	106	41	381	106
Generation (Thousand GWh)	0,13	2080	3,94	6,31	121,75	40,11
Generation per capita (kWh/hab)	9,29	1573,43	604,29	133,21	1871,06	470,44
GDP per capita (US$ 2006)	2700	7700	2100	1800	9200	3100
Real Growth Rate GDP (2006)	7,20%	10,70%	7,40%	3,00%	4,80%	8,20%

Table 14: GMS Countries Characteristics

2.2. PHYSICAL CHARACTERISTICS OF POWER SECTORS

This section describes the characteristics of the electricity sectors of the GMS countries that are relevant for the development of power trade.

1. Big disparity in the countries' markets. Cross-border Trading will be marginal for China; but may be an important and significant source of demand (20-30%) for Thailand and Vietnam, and shall be similar (or greater) than the load of the rest of the GMS countries.
2. Four countries (China, Thailand, Vietnam, and Myanmar) have transmission systems that interconnect most of their internal demand centers.
3. Two countries currently have no nationwide transmission systems (Lao PDR and Cambodia).
4. Three countries (Myanmar, Lao PDR, and Cambodia) have internal demand levels that do not allow for the development of large-scale generation projects that are only based on internal load. Therefore the possibilities of obtaining energy at low (competitive) prices are linked to cross-border trading, either by developing projects for export, or by importing from countries with lower electricity prices.
5. In Thailand, it is hardly possible for new hydro resources to be developed because of environmental restrictions, and there is a growing concern that natural gas reserves are not sufficient to satisfy future load growth. Coal resources are also limited to lignite, which has historically been associated with significant environmental problems.
6. The overall conclusion based on the analysis of the energy resources in the GMS countries confirms that there are abundant and diversified resources in the region that may allow meeting the expected energy demand well into the 21st century, without a need to depend on extra - region imports. Therefore, GMS countries will be able to diversify their energy portfolios and keep all of their energy options open.
7. Energy resources only include hydro sites, coal and natural gas. Oil reserves carry some significance, but GMS countries do not plan to develop generation plants that burn oil by-products (An exception is Cambodia, but this only to ensure short-term supply).
8. There are two hydro projects that have already been built, and are currently operating and exporting power from Lao PDR to Thailand. In addition, there are: (i) at least three other hydro projects actively being developed in the Lao PDR (the Nam Theun 2 project currently negotiating its financing, the expansion of the Theun Hinboun project, and the Nam Theun 3 project); (ii) one huge hydro-project being considered in the Salween river in Myanmar; (iii) multiple projects are being developed along the Mekong river in China; and (iv) Vietnam previews to buy electricity from two Lao's hydro projects: Nam Mo (110 MW in PPA negotiation stage) and Xe Kaman (250 MW in PPA negotiation stage and prepared to be built).

9. However, in the main part of the countries there is not enough base information to estimate costs for developing hydro plants, gas fields or coal mines (in the case of Vietnam big rivers have a master plan and most hydro power plants have pre FS, FS or even technical design). Several of the hydro projects, primarily the most important resource in the region, are at desk- or pre-feasibility levels. There are no field studies that would allow for the verification of the civil work's cost estimations. Hence, in order to forecast the pattern of probable cross-border trading, it was necessary to outline scenarios with several assumptions on the commissioning schedules of generation plants, as well as on the specific characteristics of the hydro power plants.

10. Although patterns of cross-border trading are highly dependent on the outlined assumptions, the energy flows in most of the scenarios are only limited by the capacity of international connections. This conclusion has been obtained from simulations that have been done on the optimal joint operation of GMS electricity systems. It first confirms the economical convenience of cross-border trading among the GMS countries; and secondly, the importance of paying special attention to the development of a regional transmission system with all of the factors considered (financing, transmission tolls, congestion management, regulation etc).

2.3. REGULATORY ISSUES

The following issues are relevant when considering the regulatory aspects that may influence cross-border trade in the region:

1. **Power Sector Structures:** All GMS countries are organized wherein there is a single buyer (implicit or explicit) in their generation and transmission activities. Currently, these "single buyers" are the only institutions in each GMS country that are allowed to purchase power from "independent" stand-alone generation companies and are the only entities that are permitted to import and export energy across international boundaries. In Lao PDR and soon in Myanmar, there are also "single buyers" of energy for the purpose of serving domestic load, but the governments of Lao PDR and Myanmar permit the development of private power projects for purposes of exporting power to serve power needs in adjacent countries. Only Lao PDR has IPPs that are allowed to sell energy directly to EGAT (Thailand), with a PPA. Thailand recently moved from the project of putting in place a highly competitive market to a single buyer scheme, with competition basically for the entry of IPPs to the market. In each of the GMS countries, the domestic utility serving as the "single buyer" is also the Transmission System Operator, and it is responsible for the dispatch of the existing generation.

2. **Transmission Ownership**: The single buyer is usually the Transmission Facilities Owner (TFO), which operates and maintains the national transmission network.

3. **Independent Power Producers:** All GMS countries allow for the development of stand-alone privately owned IPPs, provided such IPPs sell all of their power output to either the local domestic utility, or to the national utility serving as the single buyer in another GMS country. In all of the GMS countries (other than Myanmar), IPPs sell power to the domestic "single buyer" under long-term, essentially take or pay, power purchase agreements. Similarly, in Lao PDR (and soon Myanmar), IPPs export power for sale to the national "single buyer" utilities that are located in adjacent GMS countries under long term, essentially take or pay, power purchase agreements.

4. **Large Consumers**: With the possible exception of China and some industrial estates within Thailand (without the use of the national transmission grid), none of the GMS countries allow IPPs to sell power directly to stand-alone distribution companies, large industrial consumers or to retail consumers. Although such types of reforms have been discussed and studied in several of the GMS countries, none of the GMS countries (other than, perhaps, China) at this point, are actively pursuing such reforms.

5. **Centralized Government Power Sector Planning**. All of the GMS countries have centralized state planning of their power sectors, including investments in new generation and transmission facilities. New power plants to be developed by IPPs are selected through state planning processes. The processes by which IPPs are selected vary between the different GMS countries. Of notable importance to the development of the Regional Electricity Market for the GMS region, are some of the following key issues:

   - Thailand encouraged the development of domestic IPPs and has selected specific IPP projects through a very competitive bidding process that was initiated in 1994. The IPPs that have been selected by EGAT (the Thai national generation and transmission utility) to build power projects in Lao PDR for exporting power to Thailand, were selected on a first-come, first-serve basis pursuant to a Memorandum of Understanding between the Thai and Laos governments; whereby Thailand had committed to purchase a specified amount of power from power projects to be developed in Laos. Similarly, agreements for developing power projects for export to Thailand are in place with Myanmar and China.

     Generally, Thailand remains interested in importing power from IPP projects that are located in other GMS countries. However, EGAT is currently only willing to initiate negotiations of a power purchase agreement once an independent power project has demonstrated its financial and environmental feasibility and an agreement has been reached as to the price of the power. With respect to domestic IPPs, the basis for the development and selection of future domestic IPPs, is currently under consideration by the Thai government.

   - Vietnam has encouraged the development of IPPs through competitive bidding for specific power projects. Two such projects have been developed and financed within Vietnam. Additional domestic IPPs involving both international and domestic developers are expected. Vietnam is also interested in importing power from IPP projects that are located in other GMS countries, notably Lao PDR.

   - IPP development in Lao PDR and Myanmar are depending on the development of power projects for power exports to other GMS countries. In Myanmar, IPP projects are to be developed with the aim of selling power to Thailand. In Laos, such IPP projects are to be developed to export power to Thailand, Vietnam and possibly China.

6. **Characteristics of Power Purchase Agreements:** Generally, the Power Purchase Agreements (PPAs) that have been used for IPPs within the GMS countries share certain common characteristics. Such PPAs are long-term (twenty five or more years) take or pay contracts that require all of the power to be produced by such projects, to be sold to the "single buyer" domestic utility in each GMS country. Power sales to other third parties are contractually prohibited. [4]

   For thermal power plants, the PPAs include a two-part tariff whereby recovery of the fixed costs, debt repayment and return on equity is depending on the available for operation power plant, regardless of whether or not each power plant is actually dispatched to produce power. With respect to IPP hydro projects, the PPAs usually are energy-only tariffs, whereby payments are made when the power plants are dispatched to produce power.

   However, a financial result that is similar to the thermal power plant's PPAs, is generally achieved by such hydro power plants being contractually deemed to have been dispatched when the hydro projects have sufficient water resources and is otherwise available for dispatch. Other than the PPAs for the domestic IPPs in Thailand that resulted from EGAT's 1994 competitive IPP solicitation, the clauses of contracts for IPP contracts within the GMS region have been negotiated case-by-case with little to no standardization.

[4] In the case of Vietnam "Take or Pay" clauses are not used and there are both long term contracts (up to 20 years) and short term (several months or years) or seasonal contracts with co – generation producers.

7. **International Transmission Interconnectors:** Construction of international transmission lines also requires case-by-case negotiations between the governments and domestic "single buyer" utilities of the GMS countries. In each of these cases, the merits of the transmission project are depending on the economics of the specific power plant project under consideration; rather than the system and regional benefits that might result from the improved transmission interconnections and better integration of the power sectors of the GMS countries. In addition, some difficulties have been encountered when transmission lines for a power project to be located in one GMS country to export power to another GMS country, are required to be built in, and to cross through a third GMS country. This situation has arisen in the case of a line that should be built in Lao PDR to allow power to be exported from China to Thailand.
8. **Absence of Open Transmission Access Regimes:** Open access to transmission systems is foreseen neither for national lines nor for international connections. To this point, open transmission access has not been necessary to encourage the development of IPPs. Domestically (within the GMS countries), there is no need for IPPs to obtain access to national transmission networks to be able to sell power to entities other than the domestic utility. This is because all IPPs are required to sell all of their power to "single buyer" domestic utilities.

   For cross-border transactions, such power plants have, and are generally being built in Lao PDR, where the government has given IPPs the right to own and operate the transmission lines that are required to be built in Lao PDR to interconnect the power plants to the Thai electric system. In those few instances in which transmission lines of third parties may be required to support the power sale transactions involved (as would likely be required for power exports from China to Thailand), such arrangements are expected to be handled through case-by-case project-specific negotiations.

   Because of the absence of open transmission access, there are no transmission tariffs that are being used by the national transmission systems within the GMS countries. Further, there has been no need to develop rules for transmission system congestion management within the GMS countries because of the centralized dispatch and centralized ownership and management of national transmission systems.
9. **Absence of Formal Regulatory Regimes:** In each of the GMS countries, the power sectors have historically been managed by government-owned-and-managed national electric utilities that are supervised by governmental institutions. There are therefore no formal legal and regulatory frameworks for the power sectors in the GMS countries. This is, however, likely to change over the next years. China has already embarked on the implementation of a new legal and regulatory framework for the Chinese power sector; in 2003 a regulatory body was established (State Electricity Regulatory Commission – SERC). Similar reforms are under review in several other GMS countries, most notably Thailand.
10. **Congestion Management:** Because of a system of centralized dispatch (which assigns the available transmission capacity) it has not been necessary to develop rules for congestion management.

3. ROAD MAP FOR IMPLEMENTATION

3.1. THE GMS INITIATIVE

The Greater Mekong Subregion (GMS) comprises Cambodia, the People's Republic of China, Lao People's Democratic Republic, Myanmar, Thailand, and Viet Nam.

In 1992, with ADB's assistance, the six countries entered into a program of subregional economic cooperation, designed to enhance economic relations among the countries.

The program has contributed to the development of infrastructure to enable the development and sharing of the resource base, and promote the freer flow of goods and people in the subregion. It has also led to the international recognition of the subregion as a growth area.

In this strategy, the power sector has played an important role. Until recently, regional energy initiatives in the GMS have centred on the power sector, cross-border electricity trading, and the interconnection of transmission networks.

Recognizing that access to modern energy services is critical for economic development and for improving the quality of life of the poor, the GMS countries have recently requested ADB to initiate a comprehensive study to define a regional strategy for all energy subsectors.

3.2. THE GMS INITIATIVE IN THE POWER SECTOR

The cooperation in power sector among the countries of the GMS began formally through an inter-governmental agreement (IGA).

The Inter – Governmental Agreement on Power Trade in the Greater Mekong Sub – Region (IGA) was signed by the six member countries on November 3rd, 2002. This agreement calls for the establishment of the Regional Power Trade Coordination Committee (RPTCC) to coordinate the implementation of regional power trade under the IGA in the region.

The RPTCC reports, according to the IGA, to the GMS Ministerial Level Conference and the corresponding governments through the Ministers.

The first task of the RPTCC was to precisely determine the steps to establish and implement regional trade arrangements. This includes the accomplishment of:

1. Provision to the Parties (countries members) of a final draft of the Regional Power Trade Operating Agreement (PTOA) which specifies the rules of regional power trade;
2. Provision to the Parties of a recommendation for the overall policy and day – to – day management of regional power trade, including the necessary bodies for coordination;
3. Establishment of the short, medium and longer initiatives which need to be pursued on a priority basis in order to achieve the objectives of regional power trade within a specified timetable; and
4. Identification of necessary steps for implementation of regional trade, including means for financing.

The RPTCC began meeting regularly every 6 months since 2004, to implement what was established in the IGA. To achieve this objective, one of the main tasks carried out by the RPTCC was to engage consultancy services to design the power trade arrangements for the region, design a regional grid code, while possible patterns of exchange among the countries were also estimated, to identify benefits of the regional trade.

By the end of 2005, the report proposing power trade arrangements, grid code and institutional framework for the region was presented and discussed.

Little has been done up to the now, regarding moving forward in the implementation of the regional market. Some of the proposed institutions have been established (this will be further developed in the next sections) during 2006, and some studies have been engaged. Recognizing the importance of transmission infrastructure and of coordination in the expansion plans of the countries, a study on optimal expansion plan of transmission / generation for the region was engaged. This study is currently being finalized.

Meanwhile, the initiative has been constrained to the six initial countries pertaining to the region and there has been no new integrants of this initiative.

3.3. CURRENT SITUATION: MAIN ACHIEVEMENTS, MAIN CHALLENGES

For GMS, it has been demonstrated that regional trade generates benefits for all the countries in the region, and basic studies have already been developed. The region counts with a complete proposal for organising trade from the point of view of institutions, trading rules and a grid code. However, the required steps have not been specified.

The implementation of basic institutions and the trading arrangements for the initial phases of the market have not been implemented. The following can be identified as reasons for this situation:

- The lack of transmission infrastructure hinders the quick implementation of some of the decisions that should be required, since trading will be very limited until additional infrastructure is available.
- Decision in the countries, given their much centralised organisation, is slow and bureaucratic; this slows down the process.
- Opposing interests in some cases, or a lack of comprehension of the real benefits of trading, prevent reaching basic agreements, for example regarding some specific transmission lines.
- Little commitment is shown from the authorities to move forward quickly towards this initiative although the benefits are obvious.

From the point of view of achievements, it can be pointed out that:

- The region has a formal agreement among the countries which is a solid base to develop the regional initiative.
- The basic studies have been developed and the region has the tools and a road map for implementation.
- Additional studies are being carried out to design an optimal expansion plan which takes into account regional trade.
- A regional data base is supposed to be implemented soon.

From the point of view of the challenges, it can be pointed out that:

- More commitment from the countries is needed to carry on with the established steps to implement a fluent regional trade.
- Basic agreements to develop the regional infrastructure of transmission are required.

The following picture schematises the development, up to now, of the GMS initiative regarding power trade.

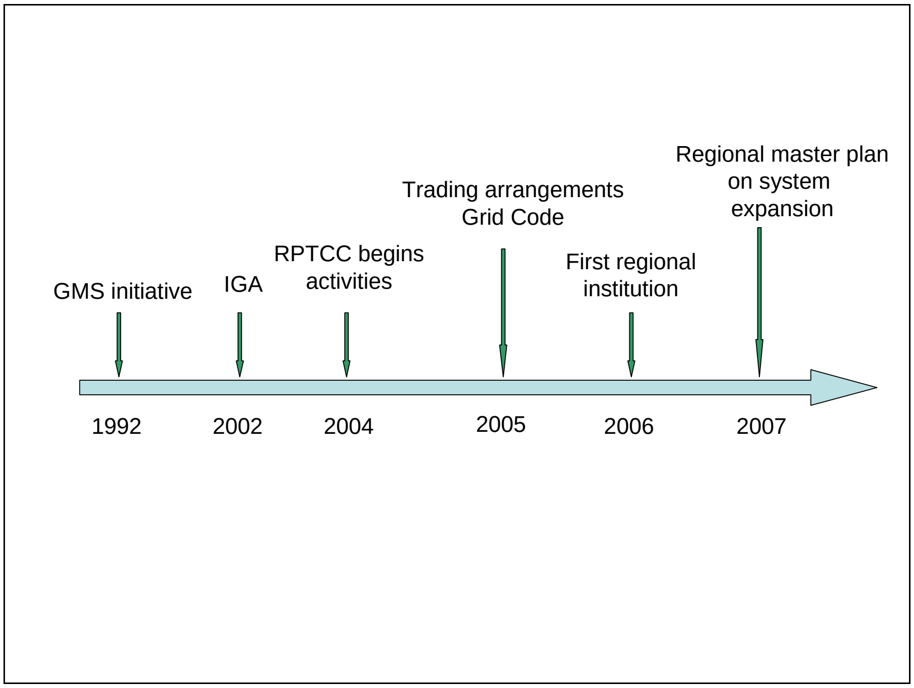

Figure 14: GMS Implementation Timeline

4. INSTITUTIONAL FRAMEWORK

4.1. *INSTITUTIONS INVOLVED IN THE INITIATIVE*

The general institutional framework depending from the RPTCC and needed for developing the Power Trade Operating Agreement (PTOA) that was proposed for a "steady state regime" consists of:

1. Technical Secretariat (TS)
2. Regional Regulatory Board (RRB)
3. Regional Transaction Coordinator (RTC)
4. System Planning Working Group (SPWG)
5. Operational Planning Working Group (OPWG)
6. Other standing working groups decided by the RPTCC (WGs)

The following diagram shows the general organization of the proposed framework.

