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Pricing Electricity Transmission in Mexico

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Abstract

We propose a combined merchant-regulatory framework for incentives to expand the large interregional transmission links of the Mexican transmission network. We make an initial implementation of a pricing two-part tariff model within the context of the "shadow" market of the Mexican electricty system. Our results suggest that the best institutional structure for expanding the Mexican transmission grid would be one of a single transmission firm that charges even tariffs along the Mexican territory.

Resumen

En este trabajo, proponemos una estructura regulatoria de mercado combinada para generar incentivos y expandir los nexos interregionales de la red de transmisión eléctrica mexicana. Primero, hacemos una implementación de establecimiento del precio a través del modelo de tarifas en dos parte, en el contexto de un mercado "sombra" para el sistema eléctrico mexicano. Nuestros resultados sugieren que la mejor estructura institucional para expandir la red de transmisión podría ser a través de una sola empresa de transmisión que cobre la tarifa de transmisión a lo largo y ancho del territorio Mexicano.

Introduction

According to most recent official statistics,1 electricity demand in Mexico will annually grow at 5.6% during 2002-2011. In order to meet such demand increase, 30,300 MW of additional generation capacity will have to be added to the electricity system in that period, a large amount compared to the total current generation capacity of 38,519 MW. Likewise, total transmission capacity has to grow at an annual growth rate of 21% during 2001-2006, which also appears very high compared to the annual historic growth rate of less than 4%.

The Mexican government plans to cope with these needs with a threefold strategy. The first one is to work on improving the implementation of the current legal framework that permits private investments in self-supply, cogeneration, and independent power producers but that keeps the monopsony power of the State monopoly Comisión Federal de Electricidad (CFE). The second strategy is to improve the economic efficiency of the existing public companies through the creation of a virtual “shadow” market which tries to emulate a competitive environment in the internal operation of the distinct CFE’s generation, transmission, distribution and system operation subsidiaries. The third strategy is to lobby in the Mexican congress so as to implement a regulatory reform that allows the creation of a (real) electricity market where CFE’s is no longer a monopsony, and that permits competition between public and private generators in order to meet the needs of electricity consumers.

The Mexican transmission network presents several signs of congestion, especially in the southeast and north of the country that might enhance the market power of regional power generators. Since the prospects of a regulatory reform that could permit private participation in transmission projects is for now halted in the congress, the Mexican government is nowadays studying the use of transmission pricing within the shadow market in order to promote adequate economic expansion of the transmission network. A “benefit-factors” pricing structure was recently proposed for the Mexican transmission system.2 In this paper we make another pricing proposal based on price cap regulation. We believe the benefit factors approach is subjective ad-hoc mechanism and, alternatively, we propose the use of two part tariffs that might relief the opposing short run (congestion) and long-run (investment) incentives of a transmission grid.

1 Secretaría de Energía (2002), Prospectiva del Sector Eléctrico 2002-2011, México.

2 As in Rubio-Odériz and Pérez-Arriaga (2000).

The literature on incentive structures for long-term expansion of the transmission network has an incipient development. There is (more or less) a consensus regarding the way to resolve short-term transmission congestion through nodal price differences. However, there is an intense debate regarding the optimal regulatory scheme to attract investment to finance the long-term expansion of the transmission network. Electricity transmission presents special characteristics due to so called "loop flows" which make impossible the definition of "available transmission capacity" in a point of time without the existence of complete information about the use of the network. In fact, under loop flows the addition of new transmission capacity can sometimes paradoxically reduce the total capacity of the network, which complicates the analysis of the welfare effects of certain transmission expansion projects. Analytical incentive structures proposed to deal with transmission expansion go from the "merchant" one, based on long-term financial right (LTFTR) auctions, to regulatory measures that make the transmission company to pay the social cost of transmission congestion.

In the international practice, regulation has been basically applied in England, Wales and Norway to guide the expansion of the transmission network, while a mixture of planning and auctions of long-term transmission rights has been applied in the northeast of the US. Such combination is also being considered in New Zealand. A combination of regulatory mechanisms and merchant incentives is alternatively used in the Australian market.

