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PANEL SESSION: ORGANIZATION OF TRANSMISSION STRUCTURES IN LATIN AMERICA

Sponsored by: International Practices for Energy Development and Power Generation Subcommittee

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Tuesday June 7, Room Gov Square 17, 9:00 a.m.-12 noon

EXTENDED PANEL SESSION SUMMARIES

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Track 1: Active Load Participation and Its Impact on Markets

This Panel Session discussed in depth the organization of Transmission structures in Latin America. Transmission networks provide the critical physical link between competitive generation and load. Therefore, the adequate resolution of transmission-related issues such as open access, planning of reinforcements, pricing of transmission services and cross-border energy trading is essential for the successful implementation of a competitive environment.

In the generation area, there is some industry consensus on the overall organization principles, the so-called “standard model”. In the transmission area, however, the situation is far less clear. Although several different approaches have been implemented worldwide, the “jury is still out”.

The Latin American countries provide a good illustration of the complexity and importance of those transmission issues. They have a great diversity in size, installed capacity, power demand and network characteristics (level of meshing and geographical extension). Because the regional infrastructure is still developing, heavy investments in both generation and transmission investments are required. In those countries where hydropower is an expansion option, it is also necessary to determine the most economic tradeoff between cheaper distant hydro, with higher transmission costs, and more expensive “local” thermal generation, with lower network costs. The network expansion-planning problem is made even more complex in competitive environments, where the economic effect of a generator’s siting decision is signaled indirectly through transmission tariffs.

Another important issue in Latin America is multi-country electricity markets, which are a natural evolution to the existing “official” international interconnections, which were originally established by the countries’ governments for sharing reserves and carrying out limited economic interchanges.

The Panel reviewed the organization of transmission structures in Latin America, with emphasis on the institutional and operational arrangements adopted in each country, and the success/difficulties observed in handling transmission planning, congestion and locational pricing and cross border trading. The possibility of organizing integrated regional markets was also discussed.

Presenters and Titles of their Presentations were:

1. Hugh Rudnick, Professor, Pontificia Universidad Catolica de Chile, Chile. “The Challenges of Transmission Expansion in the Chilean Power Sector: Market or Central Planning?”

2. Ramón Sanz, Director of the European and Mediterranean Geographical Unit, Mercados Energéticos, Spain. “Argentinean Transmission Regulatory System: Darks and Lights”

3. Luiz Augusto Barroso, Energy Markets Senior Analyst, Mercados de Energia/PSR, Brazil; Mario Pereira, Mercados de Energia/PSR, Brazil; Max Junqueira, COPPE-UFRJ, Brazil; Ivan Camargo, Universidade de Brasília, Brazil; and José M. Bressane, Mercados de Energia-PSR-ONS, Brazil. “Transmission Structure in Brazil: Organization, Evaluation and Trends”

4. Ricardo Rios, Technical Adviser, SIEPAC Executive Unit, San José, Costa Rica; Jorge Karacsonyi, Mercados Energeticos, Manuel Tinoco, SNC Lavalin, Canada/Spain/Central America. “Allocation of Transmission Capacity in the Central America Electricity Market”

5. Pablo Hernan Corredor Avella, Gerente Centro Nacional De Despacho, Interconexion Electrica S.A.E.S.P, El Poblado Medellín, Colombia; William Eduardo Amador Araujo, Interconexion Electrica S.A.E.S.P, Colombia; Silvia Elena Cossio Mesa, Interconexion Electrica S.A.E.S.P, Colombia. “Colombian Electricity Market - Transmission Operation and Congestion Management”

6. Marcelino Madrigal Martínez, Energy Regulatory Commission (CRE), Mexico; Florencio Aboytes Garcia, Comisión Federal de Electricidad (CFE), México; Rubén Flores García, Energy Regulatory Commission (CRE), Mexico. “Transmission Management, Pricing and Expansion Planning in Mexico: Current Status and Perspectives”.

Each Panelist spoke for approximately 20 minutes. Each presentation was discussed immediately following the respective presentation. There was a further opportunity for discussion of the presentations following the final presentation.

The Panel Session was organized by Luiz Augusto Barroso (Mercados de Energia/PSR, Rio de Janeiro, Brazil), Tom Hammons (University of Glasgow, Scotland, UK), and Hugh Rudnick (Pontificia Universitdad Catolica de Chile, Santiago, Chile),

Luiz Augusto Barroso, Tom Hammons, and Hugh Rudnick moderated the Panel Session.

1). The first presentation was on the challenges of transmission expansion in the Chilean power sector and focused on market or central planning. Hugh Rudnick, Professor, Pontificia Universidad Catolica de Chile, Chile l give it.

Adequate regulations in transmission activity in deregulated environments do not have a common solution worldwide with most countries compromising on alternatives that are adapted to local market conditions. Relevant issues are transmission tariff schemes and transmission expansion methods, both intimately linked. The Chilean 1982 regulation defines a user based tariff scheme with a non-regulated market approach to expansion that has proved unsatisfactory and conflictive. The main transmission company has questioned the sustainability of the activities. A new law is going through congress that is aimed at solving this problem. Opposing views of market expansion versus centralized planning are being confronted. This presentation described the process and discussed the alternative paths that may be followed.

Hugh Rudnick received the B.Sc. degree from the University of Chile, Santiago, and the M.Sc. and Ph.D. degrees from Victoria University, Manchester, UK. His research and teaching activities focus on the economic operation, planning, and regulation of electric power systems. He has been a consultant with utilities and regulators in Argentina, Bolivia, Central America, Chile, Colombia, Peru, Venezuela, the United Nations, and the World Bank, mainly on the design of deregulation schemes and transmission and distribution open –access tariffs.

2). The second presentation was on the Argentinean transmission regulatory system, and was made by Ramón Sanz, Director of the European and Mediterranean Geographical Unit of Mercados Energéticos, Mercados Energeticos, Madrid, Spain.

Organization of the transmission system is an important issue in Latin American countries, where the cost of transmission is an important part of the sector costs and it requires a differentiated regulation to improve efficiency and to ensure expansion of the system. In this presentation, a description of the Argentinean system was developed. The objectives of transformation of the transmission system when the new market model system is organized were introduced, and how these objectives are met and which are the needs of change in the regulatory environment was discussed. An evaluation of the regulatory system in the different aspects was also made.

Ramón Sanz is Madrid Executive Director of Mercados Energéticos that belongs to the European Territorial Unit. He specializes in Market and Transmission regulation, System and Market Operator Organization, Transmission Company Organization, and Planning Studies. He has broad experience in the electricity sector both on technical aspects such as power system studies and on the regulatory and organizational market aspects. He was the CEO and Vice President of CAMMESA (Independent System Operator and Administrator Company of Argentina Wholesale Market) between 1995 and 1998. He worked as Secretary of Energy in regulatory task and in the privatization process of Argentina Trancos. He has been an ME advisor in Argentina, Chile, Brazil, Uruguay, Paraguay, Peru, Columbia, Ecuador, Venezuela, Panama, Guatemala, El Salvador, SIEPAC, EEUU, Spain, Tanzania, and China. He was the President of the CIGRE Argentina National Committee (1997-1998).

3). The third presentation discussed transmission structure in Brazil; organization, evaluation, and trends. Luiz Augusto Barroso, Energy Markets Senior Analyst, Mercados de Energia/PSR, Brazil; Mario Pereira, Mercados de Energia/PSR, Brazil; Max Junqueira, COPPE-UFRJ, Brazil; Ivan Camargo, Universidade de Brasília, Brazil; and José M. Bressane, Mercados de Energia-PSR-ONS, Brazil prepared it. Luiz Augusto Barroso presented it.

The presentation described the structure and regulation of transmission-related activities in Brazil, and assessed their effectiveness/limitations when addressing issues such as network expansion, locational pricing, transmission financial rights, and others. It also discussed cross-border energy trading between Brazil and neighbor countries, and the perspectives of an integrated regional electricity market.

Luiz Augusto Barroso is Senior Analyst for Energy Markets at Mercados de Energia/PSR, Brazil. He joined MdE/PSR in 1999, where he is involved in project economics, system planning studies, and risk management in energy markets. He has a BSc. degree in Mathematics and a MSc. degree in Operations Research, both from the Federal University of Rio de Janeiro, Brazil.

4). The fourth presentation was entitled: "Allocation of Transmission Capacity in the Central America Electricity Market". It was prepared by Ricardo Rios, Technical Adviser, SIEPAC Executive Unit, San José, Costa Rica; Jorge Karacsonyi, Mercados Energeticos; and Manuel Tinoco, SNC Lavalin, Canada/Spain/Central America. Ricardo Rios and Manuel Tinoco presented it.

The six countries of Central America are developing a regional electricity market where trading is already intensive but limited by transmission constraints. These countries are currently developing a new transmission system (SIEPAC project) that will increase substantially cross border capacity. However, both in the current and future situation, it will be necessary to optionally allocate scarce interconnection capacity. This presentation explained the existing methodology for simultaneous auctions of energy and transmission capacity. It also discussed the proposal under discussion for implementation of point-to-point firm and financial transmission rights.

Ricardo Rios is Technical Adviser, SIEPAC Executive Unit, San José, Costa Rica. He has worked for the Institute de Investigaciones Electricas (Mexico), for the National Grid Company (England), for the Comision Reguladora de Energia (Mexico), and for the SIEPAC Project Executive Unit. He has an MSc degree in Computing Science from Tecnologico de Monterrey (Mexico); an MSc degree in Power Systems from UMIST, UK; and a PhD in Power Systems from Imperial College, London, UK.

5). The penultimate presentation was entitled: "Colombian Electricity Market - Transmission Operation and Congestion Management". Pablo Hernan Corredor Avella, Gerente Centro Nacional De Despacho, Interconexion Electrica S.A.E.S.P; El Poblado Medellín, Colombia; William Eduardo Amador Araujo, Interconexion Electrica S.A.E.S.P, Colombia; and Silvia Elena Cossio Mesa, Interconexion Electrica S.A.E.S.P, Colombia, prepared it. Pablo Hernan Corredor presented it

The presentation focused on the Columbian Electricity Market and emphasized transmission pricing structure and system congestion management. It also described the implemented methodology for Electricity International Transactions.

Pablo Hernan Corredor is Manager of the National Dispatch Center of Interconexion Electrica S. A. ESP –ISA. He has been working for ISA since 1977 in the area of expansion and operation planning of power systems. He obtained his Electrical Engineering degree in 1997 from the Columbian National University, Bogota; and his MSc degree in Power Systems in 1983 from UMIST, UK.

6). The final presentation was entitled: "Transmission Management, Pricing and Expansion Planning in Mexico: Current Status and Perspectives". Marcelino Madrigal Martínez, Energy Regulatory Commission (CRE), Mexico; Florencio Aboytes Garcia, Comisión Federal de Electricidad (CFE), México; and Rubén Flores García, Energy Regulatory Commission (CRE), Mexico prepared it. Marcelino Madrigal Martínez presented it.

The Mexican electricity system is partially open for competition, private agents have the right to access transmission networks for their use, and the management and expansion planning of the transmission system is undertaken in a traditional centralized fashion. This presentation described current procedures and methodologies used for open access transmission pricing, management, and expansion planning. It also discussed perspectives for such aspects if a more open-to-competition environment is set in place in the Mexican electricity system. In this regard, the presentation discussed the perspectives that could be taken into consideration for transmission cross-border congestion management, pricing, and long-term planning in a more competitive and interconnected environment.

Marcelino Madrigal Martínez is director of research and regulatory development at the Energy Regulatory Commission in Mexico where he performs research on several issues regarding regulation and design of competitive electricity industries. He has been an Associate Professor at Morelia Institute of Technology since 1966 where he leads research on electricity markets design analysis. He has served as a consultant and instructor in software development and training for the national electricity company of Mexico. His main areas of interest are the use of optimization tools for power systems and market design operations and planning, simulation of market behavior, and regulation. He has authored/coauthored several papers on optimization applications to power systems, and has BSc, MSc, and PhD degrees from I.T. Morelia Mexico, UANL Mexico, and the University of Waterloo, Canada, respectively.

The final EXTENDED PANEL SESSION SUMMARIES follow.

EXTENDED PANEL SESSION SUMMARIES

1. THE CHALLENGES OF TRANSMISSION EXPANSION IN THE CHILEAN POWER SECTOR: MARKET OR CENTRAL PLANNING?

Hugh Rudnick, Professor, Pontificia Universidad Catolica de Chile, Chile.

***Abstract* —** The need to determine adequate regulations in the transmission activity in deregulated environments does not have a common solution worldwide, with most countries compromising on alternatives that are adapted to local market conditions. Relevant issues are transmission tariff schemes and transmission expansion methods, both intimately linked. The Chilean 1982 regulation defines a user based tariff scheme with a non-regulated market approach to expansion that has proved unsatisfactory and conflictive. The main transmission company has questioned the sustainability of the activity. A change of law is going through congress aiming at solving the problem. Opposing views of market expansion versus centralized planning approaches are being confronted. The presentation will describe the process and alternative paths that may be followed.

***Index* Terms**—Transmission expansion, Transmission planning, Transmission systems, Transmission pricing, Open access.

I INTRODUCTION

The presence of economies of scale and the specificity of the electrical transmission assets transform them into a natural monopoly. These features provide strong coalition signals to the agents that use the network, interested in decreasing their final cost assignments, including costs sub additivities [1].

The challenge is to determine an adequate tariff scheme for electrical transmission that provides signals for system expansion. Alternatives for transmission expansion in present day power markets differ in the degree of intervention by the regulator in decisions made by the agents. On one extreme, the regulator totally defines expansion, while on the other; the regulator does not intervene and lets agents decide under basic defined rules. Network expansion arises as system need, given physical and economic signals, and it is the result of the interaction by the agents that directly, or indirectly, participate in the network.

A network expansion can generate multiple effects, such as load flow changes, relief of congested lines, etc., as well as a variation of the benefit of the connected agents, depending on existing expansion plans.

This has been a subject of debate in all modern power markets worldwide, market transmission expansion or central transmission planning? Several specific examples of regulated versus market experiences are being used to demonstrate the advantage of one versus the other. Prof Littlechild [2] recently reported a comparison using the Australian experience, which suggests that over-expansion by regulated transmission may be a more serious concern than under investment by market approaches.

II SYSTEM EXPANSION IN CHILEAN DEREGULATION

In Chile there is full freedom for investment in the electrical sector, the basic objective has been to minimize barriers of entry to new investors. Nevertheless, the National Energy Commission (CNE) elaborates an indicative expansion plan for the country's two electrical systems.

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The criterion used in the indicative planning consists of determining those options and project sequences, proposed by private investors or defined by the regulator, that minimize the costs of investment, operation and non served energy over a time horizon [3]. The solutions obtained around the optimum are then analyzed with minimizing risk criteria, considering future demand growth and evolution of fuel prices. It is important to emphasize the indicative character of this planning since it does not compel the private sector to accomplish the determined investments.

The indicative plan had more strength in the generation environment than in the transmission one. Transmission investments were often linked to new generation plants being developed, and thus were included as part of those actions.

Up to the mid eighties, the indicative plan was important as a good source of information for the companies planning investments, while at the same time, a good support for raising funds from financing third parties. Nevertheless, differences often arose between the perception that had the authority and the private investors of the expansion of the system. Such differences were conditioned, among other reasons, by the capital costs, the demand forecast, the evolution of fuel prices and the discount rate.

From a private point of view, the investment decision will be to develop those projects that, with the tariffs and costs perceived by the private investors, produce desired return rates and/or respond to their strategic interests. In terms of the authority, the indicative plans are defined based on a social appraisal of fuel costs, investments and return rates dictated by the National Planning Ministry. The objective is to supply demand by minimizing the cost to society.

The optimum expansion of the electrical system as determined by CNE directly impacts the regulated tariff levels determined by the authority. The law indicates that every six months, the CNE must determine "nodal prices" for energy and capacity. This is done in agreement with a regular update of the indicative plan. The nodal prices represent the generation transmission component of the final price to consumers smaller than 2 MW. It corresponds to a long-term projection (4 years) of the generation-transmission marginal costs. It is obtained through simulations of the stochastic hydrothermal operation of each system, considering the optimal system expansion as defined by the indicative plan.

As competition increased in the Chilean power sector and the introduction of natural gas combined plants reduced energy prices, a growing divergence arose between the CNE indicative plan and the investments in fact accomplished by the private sector. Differences arose in the incorporation dates of new plants and/or in generation technologies used for the expansion. The differences are so large at present that the CNE plans for a series of new combined cycle plants that nobody is planning to build, in an environment where investment has considerably slowed down.

III TRANSMISSION EXPANSION IN CHILE

A worse situation has developed in relation to transmission expansion. A long awaited separation of the transmission company Transelec from the main generator company took place in October 2000. Hydro-Quebec International acquired the transmission assets of Endesa, Chile's largest generating company. Endesa was forced to divest itself of its transmission business following requests from the Antimonopoly Commission, which questioned interests of power producers in transmission concerns.

While this awaited development was welcomed in the country, it was a major test to the transmission regulation, as it exposed the weaknesses of the tariff system in financing existing installations, less expansion. The transmission tariffs are based on a usage scheme [4], where generators claiming open access negotiate with the transmission owner on their transmission payments. These payments are allocated among all users on a prorate base of their usage. These negotiations are done on a one at a time two side basis (one generator with the transmitter), so that they do not assure the financing (or over financing) of all investments. Transelec has complained on these conditions and has minimized its new investments, unless payments are clearly identified. This has been aggravated by an incomplete tariff scheme, where there are no ways to finance transmission expansions needed by consumers. The southern part of the main electrical system is in need of urgent expansion, conditioned by load growth in the area. While there is no way to transfer these new costs to consumers so that this expansion takes place, blackouts have already taken place because of congestion.