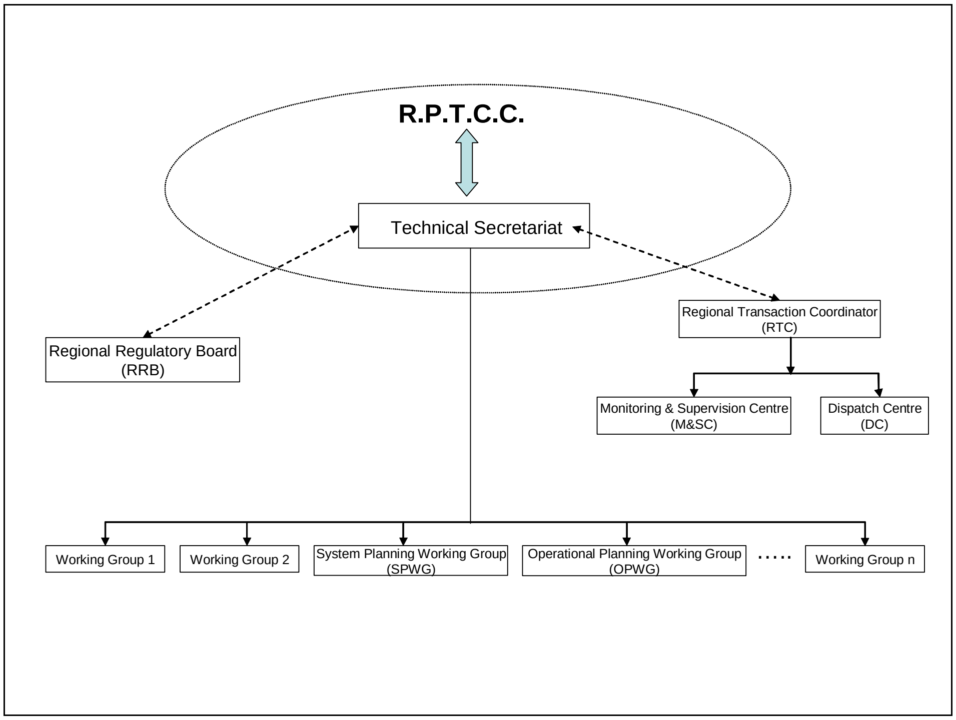

Figure 15: GMS Institutions

However, in the initiation of the PTOA, not all the institutions will be created and the establishment of them will be done in a phased way.

At the very beginning, for the kick off of the PTOA, it is proposed that the first institution to be created should be a Focal Group (FG) which will later evolve into the already mentioned Technical Secretariat. This FG will take the responsibility of the tasks required to initiate the PTOA in each GMS country, create the first groups, etc.

The Focal Group (FG) will be formed by representatives of each country whose names will be provided by the RPTCC. The FG will have to perform a series of activities, the most important of them being the following:

1. Internal procedures (development).
2. Day – to – day management of PTOA.
3. Promote the use of capacity in lines of PPAs.
4. Development of best practices for PPAs.
5. Facilitate the construction of transmission lines through third countries.
6. Establish the Planning Working Group (PWG).
7. Develop the Terms of Reference (TORs) of the PWG's tasks.
8. Follow up PWG activities.
9. Short term action plan for the FG.
10. Short / medium term action plan for RPTCC.
11. Planning of the installation of the Technical Secretariat (TS).
12. Initiate the tasks required to establish a regional database and website.
13. Promote the study of a "leading case".
14. Initial studies.

15. Training program.
16. Assume any other function required for the development of the PTOA in its early stage.

4.2. ROLES / OBJECTIVES OF THE INSTITUTIONS

The main roles/ objectives of each of the proposed institutions are described in the following points.

4.2.1. THE TECHNICAL SECRETARIAT

The design of the PTOA and actual trading among the GMS countries shall involve Working Groups (WGs) within the RPTCC, and institutions such as the Regional Regulatory Board (RRB) and the Transactions Coordinator (TC). Along the different stages that have been discussed, the number, objectives, functions and tasks of the working groups may vary according to the needs. This shall also be true for the institutions that have been identified. The RRB and TC may evolve in their independence, scope and complexity of the tasks they perform. However, in any stage, all of these organizations have to "communicate", report to and ask for decisions from the RPTCC.

The RPTCC is a high level group who will have to make decisions on different issues with a highly political component, which at the same time is likely to involve commercial, financial and technical aspects that will need to be evaluated and analysed before a decision can be made. Moreover, decisions may be needed on a day-to-day basis, and as the trade develops and the regional market becomes more dynamic this kind of decisions will be more frequent.

Given the characteristics of the RPTCC, as the regional market (trade) develops, it may turn out that it cannot cope with these tasks as quickly and efficiently as would be needed, thus turning into a hurdle towards the development of trade among the countries and projects with a regional scope.

It is therefore suggested that an executive group within the RPTCC with a management orientation should be established, to which some functions shall be delegated. The succeeding sections describe in detail the organisation of the group, as well as their objectives, functions, etc.

This Technical Secretariat (TS) group will be the day-to-day communication channel between the different WGs, RRB and TC. It shall also be an organization that will have the power to make decisions on certain aspects. It is convenient that the TS be a permanent group within the structure of the PTOA resulting from the earlier created FG, to deal with the requirements during the first steps of the PTOA.

The following diagram presents in a simplified way the general organization and communication channels between the WGs, RRB and TC.

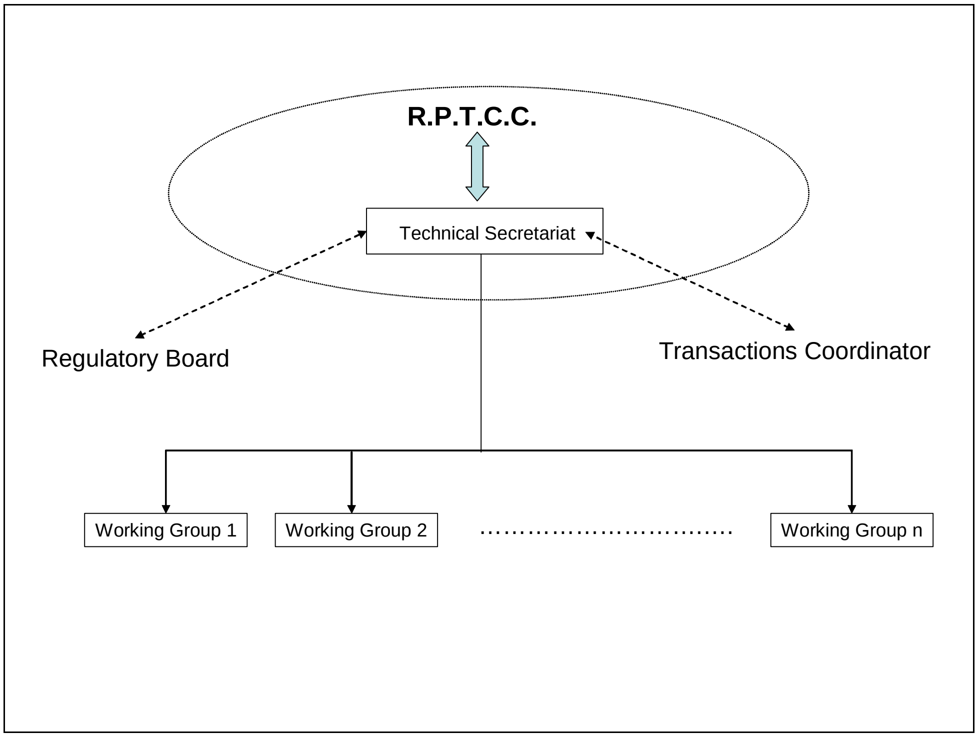

Figure 16: GMS – Technical Secretariat

4.2.2. THE REGIONAL REGULATORY BOARD

The Regulatory Board (RRB) will be a Working Group with technical profile, within the Regional Power Trade Coordination Committee (RPTCC).

Delegates from the six GMS countries that have signed and ratified the Inter Governmental Agreement on Regional Power Trade (IGA), will compose the Regulatory Board. Those countries that have not fulfilled the previous condition may designate a representative who will be granted an *observer status* only, and who shall not be allowed to participate with full members in making decisions or recommendations.

4.2.3. THE REGIONAL TRANSACTION COORDINATOR

The Regional Transactions Coordinator (RTC) is an institution that needs to be created for the beginning of Stage #2. The RTC will be a permanent and independent institution from a technical and budgetary point of view.

The Transactions Coordinator will consist of:

1. The Board composed of delegates from the six GMS countries that have signed and ratified the Inter Governmental Agreement on Regional Power Trade (IGA). Those countries that have not fulfilled the previous condition, may designate a representative who will be granted *observer status* only, but who will not be allowed to participate with the full members in making decisions or recommendations;
2. The technical staff that will actually perform the necessary activities; this staff may be from any of the GMS countries, and even from other nationalities if their special skills and qualifications are needed and are not available among the human resources of the region.

The RTC's Board will consist of six members, one member from each country. They will fulfil the requirements that have been established in the above paragraphs as well as those that are detailed in this document.

The RTC will play the role of a regional Market Operator.

4.2.4. THE SYSTEM PLANNING WORKING GROUP

The System Planning Working Group (SPWG) will be a Working Group with a technical profile, within the Regional Power Trade Coordination Committee (RPTCC).

Delegates from the six GMS countries that have signed and ratified the Inter Governmental Agreement on Regional Power Trade (IGA) will integrate these Planning Working Groups. Those countries that have not fulfilled the previous condition may designate a representative who will be granted *observer status* only, and who will not be allowed to participate with full members in making decisions or recommendations.

The main objectives of the SPWG during Stage #1 and Stage #2 will include:

1. Collaborate with the RTC in maintaining the Regional Data Base about the current generation and transmission infrastructure in the GMS.
2. Develop alternative plans and recommendations for the development of the regional transmission grid (expansion plans with a regional perspective).
3. Assist the RPTCC, the RTC and the RRB in the technical studies.

4.2.5. THE OPERATIONAL PLANNING WORKING GROUP

The Operational Planning Working Group (OPWG) will be a Working Group with a technical profile, within the Regional Power Trade Coordination Committee (RPTCC).

Delegates from the six GMS countries that have signed and ratified the Inter Governmental Agreement on Regional Power Trade (IGA) will integrate these Planning Working Groups. Those countries that have not fulfilled the previous condition may designate a representative who will be granted *observer status* only, and who will not be allowed to participate with full members in making decisions or recommendations.

The main objectives of the SPWG during Stage #1 and Stage #2 will include:

1. Collaborate with the RTC in maintaining the Regional Data Base about the current generation and transmission infrastructure in the GMS.
2. Develop alternative short–term plans and recommendation for the regional transmission grid.
3. Assist the RPTCC, the RTC and the RRB in the technical studies.
4. Participate in the definition of Performance Standards regarding safety, security, reliability and quality of service.
5. Analysis of emergencies in the RTN.

4.2.6. THE CURRENT SITUATION

Up to now, only the Focal Group has been established and has a, more or less, regular functioning.

A Planning Working Group is also in its initiation stage.

4.3. RELATIONSHIP WITH CONSTITUENT GOVERNMENTS

The RPTCC, with the support of the TS, should also address the relationship between the PTOA and the constituent governments regarding the development and approval of cross-border interconnection facilities. Admittedly, none of the constituent countries is likely to be willing to give the TS the right to veto a cross-border transmission interconnection between two countries, whose governments both support such a project, even though there may be reasons from a regional perspective to consider other alternatives. However, there are alternative structures that can transform the PTOA into the decision-making process without undermining the authority of the individual constituent governments. For example, the constituent governments in the PTOA could agree and bind themselves to not pursue cross-border interconnection projects without first having:

- notified the RPTCC organization of such a project,
- notified the RPTCC organization of such a project and considered all alternatives thereto recommended/identified by the SPWG, and approved by the RRB and the TS,
- obtained and considered the recommendations/comments of the TS organization, or
- obtained the approval of the RPTCC organization, as approved by the constituent governments.

5. REGULATORY FRAMEWORK

5.1. GENERAL DESCRIPTION OF THE TRADING ARRANGEMENTS

The trading rules for the GMS market have not been implemented yet. However, there is a general framework which encompasses trading rules, grid code and institutional framework for the region that has been developed by Mercados, and has been approved. Currently, the region is beginning to implement some of the institutions, working groups and is approaching basic tasks dealing with first steps of implementation.

Neither the current regulatory framework ("letter and spirit") in the GMS countries nor cross-border transmission facilities favour the development of a "competitive regional market". However, this market is seen as the final long-term target. Therefore, the solution adopted is a progressive evolution from the current situation to a liquid and competitive regional market in the long-term. This evolution should have well-defined stages, with targets to be achieved at each stage before advancing to the next one.

This evolution must be consistent, and in line with, the regulatory trends in the GMS countries. Although completely homogeneous regulatory bodies are not necessary for developing a regional market, it is not possible either to create a regional market with targets or concepts (the regional spirit) that are not consistent with national targets and concepts (national spirit). Considering this principle, four stages have been identified (presented in the diagram below).

Similarly, the development of a regional platform for cross-border power trading requires a progressive level of technical coordination for operation and planning activities.

The guiding idea in the evolution of the Power Trade Operating Agreement (PTOA) from the first stage to the fourth, is that during this period (aside from the transmission infrastructure and national regulations), there should also be a corresponding evolution on the underlying principles that support the PTOA at each stage.

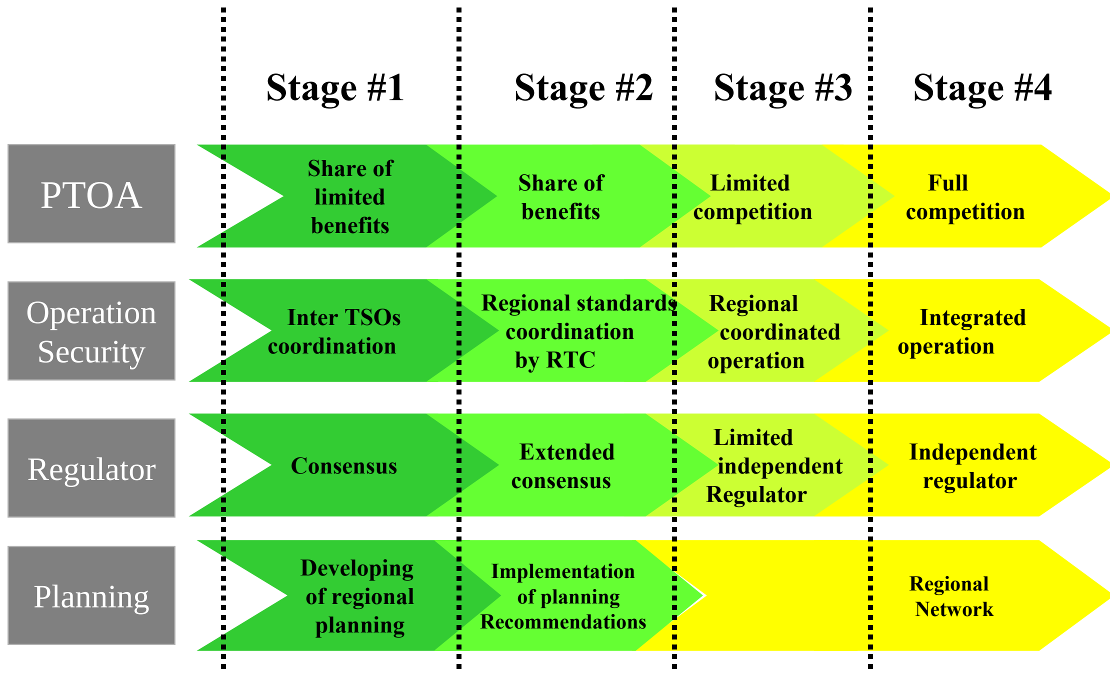

Figure 17: GMS Phases for Trading Development

The following are the principles, guidelines and characteristics of stages 1 and 2. Although stages 3 and 4 have also been developed, it is considered that they are too much for the long term, and it is almost sure that they will need to be reviewed. Therefore, only stages 1 and 2 are described in more detail.

5.1.1. STAGE #1

Stage #1 corresponds to the power transactions that are possible in the near future. The main issues that define this stage include:

- Cross-border connections are weak and have low capacity. In most cases, they are linked to a PPA that uses all the available transmission capacity;
- Most cross-border connections are in medium voltage, and were developed to supply energy to isolated zones near the borders. Transactions are based on case-by-case agreements;
- Single buyers are the only companies that are entitled in each country to make cross-border transactions;
- Most PPAs have "Take or Pay" (ToP) clauses, and are designed for the physical delivery of the energy produced by the seller;
- No general agreement exists for the development of cross-border transmission lines. Agreements are negotiated on a case-by-case basis;
- However, our simulation studies show that there are significant potential benefits associated to increments of cross-border transactions. Therefore, it is highly recommended to develop a PTOA for this stage, in spite of the difficulties identified above.

Based on the previous statements, the following considerations have arisen when designing the PTOA for Stage #1.

- Because of the important potential benefits that are associated to cross-border transactions, it is worthwhile developing rules that shall allow for the optimization of the use of the available scarce cross-border transmission capacity;
- It is also suggested to establish guidelines for future agreements for developing cross-border transmission lines: (1) associated with the development of specific

power plants that involve long term take-or-pay PPAs, to assess whether it is recommended to design lines with some surplus capacity that shall allow transactions other than those associated to the PPA; (2) to develop rules for sharing the costs when the capacity of the lines is increased, in order to accommodate cross-border transactions;

- Single buyers shall make power transactions from each country. Since at this stage there is no regional network, and PPAs will have priority in the use of cross-border connections, transactions will be agreed based on short-term convenience (i.e. differences in marginal costs) and on the availability of transmission capacity;
- However it is suggested to establish general rules for optimizing transactions that use cross-border connections. These rules shall be oriented towards optimizing the use of the surplus capacity of the existing connections, and in reducing the total variable costs in the countries at the far end of these connections;
- The general principle for these transactions shall be to share the benefits between the country selling the energy and the country buying it;
- Another milestone for this stage will be to develop general guidelines for the standardization of (at least the) commercial clauses of PPAs between agents of the different countries. The objective is to orient commercial clauses of PPAs towards financial rather than physical transactions. Financial contracts allow the optimization of the connections' economic dispatch, without introducing risks to the parties of the PPA, and thus generate extra benefits for the countries involved;
- The GMS countries' TSOs will decide the available capacity for cross-border transactions on a periodic basis (for instance daily).
- The PPA or Agent that paid for the construction of cross-border connections will have priority in the use of such lines. The remaining capacity shall be made available for short-term transactions between single buyers of the countries involved. For the succeeding stages, it will be necessary to develop more sophisticated rules for congestion management. However, even in simple networks, it is necessary to establish appropriate rules for determining transfer capacity, because probably, cross-border flows will overlap with national flows. When the regional network gets integrated, loop flows produced by cross-border and internal flows in one country will modify flows in other countries. It is thus important that the users of the regional network do not have to deal with complex load flow and stability studies to establish the transfer capacity, and receive such information from the RTC;
- For regulation, it is recommended that a Regional Board (under the RPTCC) be established for the resolution of disputes, transmission tariffs, etc;
- In order to facilitate the development of the succeeding stages, it will be highly convenient to create a working group, under the RPTCC, with the following objectives:
    - o Planning of the regional transmission network, oriented towards creating transmission capacity for cross-border transactions: (1) in the very beginning, only those that are associated with increasing the planned capacity of transmission in a PPA project, and, (2) afterwards with those that are not associated with the development of new power plants under long-term PPAs;
    - o Coordination of the arrangements for the design and construction of cross-border transmission lines.
- For this and the succeeding stages, it shall be convenient to prepare some general criteria for facilitating the construction of cross-border transmission systems, especially for lines that pass through more than two countries.