We propose a two-part pricing model within a combined merchant-regulatory structure. We believe this scheme makes sense for the Mexican transmission network characterized by the coexistence of many meshed network regions that are connected by relatively large radial links. In this paper, we concentrate on analyzing the way to implement incentive-compatible regulation for the latter links. We show how through rebalancing of a two-part tariff, adequate expansion of the large interregional transmission links could be reached while LTFTR auctions would be used inside every electricity region. We identify the best institutional framework associated to this scheme.

The plan of the paper is as follows. In section 2 we analyze the characteristics of the Mexican transmission network, and study its congestion in the context of the electricity shadow market. In section 3, we carry out an analytical review of the literature on incentive structures for transmission expansion. In section 4 we analyze the benefit-factors pricing approach and, subsequently, we present our price-cap model and make several simulations with real data. Section 5 concludes.

The Mexican Transmission System.

In 2001, the Mexican transmission and distribution network was 670,902 km long. 5.4% were 230-400 kV transmission lines, 6.2% were 69-161 kV sub-transmission lines, and the remaining 88.4% were distribution lines between 2.4 and 60 kV. Table 1 presents the detailed length evolution of transmission lines between 150 and 400 Kv. It can be seen that 98.17% correspond to tension levels between 230 and 400 Kv.

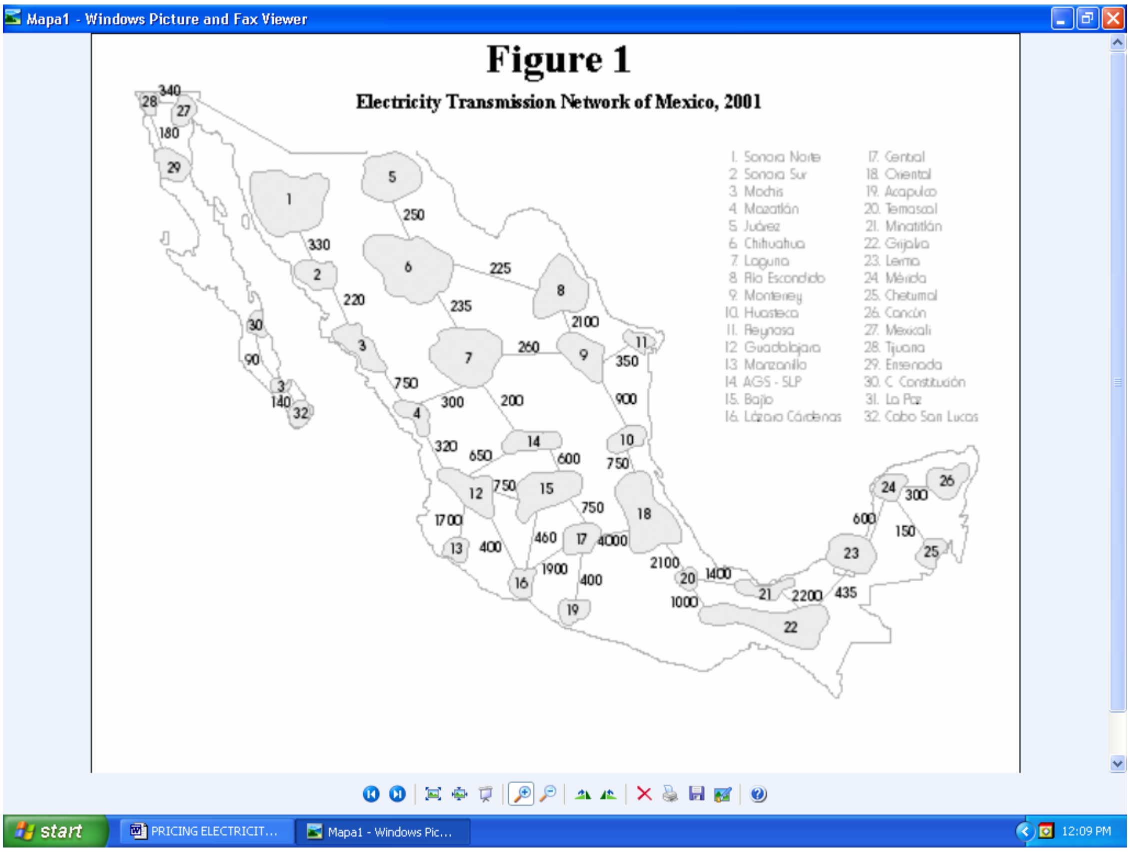
Table 1

Length of transmission lines (Km)