This has driven all parties involved, government, regulator, generators, transmitters, distributors, to look for solutions. The change of the electricity law was seen as the only approach, as bylaw modifications could not go into the root of the problem. New tariff schemes are being discussed through congress, still with the usage based allocation concept, but making consumers participate directly in financing transmission. An 80% generators- 20% consumers rule is being considered for the main transmission corridor, with an improved centralized process for the allocation of payments. The opportunity was also used by the regulator to propose changes to the transmission expansion scheme. Initially, a centralized transmission planning approach was proposed. A planning study was to be done every four years, with compulsory decisions taken by the regulator for lines to be built. The proposal was changed, as of this writing, to give this planning a more indicative character, where not only one given expansion will be defined, but several scenarios will be considered. Agents would then interact to decide the final investment. The Argentinean example of transmission expansion mechanisms [5] is an interesting approach that could have been followed, but has not been used in defining law changes. Cooperative game approaches [1, 6] could also be of interest to implement the proposals being discussed in congress.

The presentation will highlight the history of transmission expansion in the Chilean market, successes and failures, the alternatives being considered in the change of law (and eventually adopted at time of presentation), and challenges for the future.

IV REFERENCES

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BIOGRAPHY

Hugh Rudnick, IEEE Fellow, is a professor of electrical engineering at Catholic University of Chile. He graduated from University of Chile, later obtaining his M.Sc. and Ph.D. from Victoria University of Manchester, UK. His research and teaching activities focus on the economic operation, planning and regulation of electric power systems. He has been a consultant with utilities and regulators in different countries, the United Nations and the World Bank, mainly on the design of deregulation schemes and transmission and distribution open access tariffs.

2. ARGENTINEAN TRANSMISSION REGULATORY SYSTEM: DARKS AND LIGHTS

Ramón Sanz, Director of the European and Mediterranean Geographical Unit, Mercados Energéticos, Spain.

***Abstract*—**The organization of the transmission system is an important issue in Latin American countries, where the cost of transmission is an important part of the sector costs and it requires a differentiated regulation to improve the efficiency and to ensure the expansion of the system. A description of the Argentinean system is developed. The objectives of the transformation of the transmission system when the new market model system is organized is introduced, and how these objectives were met and which are the needs of change in the regulatory environment. The regulatory system for expansion, operation, remuneration, pricing, quality of service performance and international interconnections is presented. Finally an evaluation of the regulatory system in the different aspects is done.

***Index Terms*--** Power transmission, Power transmission economics, Power transmission planning.

1. Introduction

The Argentine Interconnection System is characterized by a high demand concentration near Buenos Aires and the distance between the concentrated demand location and the natural power resources (natural gas and hydroelectric potential). Consequently, the current electric system is considerably radial and there is a significant average distance between generation and demand.

The following table shows the main characteristics of the Argentinean transmission system.

TABLE I – ARGENTINEAN TRANSMISSION SYSTEM

Transmission system	500 kV	220 kV	132 kV	66 kV	33 kV	Total
High Voltage (Transener)	9101	562	6			9669
Regional Transmission		841	11215	391	24	12471
Cuyo (Distrocuyo)		634	611			1245
Comahue (Distrocomahue)			902			902
Buenos Aires (Transba)		177	5408	391		5976
North East Area (Transnea)		30	1022		24	1076
North West Area (Transnoa)			3272			3272
Patagonia (Transpa)		1111 *	798			1909
Source: CAMMESA POOLCO * 330 kV						

Generating areas are located in the system's borders whereas demand is concentrated on the central area and, therefore, the system has a "star-like" configuration. Greater Buenos Aires area represents approximately 43% of the overall demand and such percentage would increase to 70% if the Buenos Aires Province and Litoral areas were included. On the generation side, Comahue, NEA (Argentine North-East Area -Yacyretá) and NOA (Argentine North-West Area) have the majority of the generation-installed capacity.

The interconnected system is divided in two parts. The main system called "Sistema Argentino de Interconexión, SADI" is located in the central and north region of the Argentine Territory. The "Sistema Interconectado Patagónico, SIP "is located in the Patagonia region. The main transmission system (500 kV network) is operated and maintained by a privately owned company called TRANSENER. The sub transmission networks are operated and maintained by Regional Transmission Companies: Transnoa, Transnea, Distrocuyo, Transcomahue, Transba and Transpa. The following graph shows the geographic areas corresponding to each company.

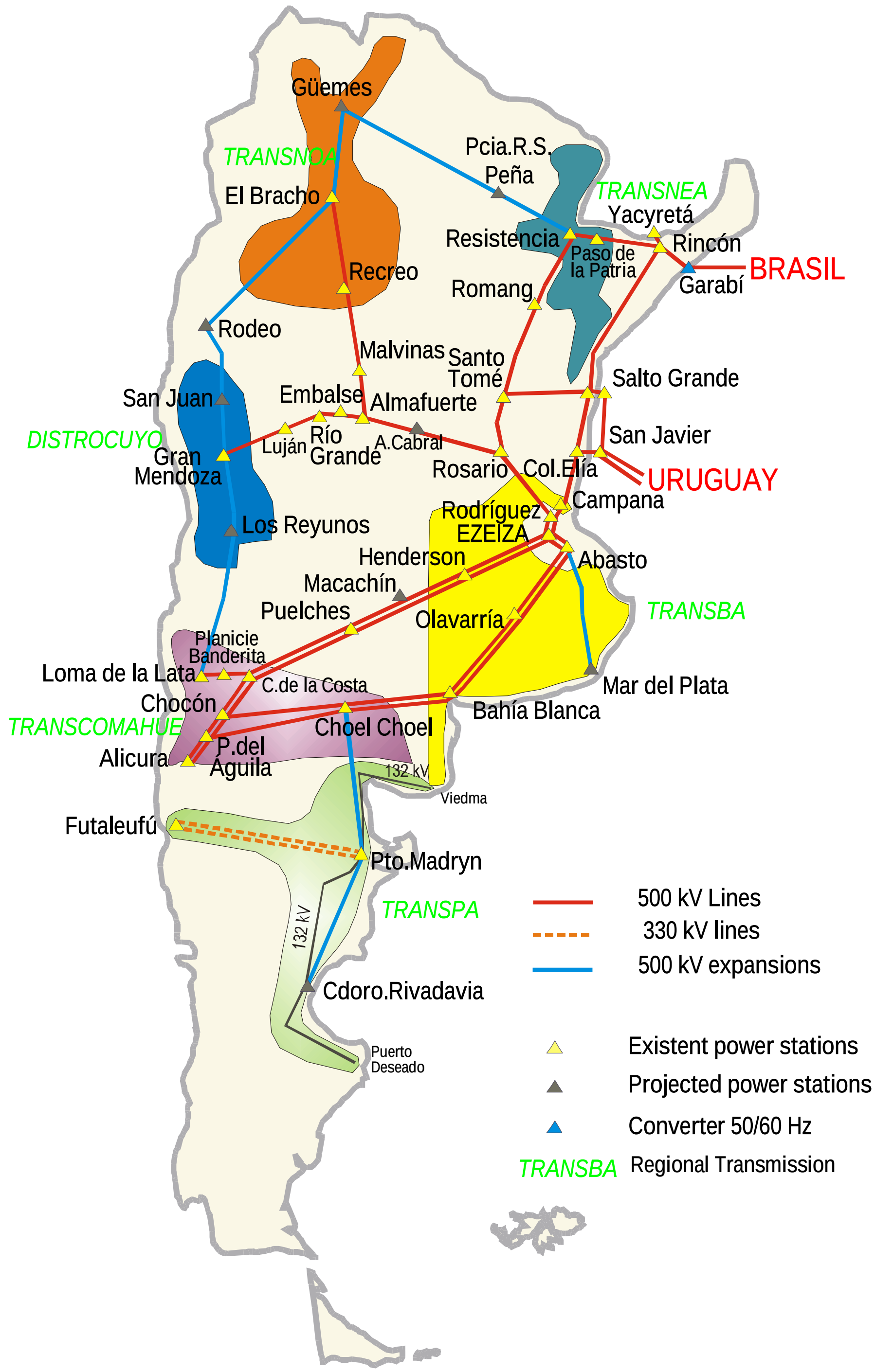

Figure 1 – Argentinean transmission system: geographic areas

They are privately owned companies that operate regional transmission networks (mainly made up by 132 kV power lines). In the remaining regions (Center, Litoral and Greater Buenos Aires), the transmission service is provided by regional distribution companies that act as Additional Suppliers of the Technical Transmission Function (PAFTT).

The transmission system that was put in service after the initial privatization process is operated and maintained by companies called “Independent Transmission Companies ITC” that are supervised by the Transmission Companies. The main ITC are LITSA, and YACYLEC.

The thermal generation installed capacity increased in the latest years, firstly in the Comahue area and subsequently in the NOA area, as well as the commissioning of the Yacyretá hydroelectric power plant in the NEA area, promoting a high degree of utilization of the transmission system, particularly in the Comahue - Buenos Aires and NOA-Center corridors.

The international interconnections are:

- 1000 MW interconnection (500 kV) with Uruguay;
- 2100 MW interconnection (500 kV) with Brazil. The interconnection were built by private investors with open access for spot exchanges;
- 200 MW interconnection (220 kV) with Paraguay;
- 650 MW interconnection (345 kV) with the north of Chile was built as a private investment

The investments in Transmission capacity expansion between 1994 and 1999, according to ENRE (Regulatory Agency), were $ 644.7 million due to 74 expansion projects. This amount represents a 30 % of new investment replacement cost of the current system.

There are several projects to expand the transmission network in the medium and long term. The additions in the 500 kV network will allow to interconnect the SADI with the Patagonia network and to mesh the actual system, allowing improving the transmission capacity and the quality of service.

The System quality of service is the following

TABLE II – SYSTEM QUALITY

Origin	Energy curtailed [MWh]		Energy Not Supplied (ENS) [MWh]		ENS/LOAD $x10^5$	
Year	1999	2002	1999	2002	1999	2002
Generator faults	3898	926	1188	266	1.73	0.37
Substations fault	588	3924	474	8539	0.69	11.84
One line fault	4764	2032	4146	998	6	1.38
Double line fault	3066	3981	1655	3497	2.41	4.85
TOTAL	12315	10863	7462	13300	10.85	18.44
Source: CAMMESA						

2. The objectives and requirements in the 1992 regulatory model

The transformation process was implemented in 1992. In that moment the EHV transmission system could be characterized by:

- Low level of using of transmission capacity
- Inefficient planning system (a line of 500 KV to the North with an average flow of 34 MVA)
- Long term discussion about the need of expansion of the main corridor Comahue- Buenos Aires
- Operation and maintenance cost that reached 6% of new replacement value in the EHV transmission system.
- High time of recovering the collapsed towers due to tornados (more than30 days in some important events)
- Gas and electricity transport competition
- Forecasted expansion in gas thermal units

The transmission investment cost in Argentina was very important. In fact, Argentina is one of the countries with highest requirement of transmission investment as the following graph shows. The last reason shows why the optimization of costs was a key issue in the transformation process.

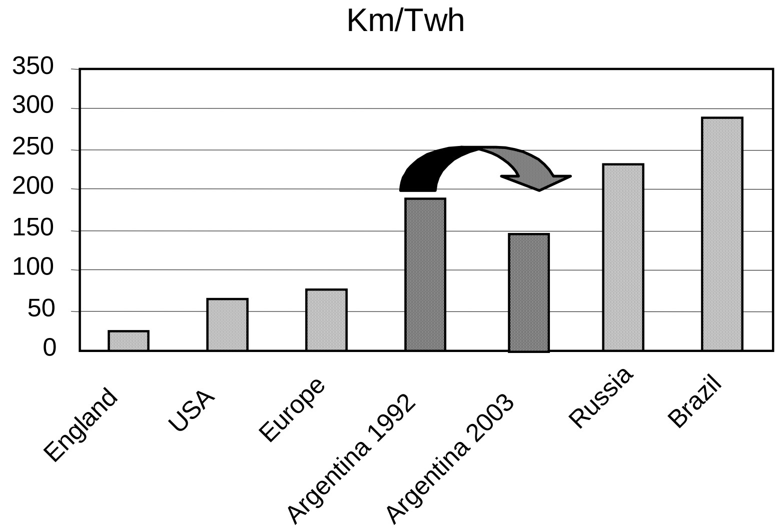

Figure 2 – Transmission investment

The objectives that were introduced for the new regulation were:

- To increase the use of the transmission system
- To improve planning efficiency
- To increase the transmission availability

3. Transmission Service organization and regulatory design

A. Organization

The Transmission activity is defined by Law as a public service, of a monopolistic nature and therefore regulated. Its rules were set through a Presidential Decree. Initial tariffs, rights and obligations, penalties, etc. are defined for each Transmission Company in its Concession Contract.

Transmission companies are not allowed to buy or sell electricity, are limited to providing transmission service through regulated tariffs and are passive agents. They are strictly a wires business. The expansion is decided by the regulatory entity and it is in charge of a new company, "the independent transmission company" that is a transmission facility provider and depends on the Transmission Companies.

The Transmission Companies are responsible for operating and performing the maintenance of transmission systems and/or transmission components, complying with quality of service standards. In exchange they get the right to collect transmission tariffs. Transmission companies do not take market risks. Their only risk is related to their quality of service obligations. They are penalized in case of non-compliance.

There are three kinds of Transmission companies:

- The high voltage bulk transmission was privatized and concentrated on a single company, TRANSENER, created from the merging of assets of three pre-existent government owned utilities. It has a concession for the operation and maintenance of the high voltage network (500 and 220 kV), which connects electrical regions. The network covers an area of some two million square km.
- Regional transmission companies responsible for the operation and maintenance of sub transmission network (in general 220 kV or less) within a region that connects the national grid of Transener to the

distribution networks. The Patagonia region, in the South of Argentina, is not interconnected yet at 500 kV to the national grid and has a concession called Transpa. Six regional transmission companies exist, including Transpa.

- Independent Transmission Companies (Transmission Facility Provider) are the Transmission Companies that result from competition in expansion. They can build, operate and maintain new lines under the operational authority of the Transmission Company to which they connect. Existing Transmission Companies can also compete for the expansion. Two independent transmission companies, LITSA and YACYLEC, own and operate the new lines that connect the new Yacyreta hydroelectric plant to the grid, under the supervision of Transener. Transener won the other important expansion from the Southwest to Buenos Aires. (There are several ITC in other voltage levels and Substations).

Wheeling in a distribution network is also considered a transmission service. Distribution companies are assigned as having an additional function for their transmission services (called PAFTT that is the abbreviation of Additional Provider Technical Transmission Function). There are 12 Distribution companies providing with this additional service.

B Open access

The electricity Law obliges open access of the transmission and distribution networks. A generator, Distribution Company or large consumers may connect to the grid after fulfilling the defined technical requirements and presenting the electrical studies, which prove that the connection does not affect quality. They may need to carry out transmission investment to fulfill these requirements.

After connection, any congestion will affect all the agents that use the link, both physically and in the nodal energy prices. In real time operation, if some equipment is negatively affecting quality and endangering the reliability of the system, the System Operator has the right to order its disconnection.

C Nodal Pricing

The pricing system reflects the physical configuration of the network and the electrical distance to the system Load Center, near the Great Buenos Aires area, which is called “The Market Node". The Entry/Exit points (nodes) to the Market are located along the Transmission Network. Each Market Participant sells and buys at its entry/exit node (the node where it connects to the system). At each node, the “Nodal Factor” (FN) measures the Transmission short-term marginal cost. It is calculated hourly by CAMMESA for all the nodes.

The Adaptation Factor (FA) of a region measures the quality and reliability of the transmission links, by evaluating the probable dispatch overcosts and non-supplied energy costs because of faults in the lines that connect the node to “the Market node”. It is calculated by CAMMESA every 12 months. In each node, hourly nodal energy prices are calculated. These prices represent the energy price at the Market node affected by the nodal factor. A regulated generation capacity price is defined in the Market node and the price for the nodes of each region is calculated by multiplying the Market node price by the Adaptation factor of the region.

When there is congestion in a line, the economic dispatch cannot be achieved. In such case, the group of nodes affected by the restriction is considered as an Area isolated from the Market node, creating its own Market (a Local Market) with its own energy Spot price (local price).

D Transmission Company revenues

The transmission Company has regulated revenues with quality of service obligations instrumented by a penalty system. The general principle is that, through their combined action, the Transmission Company receives incentives for a reliable operation. The revenue of a Transmission company has three components:

- Connection revenue: a regulated rate for each type of connection, set per hour of availability.
- Capacity revenue: a regulated rate for each type of line, set per hour of availability.
- Revenue because of Nodal Pricing: It is calculated every 5 years as the expected amount to be collected because of the difference between energy and generation capacity nodal prices. It is defined as a stabilized amount fixed for five years. (This concept was discussed by ENRE in a decision that had a legal objection).

A Transmission Company's initial remuneration system was set in its Concession Contract, and is subject to regulatory review every five years because of nodal pricing and every 10 years for fixed costs.

Transmission charges collect regulated maintenance and operation costs of lines and connections assets plus variable charges resulting from the nodal pricing scheme. No payments are assigned to cover return over investment cost of existing assets because the State transferred them at no cost to the new transmission companies upon privatization (sunk costs). This was done to facilitate the implementation (reduce the initial cost) of the new Market. For new network expansion, investment costs are included in the transmission charges.

Transmission Companies receive an essentially stable income only affected by non-achievement of continuity targets and quality of service set forth as a reference in the Concession Agreement.