5.1.2. STAGE #2

The switch from Stage #1 to Stage #2 shall occur once enough cross-border transmission capacity is operative, thus allowing power transactions among most of the GMS countries. At this stage, trading between countries whose borders are not connecting will also be possible. Nevertheless, there are no foreseen changes in the regulatory frameworks. Most or all of the GMS countries will continue allowing only the single buyers to make cross-border transactions. During this stage the range of choices for different kinds of transactions will be enhanced.

It is expected that at this stage, the cross-border transmission capacity will be related to some surplus capacity of the transmission facilities that are linked to PPAs, and, principally with the capacity that is not utilized by the PPAs, which has priority for the use of such connections. Hence, two aspects should be considered especially for the feasible transactions for this stage: (1) transmission capacity available for cross-border transactions will be highly volatile; (2) such volatility introduces difficulties for bilateral transactions between countries that do not have access to information on the PPAs using each connection.

Based on the above considerations, the balance of national markets at this stage will not be efficiently managed at the regional level. Capacity of cross-border connections will be small and volatile. National TSOs should use their own resources to balance their internal systems, including the control of scheduled flows in their cross-border connections. Nevertheless, customized rules can be developed for regional support during emergency events in one of the countries.

The proposed rules for transactions at this stage shall be strongly influenced by these two considerations.

Meanwhile, two issues must be taken into account in establishing the methodology for setting prices for energy transactions at this stage:

- The limited transmission capacity available for this stage will create congestion in most of the connections, so it is not possible to set a uniform clearing price;
- Due to the lack of markets in the countries, there are no prices in such countries that could be used as reference for setting locational prices.

Therefore, the methodology that results as appropriate for the settlement of the scheduled transactions is to use a "pay as bid" criterion. It shall have a procedure to re-distribute excess of collection (it is the differences between amounts paid by buyers and perceived by sellers) between the participants in the transactions.

The main characteristics of Stage #2 are:

1. Cross-border power trading arrangements at this stage will allow single buyers to trade besides bilateral international PPAs, through short-term opportunity transactions;
2. During Stage # 2, a Regional Transactions Coordinator shall be put in place. Its main function will be to determine the daily availability of cross-border transmission capacity, to receive offers and bids from Agents of the countries for selling-buying energy, to select the set of offers-bids that maximize the regional benefit, to inform the national TSO on the selected transactions, and ex-post, to settle the transactions effectively realized. During this stage, the RTC will have a simple governance and operative structure.
3. A "simplified regional network" will be defined, consisting of the cross-border connections and some national transmission elements that are used for cross-border flows. The simplified regional network will allow transactions between single buyers of any two GMS countries. RTC will prepare the regional economic dispatch using the Simplified Regional Network (SRN), which will include the constraints that limit the cross-border flows;

4. The RTC will prepare the regional economic dispatch, taking into consideration the following:
    - Every day, on hourly intervals, each TSO shall calculate the transmission capacity available in its national network for accommodating opportunity cross-border transactions, and will relay such capacity information to the RTC.
    - When each TSO calculates the transmission capacity available for cross-border transactions, it will take into account:
        - The national dispatch;
        - The priority of PPAs for using dedicated lines; and,
        - The technical limits for transmission capacity, given the Performance Standards
    - The RTC should receive comprehensive and reliable information from the National TSOs and/or single buyers about use of cross-border connections by PPAs.
    - The RTC will inform the single buyers of the GMS countries on the cross-border transmission capacity, available for day-ahead transactions.
    - The Agents will present to the RTC daily offers-bids[5] for selling or buying energy every hour of the day ahead.
    - The RTC selects the bids-offers that minimize the total variable costs of the countries involved, taking into consideration the available transmission capacity informed by TOSs. The transactions that are selected will be scheduled on an hourly basis. The bids and offers that are accepted become firm commitments from the Agents involved.
    - The RTC prepares the settlement by calculating the hourly payments of buyers and the corresponding revenues of sellers that participated in the transactions, which were scheduled for the day-ahead, and have actually been made during the real-time operation.
    - In order to facilitate the above activities, the RTC will develop and maintain a regional database with technical and economic information.
    - The OPWG will perform the studies that are necessary to safely operate the RTN. The RTC will participate or review the studies prepared by the OPWG.
    - The RTC will organize a Monitoring and Supervision Center (MSC), which will be responsible for monitoring the operation of the RTN, and which will coordinate the TSOs' actions during emergencies. This MSC will be the precursor to the Regional System Operator that will be put in place when Stage #3 starts.
5. Each country's TSO will receive the day-ahead schedule prepared by the RTC, which will be included in the country's dispatch. Each TSO will be responsible for controlling the cross-border connections in order to keep flows according to the day-ahead schedule prepared by the RTC. For this stage, a regional balancing mechanism is neither feasible nor convenient, therefore TSOs will adjust internal generation to meet the schedule;
6. TSOs will be allowed to schedule real-time emergency transactions when a country runs the risk of a rationing event, due to the unexpected unavailability of generation of transmission facilities, or strong deviations in the forecasted flow. When an emergency involves several countries, the respective TSOs shall request the RTC to

[5] In this report offers are proposals for selling some volume of energy at a specified price, and bids are proposals for buying some volume of energy at a specified price. During Stage #2, offers and bids are presented by single buyers to the RTC.

coordinate the necessary measures to minimize the impact of the emergency on the quality of service and operative costs.

7. A methodology for transmission tariffs will be implemented. The theoretical and analytical support to the methodology described below is developed in the Chapter 5 of this final report. The main characteristics of this methodology include:
   - It will include a set of rules to compensate the owners of cross-border transmission facilities when third parties use their lines. Thus, this tariff will compensate TFOs by hosting flows originated by cross-border transactions. Tariffs will be cost-reflective.
   - Payments to TFOs will be based on flows.
   - Tariffs will be based on an access charge methodology. Each country's Agents will pay a fixed amount each semester, based on recorded flows in the same semester of the previous year.
8. A Regional Regulatory Board (RRB), which shall operate within the scope of the RPTCC, shall make the decisions regarding PTOA rules, as well as the setting of economic parameters (e.g. tariffs). This commission shall be formed by representatives of the GMS countries, and shall regularly hold meetings. It is desirable that representatives of countries with regulatory agencies be appointed by such agencies.

5.2. MAIN REGULATIONS APPLIED

From the regulations' point of view, the GMS market has a set of "market rules" which are the result of a consultancy whose final report was approved. These "market rules" are known in the region as PTOA (Power Trade Operating Agreement) which describes the rules for trading in detail for stage #2, since stage #1 does not require "market rules".

This same consultancy developed a "regional grid code" which was also approved but is not being applied since transactions have not begun yet.

According to the general institutional framework proposed, the regional institutions are responsible for the different codes and regulations, but they have not been established yet. Therefore, the already mentioned Focal Group (FG) or the Technical Secretariat (TS), when established, will be responsible for these tasks.

However, until the corresponding institutions, such as Regional Regulatory Board and Regional Transactions Coordinator, are established, it is not clearly defined if the FG or TS would be able to approve major codes or regulations. It may happen that, in order to provide a better support if major decisions are made, the RPTCC (Regional Power Trade Coordination Committee) shall be the one to finally approve these actions.

In a steady state function, decisions are taken by the Board of the corresponding regional institution and decisions are required to be approved by consensus.

5.3. DISPUTE RESOLUTION

It corresponds to the Regional Regulatory Board to organize the functioning and procedures of a "dispute resolution panel". This panel shall serve as the initial environment where the problems or disputes between two or more agents may be discussed.

The dispute resolution panel during the first two stages will not work towards forcibly achieving a solution of the potential problems arising between two or more agents, but shall serve to facilitate an environment for the discussion and the technical support that may help in resolving the dispute.

In case disputes are not solved through amicable discussions, then a process of arbitrage is established. The main characteristics of the proposed process are:

- Disputes that may arise between two or more Parties during the implementation of power trading, and that can not be solved through amicable discussion, will be treated according to the following procedure:
    - the disputing parties will appoint representatives for purposes of formalized but amicable discussions, regarding how such disputes may be resolved though compromise;
    - in the event that the dispute involves a highly technical matter and resolution is unable to be reached through amicable discussions between the parties, the opinion of an independent 'expert' agreed by the parties will be taken into account;
    - if no amicable resolution is reached, the dispute will be resolved by an international arbitration tribunal.
- The arbitration tribunal will be integrated by one member appointed by each of the parties and a last arbitrator that will be selected by the already appointed members. This last arbiter will serve as chairman of the tribunal. In case the tribunal thus integrated, results in an even number of members, it will agree on selecting another arbiter.
- The rules and procedures for the international arbitration will be those of the International Chamber of Commerce (ICC).
- The venue for arbitration will be in a neutral country and it will be established by the tribunal once its members have been appointed.
- The arbitration will be conducted in English.
- The decisions of the arbitration tribunal will be final and binding, and the Parties will waive their right to appeal arbitration decisions to the courts.
- The role of the National Judicial Systems will be that of enforcing the arbitration award and not to review the substance of the arbitration award.

5.4. SYSTEM EXPANSION PLANNING

System expansion planning has been previewed in the institutional framework (planning working groups were foreseen) and there is a section in the proposed grid code, devoted to describe the process and requirements of the grid' regional expansion planning. This Grid Code establishes clearly the system expansion for the network.

The System Planning Working Group has as core activity the planning of the regional network's expansion, but the planning of generation expansion is not specifically previewed. The following are the main objectives and activities previewed for the System Planning Working Group:

a) General Objectives

The main objectives of the SPWG during Stage #1 and Stage #2 will include:

1. Collaborate with the Regional Transactions Coordinator (RTC) in maintaining the Regional Data Base about the current generation and transmission infrastructure in the GMS.

2. Develop alternative plans and recommendation for the development of the regional transmission grid.

3. Assist the different regional organisations in the technical studies.

b) Activities of the System Planning Working Group

1. Establish a procedure and standard format to compile the data from the different countries regarding the existing generation and transmission infrastructure.

2. Regularly compile all the data corresponding to the physical infrastructure in generation and transmission of the different countries of the GMS.

3. Deliver to the RTC the compiled data to be incorporated to the Regional Data Base, which will be made available to the GMS countries.

4. Compile and organize the information of the different countries regarding the expansion plans in generation and transmission.

5. Organize the compiled data regarding the expansion plans, and make it available to the countries.

6. Send information to the RTC on the regional generation and transmission projects and follow their development.

7. Develop medium- and long-term least cost alternative plans and recommendations for the expansion of the regional transmission systems to be put under the RPTCC's and the countries' consideration. These plans must contain the recommendation for the expansion of the regional transmission system in terms of physical infrastructure to be incorporated, costs and benefits.

8. Assist in defining common standards in the countries regarding the safety, security, reliability, and quality of service in the production and transmission of electricity to be promoted among the GMS countries.

9. Assist the RRB in the promotion of basic agreements among the member countries that will allow and facilitate the construction of cross-border interconnectors that link two or more countries.

10. Perform the technical studies that are required on demand.

The regional plan should be approved by the Board of the SPWG and submitted to the RPTCC for final approval. However, there is a gap in the question whether the plan is mandatory or not for the countries, since this decision is still too strong to be considered by the countries in their early steps of integration.

6. USE OF THE TRANSMISSION SYSTEM

6.1. REMUNERATION OF THE TRANSMISSION SYSTEMS

In the initial stages of the regional market it is previewed that the infrastructure to be used is the existing one. In this case, a compensation for the use of the infrastructure to the Transmission Facility Owners (TFOs) is previewed in the Regional Grid Code.

The Regional Grid Code establishes the formulas to be used, and the procedures to compensate the TFOs for using their facilities.

In the region, there are PPAs to export energy from one country to a neighbouring one. In the beginning, it is foreseen that the cross border flows will be scheduled according to the remaining capacity of these lines (basically) after dispatching these contracts. Therefore, there is no mechanism established for congestion management in the classic way; so, if there is no spare capacity in the lines (the long term PPAs have priority as well as domestic requirements in terms of transmission services needs), no trade is scheduled.

The foreseen mechanism then, is one to compensate TFOs for the use of their lines, including the payment of losses that may be generated for these additional flows.

7. LESSONS

The GMS market is in its very implementation initial stages. Stage 1 has not really been implemented yet. The Focal Group has been established and the establishment of a Planning Working Group is being prepared, since it has been noted the importance of regional planning and the development of infrastructure that may allow actual trade among the countries.

It can be mentioned as a lesson, that transmission infrastructure plays perhaps, the most important role in the region, since the availability of this infrastructure will define if regional trade is possible or not.

Maybe GMS can be taken as an example to illustrate the need of focusing in the development of transmission infrastructure as the key and initial element that will later allow the development of power trade. GMS has developed power trading rules and a regional grid code before developing the required infrastructure that would support power trade, and that is one of the most important reasons to explain why regional trade does not develop.

Another element that has been hindering power trade in this region is the actors' "lack of commitment" to foster power trade. Countries do not reach the basic understanding that would be needed to quickly develop power trade. The convenience of power trade in the region and the benefits that this can generate have already been proved, an initial intergovernmental agreement exists that provides a solid base to develop power trade, there is a complete proposal of market rules, regional grid code and institutional framework, however, power trade is not developing. Key reasons for this are the lack of transmission infrastructure, lack of commitment to arrive to some basic agreements and to implement the required measures.

X CHARACTERISATION OF THE REGIONAL INITIATIVES

	Nord Pool	PJM	SAPP	SIEPAC	MEKONG
Region	North of Europe (Nordic area)	USA	South of Africa	Central America	Greater Mekong Sub – Region (South East Asia)
# of countries	4 countries: (Finland, Sweden, Denmark and Norway)	13 States of the USA: Pennsylvania, New Jersey, Maryland, Delaware, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, Tennessee, Virginia, West Virginia and Washington D.C.	12 countries: Angola, Botswana, DRC, Lesotho, Malawi, Mozambique, Namibia, South Africa, Swaziland, Tanzania, Zambia, Zimbabwe	6 countries: El Salvador, Guatemala, Honduras, Nicaragua, Costa Rica and Panama	6 countries: Cambodia, Laos, Yunan (province of China), Myanmar, Thailand, and Vietnam
Population (million of habitants)	25	51	- -	40,1	218 (without China) China: 1322
Peak (MW)	70.000	144.800	40.511 (simple sum of countries peaks) South Africa: 33.461	6.375	36.825 (without China) China: 391.420

	Nord Pool	PJM	SAPP	SIEPAC	MEKONG
Objective of the initiative	The initial objective was the integration into a Nordic market in order to achieve higher output from the total Nordic power resources, as well as a more appropriate market concentration without splitting large national generation companies. "The objectives of Nord Pool Spot AS is to organize, operate, and develop a market place for spot trade in electrical power in the Nordic countries, and also offer services in connection with this trade"	PJM was established on 16 September 1927 as the "PNJ Interconnection". Three utilities formed the world's first power pool, signing the PA-NJ agreement. The objective of the power pool was to share their electric loads, and to receive power from a huge new hydro-electric plant at Conowingo, Md. Meeting power demands in Philadelphia were a primary goal In 1997 FERC approved PJM as the nation's first fully functioning ISO	Promotion of interconnections in order to achieve a regional power market in the Southern African region.	The development of a regional transmission system and the creation of a regional electricity market (MER) in Central America.	The implementation of regional power trade under the more general agreement that the countries have to promote development in the region.
Exchanges	Contracts, day – ahead, intra day	Contracts, day – ahead, real time	Contracts, soon STEM (short term market) similar to day - ahead	Contracts, day - ahead	Contracts, opportunity exchanges between TSOs, day ahead in the future.

	Nord Pool	PJM	SAPP	SIEPAC	MEKONG
Products traded	The physical day-ahead and intraday markets The financial market (forwards and futures) The balance (regulating power) market The ancillary service markets (reserves)	Energy Ancillary services Financial transmission rights Capacity credits	Energy	Energy Transmission services Ancillary services (in the future)	Energy

	Nord Pool	PJM	SAPP	SIEPAC	MEKONG
Institutions	Nordel: The association of Nordic TSOs. Market Council: A council established by power exchange with balanced representation of market participants from the demand and the supply side. User Groups: Groups established by TSOs. The groups include representatives from companies connected to the networks of the respective TSOs. The Nordic regulators meet to discuss common regional power market issues.	The operation of the market involves 400+ members, along with the grid owners. Legal agreements define the relationships between PJM and: ▪ FERC ▪ The grid owners ▪ The members ▪ NERC (North American Electric Reliability Corporation), for security standards and information exchange.	SAPP is an organisation of utilities. Within the SAPP, main organisms are: ▪ Executive Committee (equivalent to the Board) ▪ Sub – Committees (Environment, Operating, Planning) ▪ Working groups	Comisión Regional de Interconexión Eléctrica - CRIE (Regional Regulatory Commission) Ente Operador Regional - EOR (Regional MO) Empresa Propietaria de la Red - EPR (Owner Company of the Line) Consejo de Electrificación de América Central – CEAC (Overall coordination of the Project)	RPTCC – Regional Power Trade Coordination Committee Technical Secretariat Regional Regulatory Authority Regional Transaction Coordinator. Working Groups

	Nord Pool	PJM	SAPP	SIEPAC	MEKONG
Main agreements	There is no inter governmental agreement. (It is a organisation of TSOs basically) There is a common code for grid operation between the TSOs. In addition, the TSOs have entered into a business agreement concerning split ownership of the Nordic Power Exchange, Nord Pool ASA, and also the Nordic Day Ahead spot Company, Nord Pool Spot ASA, Finally, there is a general participants agreement.	PA – NJ agreement of 1927 (initial agreement) Federally regulated RTO (approved by FERC – 2002) Modifications of initial agreement by Acts or FERC Orders in: 1992, 1996, 1999, 2002, 2005.	The Inter-Governmental Memorandum of Understanding which enabled the establishment of SAPP; The Inter-Utility Memorandum of Understanding, which established the SAPP's basic management and operating principles; The Agreement Between Operating Members which established the specific rules of operation and pricing; The Operating Guidelines, which provide standards and operating guidelines.	On December 30th, 1996, in Guatemala City, the six Central American republic presidents signed a Treaty. Protocol modifying initial Treaty was signed by all presidents, in Panama City, on July 11th 1997. This Treaty and its protocol, were ratified by all national parliaments in 1998, and became mandatory for all participating countries.	IGA: Inter governmental agreement signed by the 6 countries of the region. The agreement creates the RPTCC to develop regional power trade.
Planning	TSOs responsible for planning. No regional planning	Long term expansion plan of transmission to identify needs that ensure reliability and operation of wholesale market.	Planning Sub - Committee	Indicative regional planning of generation and transmission by EOR	Planning working groups

	Nord Pool	PJM	SAPP	SIEPAC	MEKONG
Transmission remuneration and congestion	Transmission system divided in 3 levels. Point tariff for each level (type of "stamp system") paying according to volume injected / retired. Congestion: implicit auction method where the clearing price (calculated without congestion) is modified to limit flows in congested lines.	Locational Marginal Prices (LMP) Transmission congestion Charges Transmission Congestion Credits (TCC) Financial Transmission Rights (FTR)	No extra charge when neighbouring utilities trade. Published wheeling charges when using third countries systems. In the future, when STEM / DAM contracts will have priority. Remaining capacity will be calculated daily and taken into account for DAM.	Transmission Use of System Charges (TUOS) formed by: Variable cost (losses and congestion) Toll based on actual flows Complementary charge: to take into account regulated revenues requirements not collected through the previous two concepts. Congestion Rights (CR): EOR periodic auctions of congestion rights. Contracts must have CR between injection and withdrawal points.	No extra charge when neighbouring utilities trade (first stage of the market which has not begun yet). Use of available capacity of cross border lines by paying remuneration to the owner of the line. Methodology not decided yet.