	CFE		*LFC*	
	Tension level (Kv)			
Year	*400*	*230*	*161*	*150*
1981	5,997	9,581	225	786
1982	6,035	10,801	291	786
1983	6,080	10,892	291	786
1984	6,287	11,515	291	834
1985	7,610	12,237	291	842
1986	7,827	13,174	291	842
1987	7,908	13,925	291	851
1988	8,380	15,283	342	851
1989	8,810	16,090	379	888
1990	9,099	16,417	379	918
1991	9,103	17,315	379	920
1992	9,162	17,673	379	983
1993	9,710	18,267	379	920
1994	10,623	18,217	379	920
1995	10,979	18,532	379	921
1996	11,337	18,878	379	992
1997	11,908	19,375	379	993
1998	12,249	20,292	379	995
1999*	12,489	20,595	379	995
2000*	13,263	21,275	379	995

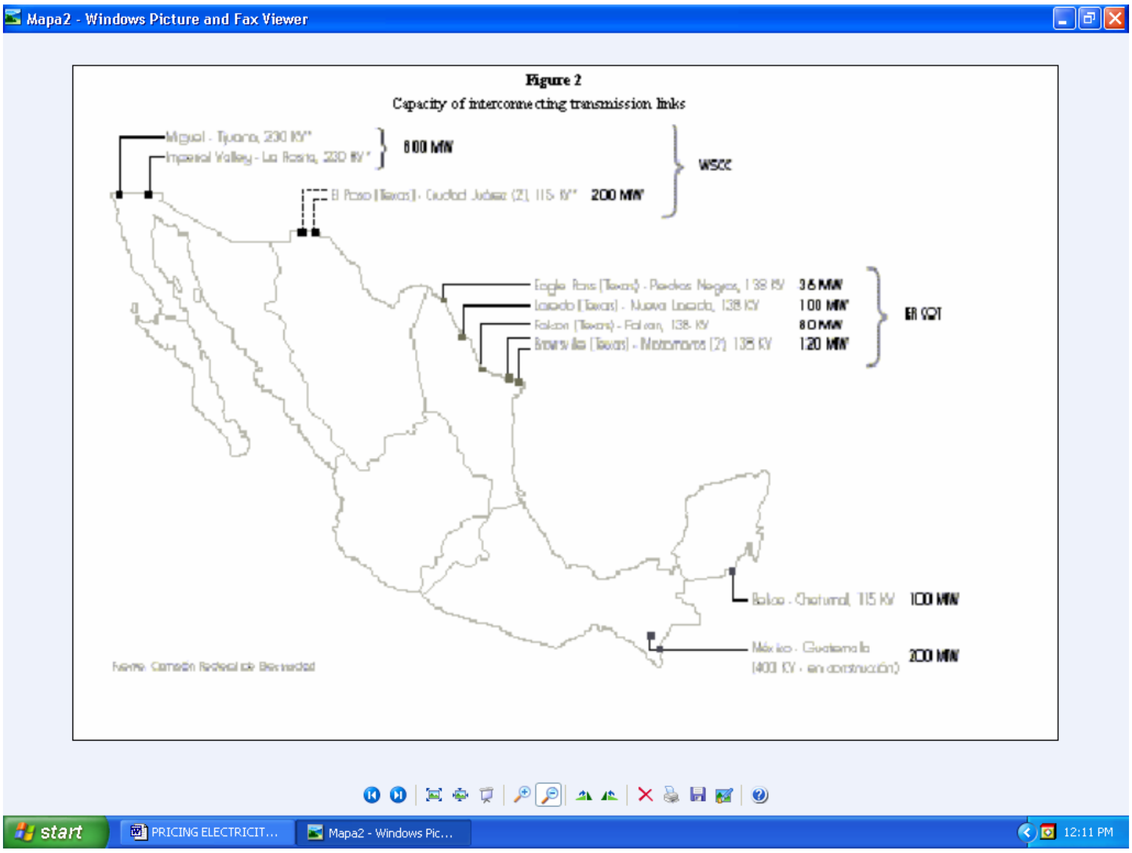
FUENTE: Banco de México Banco de Datos 1999,
* own calculations with CFE data