For quality of service purposes, Transener lines are categorized in three different levels (A, B or C) depending on their importance in transporting energy. Each category has its own penalty values reaching 200 times the remuneration per hour out of service. For transformers, the penalties depend on whether energy transfer is lost or not. There is a cap on the maximum level of penalties, which is set at 50% of the total Transmission Company income in any month and 10% of income in any year. If performance is below the standard corresponding to this cap, the regulator can end the concession Contract of the Transmission Company.

Money collected by the penalty system, is reimbursed to the users of the unavailable transmission capacity.

E Transmission Charges for Transmission Users

The Transmission Users charges are regulated to ensure that the total Transmission Company revenues will be collected. Transmission Users pay the following charges:

1) Variable Transmission charges

An agent that is distant from the market node (defined by the regulation as near to demand center) needs the grid to sell (buy) energy and capacity. The variable transmission charges are proportional to the variable transmission costs of carrying this energy to/from the Market Node.

Variable energy transmission costs are calculated on an hourly basis by the daily dispatch run by CAMMESA. They are evaluated as marginal transmission costs and calculated with the network marginal losses (nodal factor) and dispatch over cost due to reliability of the transmission system (adaptation factor).

When an agent sells / buys energy or capacity at its respective nodal prices, he is implicitly paying the variable transmission charges, that are proportional to the difference between the energy and capacity price at their respective nodes and the Market node price.

2. Fixed Transmission Charges

Variable transmission costs are not enough to cover the Transmission Companies' overall costs. Users must pay the difference between the total transmission costs (the total revenues committed to the Transmission Companies) and the variable costs through two fixed charges, as follows:

- Connection Charge: It is the cost of maintaining and operating equipment through which users are connected to the grid. If more than one user is connected to the same node, the costs are pro-rated according to their maximum capacity requirement.
- Complementary Charge: It is the difference between overall transmission costs and the expected amount to be collected through variable transmission charges and connection charges. It is evaluated by CAMMESA, for each transmission line, on a quarterly basis.

An agent is considered a user of all the lines included within its "area of influence". A line is included within its area of influence if an increase in the agent's energy exchanges produces an increase in the line's active power flow.

For new lines constructed through a bidding process, the complementary charge is equal to the annuity to cover the investment cost plus O&M cost of the expansion. An agent will pay a charge if the line is within its area of influence and such payment will be considered part of its transmission costs.

All the users of a line pay a complementary charge that is proportional to their "use" of the line during the preceding twelve months. Such use and the proportionality factor are evaluated by CAMMESA every three months.

In this way, the income of the Transmission Company and the charges paid by its users are linked. CAMMESA is responsible for collecting transmission charges from agents and paying the collected amount to the Transmission Companies.

F. Transmission Expansions

The Rules of the Transmission activity set that the expansion of network must be initiated by requirement of its users, that is:

- Generators located in export areas where not all-available generation capacity is dispatched because of transmission constrains. They need the transmission network expansion to transport their surplus to other areas;
- Distributors and Large Users located in import areas where transmission constrains do not allow supplying demand with economical generation. They need the transmission network expansion to buy economical generation and avoid failures to supply due to generation deficit.

The expansion of the transmission system is defined as a competitive activity. The Transmission Company has the right, but not the obligation, to construct new capacity that is initiated by its users. If a new company constructs the expansion, it becomes an Independent Transmission company.

As a result of the expansion rules and the Transmission costs that the users have to pay, in general it is "good business" for a Generator to build new Transmission (to maximize its revenues) when it is also efficient and economically convenient for the Market as a whole.

From the regulatory point of view there are two kinds of transmission expansions: minor or major. The Transmission Company has the obligation to do minor expansions. In the case of TRANSENER, any expansion with an estimated cost below 2 million pesos is considered a minor expansion. In this case, the only requirement for authorization by the Regulator is that the Transmission Company reaches an agreement with the Transmission Users that need this expansion.

In order to allow opening up the transmission network expansion to maximum competition, a major expansion to the network is neither a right nor an obligation of any particular Transmission Company and can be built by another company, which becomes an Independent Transmission Company. Major expansions must be "initiated" (proposed) by a coalition of Transmission Users, called the "Initiators".

Initiators can contract a major expansion directly or through a tender. If it is contracted directly, the

Initiators must pay all investment costs. Open access to the expansion exists and the charges to be paid by other users are calculated with the regulated operation and maintenance costs.

All Transmission Users pay investment costs of expansions that result from an open tender supervised by the Control Authority (ENRE) to ensure transparency and competition. “Initiators” can propose a major expansion to be paid by all Transmission Users if the coalition has at least 30% of participation in the use (benefits) of the expansion. If other agents with 30% or more participation in the use are opposed to the expansion, the ENRE will reject the proposal. All expansions require the authorization of the Control Authority (ENRE). When it receives a proposal for a major expansion, the ENRE has a public hearing.

For competitive tenders, investors must bid the annual fee for the amortization period to cover construction, operation and maintenance of the expansion. Existing Transmission Companies can bid on their own or as part of a consortium, but are not given any special consideration. The winning bid is made known publicly and becomes the annual authorized cost of the expansion, to be covered through Transmission Users charges. All Transmission Users pay this cost, even those that were not Initiators.

When an expansion is not built by TRANSENER, this company has a role of overall technical supervisor to safeguard the technical integrity of the network as a whole. For this role, TRANSENER is remunerated with a statutory fee of 3% of the construction costs. In 1999, when the system required to increase the interconnections due to security problems and to improve market competition, the government approved a fiduciary fund, product of an energy tariff addition of 0.6 $/MWh, to finance the expansion of these new lines.

G. Expansion Account

When congestion exists, local prices increase variable transmission costs due to the fact that such prices include costs additional to those corresponding to marginal losses.

Additional variable costs that result from local prices are considered the amount in excess paid by the users due to transmission capacity shortages. Such amount is not transferred to the Transmission Companies but it is accumulated in a special account, known as the Expansion Account (called Exceed Fund). In such account, the money accumulated as a result of congestion in the different network corridors is broken down. If a new transmission expansion improves the transmission conditions in a given corridor it is possible to use the respective amount accumulated in the Exceed Fund to cover up to 85 % of the expansion costs.

H. International interconnections

An import or export firm exchange with a neighboring country requires to have the firm international transmission capacity to support the commitment. To this purpose, the contract should not only have generators with enough installed capacity and energy to guarantee the commitment, but also with a firm transport in the international border that ensures the transference of the required capacity between networks. A Firm transmission contract is the tool to ensure a transmission capacity reservation.

Those who have firm supply contract must pay the investment cost of the international interconnection. The expansion is made by the winning bid of a tender that requires an annual fee as transmission cost.

I. Transmission standards

The transmission standards approved as dynamic criteria that the system must remain stable without a load and/or a generation shedding when a one-phase fault occurs in the most critical end of a line and this line is opened definitively. These criteria are applied for multiple circuits that is to say in cases in which there is an alternative way for the energy flow. With three phase fault the load and generation shedding is accepted.

The service quality introduced to the development of the interconnections was done taking into account the fact that building one more line costs an important amount of money in relation to the current investment of the existent system (a radial and elongated system) and also in relation to the energy not supplied when these criteria are applied. In all the cases the stability must be met, but load shedding, automatic load shedding and automatic disconnection of generation can be used.

The uses of the N-1 reduced criteria mentioned has an important effect in reducing the transmission cost in the system. These criteria allowed the introduction of a new AGS (automatic generation shedding) [3] system that was complemented with other protection and control arrangements, including a widespread coordinated supplementary stabilization system for the control of electromechanical oscillations across the Argentine Interconnected System; a fast load shedding scheme based on rate of change of frequency relays located at key stations in the load area; automatic post-fault voltage control devices connecting and disconnecting shunt reactors throughout the 500 kV transmission system and 132 kV distribution networks in the load area; automatic by-pass of series capacitors and tripping of 500 kV lines with light load along the duplicated segments of the corridor between Piedra del Aguila and Ezeiza.

As it was mentioned before the use of this technology reduced notably the transmission cost, but it requires the addition of defense plans called “Proyecto de Islas y Arranque en Negro” (Project for islanding and black start [1], [2]) that CAMMESA are in process of implementation). The objective of this project is the alleviation of the consequences derived from the extreme contingencies associated to the criteria mentioned.

4. Conclusions of Ten years of transmission regulation in a market environment

Most of the objectives of the 1992 regulatory design were met. However a lot of discussion about the regulatory environment exists and specially those related to expansion issues. The main conclusion of the ten years, in which the described models were implemented, were:

- The transmission capacity increased in the same proportion that the demand growth. Half of this increase was due to supplementary control system in the main corridors. The rest was due to EHV system investment that was more than 30% between 1992 and 2002 while the demand grew 60%.
- For these reason the relation between km of EHV lines and load decreased 25 %, and reduced the transmission cost participation in the end user tariff and in the costs assumed by the generators.
- Operation and maintenance cost was reduced to one third in relation to the old model and more 50% with reference to 1992 costs.
- The quality of service between 1992 and 2002 improved from 1.5 faults/100 km to 0.37-faults/100 km.
- The average recover time when a tower line collapsed in the main corridors was reduced from some cases of 30 days in the eighties to 2 days during the last decades.
- The cost of new expansion was reduced in more than 30% in relation to the declared cost in the integrated environment. The Independent Transmission Companies have produced a high reduction in expansion cost.
- The pricing scheme developed for a radial transmission system gives non-optimal signals in the forecasted new expansions.
- The planning results improve specially in the generation requirements but the lack of an organized transmission planning in relation to demand expansions produced an inefficient planning for the demand requirements.
- The expansion of international interconnections was very important and with merchant lines that in some cases were affected by the macroeconomic problems of the regions.
- The relation of transmission with the System Operation and the Regulatory Agency gave good result. The lack of political definition about contracts renegotiations and Regulatory Agency board members affect the sector behavior.

It is possible to show the points that were evaluated and the level met in relation to the objectives fixed in 1992. The main effect that was to improve the efficiency in the transmission operation and maintenance and to build and finance in an efficient way was obtained. The challenges are to introduce a new planning system adapted to expansion that are justified in security and market development and a pricing system adapted to the new structure. In these analyses, the effect of the 2001 macroeconomic problems was not evaluated. These changes produced an affectation of the power sector and specially in the financing of new expansion and the renegotiation of contracts and in the funds organized for the new transmission expansion requirements. In this moment there is an important negotiation to fix the new contracts. The lack of institutionalism in the sector makes impossible to analyze the regulatory changes.

As a summary it is possible to show the following graph:

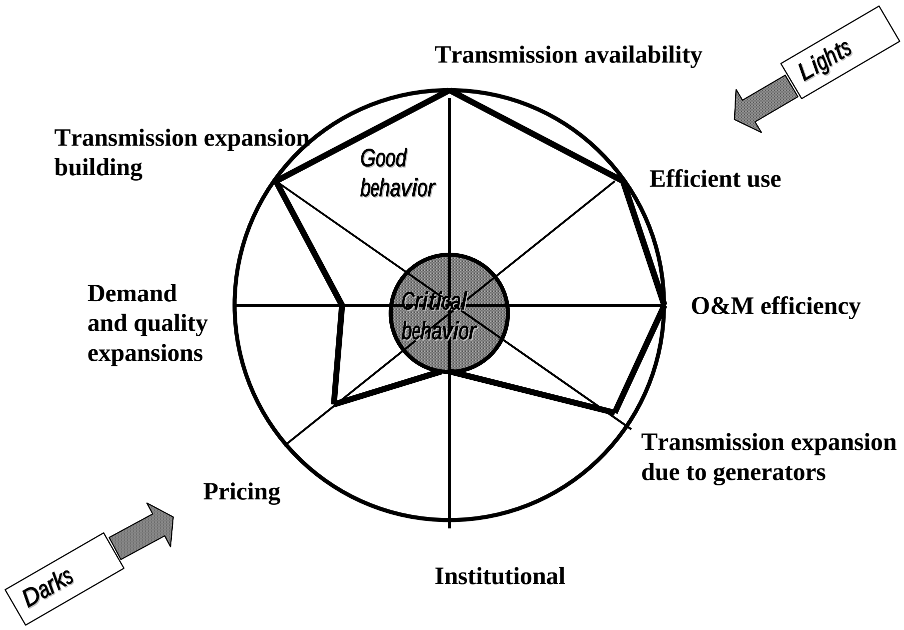

Figure 3 – Summary of overall analyses

Transmission pricing, organized planning of the expansion and the institutional recovering are the actual darks in the sector. The rest of the transmission activities have had a very good result and could remain in the necessary new implantation of transmission rules.

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Biography

Ramón Sanz is Madrid Executive Director of Mercados Energéticos (ME), belonging to Europe Territorial Unit. He specializes in Market and Transmission regulation, System and Market Operator Organization and Control, Transmission Company Organization and Planning Studies He has broad experience in the electricity sector both on the technical aspects such as power system studies and on the regulatory and organizational market aspects. He was the CEO and Vice-president of CAMMESA (Independent System Operator and Administrator Company of Argentina Wholesale Market) between 1995 and 1998. He worked as Secretary of Energy advisor in regulatory task and in the privatization process of Argentina Trancos. He had been an ME advisor in the following countries: Argentina, Chile, Brazil, Uruguay, Paraguay, Peru, Colombia, Ecuador, Venezuela, Panama, Guatemala, El Salvador, SIEPAC, EEUU, Spain, Tanzania, y China (East China, Zhejiang, y Sichuan). He was the director of regional electricity markets in South America, MERCOSUR, Andean Pact for international financing banks and regional institutions. He is an Electrical Engineer graduated in at the Universidad Tecnológica Nacional Regional Buenos Aires (UTNRBA). He has also a postgraduate course on Control Systems at the School of Science and Technology, Tucumán University. He has published over 50 articles in magazines and national / international conferences. Since 1992 he has given presentations in several national and international conferences in USA, Sweden, Spain, Bolivia, Guatemala, Ecuador, Brazil, Peru and El Salvador, mainly on the Wholesale Electricity Market organization, evolution and analysis. He was a professor of D&T at the Instituto Tecnológico Buenos Aires (ITBA) in 1996 and 1997 and has been a professor of Power Systems at the (UTNRBA). He was the President of the CIGRE’s Argentine National Committee (1997-1999) and has been coordinator of Studies Committee # 36 and head of Work Group 38-02 of Dynamic Studies in this organization.

3. TRANSMISSION STRUCTURE IN BRAZIL: ORGANIZATION, EVALUATION AND TRENDS

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Abstract**—**This paper describes the structure and regulation of transmission-related activities in Brazil, and assesses their effectiveness/limitations when addressing issues such as network expansion, locational pricing, transmission financial rights, and others. The paper also discusses the cross-border energy trading between Brazil and neighbor countries, and the perspectives of an integrated regional electricity market.
Index Terms-- Power transmission, Power transmission economics, Power transmission planning.

1. Introduction

Brazil started its power sector reform in 1996. As in many countries worldwide, the new rules were designed to encourage competition in generation and retailing [3]. In turn, transmission and distribution remained regulated activities, with provisions for open access. Other reform ingredients included the creation of an Independent System Operator (ONS), a short-term electricity market (MAE) and a regulatory agency (ANEEL), as well as the privatization of distribution and generation companies.

The transmission sector is of special importance to Brazil, for the following reasons:

- the country is hydro-dominated (85% of the installed capacity and more than 90% of the average energy production), with hydro plants in different basins, spread out over an area equivalent to the continental USA plus half of Alaska. Because the hydrological regimes in those basins are very diverse, hydro plants in the whole country are dispatched as a "portfolio", with "wetter" basins generating additional energy to compensate for "drier" ones. This type of operation is cost-effective and increases supply reliability, but requires a robust transmission network, able to transfer huge power blocks among regions, typically over one thousand kilometers. As a consequence, the whole country is electrically integrated[1], with almost 80 thousand kilometers of high-voltage transmission lines;

- transmission reinforcement costs associated to generation investments may be comparable to, and in some cases exceed, the generation costs themselves. For example, the estimated investment cost of Belo Monte, an 11,000 MW hydro plant in the Amazon region, is US$ 3.7 billion, whereas the associated transmission cost may reach US$ 6 - 7 billion [10].

- international interconnections, both direct (2,200 MW back-to-back links with Argentina) and indirect (bi-national hydro plants at the border such as Itaipu, a 14,000 MW plant owned by Paraguay and Brazil), are important energy supply options.

This paper describes the structure and regulation of transmission-related activities in Brazil, and assesses their effectiveness and limitations for addressing issues such as network expansion, locational pricing, transmission financial rights, and others. The paper also discusses the cross-border energy trading between Brazil and neighbor countries, and the perspectives of an integrated regional electricity market.

This work is organized as follows: Section II describes briefly the Brazilian power system; Sections

[1] Except for some isolated regions in the North, corresponding to 3.4% of the market.

III through IX discuss in more detail transmission expansion planning, construction of new circuits, transmission charges, locational marginal pricing (LMP), financial transmission rights (FTRs) and international interconnections. In each section, a description and an assessment of effectiveness are provided. Finally, Section X presents the main conclusions.

2. Overview of the Brazilian Power Sector

A. Physical system

The total installed generation capacity, in 2003, is 85 GW. As mentioned in the Introduction, the Brazilian system is hydro-dominated, with 110 hydro plants, arranged in 12 main river basins. Most plants have large reservoirs, capable of multi-year regulation. The remaining thermal generators (28 plants) include nuclear, natural gas, coal and diesel.