Table 15: Summary of Regional Initiatives Characteristics

XI BEST PRACTISES IN PPAS

Global experience has proven that the private sector is willing to participate in generation investment if the country and the electricity industry are reasonably predictable and sustainable so as to create comfort for both lenders and investors. On the other hand, host countries are willing to accept reasonable prices and speedy investments. This classic IPP-PPA model for attracting capital to power projects presents an important area for improvement. Identifying an optimal trade-off risk allocation for all the parts participating in PPA, the seller, buyer and buyer's customers, is a key issue for the success of the project.

When the country is entering a region that can be expected to develop a regional market for electricity, this provides an additional interest for investors, since they see a wider market, therefore more opportunities, and at the same time makes feasible projects that if looked from a regional perspective can be feasible.

1. RISK IDENTIFICATION IN PPA

In this section, we describe shortly the main risks that are often identified in PPA; next, in other sections, we analyse how these risks were allocated in different examples and what we can be learnt from past experiences.

Traditionally, the PPA establishes the allocation of risks between the seller and the buyer; therefore it stands for a tool for allocating risks. Not all IPPs across the world are pegged to PPA. As a matter of fact, there are many examples of IPPs in developing countries without PPA (i.e. Argentina, Colombia, Chile, etc). We need to carefully discriminate IPPs under the *merchant plant* model from IPPs under the *PPA* model. Under the PPA model, there are life-of-plants contracts, that assure the cash flow for of the plant's entire life (or at least for such a great number of years that what happens after that period is hardly relevant), in order to offset the inexistence of a market. A typical example of PPA addresses most or all of the following issues:

- IPPs are committed to the construction and operation of a generation plant. The methodology of opening up public infrastructure to private agents offers several options regarding the agreed final ownership of the power plant: BOO (Build - Own - Operate), BOT (Build – Operate - Transfer), BOOT (Build – Own – Operate - Transfer).

- Buyers are committed to the acquisition of the energy produced by the new facility along a specified time period that ensures the project's profitability (and bankability) according to assumptions on project power generation and an agreement on prices (tariffs) to be applied to the different concepts of charge. Usual duration of the agreement ranges between 10 and 25 years.

- The long-term scope of PPAs, the evolution of energy technologies – which would cause the preference of cost-saving units over obsolete ones, and the fear of the buyer's insolvency, imply that risk is a serious concern for investors. Usually risk is mitigated by binding clauses –as the 'take or pay' conditions, but the finally persistent economic risk can only be compensated by huge profit rates that overwhelmingly increase the buyer's payments as well.

- Some *force majeur* causes are established to exempt both parties of the payment of penalties, in extreme cases where a contract is not fulfilled. These are related to natural disasters or actions by third parties.

It is clear that in the case of “without life-of-plant contracts”, a market or alternative buyers is required. However, experience has shown that in some cases, the existence of a well designed market does not guarantee the attraction of private investment because of other drivers (immature market, country risk, small power sector, etc). In those cases, a proven successful approach has been the development of long-term contracts (mostly with maturities shorter than the plant’s useful life) fostering a mix of competition within the market, and for the market based on pre-set rules. When competition is only for the market, such as the cases of the integrated utility (IU) and the single buyers (SB) schemes, life-of-plant contracts are required.

At this stage we can summarise the reasons for PPA as follows:

- Transition Stages to market
- Cash Flow volatility (and no other hedging tools)
- No demand diversification (SB/IU)
- Weak competition in the power market
- Developed power market but country risk perceived as very high
- Barriers to merchant generation (usually hidden)
- Low creditworthiness of the off-taker
- Short term risk of shortages
- SB/IU cannot finance new plants
- Need for technology innovation or up-to-date management

In this Study, we will only assess IPP with PPA, (excluding pure merchant plants) in both, market and SB/IU power sector organizations. In designing PPA we expect to obtain an efficient risk allocation among the involved parties, in order to reach the least cost solution. The main risks that are often assessed in designing PPA can be classified as shown in the following table:

<table>
<tr><td>Market risks, those related to market conditions such as: supply risk; demand risk; price risk; credit risk; and currency risk.</td><td rowspan="2">Can be evaluated and allocated efficiently</td><td rowspan="2">Project-level risks</td></tr>
<tr><td>Infrastructure risks, those involved in the development and operation of the infrastructure, such as technological risk, cost and completion schedule overrun, etc.</td></tr>
<tr><td>Regulatory risks, those associated with potential changes in the legal, institutional, policy and regulatory framework that may have an adverse effect on the economic and financial viability of the investment or on the trading terms, among others.</td><td rowspan="3">Difficult to: (1) Allocate in any part, (2) Evaluate, and (3) Mitigate</td><td rowspan="3">Structural risk</td></tr>
<tr><td>External risks, those associated with natural events or force majeur (natural disasters, strikes).</td></tr>
<tr><td>Political risks, including limitations to profit repatriation, seizure of assets, unreasonable taxes, breach of contract by public customers, government oversight of the business, civil unrest, etc.</td></tr>
</table>

Table 16: Main Risks Involved in PPA Design

Based on the previous taxonomy, in this report we analyse how this risks were allocated in different real cases. However, it should be noted that risk taxonomy may be useful for risk engineering but it is not comprehensive enough because the sources for risks use to be complex and correlated, and only stress situations reveal the actual nature of these risks; for instance:

- Macroeconomic shocks generate currency crisis that make governments to breach the contracts or change the power market rules.

- Creeping expropriation[6], which is the most common way of expropriation in modern times, is both, a regulatory and political issue.

Unfortunately, stress situations are more common than expected in emerging countries. The exposure to macroeconomic instability is the single most important risk in power investment. It is the most prominent single explanation for the collapse of the IPP market in the late 1990s. Outstanding examples are the Asian financial crisis, Turkey, Egypt, Brazil and Argentina among others.

We should understand that a PPA, even in the case of adequate design cannot neither eliminate the political / regulatory risk nor get low prices if risks are perceived as high, or procurement is not competitive[7]. Modern risk engineering in PPA has provided a price and a volume when there is no market, but has also turned most of the market risk into regulatory/legal risks. More recently, it is common practice that the legal/regulatory risk is turned into political risk by adding specific clauses of change-in-law and international arbitration.

It seems clear that project-level risk can be perfectly allocated in PPA, but can also help in dealing with structural risks as experience shows that not all macroeconomic shock propagates to the level of individual projects in the same way across countries or projects.

2. LESSONS LEARNT FROM THE INTERNATIONAL EXPERIENCE

2.1. SELECTED EXPERIENCES

We selected projects in four countries to provide interesting insights. We also tried to find experiences in which export was an issue as well, as the cases of Uganda and partially Mexico and potentially Panama.

It is necessary to mention that most of the international experiences on PPAs involve thermal power plants. PPAs for hydro power plants face additional complexities such as reservoir management, coordination with other uses of water (irrigation, domestic, flood control, etc.).

Furthermore, public information on PPAs is normally limited to general topics, and since economic information is usually confidential, it was not possible to obtain potential useful

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[6] Creeping expropriation reduces the private value of equity assets by operating through the accumulation of changes in rules, regulations, or other institutions, and less egregious refusals to honour contracts. It usually arises as a by product of other stresses in the system, such as the Build up of social protest about rising power prices.

[7] Unfortunately, high prices may increase regulatory or political risk, originating a difficult trap.

information. In some cases, general aspects of the PPA and the host countries are described, rather than characteristics of specific projects.

We analysed the four countries shown in the following table, where they are classified based on the market organization, the type of fuel and the performance (red: failure; green: success)

	Hydro IPPs	Thermal IPPs
Market-based organization	**Panama**	**Panama**
Non-market-based organization	**Uganda**	**Mexico - India**

Table 17: Classification of PPA Analysed Cases

The Mexican case is quite interesting, as this is the only country in which IPP contracts have been uniformly enforced as originally agreed. Every IPP that has reached commercial operation is still operating and paid according to the terms of its original PPA. Mexico has not experienced macroeconomic shock comparable to those in other countries.

India presents a variety of experiences. The meltdown of the Dabhol project is well known, but other IPPs have had a tough time as well. The federal system in India divides authority over electricity services between national and state governments, a fact that considerably complicates private investment. The Babhol project is an example of how an initial bad design (LNG-based project) can undermine the path to success.

Panama is quite motivating since it has a competitive market (although organized as a gross pool). Panama has attracted more than USD 800 million in power investments including hydro projects and market-oriented fuel shifting, in a country where the peak demand roughly surpass the 1000 MW. The regulated tendering procedure for new contracts that works as an umbrella for all new upcoming IPPs is quite an interesting example.

Finally, the case of Bujagali project in Uganda is the most outstanding example of how an export-oriented hydro project, can be undermined. The analysis of this project must be made comparing what was originally previewed (regarding the project's development, objectives and timeframe) and the actual deviations from these original forecasts. Today the project integrates the generation expansion plan.

2.2. SUCCESSES AND FAILURES IN THE SAMPLE

Each experience is analysed considering: (a) Identification of structural risks (social, political, macroeconomic, etc), (b) Identification of regulatory risks by an assessment of the power sector organization and regulation, (c) Identification of project-level risks (demand, price, fuel supply, credit, currency, infrastructure, etc), (d) Description of the performance of the project/s and, finally, a short explanation of how the key risks were allocated in each case.

To compare these experiences, we developed the following table in which all the relevant information about each experience, carefully classified, is shown. In the rows "key issues for failure/success" and "Key aspects to highlight" we give attention to the lesson that should be learnt.

	Mexico	Panama	Uganda	India
Case/s under analysis	IPPs coming since 1996 when the Electricity Law (LSPEE) was modified.	New entrants (IPPs) since 1998 reform under the two stages (5-year initial SB stage and competition for the market based on regulated tendering procedures with Distrocos)	Bujagali Hydro project (200 MW on Victoria Nile River). Mostly associated to exports to Kenya	Dabhol Power Project (base-load gas-fired plant with a capacity of 2015 MW) including the Liquefied Natural Gas (LNG) plant in the state of Maharashtra.
Experience evaluation	Success (approximately 7000 MW in CCGT installed – more than USD 3000 million in investments)	Success (more than 700 MW installed/to install including 270 MW hydro and 300 MW of fuel shifting)	Failure (not commissioned yet previewed for 2010 - 2011)	Partial failure (project partially developed (I stage 740 MW running on diesel) but PPA defaulted). II stage to be completed by next year (after 14 years of agreement)
Structural risk assessment (social, political, regulatory, economic)	Large country Consolidated democracy. Minor political instability. Moderate to high economic growth, interrupted in 1995 by the "tequila crisis" (mega-currency devaluation). This crisis was overcome with the help of the US government (USD 50 billion guarantee) Since 1998, the country is performing quite well in most of the macroeconomic indicators (inflation and currency depreciation under control) Free trade agreement with USA and Canada (NAFTA). The fast development of trading within NAFTA and the geopolitical relevance of the country by USA make analysts	Small country Political instability in the past. Consolidating democracy. Pro-reform governments. FDI referred to GDP is among the highest in the region. Sound economic performance during a decade. Constant growth around 3%. Good economic indicators as inflation, sovereign indebtness, etc. Local currency pegged to US dollar. Undiversified service-based economy (banking and Panama canal fees) affected by fluctuation of prices in basic goods and commodities such as oil. Fully reformed sector since 1997. Stable framework for existing or	Small country Political instability improving from low records. Pro-reform government. High FDI inflows. Low educational level of population and high level of poverty. Very low GDP/capita. Moderate economic growth but with low social development. Weak economy focused in agriculture though circumstantially running well. No reform started at the moment of PPA agreement. No regulation at all for the main facts. When started, slow-paced. (Advances have been made today	Large country / large state where the project is located. Moderate political instability. Largest democracy of the world. Conflictive relationships with neighbouring countries: Pakistan Acute (and increasing) social inequalities but until now a stable country form the social point of view. Economic growth rates near or over 10% but economic activity not yet consolidated at all. The structure of the Indian economy is rapidly shifting from an agriculture and industry-based one to a developed-country type, with an overwhelming pre-eminence of services. High (but not explosive) inflation

	Mexico	Panama	Uganda	India
	to think that economic stability will be guaranteed in the future. Immense income and cultural gap between low social layers Strong suspicions of corruption FDI fostered since the new FDI law (1993). Though increasing it is not more than 1% of the GDP. Oil and power has special regimens. The possibility of regulatory change affecting the electricity sector is actually the greatest source of risk Highly centralised (and rigid) structure of all the sector's activities (generation, business, distribution/retail), with the CFE as single dominator. The growing finance requirements to face up to the expansion of the sector provoked some opening allowing IPPs Mexican constitution establishes that public services must be provided by public entities with no private participation. Ad hoc amendments (still controversial) were realised in the LSPEE (enacted in 1995) allowing the participation of IPPS, self-generators and import/exports (mostly to USA). The last two activities are out of the so-	upcoming IPPs based on transparent preset rules. Most of the inherent risks for IPPs are covered by existing regulation. Existing and well performing power market. Existing independent regulatory body. Existing tendering procedure for new contracts among Existing or upcoming IPPs and Distrocos. Distrocos are obliged to contract at lest 85% of their needs. Only major risk is a sudden change in regulation that is not foreseen as highly probable.	there is a sector unbundling in place and a regulatory authority) Extremely low electrification rate. Suspicions of generalized corruption.	rate and currency depreciation. Though FDI is strongly fostered, it is relatively low if compared with other emerging countries because of low infrastructure quality, the complex bureaucracy of the giant Indian administration, the protectionism of India's economic policies, the high entry-exit barriers and the traditionally severe provisions of contract enforcement. Maharashtra stands for the second most populous state in India being the second most urbanised and the most industrialised. Maharashtra is at the top of rank in receiving FDI. Opening of the generation market forced by the inability of existing integrated public utilities to cover demand increase. Existing relatively independent federal and state regulators. Regulatory mechanism for tariff setting established for final tariffs. Complex regulation network of the electricity sector. Overlapping responsibilities in some areas. Eventual breach of the agreements with the regional public utilities for financial, regulatory or technical reasons is the main risk.

	Mexico	Panama	Uganda	India
	called "public service" and should therefore be developed with total independence from the rest of the electric system. PIDIREGAS (Long-term Productive Infrastructure Projects with Deferred Impact in the Recording of Expenditure) was the represented a formula to avoid the constitutional mandate. This mechanism allowed the CFE to register as liability (as current cost) in its accounts just a small portion of the payment commitments acquired through the PPA (the expenses of the current and the following year). The rest of the total amounts registered in the PPA are treated as contingent liability. CFE is a self-regulated company. Existing independent regulator to evaluate IPPs and gas distribution.			
Project-level risk assessment	Market growing at high rates (more than 5%). No market organization or transparent dispatch rules (suspicions of irregularities) Alternatives of selling to large consumers or external agents are contemplated but require very specific adaptation between generation and	Demand for electricity has been increasing at high rates. Final tariff reflects more or less accurately the cost of service Losses and collection rates are not a major concern because the distribution companies, once privatized improve a lot. Partially alternative markets as	Internal market demand very difficult to assess (depending on rural electrification) Large grid investments required for exporting Potential competitor countries for supplying international purchasers Still close market (at the moment	No alternative market except for neighbour states (some diversification of off-taker though all are public integrated utilities) Massive system of subsidies, particularly affecting the agriculture consumers, that resulted in tariffs not covering the incurred costs Very high Non-technical losses (in some states reaching 45%):

	Mexico	Panama	Uganda	India
	demand. Special provision for fuel supply when difficult to mange (internal market) and possibility to import from USA (matures natural gas market) Through PIDIREGAS, credit risk is allocated to the buyer. High credit risk (CFE) hedged by sovereign guarantees (if PIDIRIGAS is not found unconstitutional) Non-cost-reflective tariffs. Strong politicisation of the electricity sector - existence of a wide system of subsidies, mainly covering agricultural and residential low-income customers Increase of self-supplying customers (potential decrease of alternative market)	the large customers' one (although not much extended) and the regional (central America) market No indigenous fuel supply. Completely free import market. Water management and environmental rules issued by the National Environmental Authority (ANAM) are not very comprehensive and transparent but there have not been major disputes until now. Diversified credit risk (three private distribution companies) Only financial contracts (CfDs) are allowed. High price risk for generators if COD is delayed or in cases of unavailability. Escalation allowed for thermal plants.	of the project) Unable to develope regulating dams in Victoria Nile River. High hydrologic risks for the expansion. Huge credit risk concentrated in a public utility performing quite badly.	energy theft and low collection rates represented a major cause of concern. Huge concentrated credit risk Large reserve of indigenous coal whose production remains almost totally in the government's hands (low-efficient, highly-polluting and expensive) Another relevant indigenous primary energy source is hydro power with a potential of 30000 MW Natural gas reserves not enough. Need for importing (and need for developing the infrastructure) High exposure to natural disasters: seismic activity, monsoon winds, floods, tsunami
Key issues for success/failure	Transparent procedure for contracting Public competitive bidding process Fuel supply risk allocated to the buyer when no manageable (internal market in hands of public utility) Contract based on two-part pricing	Stable regulatory framework Final tariffs reflecting actual cost of service Moderate alternative market (eligible customers and regional market) Very (regulated) precise and transparent contracting rules. Contract based on two-part	Non transparent process for granting the concession. Unmanageable public scrutiny. Project caught by a slow reform process. High regulatory uncertainty. Lack of transparent procedure for social and environmental studies and effects mitigation. Unmanageable public scrutiny. Lack of serious studies about the	Huge costs of the whole project led to high PPA prices. High cost of LNG for a power plant, doubts if these were the best option (finally stage I is burning diesel oil) No alternative market in a situation in which the single off-taker has a very low credit score. No deeper reform in order to improve cash flow of MSEB (off-

	Mexico	Panama	Uganda	India
		pricing	feasibility (construction costs, hydrologic analysis, etc) of the project and open financial closure. Inexistence of alternative markets. Single off-taker Huge credit risk of the off-taker. Public utility facing high losses in the internal market. Infrastructure risk allocated to the buyer.	taker) Non transparent process for granting the concession.
Key aspects to highlight	Constitutional mandate limiting private participation in public services remains as main obstacle for full sector liberalisation. The allocation of fuel supply risk evolved in time from allocation to buyer shifted to the seller (when manageable by the IPP) Probability-low (but with huge effects) political risk. Most critical risk allocation is depending on the constitutionality of PIDIREGAS mechanism. Overall successful results: payments fulfilled - reasonable prices.	New generation developed based on 10-year financial contracts in a small country. Hydro projects developed. Market-oriented fuel shifting investment from Bunker C to coal. No sovereign guarantees. Fuel supply risk fully allocated to generator (including hydrologic risk) Demand risk share among seller and buyer.	Despite most of the risks (currency, demand, price, infrastructure, hydrologic, etc) were transferred to the buyer and the existence of multiple guarantees, the project wasn't developed as planned. Though after the reform some risks were minimised, the project cannot be developed. The "image" of the project is undermined. The project integrates now the generation expansion plan and is previewed for 2010 – 2011.	The main problem of this project was an initial bad design regarding full supply (perhaps fostered by the central Indian government). This fact put in additional high costs and therefore high prices to the project that finally could not be managed by the developer when some political instability came out. Fuel supply risk was allocated to MSEB but when the difference between indigenous coal and imported LNG (plus the investment cost of the terminal) enlarge, this risk turned into a political one, much complex to properly hedge.