Around 115,000 MVA of the total 170,000 MVA of installed transmission and distribution capacity correspond to transmission lines. The Mexican transmission network has grown at an annual rate of 3.74% per year since 1981. Figure 1 shows the maximum capacity of the regional transmission links for the 32 regions of the Mexican electricity system in 2001. There are also several international interconnection points in the system, whose capacity is shown in figure 2



The Energy of Ministry of Mexico (Sener) foresees a 20,357 km increase in the length of 69-400Kv transmission lines for 2002-2006. Figure 3 presents the expected capacity growth for each regional link. In order to meet an annual growth rate of 5.6% in electricity demand during 2002-2011, Sener foresees that total transmission capacity will grow from 12,740 Mw in 2001 to 25,985 Mw in 2006, which represents an average annual growth rate of around 21%, a huge increase compared to the historic annual growth rate of transmission capacity. This will require annual investments of USD 1.3 billion that will be carried out through public budget in a direct way (46%), or through financed public projects, or Pidiregas (54%).3

3 Pidiregas are contracts for public projects that the Mexican government bids to private firms, and that are intertemporally paid with public funds. Final ownership is public, and private investors are supposed to independently fund such projects.


Mapa2 - Windows Picture and Fax Viewer
Figure 2
Capacity of interconnecting transmission links
Miguel - Tijuana, 230 KV*
Imperial Valley - La Rosita, 230 KV*
800 MW
El Paso (Texas) - Ciudad Juárez (2), 115 KV*
200 MW
WSCC
Eagle Pass (Texas) - Piedras Negras, 138 KV
36 MW
Laredo (Texas) - Nuevo Laredo, 138 KV
100 MW
Falcon (Texas) - Falcon, 138 KV
80 MW
Brownsville (Texas) - Matamoros (2), 138 KV
120 MW
Belice - Chetumal, 115 KV
100 MW
México - Guatemala
(400 KV - en construcción)
200 MW
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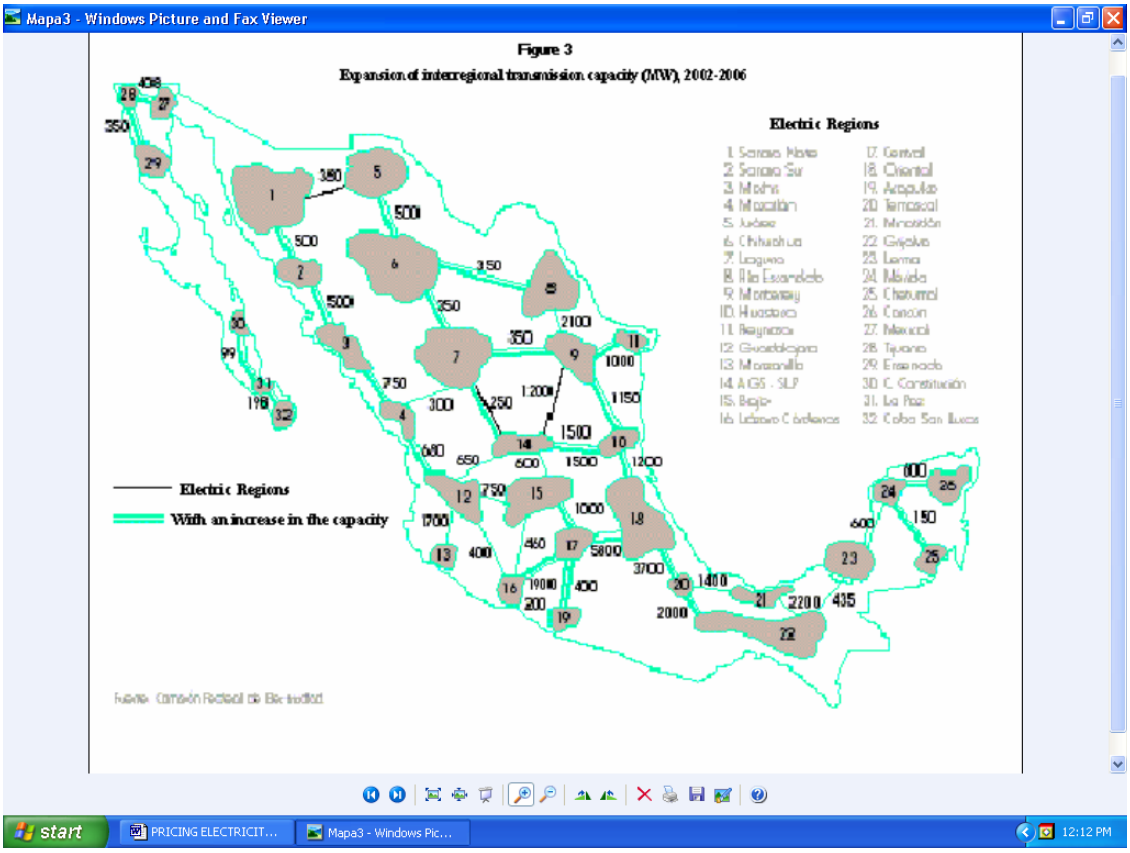