Also as mentioned, the whole country is interconnected by a meshed EHV transmission network, with voltages ranging from 230 kV to 765 kV ac, forming the so-called Basic Grid, and two 900 km bipolar 600 kV dc links from the bi-national Itaipu plant to the Basic grid. The main direct international interconnections are the already mentioned 2,200 MW back-to-back links with Argentina. Figure 1 presents an overview of the Brazilian transmission system.

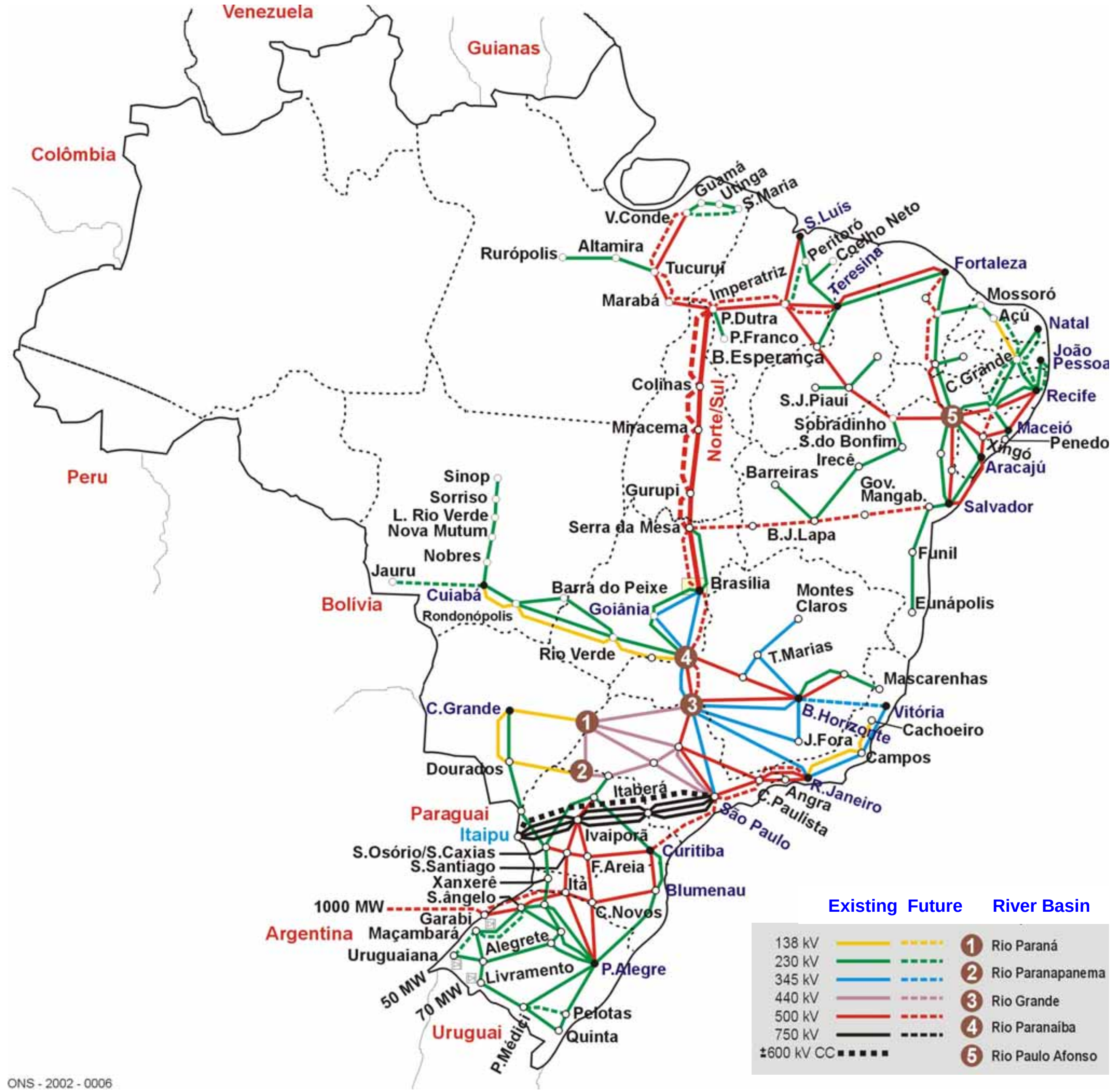

Figure 1. Brazilian Transmission System [6]

B. G, T and D Sectors

The G and D sectors are composed of 15-generation companies (Gencos) and 64 distribution companies (Discos). Most of the Discos, corresponding to 85% of the captive load, were privatized. Due to political opposition, Genco privatization was interrupted in mid-process; private investors control only 15% of the generation capacity. Finally, the transmission sector is composed of 26 transmission companies (Transcos), 13 of which were created as a result of the auction process for the construction of new circuits.

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3. Transmission Expansion Planning

A. Institutional responsibility

Long-term planning studies are carried out by the government (Ministry of Mines and Energy - MME), who proposes a reinforcement schedule for approval by the regulator, ANEEL. The system operator, ONS, also suggests to the MME short-term reinforcements for system adequacy and security (3 years ahead). Once the decision to build a new asset for the Basic Grid is taken, its concession is awarded on a competitive basis (auctions), as described in Section IV. Short-term reinforcements proposed by ONS and urgently needed installations are not auctioned, but directly authorized by ANEEL to Transcos.

B. Planning methodology

Transmission planning may be considered as a complex technical problem, because of the network modeling requirements and the geographical dispersion and temporal effects of candidate reinforcements [4]. In Brazil, the major challenges for transmission planning studies are:

- *strong coupling between transmission and generation investments* – in thermal-based systems, the transmission reinforcements due to a new generator typically include a set of circuits for connection to the main grid, plus some reinforcements on the grid itself. In other words, there is some “decoupling” between the transmission studies for different generators. In the case of hydro plants, there is a stronger coupling between G&T investment decisions. For example, if several hydro plants in the same basin are developed within a few years, it may be more economical to design a higher-voltage “collector” system, which can accommodate the total hydro generation, and then connect this system to the main grid. When the generation system expansion is centrally planned, the construction schedule can be adjusted to take advantage of this possibility. However, this is more difficult to accomplish in a competitive environment, where generators are free to decide on their entrance date.
- *several generation dispatch points* – in thermal systems, the transmission reinforcements are usually designed “around” an economic generation dispatch, usually at the peak load. In hydro systems, as mentioned, the transmission network should be robust enough to accommodate power flows in many directions, depending on, load levels and hydrological conditions.
- *large number of reinforcement candidates* – as shown in section IV, there is an intense investment in transmission reinforcements (about 40 new high voltage lines, totaling 11 thousand km, were constructed or initiated in the past five years). This means that the number of candidates to be examined and economically justified is very large. Also, as mentioned previously, transmission costs may be comparable to generation costs.

C. Assessment

Transmission planning studies in a large-scale system, under a competitive framework, requires the development of new methodologies. Although some approaches have been proposed, with encouraging results (see, for example, [7]), much work remains to be done.

4. Construction of new circuits

A. The auction process

Once the construction of new circuits is approved, ANEEL carries out an auction for their construction. The concession is awarded on the basis of the lowest annual rent for the construction and operation of the transmission facility. Each new circuit builder/operator becomes a Transco. The concession period is 30 years, with one possible renewal. The annual rent is fixed during the first 15 years, and then reduced by 50% for the remaining 15 years.

B. Assessment

The auctions have been successful: between 1998 and 2002, 30 high voltage transmission lines (230 kV and above), totalizing 7,826 km were awarded, with strong participation of both local and foreign investors. In 2003, 11 more lines, totaling 1,800 km, were auctioned. The number of Transcos increased from 13 to 26. Private investors currently account for 65% of the country's Transcos and 34% of the transmission annual rent. Figure 2 presents the evolution of the transmission system extension in operation for the Basic Grid and the % increasing participation of new installations.

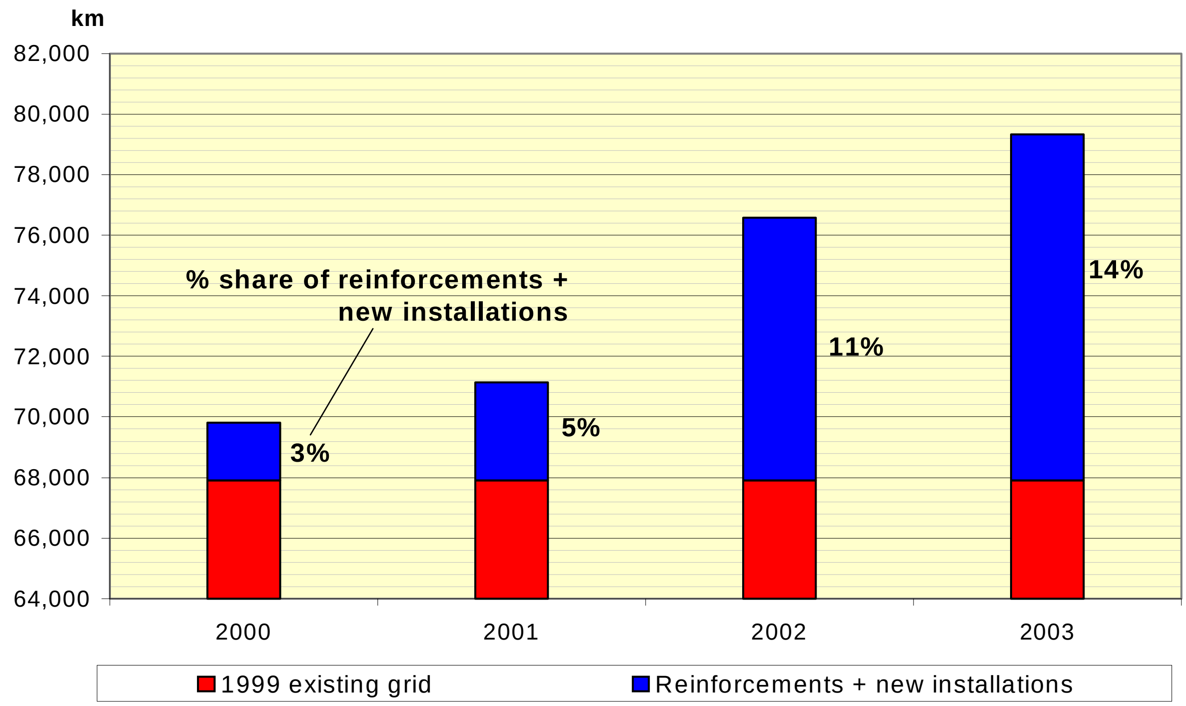

Figure 2. Transmission System Extension [5]

5. Network remuneration

A. Allowed Revenue

As seen in the previous section, new circuits receive an annual rent whose values were determined in the auction process. The regulator (ANEEL) also established annual rents for existing circuits and for reinforcements directly authorized to Transcos. Therefore, the total grid remuneration in each year (known as allowed revenue) is given by the sum of annual rents for all circuits.

B. Transmission Charges

This allowed revenue is recovered from network users (generators and loads) through a Transmission Use of the System Tariff (TUST)[2]. The allocation of TUST among the network users is discussed in section VI.

Figure 3 shows the cash flows and the contractual relations among grid users, ONS and Transcos, namely: CUST - Contract of Use of the Transmission System (settled between ONS and grid users) and CPST - Contract of Transmission Services between ONS and Transcos[3].

[2] For convenience, the administrative costs of the system operator, ONS, are charged under the same scheme.

[3] The system operator is responsible for accounting and coordinating the billing process, but has no financial responsibility in case of defaults. Contractual rules include payment guarantees from grid users as well as penalty charges to Transcos in case of transmission unavailability.

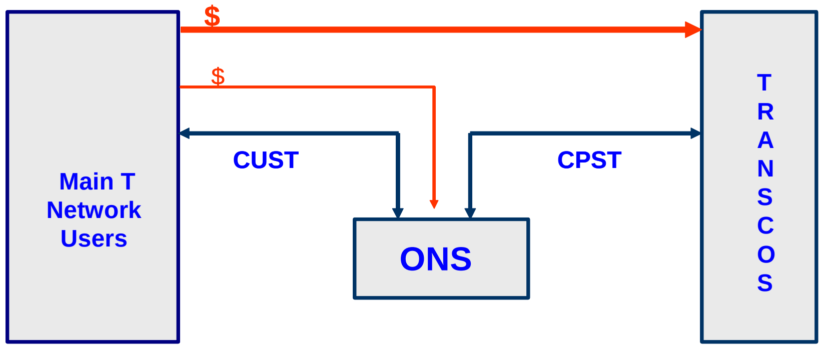

Figure 3. Contract relations and cash flows

C. Assessment

The remuneration scheme has also worked well, with no defaults even when Gencos and Discos defaulted on energy supply contracts. The total transmission annual rent is around US$1.6 billion. The participation of new installations (lines + substations) is around 37%, as shown in Figure 4.

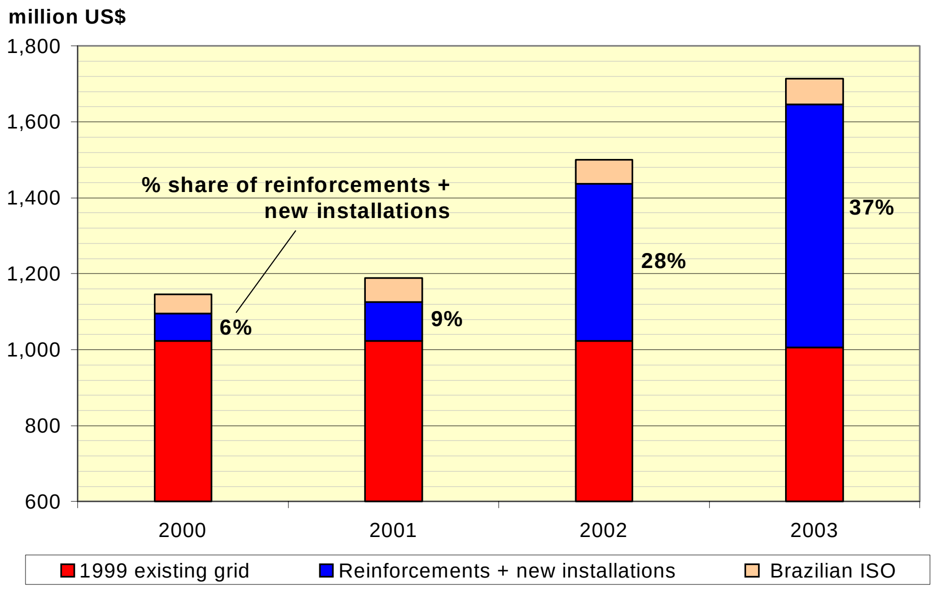

Figure 4. Transmission annual rents [5]

6. Allocation of Transmission Charges

A. Nodal charges

As seen in the previous section, the total amount charged to the network users (generators and loads) is equal to the allowed revenue of network builders/operators. We now address the issue of how to allocate these total charges among individual users. Ideally, this allocation should be *fair* – i.e. reflect the actual usage of network resources by each agent – and *efficient*, that is, induce new generators and loads to choose sites that will lead to the best overall use of the generation-transmission system.

In some countries, transmission costs are charged as "wheeling" rates, which depend on the points of production and of contracted delivery of energy. However, as will be seen in Section VII, generation dispatch in Brazil is cost-based and centralized, and there are no physical bilateral contracts. Only financial bilateral contracts are allowed, and those do not affect the centralized system dispatch. This means that the transmission network usage is not related to contracts.

Brazil has adopted a nodal charge scheme, similar to those of UK, Colombia and other countries, where generators and loads pay a yearly fixed transmission tariff ($/installed kW for generators and $/yearly peak for loads). These tariffs depend on the user's location (network busbar) and may vary from year to year (due to changes in the transmission network, entrance of new generators, load increase etc.). The charges are adjusted to ensure that generators and loads share the total costs in a 50/50 % basis.

B. Calculation of nodal charges

The nodal charge calculation is based on the construction of an "ideal" network, but whose parameters are heavily constrained by those of the existing grid[4]. The marginal costs at each bus of this "ideal" grid reflect the incremental change in transmission investments due to an incremental change in generation or load at that bus, and are the first component of the transmission charges.

Because the amount recovered by the marginal bus tariffs is usually smaller than the total allowed revenue, a second component is added to the transmission tariffs to make up for the difference. This complement is charged as a "postage stamp", that is, allocated among users as a function of their generations and loads, but not taking into account their location. (See "Nodal" model description, [11]).

Figure 5 presents contour plots (3500 buses) of TUST for year 2003 and a projection for 2005. The exporting areas can be identified by their higher tariffs. In particular, the impact of transmission reinforcements in the tariffs of the Center-West region can be observed: this exporting region in 2003 is transmission deficient and the new reinforcements in 2005 alleviate the congestions, as indicated in the figure.