Table 18: Comparison of PPA practices

2.3. THE DECALOGUE OF GOOD PRACTICES

It is well-known that a basic practice for sound PPAs is that a successful contract results from shifting the risk to the party that has most control over it. Traditionally, in the case of a PPA, some risks are clearly on the side of the seller and some other risks are on the buyer's side. However, as stated before, the nature of the risk requires a more complex analysis, starting from recognising that each case is a single and specific one.

Based on a comprehensive analysis of the PPA risk, ten sound recommendations ("best practises") can be suggested:

1. Competitive and transparent process.

A historical and undesirable characteristic of PPAs, which contributes to the enhancement of their flaws, is that they are occasionally signed with no, or little competition. This usually leads to inefficiency and over costs in the overall project. The introduction of competition in the process of PPA assignment certainly leads to reasonably low energy prices, as well as making access to new technologies easier and releasing utilities from extremely heavy financial struggles. A transparent, well-designed bidding process for granting PPA is fundamental to ensure a positive outlook from public scrutiny. The process should be designed as transparent as possible, not only with regards to the form, but also to the content, as competition might not work out when the majority of investors perceive shadows in the process.

Another matter of potential scrutiny is the environmental, mostly in hydro projects. Controversial disputes are inevitable because of the complexity of the issue but the existence of pre-set rules that deal with these issues and the investor acting as transparent as possible helps the scrutiny. Following international guidelines and getting some kind of certificates of compliance from international organizations can also alleviate the process.

2. Pricing should be efficient

The double purpose of a PPA price structure must be, on the one hand, the achievement, in a coherent and reliable way, the coverage of all the costs associated to the construction and operation of the power plant (included all the debt interests and expected returns on risk capital); and on the other hand, the tariff structure should enhance the efficiency of the generation system as a whole.

Some costs of a new project are incurred at the beginning of the project[8] and some others, related to the fuel and the maintenance and operation of the plant, are incurred along the lifetime of the facility. More precisely, there is a category of costs which are known at the moment the plant is set in operation –construction costs, debt interests and return on capital, and another category that could only be determined as the costs are actually incurred. The different nature of these two types of costs has influence on the efficient pricing.

The international experience allows identifying several types of PPA price structures:

- Single price (energy fee - $/MWh)
- Two-term prices:

[8] It should also be noted that the risks faced by investors in hydro plants are much higher than for thermal plants, since high initial investments must be recovered during the life of the PPA, and because uncertainties in initial investments are higher than in thermal plant

- Capacity fee: (capacity fee - \$/MW): The argumentation for including this term is that it ensures the buyer will recover its fixed costs, regardless of the actual energy generation. Moreover, it allows the buyer to request the quantities of energy it needs to optimize the power system. Typically, the capacity payment is conditioned to the availability of the plant, so it motivates the IPP to optimize reliability. This concept of charge is appropriate for both thermal and renewable energy facilities. From the seller's side, this is a fixed term intended to cover expenses associated to the construction of the plant and fixed operation and maintenance expenses.

- Energy fee: (energy fee - \$/MWh): It is a variable term that aims at remunerating variable costs related to the operation of the plant, such as fuel purchase and storage.

- Multiple-(energy)-term prices: In this case the price structure is tailored to the characteristics of each power system. In this case, energy prices are set by blocks (peak, off-peak, Mon-Sat, Sat-Sun, dry-wet season). The price for each block should be reflective of the marginal costs of the buyer in its power system.

Like other terms of PPAs, contract price setting has come through a process of evolution through time. Experience has shown that two-term prices are more efficient than one-term ones. Additionally, two-term prices also favour the incorporation of the IPP to a potential market organization, that otherwise requires re-negotiation of the existing PPAs. But also the methodology to operate the plant in hydro plants influences the price structure. Particularly, multiple-term prices are appropriate when the IPP is responsible for managing the reservoir.

As stated before, apart from the traditional product, there are more products/services offered by generation units and related to the operation of power systems that should be carefully priced.

These last products include the carbon credits. The nature of the capacity fee and these environmental attributes justifiy that these emission/green rights be included in the payment for contracted capacity, since they exist for the sake of the plant's technology.

Regarding ancillary services, the main conclusion that can be learnt from experience is that in order to reduce risks for both parties, the best option for non-competitive markets is to include the cost of the mandatory ancillary services that the IPP should provide in the energy or capacity tariff of the PPA. Many of the utilities that sign PPAs are part of (small) poorly-developed power systems, with frequent supply stability problems, so separate remuneration of ancillary services could be a feasible option to increase power plants' performance and hence the stability of the system on the whole. However, this alternative finally introduces risks for the seller, since the revenues of the IPP will be subject to the volatility of the System Operator's needs. And it is also risky for the buyer, who will have uncertainty on the total cost he will have to pay to obtain such services. A fixed remuneration for providing ancillary services, based on availability, whenever the System Operator requests it, will eliminate risks and create appropriate incentives. If there is a market, such as the analysed case of Panama, these services should be priced independently of the contract, based on the existing wholesale market rules.

3. Sound market analysis is imperative

Avoiding potential situation of oversupply, even when it is supposed to be the responsibility of the host country, is a must. The possibility that electricity demand projections are exaggerated is a key risk. Experience shows that countries are less likely to enforce the PPA when there is a situation of oversupply (case as China, Indonesia, Uganda, Philippine are good examples) and financial closure is more complex as well if this situation is anticipated by banks. Take-or-pay clauses seemed to be the solution but it came out difficult to enforce when the oversupply situation was outstanding. A World Bank study is irrefutable; in more than 100 national demand forecasts, the WB found that actual demand some years after the forecasts were made, was on average 20% lower than what had been projected.

Unfortunately, the nature of supply/demand in power market is essentially cyclical, unless the system is large enough or the investment is based on smaller projects. This has resulted in a situation in which it is easier to finance small installations that might ensure better responses to the vicissitudes of demand/supply uncertainties discouraging the investment in large facilities that can be more cost-efficient such as large hydro projects.

4. Fuel market (and hydrological risk allocation) is one of the key

Fuel markets are another area of vulnerability for IPPs because of the uncertainty regarding both fuel prices and security of fuel supplies. While analysing this issue, we need to discriminate fossil fuel from water as fuel, which requires a slightly more complex analysis.

Regarding fossil fuels, successful experiences have demonstrated the ability to minimize these risks by securing a fuel supply that is reliable and cost-competitive in the electricity market. It is recommended that IPP relies on a fuel that is already established in the electric power market. Unfortunately, sometimes governments try to introduce fuel diversity though IPPs but this policy increases the risk for the investor and therefore raises the prices. The allocation of fuel supply risk depends on the features of the fuel market.

Two sound recommendations are: (1) employ indigenous resources, through contract in local currency if possible, and (2) as in the successful low-price experience of Mexico ask the electric utility to absorb the cost and political machinations required to obtain fuel from the country's oil and gas enterprise. On the other hand, if there is a liquid and transparent market for fossil fuel, the risk can be fully allocated to the IPP.

In the particular case of a PPA between a hydro plant and a buyer, there is an important source of risks that may be allocated to any of the two parties: the quantity (hydrological) risk. The availability of water is a non-controllable variable against which it is only possible to hedge partially. Reservoir management, and consequently energy outcome, in hydro plants with storage capacity is a complex task.

In the case of hydroelectric projects, the traditional approach has been to allocate quantity risk to the seller. The seller can hedge selling only the energy that the project is able to supply to the buyer with some high level of probability -the so called "firm" or "guaranteed" energy. The rest of the energy, which is usually named secondary energy, is supposed to have lower economic value than the firm one. Usually the cost of the project is mostly recovered through the sell of firm energy, and the secondary energy is low priced.

When the storage capability of the reservoir is significant, firm energy can be close (within the range 60-90%) to the average expected energy (firm + secondary). But in hydro plants with scarce storage capacity, the firm energy can be a small percentage of the average one. Therefore, as it is very expensive to charge the entire project costs to the firm energy; part of the investment is usually recovered through the secondary energy. The consequence is that the seller is finally exposed to a quantity risk.

The approach described above is particularly useful when the buyer is not skilled in the operation of the hydro plant, because in such case it is natural to allocate the quantity risk to the seller. Another approach is to allocate the quantity risk to the buyers. When the buyer is a single buyer or a distribution company, it may be feasible, and usually has the capability, to hedge this quantity risk with its portfolio of self-generation and contracts including thermal back up. This scheme has been recently adopted in Brazil, where the reservoir operation is transferred from the owner of the plant to the System Operator. Therefore, the plant owner is only responsible for maintaining the plant adequately[9].

[9] Whichever the selected approach is, the basic principle to apply is that the contract price (or tariff) must be consistent with the adopted criterion for hedging quantity risk.

This arrangement is also effective when a transition from a regulated electricity sector or a single buyer scheme to a competitive market is planned, because the buyer party of the contract becomes the natural trader or dealer of the energy produced by the plant.

5. Contractual risk allocation is necessary but insufficient

Allocation of risk through a contract is a necessary first step in managing IPPs in emerging countries. Due to the volatility of the background and the complexity of the risks involved, there is no contract that can cover the entire problem over such a span. Furthermore, contracts are good tools for allocating most of the project-level risk but often insufficient for structural risks. Structural risks need structural hedging and risk diffusion among more parties.

In addition, sometimes risk allocation generates too much complex and rigid contracts that can not deal with the dynamics involved in the complexity of the concerned risks, thus, the need of looking for clear-cut but flexible contracts, actually enforceable during long periods.

Besides contracts, there are also others sources of hedging against the main important risks. Local partners can be sometimes functional to deal with regulatory and political risk. Financing through local capital market can be effective against risk generated because of macroeconomic instability (i.e. large currency devaluation). Unfortunately, in many emerging countries this type of structural hedging can not be implemented, for instance, because of the inexistence of enough developed local capital markets.

6. Do not forget additional products of a PPA

The basic specifications of a PPA are *contracted capacity (MW)* and *(produced-delivered) energy (MWh)*. However, other technical considerations, mostly related to supply quality, ancillary services, security and reliability, also appear when drawing up a PPA.

A much more sensitive scheme should take into consideration, in addition to capacity and energy, the contribution of the project to upkeep/improve all stability, quality and safety of the power system. These functions typically involve every agent interconnected to the system, particularly generators, and should remain as a basic service that them must provide whenever necessary. The contract may also include the obligation of the seller to provide some type of ancillary services, typically contribution to either frequency regulation or voltage control. The costs to provide these services may be included in the energy or capacity tariff, or can originate a separate stream of payments.

The rise of environmental concern has caused the distribution of limited emission rights to become a troublesome issue for all polluting industries, particularly electric generators burning fossil fuels. The acquisition of the right to deliver a certain amount of energy involves the acquisition of the emission rights linked to that generation. In the case of hydropower stations, as for other facilities based on renewable sources, a system of carbon credits is applied in some regions worldwide to eligible projects. This may constitute a source of additional revenues for eligible projects.

- For the alternative where quantity risk is allocated to the seller, the common approach is to apply one fixed (rolled over) tariff, or different tariffs for firm and secondary energy.

- When quantity risk is allocated to the buyer, it becomes the “owner” of the entire energy produced by the hydro plant, which is normally paid on the basis of a fixed charge that allows full fixed cost recovery and a variable charge for recovering fuel and variable O&M expenses.

7. Countries with history of cost-reflective tariffs and high collecting rates (and low losses) use to be preferred

It is important to mention that not all emerging countries have low collecting rates, high losses or non cost-reflected tariffs. Actually, these three facts used to be quite correlated. Countries with cost-reflective tariff use to get high collection rates and low losses; on the other hands, the situation of low collection rates, high non-technical losses and distorted tariffs is quite common (the fourth element is frequently the lack of power).

The short-blanket problem (harming the credit score of the off-taker/s) is absolutely relevant. Unfortunately, the solution to this problem, in most of the cases requires of a cultural shift by means of a comprehensive reform that is out of the management of the IPPs. Independently of the multiple guarantees and completeness of the contract, if there is no money, it will be very difficult to honour the contract in the long run.

The situation is much riskier when there is only one off-taker as a single buyer entity or bundled public utility. This was a serious risk for the (flawed) Bujagali project in Uganda in which the primary customer for its power, the Uganda Energy Board (UEB), had a poor record for collecting payments and there was no alternative market for diversifying the credit risk.

8. Avoid situations where pricing authorities are not clearly defined and overlapping exists among different political levels / institutions

IPPs could become caught in the politics of power sector, making it impossible for government counterparties to make and honour credible contracts when the regulatory framework for tariff setting is ambiguous. Many ambiguities arise when governments, are unable to negotiate as single actors. The outstanding case is China where final authority for contracting decisions is often unclear, resting somewhere between local authorities in the power bureau and provincial government, and national authorities in Beijing. This arrangement has made it very difficult for investors to anticipate the real risk. In many cases the IPP is seized by some part of the government to creep the contracts, directly, by not authorising the contract escalation or indirectly by not approving the pass-through to final customers of the cost of the contracts, damaging the credit scoring of the off-taker.

9. Hydro projects are more complex

A water resource project may have multiple purposes further to electricity generation: irrigation, flood control, recreation or environmental sites. These types of facilities should find an optimal balance between competing uses of water. As this optimal balance is not simple to achieve, few large successful hydro project have been developed under PPA agreements.

In many cases, the legal framework sets the priorities for different uses of water. In this case, it is essential to inform the IPPs of these priorities. In other cases, they should be aware of possible constraints that may negatively affect energy generation, or may create additional responsibilities (and costs) for the operator of the hydro plant. Typically, international experience shows different ways to address the conflict among all the uses of water. Institutional arrangements for the development, abstraction and distribution of water supplies might be classified as follows:

- Regulatory systems that issue permits for abstracting natural waters from rivers, reservoirs, lakes or aquifers.
- Large public or private projects that develop natural waters and provide for their distribution through contracts with water users.
- Riparian water law systems that permit 'reasonable use' of water by land owners adjacent to water bodies.
- Priority ('appropriations') water law systems that permit the establishment of water use rights characterized by priority ordering and transferability.

It is important to identify which arrangement is used in the country where the hydro plant is located, and quantify the impact of other usages of water on electricity generation. Some of the issues that may economically affect a PPA are:

- Additional water diverted up-stream of the hydro plant, which diminishes energy production, for instance, linked to new irrigation consumption.
- Need to release water for irrigation/domestic/environmental use, which may force the IPP to produce energy when energy prices are not optimal (in a market environment), or limit its possibility to fulfil minimum energy production (firm energy) agreed with the buyer.
- Flood control obligation, which forces the IPP to maintain a “flood control volume” which reduces the possibility to store water in the wet season.

These and other uses of water may harm revenues of the IPP, therefore, all these constraints must be known in advance, and the obligations of the IPP regarding other uses of water must be part of the PPA.

The other issue is the environmental restrictions. When hydro projects include large dams, this could be a serious problem. The problem is unavoidable but solutions to that problem can be better or worse. A set of key recommendation can be listed:

- The existence (before the project starts) of clear and transparent procedures in the host country to deal with environmental and social effects, including the TOR for the studies, expropriation rules, etc.
- The need to perform and implement a comprehensive social development plan by the project developer
- Carry out all the necessary additional investment required to fulfil the environmental procedure. Avoid over-the-counter negotiation that can be publicly scrutinized in the future.
- In the case of no pre-exiting rules (and thus no comfortable background), at least, fulfil the recommendations of the World Commission on Dams.

10. An finally remember the Borch theorem

An application of the Borch Theory to regulation lead us to the common statement that successful contracts result from shifting the risk to the party that has most control over it.

As stated before, this is insufficient for the more complex risks, but necessary for most of the project-level risks. Some risks must be clearly allocated to the seller: construction, financing and operation; and some other risks to the buying side: price, demand. Most of the other risks (credit, fuel supply, regulatory, political, currency, etc) are more complex to allocate and finally their allocation is depending on the country specificities.

Unfortunately, there are risks that can be fairly allocated, thus the need for insurance policies, but this solution used to be expensive and in many cases, experiences showed that enforceability is neither simple nor fast.