The Shadow Electricity Market and Transmission Congestion

There have recently been several initiatives to reform the Mexican electricity sector, such as the 1999 privatization proposal of the Zedillo administration or the more conservative regulatory reform proposal made by the Fox administration in 2002.4 However, the only concrete reform carried out so far is the one in 1992 that allowed for private investment in co-generation, self supply, and independent power producer (IPP) projects under a single-buyer (or monopsony) scheme. According to this scheme, all private producers must sell their exceeding power to CFE relying on a government credit: IPPs operate under 25-year power purchase agreements with CFE. So far, this scheme has attracted some private investment. In 2001, private capacity generation represented 12.6% of total capacity generation.

Additionally, even though there has not been any major reform process in the Mexican electricity sector, an internal (or shadow) market is being implemented by CFE in a nodal fashion since September 2000. This virtual market seeks to emulate a competitive market. It uses a merit order rule for

[4] See Carreón and Rosellón (2002)

generation dispatch in a one-day-ahead market as well as in a real-time market. The one-day-ahead market establishes production, consumption and price schedules for each of the hours of the following day. The differences between forecasted and actual schedules are cleared at real-time prices.

Bids are actually submitted to the system operator (CENACE) by the different “programmable” thermal CFE’s generation plants, which are administratively separated so that they function as different power producers.[5] Total generation capacity amounts 38,519 MW, with the following generation mix: hydro 26%, thermal 38%, combined cycle 9%, gas 7%, carbon 7%, dual 6%, nuclear 4%, geothermal 2%, and others (wind, solar) 1%. Payments to generators include a “capacity” payment intended to foster the development of generation capacity reserves. The distribution companies are also divided into several distribution units.

A MW-Mile method (as in Shirmohammadi, et al, 1989) is used to set transmission tariffs. Through this method, charges for transmission services for tensions greater than or equal to 69 Kv are calculated as the maximum between “fixed costs plus variable costs” and “operation and maintenance costs”. Administrative fixed costs are added to this amount. Fixed costs are basically the long-run incremental cost of the transmission network. They are allocated among consumers of the current grid and consumers of the future expanded grid according to the impact both have over the complete network.[6]

Nodal prices are determined in the 1,400 nodes of the main transmission grid through use of a power flow model.[7] Using this nodal price system, Madrigal (2000) and Madrigal et al (2002) estimate transmission congestion rents as well as detect main congestion transmission links. Table 2 presents their estimation for congestion rents for three scenarios of the load duration curve in 2000. Annual estimated congestion rents arising from congestion in transmission amount USD 1.4 billion. Table 3 presents the main transmission lines subject to congestion. Instituto de Investigaciones Eléctricas (2003, p. 44) show a volatile structure of nodal price differences between the Río Bravo node (in the Northeast US-Mexico border) and the Querétaro node (in the center of the country. For example, during January 2000 there were some days where the price difference between these two nodes could increase from less than USD 10 per MWH to more than USD 60 per MWH. Among other factors --including low hydro production and high-cost generation-- this is explained by transmission congestion.