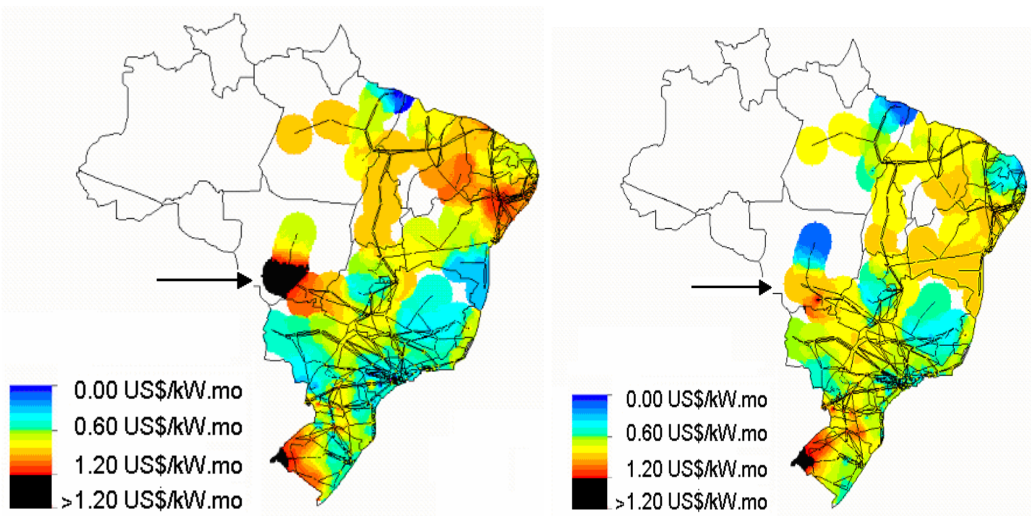

Figure 5. Brazilian System – transmission tariffs (years 2003 and 2005)

C. Assessment

Although the nodal charge scheme is conceptually attractive, it recovers only 20% of the required revenue[5]; the "postage stamp" complement covers the remaining 80%. As a consequence, the locational signals in the final transmission tariff are very much weakened. For example, the average transmission tariff in southeastern region of the country results practically the same, around 9.1 US$/kW per year in 2003, both for hydro and thermal generators (which are closer to load centers). This means that there is currently a cross-subsidy between thermal and hydro generation. Alternative allocation methods that provide more efficient signals are currently being investigated[6].

[4] For example, only the existing circuits are allowed as rights-of-way.

[5] One reason for this under-recovery is that the nodal charge scheme tends to recover an amount related to the average loading of the transmission circuits. Because networks usually have redundancy in order to allow for circuit outages ("N-1" criterion), the grid looks "under-used" when power flows are considered for "base case" conditions alone (all circuits available). In the case of Brazil this situation is emphasized because of hydro predominance and the need to allow the transfer of huge power blocks in different directions, depending on hydrological conditions, resulting in low average loading of long tie lines.

[6] see "Nodal" model description, [11]

7. Locational Marginal Pricing

A. System dispatch

There is no price-bidding scheme for the system dispatch: the system economic dispatch is cost-based[7], and is carried out by the system operator as if all generators belonged to the same owner, and there were no contracts. In particular, hydro plants are dispatched with basis on their expected opportunity costs ("water values"), calculated by a multi-stage stochastic optimization model that takes into account a detailed representation of hydro plant operation, as well as inflow uncertainties. The solution algorithm is the stochastic dual dynamic programming (SDDP), an extension of the traditional stochastic DP recursion, which can handle hundreds of state variables (in this case, reservoir storage levels) (see [1,2]).

B. Detailed LMP calculation

In addition to the optimal production schedule for each hydro and thermal plant, the SDDP solution scheme can calculate the short-run marginal cost (SRMC) for each network bus, which would correspond to the LMPs. Figure 6 shows a contour map (3500 buses) of those SRMCs for a given stage (month) and load level, for an operational planning study [2].

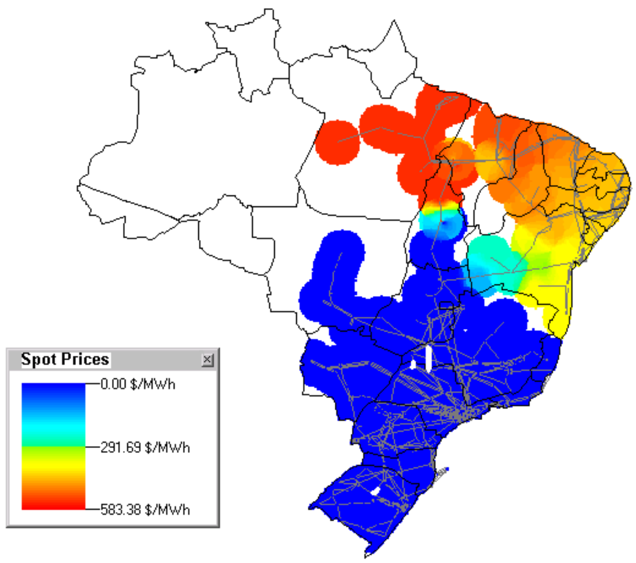

Figure 6. Brazilian System – nodal marginal costs

C. Simplified LMP Calculation

For the purposes of accounting and clearing at the short-term market, the LMPs are calculated with a simplified procedure:

- the network is divided into "zones";
- the transmission limits of all circuits within a zone are made infinite; only the tie-lines between zones are retained;
- the price in each bus is calculated as the SRMC for a "reference bus" in each zone, adjusted by a loss factor.

1) Definition of zones

The system is currently divided into four zones, (roughly) corresponding to the country's major regions:

[7] Thermal generators are allowed to present weekly price bids. However, because the system is hydro-dominated, spot prices are in practice determined by the expected opportunity cost of hydro, which in turn depends on both future hydrological conditions and – to a lesser extent - on the projected future thermal costs, which are not-bid based, but determined by the ONS.

South, Southeast/Center-West, Northeast and North (see Figure 7). The major "structural" transmission constraints lie on the tie lines between those zones.

Figure 7. Brazilian Zones (S: South, SE/MW: Southeast and Center-West, N: North and NE: Northeast)

2) Loss Factors

If there are no transmission constraints, the ratio between the spot price in a given bus and that of a reference bus is equal to the marginal loss factor. This means that the bus spot prices can be calculated in two steps: (i) calculation of the price at the reference bus; (ii) use of marginal loss factors to "map" this reference price to all the other buses.

This procedure was adopted in Brazil, with one modification: the marginal loss factors were adjusted by a constant factor to ensure that the total revenue received by generators (energy production multiplied by the respective bus spot price) is equal to the total spot payment by loads (consumption multiplied by spot price). Figure 8 shows a histogram and cumulative distribution of the projection of loss factors for a given node in the South zone in year 2005. Note that those factors are highly variable. The reason is that they dependent on the physical system dispatch, which in turn is highly dependent on the hydrological conditions.

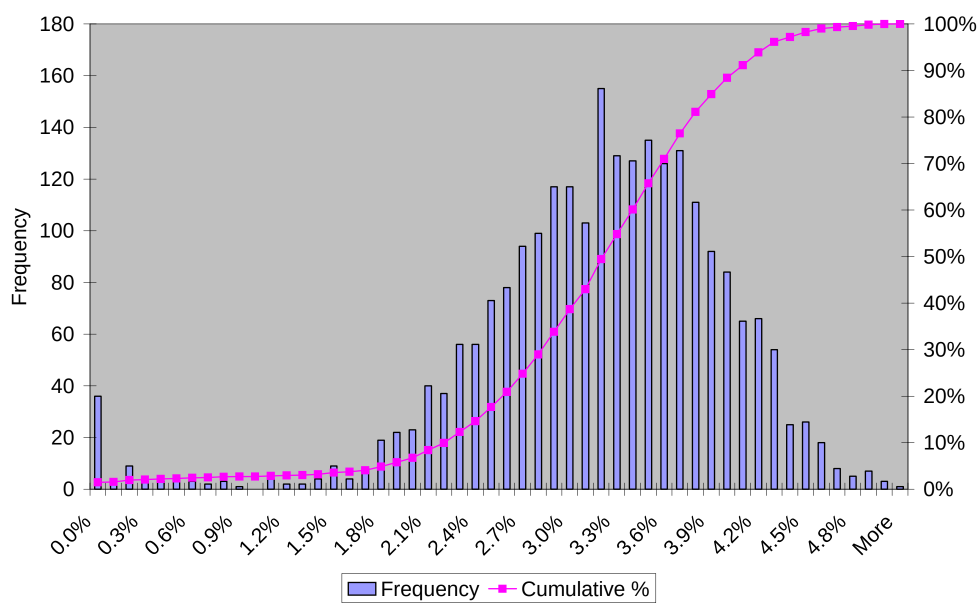

Figure 8 – Example of loss factor variability

Also, until January 2004, the loss factors are averaged over all buses, i.e. there are no differentiated prices inside each zone. Figure 9 presents a contouring map of the expected marginal loss factors for the year 2005 (see "Perdas" model description, [11]). A great dispersion of values within the country can be observed.

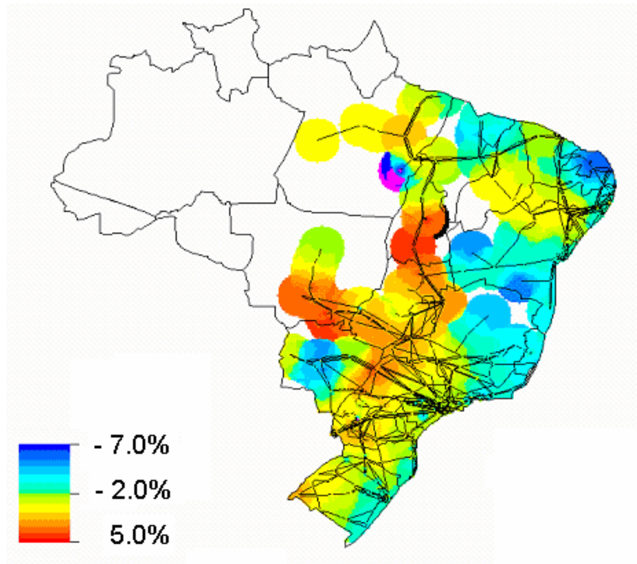

Figure 9. Brazilian System – loss factors

D. Assessment

The pros and cons of using a "full" LMP scheme instead of the simplified scheme (zonal pricing plus locational losses) are being discussed. The main reason for adopting this simplified scheme is to protect generation investors from temporary "congestion islands" within a region, which may appear as a result of delays in installations or unavailability of transmission circuits. Differently from thermal systems, where congestions usually have a short duration (hours), these events in Brazil may last for several months, causing severe financial losses. Also, it is felt that price signals for demand-side actions may not be effective under the regulation, for two reasons: (i) generation rescheduling in the case of congestion is mandatory and cost-based (i.e. there are no prices for increments or decrements); (ii) most loads are 100% contracted and are not sensitive to price increases.

8. Financial Transmission Rights

A. Congestion

If there are no transmission congestions, the spot prices in two different zones will be the same (except for the loss factors). Otherwise, there will be a price difference across the tie lines. In some circumstances, the price differentials due to congestion can be huge. For example, during the rationing period in 2001, there was a major congestion in the tie lines from the South region (which experienced no drought) to the Southeast region (which was under rationing). For several months, the energy spot price in the South was about 2 US$/MWh, whereas the Southeast prices reached the regulated price ceiling, about 300 US$/MWh. This created a very serious financial exposure for generators located in South region, which had supply contracts to loads in the Southeast.

One consequence of transmission congestion between zones is that the total amount ($) paid by loads exceeds the amount received by generators. This difference, known as a "transmission surplus", corresponds to the marginal revenue of the congested tie lines. As it is well known, this surplus can be used by generators contracted across the zones to hedge against the spot price differentials. In exchange for a fixed payment to the owner of transmission assets, the agent gets financial transmission rights (FTRs) to the "transmission surplus". As part of the transition to a market-based model, all Brazilian generators signed mandatory vesting contracts called Initial Contracts. Because some of these contracts are across zones, an "automatic" FTR was created and assigned for them.

This system should last until the end of 2005, when the last vesting contracts expire. An auction mechanism, where agents would bid for FTR rights, was proposed for implementation in 2005; but this issue is still not regulated.

9. International Interconnections

A. Current Interconnections

There are essentially three main opportunities for energetic interconnection for Brazil with neighboring countries: electricity exchanges, power projects at the border and natural gas integration.

With regard to electricity exchanges, Brazil has small transmission interconnections with Uruguay (70 MW), Paraguay (70 MW) and Venezuela (200 MW), and an important 2200 MW interconnection with Argentina. This project comprises a 500 kV transmission system and, due to difference in frequencies (50 Hz in Argentina and 60 Hz in Brazil), there is a back-to-back 50–60 Hz conversion close to the border. The main opportunity for this interconnection is associated to the joint optimization of the hydrothermal operation: the hydrothermal share in Brazil is different from the share of both countries together, since Argentina is a thermal-based country. Therefore, there is a potential for a synergic gain for both countries with exports from Brazil to Argentina in the wet seasons in Brazil (and inversely in the dry seasons).

Power projects at the border can also be considered an indirect international interconnection. The main example is Itaipu, a 14,000 MW hydropower plant jointly owned by Paraguay and Brazil.

Finally, the southeastern region of Brazil is integrated to Bolivia through a gas pipeline (capacity of 31 MM^3/day), which brings the opportunity of development of gas-fired generation in Brazil and consequently of a gas market. Integration through pipelines with Argentina is another possibility under evaluation.

B. A Regional Market

An important issue in the region is multi-country electricity markets, which are a natural evolution to the existing "official" international interconnections, which in turn were originally established by the countries' governments for sharing reserves and carrying out limited economic interchanges.

The creation of a regional market is a natural step towards economic efficiency and economic growth. While there are important opportunities for both electric and gas integration within the region, some important aspects remain to be discussed, such as the compatibility of regulatory frameworks and taxes systems. For example, some countries have a price-bidding scheme for WEM settlement whereas others use a cost-based scheme; there are also different schemes for transmission pricing and electricity/gas tariffs, etc. Another aspect concerns the "benefit" allocation among countries of the integration, since the energy spot prices of the exporting country can increase if the amount exported is significant and, conversely, affects the price volatility of the importing country, decreasing the spot prices.

C. Assessment

International interconnections are the core for the creation of a regional market and have been of great importance to Brazil. The creation of a regional market has been analyzed since the last decade. Integration of wholesale energy/gas markets and joint operations/regulatory procedures in the region were focus of studies carried out by multilateral energy organizations [8,9] during 1999-2001. Although encouraging results have been proposed much work remains to be done.

10. Conclusions

The transmission structure organization in Brazil has been working well both in terms of assured expansion and attracting private investments. Due to new transmission facilities the interchange capacity limits in between regional systems have increased, avoiding congestion risks. Regulatory risks have also been low, since regulations in place are almost consolidated and considered stable by market players. However, some challenges remain to be tackled, essentially concerning the strong coupling between generation and transmission planning, transmission tariffs allocation, LMP scheme and creation of a regional market. Additionally, it must be mentioned that improvement of the regulatory framework for the T/D frontier is a topic that is being currently focused by the regulator. Clearly settling the rules for system reinforcement in this interface area has been proved to be highly relevant not to jeopardize the reliability of load supply.

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4. ALLOCATION OF TRANSMISSION CAPACITY IN THE CENTRAL AMERICA ELECTRICITY MARKET

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Abstract--The six countries of Central America are developing a regional electricity market where trading is already intensive but limited by transmission constrains. These countries are currently developing a new transmission system (SIEPAC project) that will increase substantially the cross border capacity. However, both in the current and future situation, it is necessary to optimally allocate the scarce interconnection capacity. This paper explains the existing methodology for simultaneous auctions of energy and transmission capacity, and the proposal under discussion of implementation for point-to-point firm and financial transmission rights.

Index Terms-- Power transmission, Power transmission economics, Power transmission planning.

1. Introduction - SIEPAC Project

The six republics of Central America, Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica and Panama have signed in 1996 (ratified in 1998) a Treaty where they agreed the future creation of a regional market of electricity (MER) in Central America. The MER will allow market participants of the six countries permanent trading of energy, coordinated by a regional system and market operator (EOR).

The agreement includes the development of a regional transmission system (SIEPAC) that will reinforce the existing interconnection among the countries of the region.

Therefore, the SIEPAC project has two main objectives: (i) the gradual formation and consolidation of a regional electricity market through the creation and establishment of appropriate legal, institutional, and technical mechanisms to promote private sector participation, particularly 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.

It is expected that the SIEPAC will enable the following objectives:

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 systems in the six countries, taking advantage of the diversity in the electricity supply sources in the region, with reduction in operating costs
3. Tapping the advantage that peak demand varies in the countries of the region, which makes the reserve and expansion needs smaller in interconnected systems.
4. Assistance for any country with rationing problems, which economically translates into lower failure costs and less unserved energy.
5. Greater reliability in the systems' operation and greater security in meeting demand.

Since the signature of the treaty, the following steps have been undertaken:

- Year 2000: General design of the regional market is completed.
- Year 2000; starts functioning of the Regional Regulatory Agency CRIE
- Year 2001: starts functioning of EOR.
- Year 2002: CRIE approved the transitory code for operation of the MER; MER operation starts.

- Year 2002-2004: development of definitive market and transmission codes, and organization of CRIE and EOR.

2. Transitory Code

A. 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 the international electricity trade. The dispatch mechanism allows market participants to submit energy only bids and offers (opportunity market) and requests for point to point transmission services, while the charges for transmission services are calculated through a regulated procedure.

In an opportunity market 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[8].

Before the entrance into operation of the tie line between El Salvador and Honduras (230 kV) in beginnings of 2002, Guatemala and El Salvador formed the Northern subsystem while Honduras, Nicaragua, Costa Rica and Panama formed the Southern subsystem.

Guatemala and El Salvador interchanged energy at the common border. Honduras, Nicaragua, Costa Rica and Panama, additionally to trade between neighboring 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 process of integration.

The wheeling charges were simply the difference of short run marginal costs at the border (fictitious) 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 as it continues using the CVT curves (now for El Salvador and Honduras – potentially transited 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 trough bids and offers to the opportunity market), (2) physical flexible (request 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 being applied or proposed in other markets, e.g. option (2) has been recently introduced at PJM (up to congestion transactions, with a limit of $25/MWh - the reason for introducing this limit is unknown to the authors) [1]; and a very similar scheme has been proposed to auction the tie-lines transmission capacity in Europe [2, 3], see also [4].