XII ANNEX I: DETAILED FRAMEWORK OF A GENERIC PPA

The following are the typical clauses found in a PPA:

CLAUSE 1: INTERPRETATIONS AND DEFINITIONS

CLAUSE 2: I OBJECT OF THE CONTRACT

CLAUSE 3: DOCUMENTS OF THE CONTRACT

CLAUSE 4: BEGINING AND DURATION OF THE CONTRACT

CLAUSE 5: ASSUMPTION OF RISKS

CLAUSE 6: EXECUTION OF THE CONTRACT

CLAUSE 7: DECLARATIONS OF THE SALESPERSON

CLAUSE 8: OBLIGATIONS AND GENERAL GUARANTEES OF THE SALESPERSON

CLAUSE 9: DECLARATIONS OF THE BUYER

CLAUSE 10: OBLIGATIONS AND GENERAL GUARANTEES OF THE BUYER

CLAUSE 11: OPERATIVE COMMITTEE OF THE CONTRACT

CLAUSE 12: INSTALLATION OF THE SALESPERSON'S PLANT

CLAUSE 13: SUPPLY OF FUEL

CLAUSE 14: RATE OF ENERGY AND POWER

CLAUSE 15: SITUATION OF CURTAILMENT

CLAUSE 16: UNAVAILABILITY OF THE SALESPERSON

CLAUSE 17: POINTS OF DELIVERY OF THE ENERGY

CLAUSE 18: SUPPLY OF ANCILLARYSERVICES

CLAUSE 19: PAYMENT OF THE SERVICE

CLAUSE 20: PRIMARY ENERGY

CLAUSE 21: MEASURES FOR THE TRANSITION (IF REQUIRED)

CLAUSE 22: METERING

CLAUSE 23: ACCESS TO THE PLANT'S FACILITIES

CLAUSE 24: SUSPENSION OF THE SERVICE

CLAUSE 25: SURRENDER OF THE CONTRACT

CLAUSE 26: TERMINATION OF THE CONTRACT

CLAUSE 27: DEPOSIT OF FAITHFUL EXECUTION INFAVOR OF THE BUYER

CLAUSE 28: DEPOSIT OF FAITHFUL EXECUTION INFAVOR OF THE SALESPERSON

CLAUSE 29: PENAL CLAUSES

CLAUSE 30: NOTIFICATIONS

CLAUSE 31: FORCE MAJEUR

CLAUSE 32: AGREEMENTS AND FRIENDLY RESOLUTION OF DISPUTES

CLAUSE 33: RESOLUTION OF DISPUTES

CLAUSE 34: JURISDICTION

CLAUSE 35: ADDRESSES

XIII ANNEX II: EXAMPLE OF PPA

Power Purchase Agreement Term Sheet

[SERVICE PROVIDER]

XXX COMPANY

POWER PURCHASE AGREEMENT

CONFIDENTIAL NON-BINDING SUMMARY OF PRINCIPAL COMMERCIAL TERMS

This Confidential, Non-Binding Summary of Principal Commercial Terms ("**Term Sheet**") is preliminary and is intended to set forth certain basic terms of, and to serve as a basis for further discussions and negotiations between the Parties with respect to, the potential Transaction described herein ("**Transaction**") to be set forth in an agreement ("**Definitive Agreement**"). Refer to Sections VII.B., XIII and XVI of the RFO for a description of the purpose and effect of this Term Sheet.

Parties	[SERVICE PROVIDER], a _ ("**Seller**") and XXX, ("**Buyer**"), referred to individually as "Party" or collectively as "Parties".
Transaction	Seller will provide and make available to Buyer and Buyer

will purchase and pay for all Products provided by the Unit(s) pursuant to the terms contained herein.

Unit(s)

Any Qualifying Facility ("**QF**") generating station with a minimum capacity of 1 MW or a New Unit (non-QF) with a minimum Capacity of 25 MW. The location (street address and county), the technology and fuel type of the Unit are to be specified by Seller in Appendix F.

To qualify as a "**New Unit**" (non-QF), the date the Unit achieves Commercial Operation, ("**Commercial Operations Date**") shall be no earlier than January 1, 2007 (where "**Commercial Operation**" is defined to mean that commissioning is complete, the Unit(s) have been shown by test to be capable of delivering at least 98% of the relevant monthly Capacity listed by Seller in the Offer Data Forms to the grid on a sustained basis, and the Unit(s) has been released by the contractor to Seller for commercial operations).

Seller understands and agrees that Buyer will consider no partial Unit(s).

Contract Term and Services Term

The "**Contract Term**" will commence upon execution and delivery of the Definitive Agreement ("**Execution Date**") and continue until final settlement (after the end of the Services Term, defined below). The Definitive Agreement will include conditions relating to regulatory approvals and the posting of Delivery Date Security (defined below) which must be satisfied prior to the time the remainder of the Parties' obligations become effective. Only upon satisfaction of such conditions will the "**Effective Date**" be deemed to have occurred. The Seller's Offer Deposit (required pursuant to the Request for Offer) must remain in place until the Effective Date and will be returned to Seller upon the occurrence of the Effective Date.

The "**Services Term**" will be the period over which Products are available to Buyer. Seller will specify the length of the Services Term. The Services Term shall be a minimum of five (5) years, commencing as of the first of January, February, March, April, May or June (Seller to specify), during the years 2007, 2008, 2009 or 2010. However, Buyer has a preference for deliveries beginning between January 1 and June 1 in 2008, 2009 or 2010. The Services Term must begin on the first, and end of the last day of a calendar month.

Product

"**Product**" shall mean collectively Energy, Capacity, and Other Products, as defined herein. Seller may not commit to provide any Product to any third person from the Unit(s) committed to Buyer; provided that the Seller shall not be prohibited from operating the Unit as required by law or direction of the California Independent System Operator Corporation ("**CAISO**").

"**Capacity**": Seller shall offer the Capacity of whole Units. Seller's Offer should set forth a monthly schedule showing the maximum MWs of Capacity that the Seller is offering to make available to Buyer in each month of the Services Term ("**Contract Capacity**"). The Contract Capacity values should reflect expected seasonal variations in the Unit's Capacity, if any. The Seller may offer the Capacity of a Unit to Buyer for fewer than 12 months per year. Buyer shall have exclusive rights to each Unit (for each month in which it is offered).

The amount of Capacity that Buyer will pay for each month will be the lesser of the Contract Capacity, the capacity of the Unit(s) as established by seasonal testing (described below) and the amount the Unit is deemed to contribute to Buyer's Resource Adequacy ("**RA**") requirement, as discussed below ("**Monthly Contract Capacity**"). The Monthly Contract Capacity is therefore subject to prospective adjustment as of the first of the month following each seasonal test or the implementation of, or change to, the Unit's (s') RA rating.

"**Energy**": Seller shall offer Buyer the exclusive rights to all electric energy produced by the Unit(s) up to the Monthly

Contract Capacity defined above.

"**Other Products**": Seller shall offer Buyer all the capabilities of each Unit, including without limitation, Ancillary Services, other products such as black start capability and replacement reserves that are not defined as Ancillary Services, and rights such as Environmental Attributes. Seller should identify the Other Products that the Unit is capable of providing and set forth in the Term Sheet for its Offer such additional terms and conditions as appropriate for such Other Products for consideration by Buyer.

For clarity:

> "**Ancillary Services**" means all products deemed to be "Ancillary Services" by the CAISO and/or the Federal Energy Regulatory Commission ("**FERC**") as of the Effective Date or a future date during the Contract Term, including but not limited to reactive power, regulation (including load following) spinning reserves, non-spinning reserves, and replacement reserves associated with the Unit(s).
>
> "**Environmental Attributes**" has the meaning set forth in the Standard Terms Decision (CPUC D-04-06-014)

Seller may not add production capability to the Unit(s) without Buyer's consent or add other new production capability, which in any way impairs Buyer's rights to the Products as defined herein. Seller may not commit to provide any Product to any third person from the Unit(s) committed to Buyer.

Resource Adequacy	The California Public Utilities Commission ("**CPUC**") or the CAISO or a successor control area operator may, during the term of the Definitive Agreement, put into place an RA requirement whereby eligibility to count MW toward the RA requirement may be determined by identifying specific Unit(s) or a combination of Unit(s) . This RA requires that

	unit specific capacity be identified and the physical unit be made available to the CAISO for dispatch. Seller agrees that the Unit(s) or combination of Units offered to Buyer here will meet all requirements necessary to qualify as a resouce capable of contributing to Buyer's RA requirement and will consent in the Definitive Agreement to take such measures as necessary to qualify as a resource that counts toward Buyer's RA Requirement. In addition, Seller agrees to comply with all associated bidding/dispatch requirements imposed through either CAISO market design and tariffs, CPUC or FERC. Such bidding requirements may be imposed in the day ahead, hour ahead or real time timeframe. Buyer will also have exclusive rights to all RA related products such as capacity tags, capacity credits, or installed capacity ("**ICAP**") products. Seller shall comply with any CPUC or CAISO requirements for meeting RA.
Testing for Capacity and Energy Deliverability	Each Unit will be subject to testing within the 30 days preceding the Initial Delivery Date (as defined below) and seasonally thereafter during the Services Term, as established in the Definitive Agreement, to determine the maximum Capacity of the Units at 100% Base Load and Base Load with full power augmentation to confirm the ability of the Units to achieve the Monthly Contract Capacities and deliverability of the associated Energy. For a combustion turbine, "**Base Load**" is defined as operating on its base load temperature control curve. Seasonal testing under the Definitive Agreement will be done to establish the maximum Capacity of the Units for the periods (1) June 1 through September 30 ("**Summer Months**") based on test results adjusted to July Peak Conditions (as defined below) and (2) January 1 through May 31 and October 1 through December 31 ("**Non-Summer Months**") based on test results adjusted to standard "**ISO Conditions**" (59°F and 60% relative humidity). "**Peak July Conditions**" are the conditions (temperature and humidity for the site) based on the average of the monthly maximum daily peak temperatures of the preceding 10 years for the month of July as provided by the National Climatic Data Center ("NCDC") at http://www.ncdc.noaa.gov/servlets/ULCD. Data from the NCDC should be for a geographically nearby weather station that approximates the conditions at the specific plant site. Buyer shall have the right to approve the weather station employed in the development of the Peak July Conditions.
Commencement	The "**Initial Delivery Date**" is the date on which the

of Services	Seller's obligation to make Capacity available and to deliver Energy and Ancillary Services (as scheduled) commences, and Compensation payable by Buyer to Seller begins to accrue. The Initial Delivery Date shall not occur until the Seller has satisfied all conditions precedent to the Initial Delivery Date, which in the case of new generation, shall include (at minimum): • completion of the electric transmission interconnection necessary for delivery of electricity to the Buyer at the Delivery Point; • completion of all equipment necessary for fuel delivery; • demonstration that Buyer holds all required environmental permits and to the extent required, emission credits; • each Unit has achieved Commercial Operation; and • Seller has posted any applicable Collateral Requirement (as set forth in the "Credit Requirements" section below), to be available as of the Initial Delivery Date.
Construction Period Credit Requirements	As a condition precedent to the occurrence of the Effective Date, Seller shall be required to post collateral in the form of an irrevocable standby letter of credit acceptable in form and content to PG&E ("**Letter of Credit**") to secure Seller's obligations in the period between the Effective Date and the Initial Delivery Date ("**Delivery Date Security**"). Each Letter of Credit provided by Seller in connection with this transaction must be from an issuer satisfying the requirements set forth in Section VI.C. of the RFO and be in a form to be provided that will be similar to that attached as Appendix B to the RFO. The Delivery Date Security shall be an amount equal to the total of $15,000 plus the maximum amount of the Delay Damages (defined below), the sum of which is then to be multiplied with the maximum Contract Capacity committed for the Services Terms.
Early Termination Rights for Permitting	Buyer will allow Seller to terminate its Definitive Agreement and Buyer will return the Delivery Date Security to Seller less $15,000 per MW as a termination fee, should the Seller, after making all commercially reasonable efforts to do so, be

Failures	unable to secure the necessary permits: (a) within 18 months of the CPUC decision granting Regulatory Approval of the Definitive Agreement for projects over 100MW; or (b) within 12 months of the CPUC decision granting Regulatory Approval of the Definitive Agreement for projects under 100MW (due to the reduced timeline for securing permits under the California Energy Commission Small Power Plant Exemption). Alternatively, upon a failure to timely secure the necessary permits, Buyer will permit Seller to extend the permitting completion deadline by six months if Seller agrees, going forward, to forfeit the full amount of the Delivery Date Security should it be unable to obtain the necessary permits for construction and operation within the 6 month extension.
Expected Initial Delivery Date and Delay Damages	Seller shall establish the projected Initial Delivery Date ("**Expected Initial Delivery Date**") consistent with the other provisions of this Term Sheet. Buyer and Seller shall establish milestones with respect to Seller's satisfaction of the conditions precedent to the Initial Delivery Date and the expected date of completion for each milestone. At least three months prior to issuance of the notice to proceed by Seller to its EPC contractor, Seller shall provide Buyer a construction schedule. Seller shall provide Buyer monthly progress reports, including projected time to completion, and Buyer shall have the right, during business hours and upon reasonable notice, to inspect the construction site and otherwise inspect or audit to enforce its rights pursuant to this section.
	Unless the Definitive Agreement is terminated in accordance with the preceding section concerning permitting delays, if Seller falls behind in its schedule by more than 365 days, such event will be deemed an Event of Default and Buyer will have the option to exercise the remedies available to it upon an Event of Default by Seller (set forth in the "Remedies" section below). In the event Seller has not satisfied the conditions precedent by the Expected Initial Delivery Date with respect to one or more Units, Seller will be required to pay liquidated damages ("**Delay Damages**") in the amount of $250 per MW per day during the Summer Months and $62.25 per MW per day during the Non-Summer Months, up to a maximum of 365 days; in each case measured by reference to the maximum Contract Capacity committed for the Services Term. If Seller fails to pay

liquidated damages when due, Buyer may deduct amounts due from the Delivery Date Security. In the event that Seller has not satisfied the conditions precedent to the Initial Delivery Date within twelve months of the Expected Initial Delivery Date, the Seller's failure to satisfy such conditions will constitute an Event of Default (as defined hereinafter). If such an Event of Default occurs, Buyer may elect at any time to exercise the remedies that are available upon an Event of Default (defined in the "Remedies" section below), or in the alternative, Buyer will have the option to extend the end date of the Services Term by a period equal to the difference between the Expected Initial Delivery Date and actual Initial Delivery Date. Within ten business days following the Initial Delivery Date, Buyer will return the remainder of the Delivery Date Security to Seller (after satisfaction of any liquidated damage amounts then due).

In the event that Seller fails to meet any of the milestone target dates or the Expected Initial Delivery Date due to Force Majeure, the applicable date may be extended by an additional period equal to the period by which performance was delayed due to Force Majeure without penalty, not to exceed twelve months in the aggregate for all Force Majeure delays.

Scheduling Rights

Buyer shall have day-ahead, hour-ahead and real-time scheduling rights, within the defined operational limitations of the Unit(s).

Buyer shall have the right to schedule deliveries of Energy and Ancillary Services from the Unit(s) throughout the Services Term. Notwithstanding the foregoing sentence, depending on the Initial Delivery Date and then-applicable standard scheduling protocols, Buyer will have the right, in accordance with then-applicable standard scheduling protocols, to schedule the Unit(s) in advance of the Initial Delivery Date as necessary to commence deliveries of Energy and Ancillary Services on the Initial Delivery Date.

Scheduling

Seller shall provide complete and accurate notice of each

Protocols

Unit's availability on a month-ahead, week-ahead and day-ahead basis. In addition, Seller shall notify Buyer of any event that would constrain or reduce the output of the Unit as soon as practicable but at least within 10 minutes of the event, and shall provide an estimate of the expected duration of such event within 1 hour thereafter. If the event duration is greater than 24 hours, the Seller will update Buyer daily with any revised estimates regarding the Unit's(s') return to full output capability. Seller must notify Buyer of any event constraining or reducing output whether or not the unit is scheduled for operation. Seller shall notify Buyer promptly at the time the availability of Capacity previously unavailable is restored, whether or not the unit is scheduled for operation.

Buyer will be the Scheduling Coordinator ("SC") for the Unit. Scheduling shall be in full compliance with CAISO Tariffs protocols and WECC scheduling practices for day-ahead,, hour-ahead and real-time Energy and/or Ancillary Services.

Seller will agree to adhere to Buyer's schedule (provided that Buyer's schedule may be superseded by instruction of the CAISO and by law).

<u>The following provision is applicable only to Fuel Conversion Agreements</u>: Buyer shall have no obligation or liability of any kind with respect to any uninstructed deviations. Should Seller fail to operate the Units in a manner to comply with Buyer's dispatch schedule (unless due to an Unscheduled Outage or CAISO instructed operations) and a deviation occurs between the scheduled Energy and the delivered Energy or between scheduled Ancillary Services and delivered Ancillary Services ("**Seller's Deviation**"), Seller shall reimburse Buyer for any charges Buyer incurs as a result of Seller's Deviation, including charges imposed on Buyer as the SC, by the CAISO for Seller's uninstructed deviations, including but not limited to the costs of real-time or replacement Products and penalties; Buyer's additional gas costs (determined using Guaranteed Heat Rates and Start-Up Fuel Amounts); and any amounts paid by Buyer to Seller for Products not delivered; net of the revenues Buyer receives due to Seller's Deviation ("**Deviation Charges**"). However, all CAISO-instructed deviations from Buyer's Schedule shall be for the account of Buyer.

	The following provision is applicable to Definitive Agreements that are not Fuel Conversion Agreements: Buyer shall have no obligation or liability of any kind with respect to any uninstructed deviations. Should Seller fail to operate the Units in a manner to comply with Buyer's dispatch schedule (unless due to an Unscheduled Outage or CAISO instructed operations) and a deviation occurs between the scheduled Energy and the delivered Energy or between scheduled Ancillary Services and delivered Ancillary Services ("**Seller's Deviation**"), Seller shall reimburse Buyer for any charges Buyer incurs as a result of Seller's Deviation, including charges imposed on Buyer as the SC, by the CAISO for Seller's uninstructed deviations, including but not limited to the costs of real-time or replacement Products and penalties; Buyer's additional gas costs (determined using Guaranteed Heat Rates and Start-Up Fuel Amounts); and any amounts paid by Buyer to Seller for Products not delivered; net of the revenues Buyer receives due to Seller's Deviation ("**Deviation Charges**"). However, all CAISO-instructed deviations from Buyer's Schedule shall be for the account of Buyer.
Operational Constraints	The operational constraints of the Unit(s) shall be those set forth in response to the RFO on Appendix F.
Delivery Point	The "**Delivery Point**" for any non-QF is a specified interconnection point on PG&E's transmission system (to be specified by Seller in Appendix F) within what is presently defined as NP15. The point of interconnection of the substation must be within the CAISO-controlled grid. For QFs, the "Delivery Point" (the point of interconnection) must be within PG&E's service territory (NP15 or ZP26).
Electric Interconnection and Transmission	Seller shall be responsible for all costs related to upgrades to transmission facilities and construction of interconnection facilities required to interconnect the Unit(s) to the Delivery Point and enable Energy to be delivered to the grid at the

Service	Delivery Point, consistent with all standards and provisions set forth by the FERC, CAISO or any other applicable governing agency and the interconnecting transmission owner.
	Seller will be responsible for funding any upgrade(s) to the transmission network as required by the CAISO and be entitled to receive a funding return, if applicable, pursuant to its arrangements with, and the applicable tariffs of, the transmission owner and the CAISO. Regardless of whether PG&E is the interconnecting transmission owner, PG&E in its capacity as Buyer shall not be responsible for Seller's interconnection arrangements or costs.
	Seller shall be responsible for the costs of delivering its power to the Delivery Point consistent with all standards and provisions set forth by the FERC, CAISO or any other applicable governing agency or tariff.
Gas Interconnection	Seller shall be responsible for all costs related to upgrades to transmission facilities and construction of interconnection facilities required to interconnect the Unit(s) to the natural gas system and enable delivery of fuel to the Unit(s), consistent with all standards and provisions set forth by the FERC, CPUC, California Department of Transportation or any other applicable governing agency. (For non-gas facilities, Seller also shall be responsible for all fuel delivery facilities).
Fuel Supply and Transportation	<u>For Fuel Conversion Agreements</u>: During the Services Term, Buyer shall be responsible for providing transportation of natural gas to the Unit(s), and all costs related to providing such transport including inter-state, intra-state and Local Distribution Company ("LDC") charges. Buyer will only agree to Fuel Conversion Services with plants connected to CPUC or FERC-jurisdictional pipelines. Buyer shall directly pay all charges associated with inter-state or intra-state transport. Seller shall pay all LDC charges associated with delivering natural gas to the Unit(s), and Buyer shall reimburse Seller for such LDC costs. During the Services Term, Seller shall provide Buyer timely access to gas records and bills

associated with gas LDC services.