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5 Non “programmable” generators, are small producers that only supply power according to a previously set energy delivery schedule. Hydro generators also make available all their generation capacity, and face production constraints in the one-day-ahead market. Both types of generators then have zero variable costs.

6 The implementation details of this method are shown in annex 1.

7 As described by Schweppe et al (1988)

Table 2
Annual Congestion Rents

Load Duration Curve

Scenario	Annual Duration (%)	Annual Duration (hours)
High	00.15	13.14
Medium	70.00	6132.00
Low	29.85	2614.86
Total	100	8760

Revenues, Payments and Rents from Congestion

Scenario	Generators' income (pesos)	Demand Payments (pesos)	Congestion Rents (pesos)
High	9951916.98	11441067.31	1489150.33
Medium	4303243	6266757.05	1963514.05
Low	2811096.18	4260572	1449475.83
Annual Est	33868877214	49718889151	15850011937

Source: CRE

Table 3
Main congested transmission lines and import areas

Main Congestions during Peak Demand

Line			
From	To	Flow (MW)	Limit (MW)
Central	Balsas	-600	600
Oriental	Veracruz	-440	440
Sureste	Campeche	100	100
Colima	Occidental	1216	1216
Sonora	Sonsur	-410	410
Laguna	Chihuahua	200	200
Coahuila	Monterrey	1550	1550
Monterrey	Laguna	250	250

Main Importing Areas

Area	Capacity	Generation	Demand	Exportation
Sonnorte	806.00	718.42	1128.42	-410.00
Laguna	643.00	335.95	745.95	-410.00
Coahuila	2734.00	2575.79	876.46	1699.30
Monterrey	1640.00	1367.00	3080.99	-1713.99
Bravo	520.00	520.00	559.98	-39.98
Central	2632.00	2632.00	6519.01	-3887.01
Veracruz	1845.00	510.11	523.80	13.69
Occidental	1912.00	1594.49	4023.81	-2429.32
Campeche	150.00	0.00	146.26	-146.26

Source: CRE

Madrigal (2000) and Madrigal et al (2002) further develop a power flow linear model so as to study the effects of transmission congestion on local generation market power in a hypothetical future electricity market in Mexico. The Yucatan area (zones 21, 22, 23, and 28) is particularly isolated since its only link to the system is a 100 Mw congested line that links the Campeche zone to the rest of the system. The "must-dispatch" and Lerner indexes are calculated for distinct technology generators, and it is shown that a 179 MW generator could make use of its market power in the area due to congestion in transmission links, actually charging a USD 2000 per MW electricity price. Similar results are reached for the central and the Northeast areas.

In a similar effort, Comisión Federal de Electricidad (2000) confirms that the isolated Peninsular and Northwest regions are more susceptible for market power abuse than central regions. Hartley and Martinez-Chombo (2002) further analyze the impact of Sener not developing its proposed expansion of transmission links on additional investment in generation capacity. They particularly find that the upgrades between regions 22 and 20 (additional 1,000 MW of capacity), and regions 18 and 20 (additional 3,700 of capacity) are critical to transmit power from the hydro plants in the Grijalva river region (22) to the central part of the nation. If these projects are not built by the end of 2004, forecasted demand in 2005 will not be able to be met without the construction of additional new generating capacity

Incentive Structures for Transmission Investment

Different from other industries, electricity transmission presents special characteristics --beyond economies of scale and cost subbaditivity-- that complicate the regulatory analysis of adequate incentives for network expansion. Externalities in electricity transmission are mainly due to "loop flows", which arise from interactions in the transmission network.8 The effects of loop flows imply that transmission opportunity costs and pricing critically depend on the marginal costs of power at every location. Energy costs and transmission costs are not independent since they are determined simultaneously in the electricity dispatch and the spot market. Then, as explained by Bushnell and Stoft (1997), certain transmission investments in a particular link might have negative externalities on the capacity of other (maybe remote) transmission links. In fact, the addition of new transmission capacity can sometimes paradoxically reduce the total capacity of the network (Hogan, 2002b).

[8] See Joskow and Tirole (2000), and Léautier (2001).