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

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

transmission services with the demands for the “pure” wheeling services (associated to contracts - the EOR would not have information on the prices of these contracts, solely the prices that the agents are willing to pay for the wheeling services: injection/extraction in pairs).

B. Operative toll

In the definitive 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 tough, an operative toll is being used, i.e. applicable to the transactions that occur in the MER. The toll ($/MWh) is applied only to the energy transmitted through the tie lines between countries. The operative toll values approved by the CRIE as an Annex of the RT MER, are available at http://www.omca.net/. The operative toll causes a dead weight loss that should be evaluated.

C. 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 economic dispatch of the wheeling system (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), modeling 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 the CVTs = 0.0 which causes some inefficiencies.

Figure 1 shows a scheme of interactions among market participants, EOR and countries system operators.

D. 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 following MER dispatch (24 hourly dispatches):

$$\text{Max } \sum(\text{Price}_{transaction,i} * P_{transaction,i}) - \sum \text{Cost}_{transmission,k}(f_k)$$

Subject to:

Nodal balance equations:

$$[Pg - Pd] = \sum([IT_{transaction,i}] * P_{transaction,i})$$

$$[B][\theta] = [Pg - Pd]$$

Offers limits:

$$P_{transaction,i} \leq (P_{transaction,i})^{max}$$

Transmission limits:

$$(-f_k)^{max} \leq f_k \leq (f_k)^{max}$$

Where:

$\text{Price}_{transaction,\ i}$: offer i price ($/MWh).

- 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.

$P_{transaction,i}$: Offer i accepted power (extraction, injection, transmission service)
f_k, $(f_k)^{max}$: link k flow and transmission limit
$Cost_{transmission,k}(f_k)$: link k transmission cost, CVTs for the national systems and operative toll for the tie-lines
$(P_{transaction,i})^{max}$: maximum amount of MWh requested (purchase), offered (sale), or required to be transported
Pg – Pd: Net nodal power (injections minus extractions)
$[IT_{transaction,i}]$: incidence vector defining the energy injections and extractions associated to transaction i.

- If transaction i is an extraction request, $[IT_{transaction,i}]$ is a null vector, except for $[IT_{transaction,i}]_x = -1$, where x is the node at which the extraction request is made.
- If transaction i is an injection offer, $[IT_{transaction,i}]$ is a null vector, except for $[IT_{transaction,i}]_x = +1$, where x is the node at which the injection offer is made.
- If transaction i is a request for transmission services between two nodes x and y, $[IT_{transaction,i}]$ is a null vector, except for $[IT_{transaction,i}]_x = +1$, and $[IT_{transaction,i}]_y = -1$, where x and y are the nodes between which the transmission services are requested (injection / extraction).

The algorithm determines the optimal dispatch of the opportunity bids and offers and the optimal allocation of transmission services, and produces the buying / selling opportunity prices (nodal prices) and the transmission services prices (differences of nodal prices).

In this way, it is assured that no discrimination exist, in the allocation and pricing of transmission services, between contracts (that would only request the wheeling services between the shipment and reception points), purchase bids to the opportunity market (amount and maximum price willing to pay for the energy at the extraction point) and sale offers to the opportunity market (amount and minimum price willing to receive for the energy at the injection point).

The application of this coordinated dispatch scheme to the Central America countries is equivalent to formulate an “optimal dispatch” – or a transportation problem – of energy injection and extraction offers, individually (opportunity offers) or balanced – “in couples” – (requests for wheeling services required by contracts). Once the transmission “supply” curves are obtained: CVTs + operative toll for tie-lines, the formulation of the co-ordinated dispatch of energy (opportunity) and wheeling services for the six Central America countries, is reduced to a problem of 15 nodes (10 230 kV substations and 5 borders), and 14 links (5*2 tie-line sections with costs = operative toll, and 4 national systems with costs = CVTs curves for El Salvador, Honduras, Nicaragua and Costa Rica).

The dispatch scheme can be seen as the solution of a problem in two levels (or steps). The results of the first level (national: evaluation of CVTs + operative toll) are used as an input in the second level (regional: joint dispatch of energy and transmission). Figure 1 depicts the coordinated dispatch scheme in graphical form.

3. General design of the MER

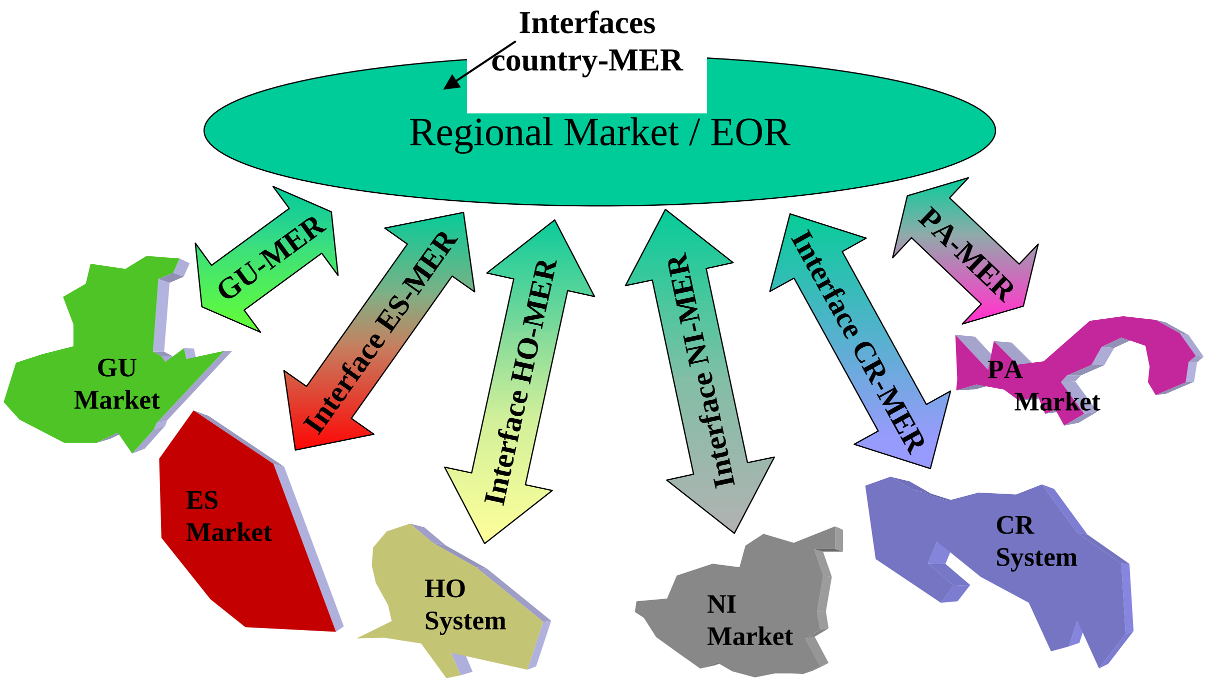
The development of the Transmission Code (TC) follows the concepts and criteria established in the General Design. Some of the more relevant dispositions of the General Design are:

- The MER constitutes the seventh market, superposed with the existing markets in the six countries.
- Market participants of the six countries are allowed to participate in the MER
- Two regional institutions are created:
  - CRIE (regional regulatory agency)
  - EOR (independent system and market operator)
- Countries can preserve local regulations, with the changes necessary for compatibility with regional codes.
- The Regional Transmission Grid 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 countries grids, the SIEPAC project, 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.
- Day ahead spot market and real time balance.
- The rules for transmission access must allow firm contracts; this means contracts that can be physically dispatched when requested by the parties.
- Parties of firm contract 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 obtain CR.
- 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.
- Development of the RTR will be centrally planned by the EOR
- Market participants of third parties are allowed to build at its own risk transmission facilities. Sponsors of this type of expansions will receive the CRs corresponding to the new facilities, and will have the right to perceive a toll.

It is worth mentioning that presently four countries have restructured their electricity sectors, partially privatized generation and distribution activities and created electricity wholesale markets, with rules that are somewhat different. Therefore, it was necessary to identify and design suited interfaces for the interaction between countries markets and the regional (seventh) market.

The detailed rules are currently being developed by two consultant groups (market code and transmission code) therefore, it is only possible at the moment to describe the proposal that are being discussed, which may change before final approval.

The next picture shows the way each country market interacts with the MER through specific interfaces.



4. The Transmission Code

A. Content of the Transmission Code

A consultant consortium is currently developing the definitive Transmission Code (TC). This document will deal with the following main subjects:

1. Open access to the RTR
2. Transmission rights (Congestion Rights)
3. Transmission Use of System Charges (TUOS)
4. Regional Grid Planning
5. Risk Investments in Transmission
6. Interfaces with the countries transmission regulations
7. Definition of the Regional Transmission Grid (RTR)
8. Security criteria and rules

B. Proposal for Congestion Rights

The proposal under discussion is to implement point-to-point CR with the following characteristics:

- CRs are defined for a set of injection nodes; withdraw nodes, and associated power.
- There will be two types of CR: (1) firm (2) financial
- Firm CR entitles the holder to be scheduled for injecting and withdrawing the associated power. Besides, the holder can inject the power and withdraw the same quantity at the same price.
- Financial CR entitles the holder to inject the corresponding power in a node(s) and to withdraw the same capacity in the other node(s) at the same price, or alternatively, to be paid for the difference of prices among the injection and withdrawal nodes, times the associated power.
- Generators with plants located in specific nodes of the network will be allowed to offer counter-flows, to increase the power that can be allocated to CR.
- Initially CRs are allocated to participants that pay TUOS; which will receive revenues associated to Congestion Rights (or alternatively, revenues from the auction of Congestion Rights). Thus, in

exchange for paying the fixed costs of the transmission system, those paying TUOS would receive the financial benefits – the stream of congestion revenues – resulting from usage of the transmission system.

- The EOR will schedule monthly and yearly auctions for congestion rights.
- Auctions will be allocated to bidders through the following algorithm

$$\text{Max } \Sigma_j C_j \alpha_j TO_j + \Sigma_k C_k \alpha_k T_k - \Sigma_h C_h \alpha_h TCF_h \qquad (1)$$

Subject to the Simultaneous Feasibility Test:

Feasibility of firm contracts:

$$\Sigma_k \max(0, [H_e \alpha_k T_k]_{ei}) + [H_e \Sigma_h \alpha_{eh} TCF_h]_i \leq b_{ei}$$

$$i=1,\ldots I \quad e=0,..M \qquad (2)$$

Financial sufficiency**:**

$$[H_e \Sigma_j \alpha_j TO_j]_i + [H_e \Sigma_k \alpha_k T_k]_i + [H_e \Sigma_h \alpha_{eh} TCF_h]_i \leq b_{ei} \quad i=1,..I \quad e=0,..M \qquad (3)$$

Capacity awarded to firm CRs must be lower or equal than bidden capacity:

$$\alpha_k \leq 1 \qquad (4)$$

Capacity awarded to financial CRs must be lower or equal than bidden capacity:

$$\alpha_j \leq 1 \qquad (5)$$

Capacity awarded to counter-flows must be equal or lower than bidden capacity and equal or higher than capacity scheduled in state e:

$$\alpha_{eh} \leq \alpha_h \leq 1 \qquad (6)$$

Where:

$[\,.\,]_i$ is the row i of the vector that results from the scalar product of matrix H_e and vector T.
e: sub-index associated to state of the transmission system either base (0) or contingency (1...M)
H_e: power transfer distribution factors matrix corresponding to state e of the transmission system.
b_{ei}: maximum capacity of link i in state e
I: number of transmission links, equal to number of rows of matrix H_e
α_k: fraction (p.u. of Tk) of the firm CR awarded to participant k in the CR auction
α_j: fraction (p.u. of TO_j) of the financial CR awarded to participant j in the CR auction
α_h: fraction (p.u. of TCF_h) of the counter-flow awarded to participant h in the CR auction
α_{eh}: fraction (p.u. of TCF_h) of the counter-flow used in state e
T_k: vector with the quantities (MW) of firm CR that participant k offers to buy (+) or sell (-). Offer to inject or withdraw must be balanced
TOj: vector with the maximum quantities (MW) of financial CR that participant j offers to buy (+) or sell (-). Offer to inject or withdraw must be balanced
TCF_h: vector with the maximum quantities (MW) of counter-flows that generator h offers to sell (+). Offer to inject must correspond to the node(s) where generator h has its plants.
C_k: economical offer of participant k for firm CR T_k.
C_j: economical offer of participant j for financial CR TO_j
C_h: economical offer (-) of generator h for counter flow TCF_h

With this approach, equations (1) to (6) constitute a linear programming model. It is possible to consider offers where participants are only interested in buying the CR for the total T_k or TO_j. In such case

α_j must be 0 or 1. In this case the auction model becomes a mixed linear programming model.

5. Conclusions

Development of a regional electricity market in Central America constitutes a challenging task. Particularly the definition of the rules describing the method for setting transmission tariffs and allocation of rights has special difficulties.

Nevertheless the market is currently running smoothly, with transitory rules that encouraged an intensive use of the existing cross border connections. It is expected that with the commissioning of the SIEPAC project, energy trading will increase rapidly, including long term firm contracts that currently have difficulties because the lack of cross border transmission capacity.

Thus, either for the current or future situation, an efficient method for allocation of the transmission capacity constitutes one of the key issues for designing the market. Particularly the coexistence of firm and financial transmission rights will require particular monitoring and fine-tuning in order to achieve efficiency and produce appropriate signals for expansion of the transmission system

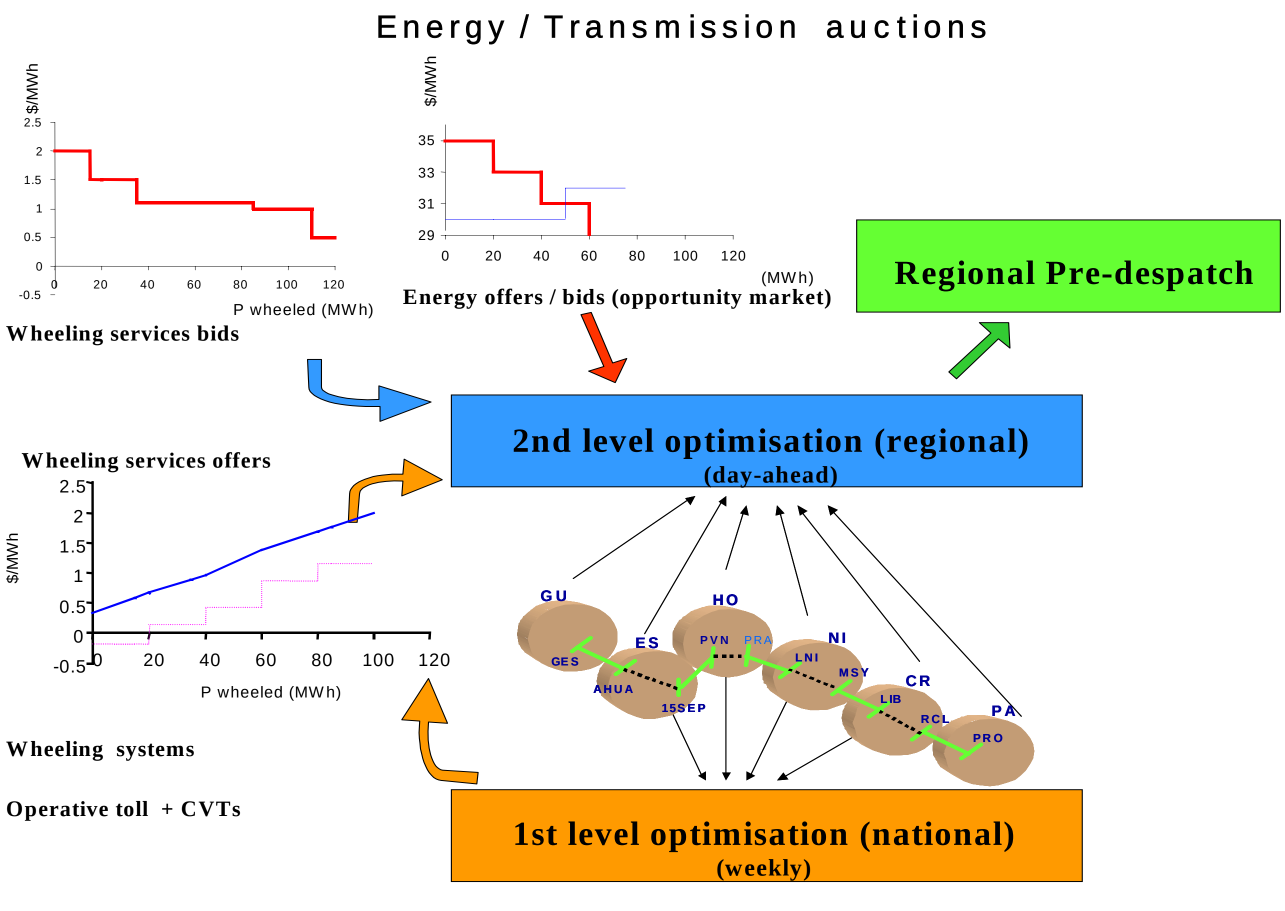


Figure 1 – RT MER. Scheme for the Day Ahead Dispatch

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5. COLOMBIAN ELECTRICITY MARKET - TRANSMISSION OPERATION AND CONGESTION MANAGEMENT

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Abstract-- The paper focuses on the Colombian Electricity Market emphasizing the transmission pricing structure and system congestion management. It also describes the implemented methodology for Electricity International Transactions.
Index Terms-- Power transmission, Power transmission economics, Power transmission planning.