During the Services Term, Buyer will provide and schedule, at Buyer's expense, all pipeline quality natural gas for all of Buyer's dispatched start up, operations to meet Buyer's or CAISO's schedules, and Buyer's requested testing. Fuel for non-dispatch operations, Seller's other testing, and all other fuel will be arranged by Buyer, at Seller's expense, provided Seller provides Buyer appropriate notice (to be established by contract). Fuel (and all fuel-related services) required prior to the Initial Delivery Date, including fuel needed for commissioning and pre-operational testing, will be arranged and scheduled by Seller, at Seller's expense.

During the Services Term, Seller shall assign all LDC balancing rights to Buyer. During the Services Term, Buyer shall be responsible for managing gas deliveries at its expense, provided that each Party will seek to mitigate gas imbalances and Seller will reimburse Buyer for gas imbalance charges other than gas imbalances that arise due to Buyer's failure to provide timely nomination or scheduling services. Notwithstanding the foregoing, the commodity-related component of imbalance charges, penalties and cash-out costs incurred due to variations in gas consumption due to heat rate variations are addressed through the Heat Rate Payment provisions and thus only the additional component of such costs shall be Seller's responsibility pursuant to this imbalance provision.

For Definitive Agreements other than Fuel Conversion Agreements: Seller shall be responsible for all arrangements for and costs of fuel supply and delivery, including all ancillary services such as balancing or storage. (The preceding is without prejudice to such pricing proposals as Seller wishes to offer, which may tie the price of energy to the cost of fuel).

Guaranteed Availability

Seller shall meet the following "**Guaranteed Availability**" requirements:

Summer Months:

98.0% Availability

Non Summer Months:
94.0% Availability

The calculation for "**Availability**" is:

$totpotenrgy_m/[cap_m*(mnthhrs_m-mainthrs_m)]$

Where:

$totpotenrgy_m$ is the total amount of Energy (measured in MWh) that the Unit(s) could have produced for the month to which the calculation applies if it had been scheduled at its full Monthly Contract Capacity ("**MCC**") for such month (measured in MW) for every hour in which the Unit(s) was available to operate for Buyer, exclusive of hours in which the Unit(s) was unavailable due to Planned Maintenance. Hours in which the Units were unavailable to Buyer (in whole or in part) due to outages other than Planned Maintenance, including forced outages and Force Majeure, or due to failure of Seller to provide notice to Buyer of the Unit's(s') availability and capability to operate or due to a failure of the Unit(s) to deliver Energy or Ancillary Services in accordance with the schedules established by Buyer (or CAISO instruction), unless attributable to ambient conditions, shall be excluded from the determination of $totpotenrgy_m$ to the extent of such unavailability (which may be less than 100%). Accordingly, $totpotenrgy_m$ will reflect a proportional downward adjustment from the MCC for deratings, partial outages of Unit(s) and partial hours of unavailability, as well as for full hours in which the Unit(s) were entirely unavailable. To the extent the Unit(s) were unavailable to Buyer due to instruction of the CAISO, the Unit(s) shall be deemed to have been available for purposes of determining $totpotenrgy_m$. If Seller's availability notice is not timely enough to permit Buyer to schedule the Unit in the Day-Ahead Market (or such other period as the Parties agree), the Unit will be deemed to be unavailable for purposes of determining $totpotenergy_m$.

cap_m is the Monthly Contract Capacity of the Unit(s) committed to Buyer for the applicable month, as defined in the Definitive Agreement

$mnthhrs_m$ is the total amount of hours for the month

$mainthrs_m$ is the total amount of hours that the plant was unavailable due to Planned Maintenance, taken in accordance with the Maintenance Outage protocol.

Non-Availability Discount

Every month the Capacity Payments and Fixed O&M Payments due Seller from Buyer for that month will be subject to reduction for shortfalls in Guaranteed Availability for that month. The applicable "**Non-Availability Discount**" will be equal to:

Summer Months: If Availability is 97% or less, then 2% reduction in Capacity Payments and 2% reduction in Fixed O&M Payments for every 1% reduction in Availability below 98%; and

Non-Summer Months: If Availability is 93% or less, then 2% reduction in Capacity Payments and 2% reduction in Fixed O&M Payments for every 1% reduction in Availability below 94%.

In the event that the availability drops below 70% in any Summer Month or 60% in any Non-Summer Month, Buyer shall have no obligation to make Capacity Payments and Fixed O&M Payments for the month when Availability dropped below the above thresholds.

An Event of Default may result under the following conditions:

1) The Unit(s) are below 70% Availability for a period of 6 consecutive months, and such reductions in Availability are not due to a Force Majeure event; or

2) An event of Force Majeure that prevents the unit from achieving at least 70% Availability for a period of 12 consecutive months.

In addition to the above, in the event that the Unit(s) fails to meet the standards established by the CAISO for the provision of Ancillary Services (e.g., Section 2.5.25 of the CAISO, or such additional or substitute standards as may be applicable from time to time), the Capacity Payment shall be reduced by an amount equal to the charges assessed on Buyer due to such failure.

Availability Bonus Structure

Every Summer Month that Seller exceeds Guaranteed Availability for such month the Capacity Payment for such month shall be determined in accordance with the following:

- Summer Month at 99% or above = 102.0% of Capacity Payment

Start-Up Adjustment

If a Unit has not been scheduled to start at least 50 times in a calendar quarter, the monthly calculation of Availability shall be subject to a Start-Up Adjustment based on its Start-Up Factor. The "**Start-Up Factor**" is defined as:

CNS/NSR

where "**CNS**" is the completed number of successful starts as scheduled by the Buyer over a quarter and "**NSR**" is the number of starts requested by the Buyer over a quarter.

The "**Start-Up Adjustment**" will be determined from the table set forth in Attachment 3 by locating the appropriate percentage based on the NSR and the Start-Up Factor

The Start-Up Adjustment will be subtracted from the calculated Availability value for each month in the quarter (determined in accordance with the procedure set forth in the "Guaranteed Availability" section above) and the resulting number shall be the final Availability value that is applied to the Non-Availability Discount and the Availability Bonus.

To the extent that the previous months' Availability was decreased because of a Start-Up Adjustment and a Non-Availability Discount would apply, the resulting reduction in the previous months' Capacity and Fixed O&M payments will be calculated and divided by 12 and applied monthly to reduce the next 12 month's Capacity and Fixed O&M payments owed to Seller.

Maintenance Outages

Seller will be responsible for all operation and maintenance of the Unit(s) and will bear all costs related thereto. The Parties shall agree to, and include in the Definitive Agreement, detailed "**Maintenance Protocol**" for the Unit(s), subject to inclusion of the following:

- Seller shall provide a schedule of its expected annual planned partial or full maintenance outages ("**Planned Maintenance**") for the next calendar year by September 1 of each year of the Services Term; and shall update such schedule for each calendar quarter no later than 30 days before the commencement of such quarter.
- Planned Maintenance lasting longer than five consecutive days may be taken only after a minimum of 50 business days advance notice prior to the month in which the Planned Maintenance will occur. Planned Maintenance lasting longer than two consecutive days but shorter than five may be taken only after a minimum of 30 business days advance notice prior to the month in which the Planned Maintenance will occur. Planned Maintenance lasting less than two days may be taken only after a minimum of 15 business days advance notice prior to the month in which the Planned Maintenance will occur.
- There shall be no Planned Maintenance during Hours Ending ("HE") 7-22, Monday through Sunday, of the Summer Months and December and January, absent written pre-approval of Buyer;
- Planned Maintenance outages, be they full or partial Planned Maintenance Outages, may not exceed 1,000 hours total in any consecutive 12 month period when major maintenance overhauls are required or 250 hours total in any consecutive 12 month period without the written consent of Buyer;
- Seller may schedule only one major maintenance overhaul during a consecutive 60 month period without the written consent of Buyer;
- Any Planned Maintenance outage shall be scheduled

and coordinated with Buyer and the CAISO (and if Buyer is the SC, Buyer shall schedule Planned Maintenance with the CAISO); and

- Outages taken outside of the times permitted for Planned Maintenance or not otherwise in accordance with the Maintenance Protocol shall be treated as forced outages and the Unit(s) will be deemed to be unavailable during such periods for purposes of determining Availability; Capacity Payment and Fixed O&M Payment reductions due to reduced Availability may apply.

Guaranteed Heat Rate

The efficiency of the Unit's(s') ability to convert fuel into power will be guaranteed by Seller over a range of operational levels at standard "ISO Conditions" (59°F, 60% relative humidity) and the mean site elevation as well as Peak July Conditions.

Seller should specify the "Guaranteed Heat Rates" in Appendix F based on Higher Heating Value ("HHV") and on net generation delivered at the Point of Delivery at which the Unit(s) will convert pipeline quality natural gas into power at the following efficiencies (MMBtu/MWh) at ISO Conditions and Peak July Conditions:

- at Base Load with full power augmentation;
- at 100% of Base Load on the combustion turbine(s);
- at 75% of Base Load on the combustion turbine(s);
- at 50% of Base Load on the combustion turbine(s); and if applicable
- at minimum load on the combustion turbine(s), if less than 50%.

"Base Load" has the meaning set forth under "Testing for Capacity and Energy Deliverability."

To incorporate heat rate degradation as the plant ages, Seller may provide a different Guaranteed Heat Rate set of data for every year of the contract. The Seller shall specify this data in Appendix F.

For the purposes of scheduling the output of the plant, Seller will also provide detailed heat rate curves to Buyer that will be consistent with the guarantee points described above. These curves will also provide additional information as to the amount of fuel consumed and the amount of electrical energy produced at various temperature conditions and throughout the full range of operational levels.

Heat Rate Testing

Prior to the Initial Delivery Date and thereafter on a seasonal basis (Summer/Non-Summer), Buyer shall schedule, with no more than 24 hours of advance notice, a heat rate test. The tests will be for every operating point specified in the Guaranteed Heat Rate section above and will be conducted simultaneously with the capacity tests described in the Testing for Capacity and Energy Deliverability section. The tests will be performed in general accordance with ASME Performance Test Code #46. The test results will be adjusted by standard and accepted engineering methods to coincide with ISO Conditions (applicable if the test occurs during a Non-Summer Month) or Peak July Conditions (applicable if the test occurs during a Summer Month). The cost of such test shall be shared equally by Buyer and Seller. The average tested heat rate ("**ATHR**") shall be simple average of the tested heat rate at each of the operating points specified above.

Should operational data that includes fuel consumption and net plant output provide indications that the plant fuel conversion efficiency does not equal the Guaranteed Heat Rate, Buyer or Seller shall have the right to request and schedule heat rate tests on the Unit(s) for purposes of assessing the efficiency of fuel conversion and establishing a new ATHR. Heat rate tests requested by Buyer shall be performed within 24 hours of the time of request. The costs of the test will be borne by the requesting Party. As is the case for a seasonal test, the tests will be for every operating point specified in the "Guaranteed Heat Rate" section; the test results will be adjusted by standard and accepted engineering methods to coincide with ISO conditions (applicable if the test occurs during a Non-Summer Month) or Peak July Conditions (applicable if the test occurs during a Summer Month); and the ATHR shall be the simple average of the tested heat rate at each of the operating points specified in the "Guaranteed Heat Rate" section.

Heat Rate Payment[10] A "**Heat Rate Payment**" will be based on the ATHR (whether established through a seasonal test or a test requested by a Party) compared to the simple average of the Guaranteed Heat Rate at the same operating points for the same conditions ("**AGHR**"). If the ATHR is 1% or more higher than the simple average of the AGHR ("**High Test**") Seller shall compensate Buyer as follows:

Compensation shall be based on daily cost of replacement fuel, the historical daily volume of MWh produced and the difference, in MMBtus between the ATHR and the AGHR.

For each day, the following formula will apply:

DCMP = DCRF x ADV x DMMBTU

Where:

DCMP = the total compensation for one day in $s

DCRF = the daily cost of replacement fuel in $/MMBtu

ADV = the actual daily volume of MWhs produced

DMMBTU = the difference in MMBtus between the ATHR and the AGHR in MMBtus

This DCMP will be calculated for each historical day from (i) the date of the last heat rate test during which the ATHR was found to be less than 1% higher than the simple average of the AGHR until (ii) the date of the High Test. These DCMPs will be summed and multiplied by 50 percent as the Heat Rate Payment from Seller to Buyer for the time period since the last actual heat rate test and the date of the High Test. Additional Heat Rate Payments will continue to be

[10] A Seller offering a power purchase agreement that is not a Fuel Conversion Agreement may propose an alternative heat rate guarantee structure as appropriate with respect to its proposed pricing structure.

calculated per the above formula for periods following the High Test without the 50 percent multiplier and will continue to accrue for the benefit of Buyer until a new heat rate test shows otherwise.

The daily cost of fuel will be based on the applicable gas distribution charges and the index cost of gas as published by Platt's Gas Daily (in the internet publication currently accessed through www.platts.com) in the table entitled "Daily price survey" under the heading "Midpoint" for the applicable date of delivery. The index will be for the applicable gas trading point (e.g. PG&E Citygate).

An event of Default may result if the ATHR, as tested, is 10% greater than the AGHR unless Seller is able to cure the deviation and demonstrate by testing, within the following 30 consecutive days, that the ATHR, as tested, is less than 10% greater than the AGHR.

Heat Rate Bonus	A "**Heat Rate Bonus**" will be based on the ATHR (whether established through a seasonal test or a test requested by a Party) compared to the AGHR (at the same operating points for the same conditions). If the ATHR is 1% or more lower than the AGHR, Buyer shall pay a bonus to Seller as follows:
	This bonus shall equal $0.10 per MWh of actual production for every percent that the ATHR is less than the AGHR during the period from the day following the test in which such ATHR was determined until the day on which a subsequent test demonstrates that the ATHR is less than 1% less than the AGHR.
Compensation:	A. "**Capacity Payment Rate**"—specify the annual values in Appendix E as $ per kW-year (price to include right to Other Products, including without limitation, Ancillary Services, Resource Adequacy, and Environmental Attribute products);

B. "**Fixed O&M Rate**"—specify the annual values in Appendix E as $ per KW-year (price to include right to Other Products, including without limitation, Ancillary Services and Resource Adequacy products);

C. "**Variable O&M Rate**"—specify the rate or rates in Appendix E as $ per MWh;

D. "**Variable Energy Rate"** (if applicable)—specify the rate or rates in Appendix E as $ per MWh

The monthly Capacity Payment Rate and the Fixed O&M Rate are allocated monthly per the schedule in Attachment 1 and multiplied by the Monthly Contract Capacity of the Unit(s) committed to Buyer for the specific month to determine the applicable monthly capacity payment ("**Capacity Payment**") and fixed O&M payment ("**Fixed O&M Payment**") (before adjustment). The Capacity Payment and Fixed O&M Payment will be paid monthly, in arrears, for each month of the Services Term. Each of the Capacity Payment and Fixed O&M Payment are subject to the Non-Availability Discount, as applicable for that month, including Non-Availability Discount Amounts due to the Start-Up Adjustment (if applicable). If the Services Term includes partial years, the Capacity Payment and the Fixed O&M above shall reflect the cost for such partial year, and the payment rate shall be allocated monthly based on the relative value of the partial year's monthly allocation factors. Ninety days prior to a start of a full calendar year, Buyer may notify Seller of modifications to Attachment 1. Buyer may not modify Attachment 1 such that any individual month has a percentage allocation of less than 2.5% or greater than 25%; and the total in any calendar year must equal 100%.

"**Variable O&M Payment**": For each month of the Services Term, the Variable O&M Payment will equal the Variable O&M Rate multiplied by the amount of Energy scheduled by Buyer in the applicable month.

F. "**Losses**"

Seller shall not be responsible for transmission losses at or after the Delivery Point.

Start-Up Costs

A "**Start-Up**" is any schedule adjustment by Buyer that will require that the Unit(s) begin producing power at no less than minimum dispatch level output from a state of no or zero production. Start-Ups can be classified in the following manner:

- Hot start: "x"number of hours or less since shutdown;
- Warm start: Greater than "x," up to and including "y," number of hours since shutdown; and
- Cold start: greater than "y" hours since shutdown.

Where the "x" and "y" are defined in Appendix F.

Buyer will provide Seller the quantities of gas per start for Unit(s) Start-Ups ("**Start Up Fuel Amounts**") (i) necessary to meet Buyer's schedule and (ii) following a shutdown of the Unit(s) at the end of a Buyer requested scheduling period, for each of the following:

- Hot start;
- Warm start; and
- Cold start.

The MMBtu values per start, by year for each of the above starts will be specified in the appropriate field in Appendix F; specified per combustion turbine and steam turbine, as applicable.

Buyer will also pay Seller the associated costs for each Start-Up ("**Start-Up Charge**")of the amount per start, specified by year in Appendix F for each of the following:

- Hot start;
- Warm start; and,
- Cold start.

The amount of time, in minutes, required for Start-Up (from zero schedule to Minimum Schedule) will be no more than the amount per start, specified by year, in Appendix F for each of the following:

- Hot start;

- Warm start; and
- Cold start.

The maximum number of starts allowed per year for each year of the contract are specified in Appendix F for each of the following:

- Hot starts;
- Warm starts; and
- Cold starts.

Buyer will not provide fuel or pay for Start-Up if the preceding shutdown was caused by an outage that was not scheduled by Seller.