1. Introduction

In 1991, a new Political Constitution was issued. It assigns to the State the responsibility to achieve efficiency in the provision of public services. It establishes the competition mechanism, accepts the private agent participation and strengthens the role of the State as regulator. It assigns to central, departmental and municipal governments the responsibility to ensure the public service provision by their own or through third party; and it grants citizens the rights to enjoy a healthy environment, whose preservation is also responsibility of the State.

In July of 1994, the Colombian Congress passed the Public Service Law (Law 142 of 1994) and the Electricity Law (Law 143 of 1994). Public Service Law establishes the general principles and policies to rule the provision of Public Services[9] in the country as well as procedures and mechanisms for its regulation, surveillance and control. On the other hand, Electricity Law details and regulates the following five areas of business of electricity industry: Generation, Interconnection, Transmission, Distribution and Trading. In practice, Interconnection is considered a part of Transmission activity.

On July the 20th of 1995 new rules, where competition is the key issue for gaining efficiency, changed the operation and the way of doing business in the Colombian power sector.

2. Market Participants And Governance

The Electricity Law defines the functions of policy making, planning, regulation and operation as well as the role of entities and agents involved in any business activity (Generation, Transmission, Distribution and Trading) of the electricity industry.

Policymaking: It is a responsibility of the Ministry of Mines and Energy, who also establishes the criteria for the economic exploitation of conventional and non-conventional energy sources.

Planning: It is a responsibility of the Mining and Energy Planning Unit (Unidad de Planeamiento Minero Energético-UPME) to formulate the investment plans which are indicative. By means of an auction process, UPME submits to investors the projects included in the expansion plan for the transmission network.

Regulation: Regulation is a responsibility of Energy and Gas Regulatory Commission (Comisión de Regulación de Energía y Gas -CREG-), which is a Special Administrative Unit ascribed to Ministry of Mines and Energy. It has budgetary and administrative autonomy. Its running costs are covered by all of

[9] Public Services include the following services: aqueduct, sewage, electricity, cleaning, basic commuted public telephony, mobile rural telephony, and gas fuel distribution.

the agents involved in electricity industry and who are subject to regulation by CREG.

Surveillance and control: It is a responsibility of the President of the Republic through the Superintendence of Public Services (Superintendencia de Servicios Públicos Domiciliarios-SSPD-), and this through the Delegate Energy Superintendent. The purpose is to control the efficiency and quality of public services, including electricity services, and to supervise and to control the market participant's behavior.

System operation: The National Operation Council (Consejo Nacional de Operación-CNO-) has been established to ensure the fulfillment of criteria for a safe, reliable and economic operation of National Interconnected System (SIN). It is the traditional forum for discussion and deliberation on operating and commercial issues. Agents are responsible for the operation of their installations, but ISA, by means of National Dispatch Center-CND- is responsible for the coordination, supervision and control to ensure a safe, reliable and economic operation of SIN. CND is also responsible for the indicative operational planning.

Market Operation: This function has to deal with the settlement and billing process of all of the transactions carried out in the Power Exchange. Regulation assigns to ISA the responsibility to perform this function, by means of the Wholesale Energy Market area, another internal business unit of ISA.

Generation: Consists of production of electricity from primary energy sources like: hydro, coal, gas, diesel and fuel oil, mainly. It is a full competitive activity with the most dynamic private investor participation. Generators must submit offer prices to System Operator, for each one of their generating resources (units or power plants) having an installed capacity greater than 20 MW. When the installed capacity is below 20 MW, Generators may, at their discretion, submit offer of prices for these generating resources. Generators can trade, by themselves, their production in the Power Exchange and with Traders in the Long Term Energy Market. Also, Generators are free to participate in any auction open by Traders to provide Bilateral Contracts for Regulated or Non-regulated Customers.

Transmission: Consists of the transport of bulk power from production centers to customers or to Distribution Networks, through transmission networks with voltage levels of 220 kV and above, called National Transmission System (Sistema de Transmisión Nacional-STN). Due to its monopoly nature, transmission is a regulated activity. This means that transmission owners must provide open access to customers in a non-discriminatory basis, while receiving regulated revenues through the use of transmission system charges. These charges are paid by generators and traders, in proportion to the respective installed capacity and energy demand. Connection to the STN is a competitive business, and can be provided by anyone entitled to do it.

Distribution: Consists on the transport of power from either the STN or embedded production centers to end customers using networks with voltage levels below 220 kV. Distribution is also considered as a monopoly, which is regulated to provide open access, also in a non-discriminatory basis, to customers and to receive regulated revenues.

Trading: Consists on purchasing energy in the wholesale energy market, short and long term, and selling it to end customers. This business activity did not exist before 1995, and was established by Electricity Law. Traders are the only agents, on the consumption side, allowed to trade energy in the Power Exchange. Any customers who want to trade in the Power Exchange need to register as a trader.

Customers: Customers are the end users of electricity services. They are classified in Regulated and Non-regulated Customers. Regulated Customers buy energy from Traders at tariffs regulated by CREG. A Non-regulated Customer has the following options: a) To buy energy in the Power Exchange through a Trader, b) To buy energy in the Power Exchange on its own if it registers as a Trader, c) To buy energy in the Long Term Energy Market to any Trader or Generator by means of Bilateral Contracts. A customer is classified as Non-regulated if it fulfills one of the following two criteria: a) To have an average installed capacity equal to or greater than 100 kW during the last six months, or b) To have an average monthly consumption of 55 MWh in the same period.

3. Congestion Management

The limitations presented in the SIN operation have their origin in the capacity of electric infrastructure associate, or in the application of criteria of security and reliability in the electricity provision.

In order to guarantee the security in Colombian system, the following basic rules must be achieve:

- The voltage should not be under 90% or over 110% of the nominal value (95%-105% at 500 kV).
- The reactive power on generation units must be agreed to their capacity curves.
- To establish voltages objective on different special points/nodes on the system.
- Usually, to control the voltage, can be used all the available elements: Generators, Compensations and under load Taps.
- The system should maintain stable even with a three-phase fault, clear using the principal protections and the permanent element way out.
- The system generators must oscillate on a damp and consistent way.
- If an element goes out of the net, there should not be additional trips to avoid cascade events.
- Before the isolation of a network radially connected to the STN, the frequency must keep the operative levels using the loading shedding scheme.

4. Energy Economic Dispatch

In order to guarantee a safe, economic and reliable operation of the Transmission System, a number of dispatches are made by National Dispatch Center -CND- following the next sequence:

A. Ideal Predispatch

It is a dispatch for the 24 hours of the day considering generation bids and energy forecast. At this stage it is not considered neither generation constrains and transmission congestion.

B. Predispatch

It is a dispatch for the 24 hours of the day considering generation bids, energy forecast, as well as generation constrains and transmission congestion.

C. Preliminary Dispatch

It is a dispatch based on pre-dispatch considering the outage probability of elements, which conforms the transmission network, and the rationing expected value of event occurrence.

D. Dispatch

This is the final dispatch based on preliminary dispatch. It is made through optimization process of 24 hours term approaching the minimization of operating costs subjected to generation and transmission constrains.

E. Electric Analysis

The modern electric energy markets stipulate that the agent in charge of generation dispatch fulfills two basics principles: economy and security. The fulfillment of the second principle requires the dispatch of supplementary generation incurring in additional costs to the operation. These costs are known as constrains costs and, in Colombia, they should be paid, with some exceptions, by the demand side.

5. International Electricity Transactions – Tie

Since 1th of March 2003 Colombia and Ecuador have integrated their electricity markets through a scheme based on bids at the border nodes. These transactions are called TIE.

TIE are hourly based interchanges, accomplished every day, as a result of market conditions which at the end determine the direction of the power flow through the line. Consequently, the interchanges flows from the system with lower prices toward the system with higher prices.

The legal and regulatory base of TIE is the 536th Decision of the Andean Community (CAN) determining general rules for electricity interchanges between countries of this South American Region.

In order to accomplished this challenging task stipulated by CAN, the regulatory body –CREG- and the National Operation Council –CNO-, in Colombia, and the Ecuadorian Electricity Council -CONELEC- issued a series of rules to adequate their own electricity to this new conditions.

The most important issues related to TIE are described as follow:

- Calculation of an hourly based economic dispatch for both countries in order to determine the best economic criteria for the energy interchanges and the direction of the power flow (Import/Export).
- Definition of Financial Guarantees in order to support the electricity imports thought pre-payments mechanisms in both countries. This scheme has given solvency to the systems and avoided financial risk.
- Accomplishment of operative and commercial agreements between countries participants of TIE.

The achievement of TIE is an obligation imposed by the Andean Community; supranational body conformed by Venezuela, Ecuador, Perú, Colombia y Bolivia.

6. Conclusions

This paper has presented the main issues related to the development of the Colombian Electricity Market. The Deregulation of this electricity market has shown to be a successful process in terms of its initial objectives. The transmission activity has faced an important progress moving from a monopoly scheme for transmission expansion towards the construction of transmission lines based on bids schemes. On the other hand, the economic dispatch is made in order to find a feasible generation programming for the operation based on different steps using advanced analysis techniques and optimization models considering characteristics and constrains of generation and transmission elements of the system. Additionally, the new challenges imposed by the Electricity International Transactions have been approached by introducing new analysis methods and the development of new computing tools to be applied in the economic dispatch.

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Biographies

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6. TRANSMISSION MANAGEMENT, PRICING AND EXPANSION PLANNING IN MEXICO: CURRENT STATUS AND PERSPECTIVES

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Abstract— The Mexican electricity systems is partially open for competition, private agents have the right to access transmission networks for their use, the management and expansion planning of the transmission systems is done in a traditional centralized fashion. This paper will describe the current procedures and methodologies used for open access transmission pricing, management and expansion planning. The paper also describes the perspectives for such aspects if a more open to competition environment is set in place in the Mexican electricity system; in this regard the paper will describe the perspectives that could be taken into consideration for transmission cross-border congestion management, pricing and long-term planning in a more competitive and interconnected environment.

Index Terms-- Power transmission, Power transmission economics, Power transmission planning.

1. Introduction: Current Regulatory Framework

Since its nationalization in the 1960's, the Mexican electricity industry is mainly conformed by an arrangement of two state-owned and vertically integrated utilities named CFE (Comisión Federal de Electricidad) and LyFC (Luz y Fuerza del Centro). CFE´s responsibility is to perform all the activities such as operations control and planning, necessary to generate transmit and distribute electricity for all the public service costumers in the country, except for Mexico City and its metro area, served by the second company, LyFC. Since the early 60´s to 1992 the electricity industry in Mexico remained fully vertically integrated, state-owned and centrally planned, except for the natural private investments in self-supply and co-generation.

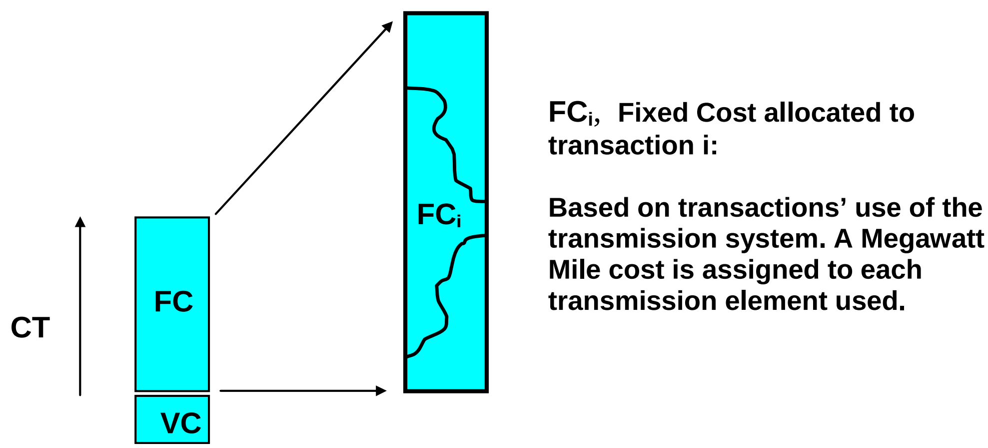
With the objective to complement public investment in generation expansion, in 1992 the Electricity Law (*Ley del Servicio Público de Energía Eléctrica*) was modified by congress to allow private investment in generation through long-term Power Purchase Agreements (PPA´s) awarded under a competitive bidding process carried out by CFE. One of CFE's main reasonability is to perform the centralized technical planning of the electricity energy sector; the minister of Energy and the minister of Finance then evaluate this resulting generation and transmission plan in order to find the best investment arrangement to cope with the need of the plan. The changes in the Electricity Law in 1992, allowed also for free access to the transmission network, so that other private supply figures can realize their contracts, among these figures are: (i) cogeneration, (ii) self supply and (iii) import and exports. The Energy Regulatory Commission (CRE) is responsible for issuing the methodologies for open access transmission rates that the public companies that own transmission will charge to the network users regulates the private supply figures above mentioned.

Since 1999, the Mexican electricity sector has been immersed in a debate over structural reforming the sector [6-7], and amalgam of factors, including the new political configuration in the country, and the effect of the continuing worldwide debate over restructuring, has delayed some of the agreements. At the same time, the continued transmission reinforcement in the network and specially the increasing number of cross-border interconnections with countries that have strongly different regulatory structures, are staring to give some signals that the regulatory principles for transmission management and pricing could be on need for adjustment regardless of the form of structural reforms inside the country that may be approved [8-9].

The reminder of the paper is organized as follows, Section II summarizes the current methodology used to for transmission pricing in Mexico, Section III describes the procedures and tools used for the centralizes operation and planning of transmission resources, Section IV outlines and scenario of possible regulatory changes that could affect the way pricing, management and planning of the transmission system, Section V concludes with the paper.

2. Transmission Pricing Methodology in Mexico

The general economic principle governing the Mexican open-access transmission tariff methodologies is based on long-term cost recovery of transmission investment costs. The long-term transmission investment cost (CT) is then allocated to all the users of the transmission system according to the transmission pricing methodology issued by the Energy Regulatory Commission (CRE). Among the several variations existing to allocate transmission costs [3], three mayor categories can be identified: (i) pan-caking or simple license plate cost allocation, (ii) cost allocation based on transmission usage, and (iii) cost allocation based on marginal cost information. The methodology used in Mexico to price transmission services for third-parties using the national transmission and distribution networks, is based on a combination of methods that together provide signals for efficient use of transmission resource and fully recover the long term transmission investment costs. In general, the methodology distributes the long term transmission cost (CT) based on a modified Megawatt-Mile method (category i) that takes into account the intensity of transmission usage (category ii) by each party; variable cost incurred by transmission losses are also allocated to transmission users –See Figure 1.



FC **Recover long term transmission investment costs CT**
VC **Transmission losses generated by each transaction**

Figure 1. Transmission Pricing in Mexico: Fixed costs and variable cost allocation, based on a modified Megawatt Mile & Transmission Usage Method.

A. Fixed Cost Allocation

Each element in the transmission system F_{ij} is assigned, according to its length, a \$/MW Mille cost w_{ij} based on the long term transmission investments cost (CT). The particular use of each element in the transmission system by a transaction f_k is what defined the fixed cost to be paid by each third-party usage of the transmission FC_k. This fixed cost to be allocated to each transaction k is computed by identifying the use of the transmission system through a classic "with and without transaction" power flow impact scenarios. That is, the fixed cost allocated to each transaction is expressed as the cost-usage ratio:

$$FC_k = \left[\frac{FC}{FC_{k,with} + FC_{k,without}} \right] FC_{k,with} \quad \textbf{(1)}$$

The fixed cost is therefore fully distributed to the third-parties users of the transmission system (with the transaction scenario) and the native load in the system (without the transaction scenario). The correspondent cost impact, with and without the transaction, is evaluated by multiplying the transaction impact in each line (ij) transmission flow and its correspondent $/MW Mille cost, as follows:

$$FC_{k,with} = \max\{\sum_{\forall ij} w_{ij} (F_{ij,with} - F_{ij,without}), 0\} \quad \textbf{(2)}$$

$$FC_{k,without} = \sum_{\forall ij} w_{ij} F_{ij,without} \quad \textbf{(3)}$$

In (2) and (3) $F_{ij,with}$ and $F_{ij,without}$ are, respectively, the maximum power flows in transmission line ij when transaction k is considered and not considered in the transmission system. The maximum power flow is obtained from given minimum and maximum load scenarios in the system and through traditional load flow studies. As can be seen in (3) only flow increases in are considered in to evaluate the impact in transmission flows. In general terms, as explained here, fixed cost is allocated according the use of the transmission system and a $/MW mile cost representation of the transmission system. The use of the transmission system is measured in terms of the impact in transmission flows of each transaction; the more congestion is causes in the system the more it pays for the use of the system. These type of "flow-impact" signals are more important in Mexico due to the strongly physical and electrical longitudinal nature of the network where the primary fuel resources are located far away from the load consumption centers causing important and lengthy transmission flows, specially from the south-east and gulf of Mexico to the center and north. If a third-party transmission access right causes more congestion is pays more, if it alleviates congestion in the system it may only pay minimum charge; at the end, the total long-term cost to be recovered are distributed among all the users of the system, the native load and the third party users.

The full details of the simplified representation of fixed cost in equation (2-3) can be found [5].