Billing and Payment

Each month during the Services Term, Seller shall invoice Buyer, in arrears, for all Compensation amounts, including the Non-Availability Discount on Capacity Payments and Fixed O&M Payments, the Start-Up Charges, and the Heat Rate Bonus (if applicable). Each month during the Services Term, Buyer shall invoice Seller, in arrears, for the Deviation Charges, including those CAISO charges which have been charged to Buyer and not previously invoiced to Seller for which Seller is responsible for paying to Buyer pursuant to the Definitive Agreement (which due to delays in CAISO billing, may relate to months prior to that most recently ended); and in addition, any fuel related expenses (including without limitation the Heat Rate Payment and gas imbalance charges) for which Seller is responsible, the Non-Availability Discount as it applies to Ancillary Services and Liquidated Damages due to failure to meet the Expected Initial Delivery Date, if applicable, for such month. If each Party is required to pay the other an amount in the same month pursuant to the Definitive Agreement, then the Party owing the greater aggregate amount will pay to the other Party the difference between the amounts owed. Payment of all undisputed amounts owed shall be due by the later of ten days after delivery of the owed Party's invoice or the twentieth day of the month (or, in each case, if the due date is not a business day, on the next following business day). The Parties shall resolve disputed amounts pursuant to a dispute resolution

	process to be included in the Definitive Agreement. In the event of termination, Buyer, as calculation agent, shall determine the amount of the Termination Payment, and either (a) if Seller is the owing Party, provide Seller an invoice within ten business days of the termination date, which shall be due within 10 business days after receipt; or (b) if Buyer is the owing Party, pay Seller the Termination Payment within 20 business days of the termination date.
Events of Default	Either Party will be in Default under the Definitive Agreement upon the occurrence of, including but not limited to any of the following: Applicable only to Seller: • Any material asset of Seller is taken upon execution or by other process of law directed against Seller or if taken upon or subject to any attachment by any creditor of or claimant against Seller and the attachment is not disposed of within twenty-one (21) days after its levy. • Upon the occurrence of any material misrepresentation or omission in any metering or any report or notice of availability required to be made or delivered by Seller to Buyer by the provisions of the Definitive Agreement, which misrepresentation or omission is caused by Seller's willful misconduct, gross negligence or bad faith. • Seller fails to post, supplement or renew when due the Offer Deposit or the Delivery Date Security. • Seller fails to comply with Resource Adequacy requirement of the Definitive Agreement. • During the Services Term, the Unit(s) are below 70% Availability for a period of 6 consecutive months, and such reductions in Availability is not due to a Force Majeure event; • During the Services Term, an event of Force Majeure prevents the unit from achieving at least 70% Availability for a period of 12 consecutive months. • During the Services Term, the ATHR, as tested, is 10% greater than the AGHR unless Seller is able to cure the deviation and demonstrate by testing, within the following 30 consecutive days, that the ATHR, as tested, is less than 10% greater than the AGHR. • A failure to complete the conditions precedent to the

Initial Delivery Date on or before the earlier of 365 days after the Expected Initial Delivery Date or a delay in the construction schedule of more than 365 days.

Applicable to both Parties:

- A Party fails to pay an amount when due and such failure continues for ten business days after notice thereof is received.
- A Party fails to perform any of its material obligations under the Definitive Agreement and such default continues for thirty (30) Days after notice thereof is received, specifying the Event of Default; provided, however, that such period shall be extended for an additional reasonable period if cure cannot be effected in thirty (30) days and if corrective action is instituted by the defaulting Party within the thirty (30) day period and so long as such action is diligently pursued until such default is corrected.
- A Party applies for, consents to, or acquiesces in the appointment of a trustee, receiver, or custodian of its assets (including, in the case of Seller for a substantial part of the Unit(s)), or the initiation of a bankruptcy, reorganization, debt arrangement, moratorium or any other proceeding under bankruptcy laws.
- Absent the consent or acquiescence of a Party, appointment of a trustee, receiver, or custodian of its assets (including in the case of a Seller, for a substantial part of the Unit(s)), or the initiation of a bankruptcy, reorganization, debt arrangement, moratorium or any other proceeding under bankruptcy laws, which in either case, is not dismissed within sixty (60) days.
- A Party fails to comply with Credit Requirement provisions of the Definitive Agreement including without limitation failure to post the initial Collateral Requirement when due.
- Any governmental approval necessary for a Party to be able to perform all of the transactions contemplated by the Definitive Agreement expires, or is revoked or suspended and is not renewed or reinstated within a reasonable period of time following the expiration, revocation, or suspension thereof, by reason of the action or inaction of such Party and such expiration, revocation or suspension creates a material adverse impact on the other Party.
- Upon the occurrence of any material breach of any

representation, covenant, or warranty made by a Party made in the Definitive Agreement, thirty (30) days after the written notice from the other Party that any material representation, covenant or warranty made in the Definitive Agreement is false, misleading or erroneous in any material respect.

Remedies: Upon the occurrence of an Event of Default, the non-Defaulting Party may elect to exercise any or all remedies available to it, including but not limited to, the following:

- Terminate the Definitive Agreement.
- Prior to the Initial Delivery Date, if Seller is the Defaulting Party, Seller will pay a Termination Payment equal to the undrawn portion of the Delivery Date Security and if Buyer is the Defaulting Party, Buyer will pay a Termination Payment of $15,000 per MW multiplied with the maximum Contract Capacity committed for any month of the Services Terms.
- On and after the Initial Delivery Date, the Termination Payment will be the aggregate of all Settlement Amounts netted into a single amount, where the Settlement Amount is equal to the Losses or Gains, and Costs, expressed in U.S. dollars, which the Non-Defaulting incurs as a result of the liquidation of the transaction, where the Settlement Amount, Losses, Gain and Costs, have the meanings set forth in the Master Power Purchase & Sale Agreement published by EEI. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.
- Exercise any other right or remedy available at law or in equity, other than specific performance.

The rights and remedies of a Party pursuant to the Remedies Section of the Definitive Agreement shall be cumulative and in addition to the rights of the Parties otherwise provided in the Definitive Agreement.

Force Majeure "**Force Majeure**" shall mean any event or circumstance to the extent beyond the control of, and not the result of the negligence of, or caused by, the Party seeking to have its performance obligation excused thereby, which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it has been unable to overcome, including but not limited to: (1) acts of God, including but not limited to landslide, lightning, earthquake, storm, hurricane, flood, drought, tornado, or other natural disasters and weather related events affecting an entire region which caused failure of the Unit(s); (2) fire or explosions; (3) transportation accidents affecting delivery of equipment only if such accident occurs prior to the Commercial Operation Date; (4) sabotage, riot, acts of terrorism, war and acts of public enemy; or (5) restraint by court order or other governmental authority. Force Majeure shall not include (i) a failure of performance of any Third Party, including any party providing electric transmission service or natural gas transportation, except to the extent that such failure was caused by an event that would otherwise satisfy the definition of a Force Majeure event as defined above, (ii) failure to timely apply for or obtain Permits or (iii) breakage or malfunction of equipment, (except to the extent that such failure was caused by an event that would otherwise satisfy the definition of a Force Majeure event as defined above).

A Party shall not be considered to be in default in the performance of its obligations under the Definitive Agreement to the extent that the failure or delay of its performance is due to an event of Force Majeure; and the non-affected Party shall be excused from its corresponding performance obligations to the extent due to the affected Party's failure or delay of performance. Notwithstanding the forgoing, (i) a failure to make payments accrued prior to the event of Force Majeure when due shall not be excused; and (ii) the unavailability of the capacity of the Units due to Force Majeure shall be deemed to be unavailability for purposes of determining Availability and the Non-Availability Discount

Metering

Seller shall install, maintain, operate and replace (as needed) electric meters and back-up meters at the Delivery Point to determine energy, and gas meters at the interconnection point for fuel deliveries, in each case at its sole cost and expense. The meters will be sealed by both Parties, which seals will only be broken by both Parties for inspection, testing or adjustment. The electric meters shall meet all specifications of the CAISO, and shall be checked annually by Seller, who shall provide Buyer with not less than 14 days prior notice of such tests. Similarly, gas meters must meet applicable specification of the service provider and shall be checked annually by the Seller or the service provider; and Seller shall provide Buyer with not less than 14 days prior notice of such tests. Buyer will have the right to have a representative(s) present during such tests.

Either Party may from time to time request a retest of the meters if it reasonably believes that the meters are not accurate within the tolerance limits established by the CAISO or the applicable service provider. The requesting Party shall pay for any such retest and shall provide the other Party with not less than 14 days prior notice of such retest. Such other Party will have the right to have a representative present during such retest. If any tested or retested meter is found to be not accurate within the tolerance limits established by the CAISO or the applicable service provider, Seller shall promptly arrange for the correction or replacement of the meter, at its expense, and the Parties shall use the measurements from the back-up meters to determine the amount of the inaccuracy. If the back-up meters are found to be not accurate within the tolerance limits and the Parties cannot otherwise agree as to the amount of the inaccuracy, the inaccuracy will be deemed to have occurred during the period from the date of discovery of the inaccuracy to the earlier of (a) one-half of the period from such discovery to the date of the last testing or retesting of the meters or (b) 180 days. Any amounts due by Buyer or to be refunded by Seller as a result of any meter that is not accurate within the tolerance limits will be invoiced by such Party within 15 days of the discovery of such inaccuracy, with payment due within 30 days.

To support invoice settlement purposes, Seller shall provide Buyer with access to all real-time meters, billing meters and back-up meters (i.e., all metering). Seller shall authorize Buyer to view the Project's CAISO on-line meter data and any gas real-time metering. Within Schedule 3 of Seller's Meter Service Agreement with the CAISO, Seller shall identify Buyer as an authorized user with "read only" privileges.

Compliance with Law, Environmental Risk and Indemnity	Seller, as owner and operator of the Unit(s), will be responsible for complying with all applicable requirements of law, the CAISO, NERC and the WECC, whether imposed pursuant to existing law or pursuant to changes enacted or implemented during the Contract Term, including all risks of environmental matters relating to the Unit(s) or the site. Seller will indemnify Buyer against any and all claims arising out of or related to such environmental matters and against any costs imposed on Buyer as a result of Seller's violation of any applicable law, or CAISO, NERC or WECC requirements. For the avoidance of doubt, Seller will be responsible for procuring, at its expense, all permits and all emissions credits required for operation of the Unit(s) in compliance with law.
Credit Requirements (as of the Initial Delivery Date)	The amount of unsecured credit to be extended to a Party by the other Party will be determined based on the senior unsecured long-term debt rating or the issuer credit rating of the Party ("**Collateral Threshold Amount**"). The Collateral Threshold Amount may be set at zero. Buyer intends to compute a market value for the products sold under the Definitive Agreement, with weekly collateral posting requirements (in excess of the Collateral Threshold Amount) tied to changes in market value of the products. From the Initial Delivery Date, Seller will also be subject to an amount equal to the product of $30,000 multiplied by the maximum Monthly Contract Capacity to be provided in any month of the Services Term during the first two years for a 24 month generation technology and $60,000 multiplied by the maximum number of MW of Capacity to be provided in any month of the Services Term during the first five years for a 60-month generation technology (the "**Independent Amount**"). The Parties agree that each Party will post Collateral equal to the Collateral Requirement in accordance with the formula below (when positive for such Party), which is based on an on-going rolling two (2) or five (5) year Mark to Market (MtM) Value, calculated in accordance within Attachment 2. If Buyer has to post, the Collateral will be in the form of a Letter of Credit. If Seller has to post Collateral, Seller will have the option to post in the form of a Letter of Credit or cash. The determination of two or five years is dependent on the generation technology underlying the

Definitive Agreement and the length of time that would be required to procure a like-kind replacement of the Definitive Agreement in the market. The Parties also agree that during the rolling two or five year term the Mark-to-Market Value shall equal the difference between the initial monthly intrinsic value ("**Initial MIV**") and the current monthly intrinsic value ("**Current MIV**") as set forth in Attachment 2. During each week during the term of the Definitive Agreement, the Current MIV shall be calculated according to the formula set forth in Attachment 2 for the next twenty-four (24) or sixty (60) months. PG&E shall be the calculation agent and will provide notice weekly to Buyer of the Collateral Requirement amount to be posted by Buyer or Seller, as applicable. Within three business day of such notice, the Party required to post shall post the Collateral Requirement or the non-posting Party shall return such collateral previously posted that is in excess of the posting Party's then current Collateral Requirement. The following shall apply for the full term of the Definitive Agreement:

The "**Collateral Requirement**" at any point in time for Seller after the Initial Delivery Date is the amount calculated which is equal to (x) less (y), but no less than zero, where:

(x) is

the positive amount of the Mark-to-Market Value as determined pursuant to Attachment 2.

plus

the Independent Amount

(y) is

the amount of Collateral previously provided by Seller plus

the Collateral Threshold Amount applicable to Seller.

The "**Collateral Requirement**", at any point in time, for Buyer after the Initial Delivery Date is the amount calculated which is equal to (x) less (y), but no less than zero, where:

(x) is

the product of the negative amount of the Mark-to-Market Value as determined pursuant to Attachment 2 multiplied by (-1)

(y) is

the amount of Collateral previously provided by Buyer

plus

the Collateral Threshold Amount applicable to Buyer.

Confidentiality

Seller shall maintain all commercial terms confidential for the greater of

(1) the term of the Confidentiality Agreement dated __________ by and between Seller and Buyer, if any;
(2) three years from the date of this Term Sheet; or
(3) the Contract Term.

Neither Party shall disclose the terms or conditions of this Term Sheet to a third party (other than either Party's employees, lenders, counsel, accountants, advisors or ratings agencies, and in the case of PG&E, the Procurement Review Group, who, in each case, have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding or request applicable to such Party, or as Buyer deems necessary in order to demonstrate the reasonableness of its actions to duly authorized governmental or regulatory agencies, including, without limitation, the California Public Utilities Commission ("CPUC") or any division thereof; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation. The confidentiality obligation hereunder shall not apply to any information that was or hereafter becomes available to the public other than as a result of a disclosure in violation of this Section. This confidentiality provision shall become binding upon delivery of the completed Term Sheet.

Dispute Resolution: All disputes that cannot be resolved after referral to senior management of the Seller and Buyer shall be resolved by mediation or arbitration. If arbitration is used, the resolution shall be determined exclusively through "baseball-style" arbitration conducted in San Francisco, California under the rules of the American Arbitration Association before a panel of three (3) arbitrators.

Other Terms and Conditions The Parties will be expected to make customary representations and warranties.

The Definitive Agreement will be governed by California law.

Seller will agree to maintain customary books and records, including without limitation, operating logs, meter readings and financial records and make such books and records available for audit.

The right of Seller to assign the Definitive Agreement or to transfer control of the Units (directly or indirectly) to another person, whether or not affiliated, shall be subject to Buyer's consent, not to be unreasonably withheld upon a showing of the proposed assignee's technical and financial capability to fulfill the requirements of Seller. Assignment of the Definitive Agreement and liens upon the Units for purposes of project financing shall be permitted; and Buyer will execute such additional consents as reasonably required by Seller in connection with such assignment; provided that Buyer shall not be required to consent to any additional terms or conditions, including extension of the cure periods or additional remedies for lenders; and provided further, Seller shall be responsible for Buyer's reasonable costs associated with review, negotiation, execution and delivery of such documents, including attorneys fees.

Seller will agree that the Units and the Products will be free of liens other than permitted liens as agreed to by the Parties.

Each Party shall be responsible for taxes assessed upon it, including any new taxes that may be imposed during the Contract Term.

Non-Inclusive; Non-Binding; Definitive Agreement	This Term Sheet does not contain all matters upon which agreement must be reached in order for the Transaction to be completed. Except for the Confidentiality provision herein, this Term Sheet does not create and is not intended to create a binding and enforceable contract between the Parties with respect to the Transaction. Refer to Sections VII.B., XIII and XVI of the RFO for a description of the purpose and effect of this Term Sheet. A binding commitment with respect to the Transaction can only result from the execution and delivery of a mutually satisfactory Definitive Agreement ("Definitive Agreement") and the satisfaction of the conditions set forth therein, including the approval of such Definitive Agreement by all applicable governing and/or regulatory body(ies) and the management of PG&E, which approval shall be in the sole subjective discretion of the respective governing and/or regulatory body(ies) and management.

Attachment 1 – Fixed Payment Allocations by Month

January	8%
February	5%
March	4%
April	4%
May	4%
June	8%
July	14%
August	15%
September	11%
October	9%
November	9%
December	9%

Attachment 2—Valuation Formulas for Credit Requirements

Formula Definitions:

t0 – date Definitive Agreement approved by the appropriate regulatory bodies

t - ongoing Transaction date after Initial Delivery Date

Ppeak(i, t) - price of monthly forward NP-15 defined peak power for month *i* as observed at the moment of time *t* measured in $/MWh

Poff-peak(i, t) - price of monthly forward NP-15 defined off-peak power for month *i* as observed at the moment of time *t* measured in $/MWh

Pgas(i, t) - price of monthly forward gas for month *i* as observed at the moment of time *i* measured in $/MMBtu

VOM, - Variable O&M (measured in $/MWh) for year of current month set forth in Definitive Agreement for month *i*

HR – the Heat Rate at Maximum Capacity set forth in the Definitive Agreement at ISO Conditions

HourlyVolume – Maximum MW size set forth the Definitive Agreement for the specific month

NumberofPeakHours(i) - number of WECC defined peak hours in month *i*

NumberofOff-PeakHours(i) - number of WECC defined off-peak hours in month *I*

Calculation of "Mark-to-Market Value":

Mark-to-Market Value = Sum Over next twenty-four (24) or sixty (60) Months[Gains or Losses(i)]

Gains or Losses(i) = MIV(i,t0) – MIV(i,t)

Initial MIV calculation formula:

MIV(i,t0) = [NumberOfPeakHours(i) * max[(Ppeak(i,t0) - HR*Pgas(i,t0) - VOM,), 0] * HourlyVolume] + [NumberOfOff-PeakHours(i) * max[(Poff-peak(i,t0) - HR * Pgas(i,t0) - VOM,), 0] *HourlyVolume]

Initial MIV will be calculated once at *t0* for the expected delivery life of the contract.

Current MIV calculation formula:

MIV(i,t) = [NumberOfPeakHours(i) * max[(Ppeak(i,t) - HR*Pgas(i,t) - VOM(i)), 0] * HourlyVolume] + [NumberOfOff-PeakHours(i) * max[(Poff-peak(i,t) - HR * Pgas(i,t) - VOM(i)), 0] *HourlyVolume]

Attachment 3—Start-Up Adjustment Table

Start-Up Factor	NSR less than 10	NSR = 10 to 20	NSR = 20 to 30	NSR = 30 to 50
98% or more	no penalty	no penalty	no penalty	no penalty
95% to 97%	no penalty	no penalty	no penalty	10%
80% to 94%	10%	15%	20%	25%
60% to 79%	30%	40%	50%	60%
40% to 59%	60%	70%	80%	90%
less than 40%	100%	100%	100%	100%

XIV ANNEX III: EXAMPLE OF PPA