B. Variable Cost Allocation

Variable cost in the transmission cost allocation in Mexico considers the cost incurred in real power transmission losses caused by the each transaction using the transmission system. Losses are evaluated using traditional load flow studies, and the price of losses is evaluated using short-run energy marginal costs. That is, variable cost allocated to each transaction k, are computed using an expression of the form:

$$\begin{aligned} VC_k = \rho_e[&\sum_{\forall ij} (F_{ij,with} - F_{ji,with}) \\ &- \sum_{\forall ij} (F_{ij,without} - F_{ji,without})] \end{aligned} \quad \textbf{(4)}$$

Expression (4) basically evaluates the transmission losses in each network element incurred when adding the transaction in the system. ρ_e, stands for a short-run marginal valuation of the energy costs. Other minor administrative charges apply, total cost allocated to each transaction, variable plus fixed charges have to pass a minimum transmission charge tress-hold, otherwise such minimum transmission charge applies. All the details of the methodology for transmission pricing in Mexico can be consulted in [5].

3. Current Procedures and Methodologies for Transmission Management and Expansion Planning in Mexico

Power system planning is part of a national energy planning process, which in turn defines fuel policies and diversification strategies to coordinate the execution of alternative projects, such as hydroelectric, geothermal and nuclear power plants. CFE is the organization responsible to perform expansion power planning studies to determine a sequence of capacity reinforcements in generation and transmission in Mexico. Resources, generation, and bulk transmission planning are handled by the planning division in central offices of CFE.

Mexican government manages the energy sector, including electricity through the Energy Ministry and the Energy Regulatory Commission.

A. Centralized and Coordinated Management of National and Cross-Border Transmission Resources

The administration of the national grid is carried out by CFE through the Centro Nacional de Control de Energía (CENACE). There are 8 control centers that coordinate the operation at regional level, and a national center that defines the operation policies and the security standards.

The cross-border interconnections are also coordinated by CENACE trough agreements with ISO's of California and ERCOT.

B. Main Bulk Power System Generation and Transmission Expansion Planning Procedures

The main objective in the planning process is to determine an optimal expansion plan that meets future electricity demand and minimizes the investment, operation and loss of load costs, providing adequate levels of reliability and quality under environmental, financial and energy regulations.

Due to the complexity, the problem is solved by decomposition in time (long – mid – and short term time frames) and by geographical hierarchy (generation, bulk transmission, regional transmission, and distribution networks). See table I. Additional to the uncertainty of classical planning methods, regarding load forecast, fuel availability, generation and transmission forced outages rates and hydrological conditions, CFE has to consider the uncertainty of private sector investment under the co-generation and self supply schemes which is a key issue in the planning procedure due to the impact of size and location of these resources.

Table I. Power system planning decomposition

Term	Generation Studies	Bulk Transmission	Regional transmission	Distribution
Long-term year N+10 to N+30	Guidelines for Generation Expansion	Guidelines for Bulk Interconnections		
Mid-term year N+5 to N+10	Generation Program	Bulk Transmission Program		
Short-term year N+3 to N+5	Generation Adjustments	Transmission Network Adjustment	Regional Sub transmission Program	Distribution Program
Near-term year N to N+3	Operation Studies and Decision Adjustments	Operation Studies and Decision Adjustments	Studies and Decision Adjustments	Studies and Decision Adjustments

With locations, sizes and dates determined for hydro and thermal plants, several models are combined to define the required electrical network.

The transmission planning methodology used is based on a minimum cost analysis that selects projects, which show long-term utilization, that improve system reliability, and are least-cost options.

The methodology involves four stages. It begins defining a group of feasible generation scenarios. Then, the methodology develops minimum cost transmission plans for all the generation scenarios. The next stage is to schedule the transmission programs required during the corresponding period, starting from the final year and proceeding backwards (mid and short term). The objective is to identify both priorities and optimum timing to develop each project. Finally, the methodology proceeds to classify transmission projects for implementation purposes, which allows identifying robust programs, when these exist. A robust program is comprised of projects that include all desirable attributes (reliability, flexibility and economy). This last stage helps the design of hedging mechanisms to mitigate associated risks with the final plan.

The planning methodology also includes a profit analysis which quantifies costs and benefits of the transmission program to assure that an acceptable profitability is achieved.

C. Increasing Role of Reliability and Cost Driven Cross-Border Interconnections

The Mexican electric system has 13 tie lines with electric systems along the Mexico-USA border. Some of these ties have been used for permanent interchanges of energy, while others are used only for emergency assistance.

For several years interconnections between San Diego Gas and Electric (SDG&E) and CFE have been used to buy and sell electricity on a long-term basis and through economy transactions. Transfer capability is 400 MW southbound and 800 MW northbound. Tie lines between CFE and El Paso Electric Company (EPECO) at 115 kV have a combined transfer capability of 200 MW; they are used for emergency assistance with block load schemes. Three interconnections between CFE and AEP Texas Central Company at 138 kV are operated in a normally open mode to be used under emergencies.

Recently American Electric Power (AEP) installed an asynchronous tie at Eagle Pass using HVDC light technology. The tie is rated at 36 MVA at 138 kV and allows a bidirectional interchange of power between US and Mexico is an open access tie that enables parties to trade electricity in this border region.

CFE and the Electric Reliability Council of Texas (ERCOT) have a long history of emergency assistance across the Mexico/United States border. A recent study [15] continues that tradition by performing a contemporary analysis of the CFE and ERCOT transmission systems to determine the short-term (phase I) and long-term (phase II) opportunities for interconnections. The study is separated into phases as follows:

Phase I: Immediate consideration of support to the transmission systems along the Texas border where older inefficient generation is no longer economical to operate. In addition, synchronous ties may allow new block load support in remote areas where lengthy transmission additions are required. Phase I alternatives leverage the existing interconnections and infrastructure that do no require lengthy regulatory review.

Phase II: Will evaluate opportunities for long-term interconnections that can support additional economic transactions and emergency assistance between CFE and ERCOT. The studies will not be constrained by infrastructure limitation, and they are likely to involve new transmission improvements for higher transfer capabilities. In both phases, both high voltage synchronous and asynchronous transmission interconnections will be considered, but the primary effort is focused on asynchronous interconnections that utilize Flexible Alternating Current Transmission Systems (FACTS) technology to allow the scheduling of power transfer between the electrical grids.

At the southern border there is an interconnection project with Guatemala. It will be a 400 kV tie line, with 200 MW transfer limit due to constraints in the 230 kV Guatemala's transmission grid. The interconnection will allow economy energy transactions between both countries and medium and long-term bilateral contracts. Additionally the tie will help to the control of power flows in Guatemala, reducing losses and improving power reactive margins. In the future is likely to increase with the reinforcement of interconnection in Central America. Figure 2 shows actual and future cross-border ties.

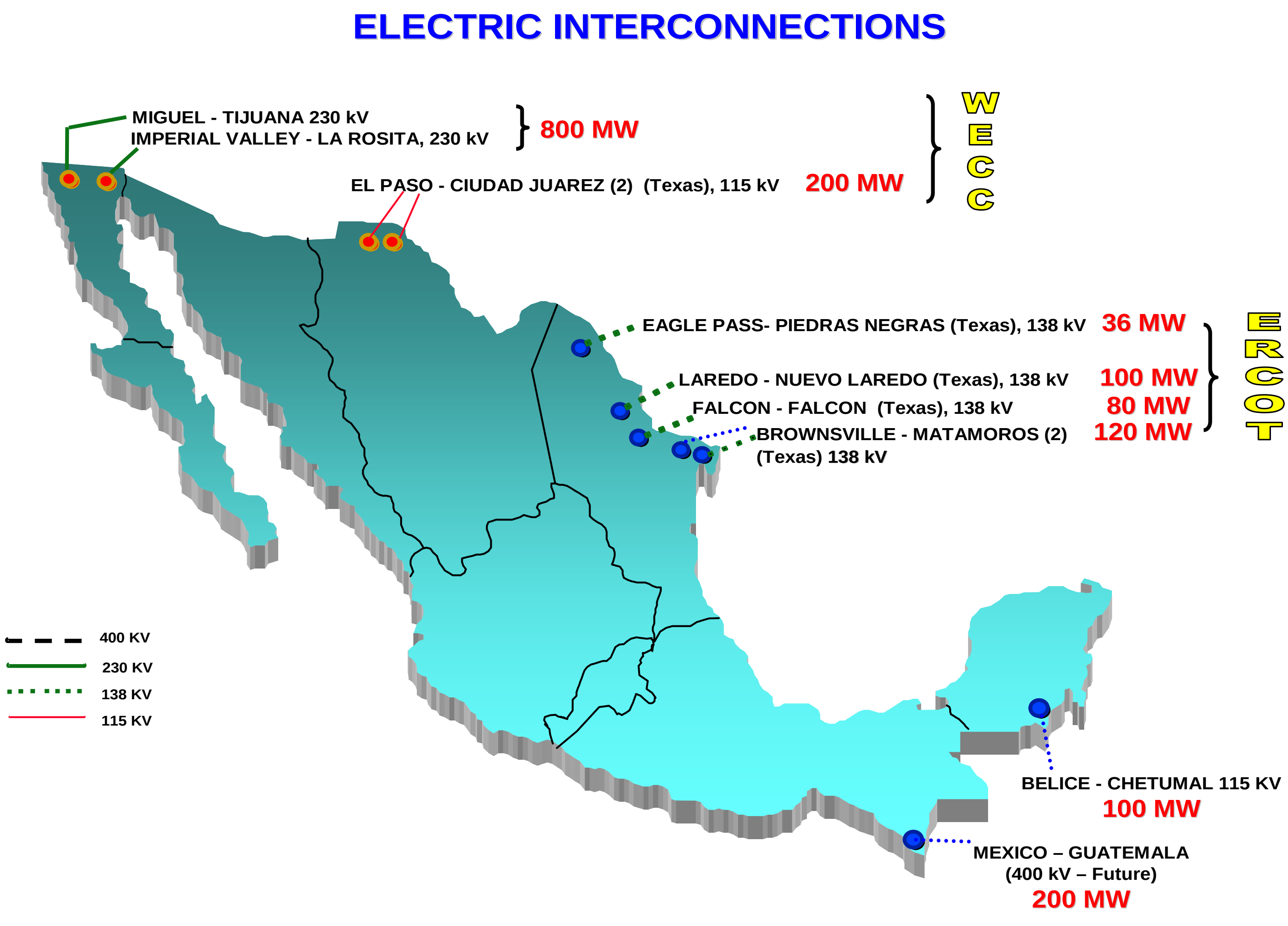


Figure2. Cross-border country interconnections

D. Actual Generation and Transmission Infrastructure Picture

At the end of 2002, installed generation capacity for public service was 41,177 MW with composition shown in Figure 3.

Total energy production was 201,059 GWh, with a peak load of 28.19 GW. Sales to

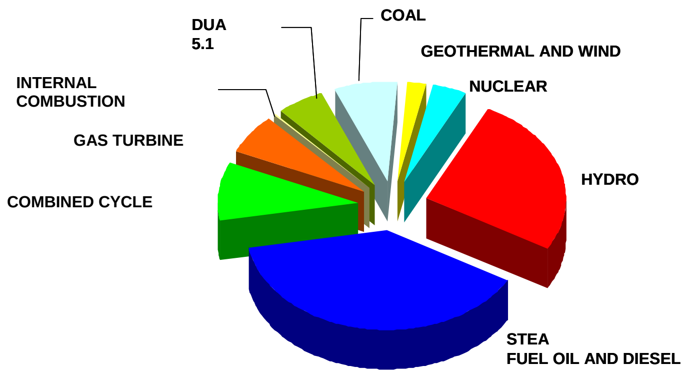


Figure3. Composition of generation capacity in Mexico

customers are

59.8% of industrial and high voltage customers; 24.7% to residential users, 8.4% to commercial customers, 5.8% for agricultural irrigation, 4.6% for municipal services such as street lightning and water pumping, and the remaining 1.7% exports to electric utilities in the US and Belize.

The national transmission grid is formed by a system based on 400 kV, 230 kV and 115 kV lines that cover most of the country. Today only the Baja California Peninsula remains isolated from the main electric network. The main transmission system includes 86,636 kilometers of high voltage lines, and total substation capacity is 119,707 MVA. Table II shows the composition of the transmission system, while figure 4 shows the transfer capabilities between regions.

Table II. Main bulk transmission grid

Voltage (KV)	**Length (Km)**
400	14,503
230	24,058
69-161	48,075

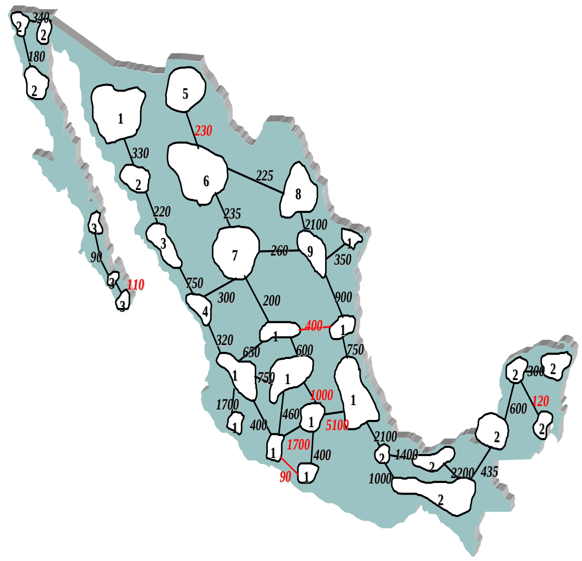


Figure4. Transfer capabilities between regions (MW)

4. Perspectives on Transmission Management, Pricing and Planning in a More Open to Competition Environment

The Mexican electricity sector has been immersed over a de-regulation debate towards a more open to competition environment since 1999; there has been a strong interest in the subject and several factors have influenced the absence of agreement [10-11]. There is close to a dozen of reform proposals from which, at least, five of them structurally propose changes towards a more open to competition environment. One of the probable outcomes is that competition will be allowed for a particular set of large costumers that will be able to long-term contract energy services from merchant generation at their convenience, as expressed in the presidential proposal in 2002 [12]. In this scenario a bilateral market for large consumers will be open, operations and transmission will remain vertically integrated by the public company CFE. In this scenario congestion management procedures and rules for real-time energy imbalance inside and cross-border country are also required and will be defined by CRE as identified in the presidential reform proposal. The way transmission management, pricing and expansion planning could be adjusted under this moderately open to competition scenario, are explained in the following sections.

A. Cross-Border Pricing and Congestion Management

The increasing number of interconnections, the actual rights that Mexican users have to import and export energy for self-consumption along with the probable more open to competition environment for large consumers, suggests that cross-border electricity trade could increase to bigger numbers, and some level of minimum harmonization may be required regardless of structural reforms. Even tough the main bulk transmission system will still be managed in a centralized fashion with the objective to guarantee minimum cost and reliability needs and standards; special consideration for transmission management need be considered for cross-border trade. There are two main factors that need be considered in the future: (i) cross-border congestion management and (ii) cross-border transmission pricing. If increasing numbers of users intend to use the increasing number of cross-border capacities, first-come first-serve basis for transmission reservation may need be adjusted to other congestion management protocols, such as auctioning, market-splitting or coordinated congestion through nodal prices [12]. For cross-border pricing of transmission resources, the increasing number of interconnections and the differences in financing of the infrastructure may require the adjustment or harmonization of pricing methodologies with neighbors. A monopolist in one region, connected to competitive regions, has been proved to have the incentives to reserve cross-border capacities in detriment of general welfare to the rest of the users that have access to imports for self-supply. Identification of minimum required adjustment in pricing might also be required to avoid such situations and provide the signals for an efficient short- and long-term use of the transmission interconnection [13]. General principles of this minimum harmonization must account for: efficiency, non-discrimination, feasibility of implementation, ability to adjust to the involved market structures.

For the operation of the interconnections new reliability committees to the existing may be established with the new merchant agents (generator and large consumers) and regulatory authorities; reliability and security will still be a premier objective in the management of the interconnections and the main interconnected bulk transmission system.

B. Centralized Planning Under Competition

Under any reform scenario in place, the main bulk transmission system will be still planned under a centralized fashion by CFE, the main electricity utility. Merchant transmission arrangements for investment in transmission will not be consider as expressed in all the proposals, private investment in transmission is only allowed for the small projects required for the interconnection of private generation plants to the bulk transmission system. Centralized planning procedures for transmission expansion planning may be adjusted to account for the new, out-of planning or merchant agents in the system, such as generators and large costumers that will have choice for supply. Centralized planning of transmission that considers the appearance of market reaction of such agents needs be considered in the central planning to secure a consistent transmission plan as has been recognized in [14]. A proposal guideline for centralized transmission planning that incorporates the effects of competition over the transmission network can be found in [8].

5. Conclusions

The Mexican electricity system is partially open for competition, private agents have the right to access transmission networks for their use, the management and expansion planning of the transmission systems is done in a traditional centralized fashion. Open-access transmission pricing in Mexico is based on a modified MW-mille method that distributes transmission costs according the use of the transmission system made by each transaction, the use is measured using traditional load flow studies and the classic “with and without” scenario basis. Transmission expansion planning and operation is still made in a traditional centralized fashion, reliability and cost driven cross-border interconnection continues to be build with the United States and also with Central America, reliability and operational agreements have been signed for the operation of such interconnections and are expected to continue growing along with more required reliability considerations and coordination groups. The continued debate over de-regulating the electricity sector to a broader competition in which large consumer could have costumer choice for supply and the continued increase on cross-border interconnections brings some challenges for the future management, pricing and planning of the system. Minimum harmonization requirement for cross-border pricing and congestion-management regulation of transmission may be need identified. Even tough combinations of regulated and merchant investment for the bulk transmission system is not oversee in any of the reform proposals, the technical central planning for transmission could be in a need for adjustment in order to take consideration of uncertainties resulting from self-profit economic driven decisions of the new merchant consumers and generators operating over the transmission network, that will constitute the costumer-choice market for electricity considered in the presidential reform proposal.

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