This situation is further complicated by the fact that equilibrium in the forward electricity transmission market has to be coordinated with equilibrium in three other markets: the energy spot market, the forward energy market (or bilateral contract market), and the generation capacity reserve market (see Wilson 2002). Furthermore, the effects of an increase in transmission capacity are uncertain. As shown by Léautier (2001), the net welfare outcome of an expansion in the transmission grid depends on the weight in the welfare preferences of the generators' profits relative to the consumers' weight. Thus, incumbent generators are not the best economic agents to carry out transmission expansion projects. Although transmission expansions might allow established generators to enhance their revenues due to improved access to new markets and increased transmission charges and FTRs, such gains are overcome by the loss of their local market power.

The literature on incentives for long-term expansion of the transmission network has an incipient development. As Joskow and Tirole (2003) argue, the economic analysis of electricity markets has focused on short-term issues (such as spot markets for energy, short-run congestion management, nodal pricing, and day ahead auction rules) and has typically considered the transmission network capacity as given, fixed, and of common knowledge. However, transmission capacity is stochastic and its development mutually depends on the evolution of generation investment.

There is (more or less) a consensus in the economics literature regarding the way to resolve short-term transmission congestion. As shown in Hogan (2002a), the difference of electricity prices between two nodes in a power flow model defines the price of congestion. However, there is an intense debate regarding the way to attract investment to finance the long-term expansion of the transmission network, and to solve the dual opposite incentives to congest the network (in the short run) and to expand it (in the long run).

There are (at least) three existing hypotheses on incentive structures for attracting investment to electricity transmission: the long-term financial-transmission-right hypothesis, the incentive-regulation hypothesis, and the market-power hypothesis. Each one relies on a distinct institutional set up. The first approach, the "merchant" option, relies on the auction of LTFTR by an independent system operator (ISO). This approach directly faces the problems implied by loop flows so that, in order to proceed with a line expansion, the investor pays for the negative externalities generated. To restore feasibility, the investor has to buy back sufficient transmission rights (proxy awards) from those who hold them initially, or an ISO would have to retain some transmission rights in an auction for long-term rights to make sure that the expansion project does not violate the property rights of the original transmission right holders. This is the basis of a LTFTR auction (see Hogan, 2002 b).

Joskow and Tirole (2003) carry out criticisms to the merchant approach. They however concentrate their analysis on the short-run version of the FTR model. They argue that the efficiency results of this model rely on perfect-competition assumptions that are not met in the reality of transmission networks.9 Additionally to technical difficulties in defining an operational FTR auction,10 these authors think that the FTR typical analysis is static, which contradicts the dynamic nature of transmission investment and the interdependency between generation and transmission investments. Joskow and Tirole carry out an extensive analysis on the implications of lifting these strong perfect competition assumptions:

Market power: The existence of market power and vertical integration might jeopardize the success of FTRs auctions. Due to market power in constrained regions, prices will not reflect the marginal cost of production. Generators in constrained regions will tend to withdraw capacity to bring up their prices and this will overestimate the cost-saving gains from transmission investments.11

Lumpiness: Lumpiness in transmission investment implies that the total value paid to investors through FTRs understates the social surplus created by such an investment. The large and lumpy nature of major transmission upgrades then calls for the need of long-term contracts before making a transmission investment, or of property rights to exclusively use the incremental investment for a certain period of time.

Contingencies: The difficulties associated with contingencies in long-run electricity transmission might question the real capacity of the FTR/merchant approach to solve the loop flow problem. Additionally, existing transmission capacity and incremental capacity are not well defined and are of a stochastic nature. Even in the two-node case,

9 These assumptions include: no increasing returns to scales, no sunk costs, nodal prices are able to fully reflect consumers' willingness to pay, the network externalities are internalized by nodal prices, there is no uncertainty over congestion rents, there is no market power so that markets are always cleared by prices, there exists a full set of future markets, and the ISO has no internal intertemporal preferences regarding effective transmission capacity.

10 No restructured electricity sector in the world has adopted a pure merchant approach towards transmission expansion. The closest case is Australia where a mixture of regulated and merchant approaches has been recently implemented. Pope (2002), and Harvey (2002), recently propose LTFTR auctions for the New York ISO that provide a hedge against congestion cots. Gribik et al (2002) propose an auction method based on the physical characteristics (capacity and admittance) of the transmission network.

11 As shown in an extensive body of literature, generators can better exert local power when the transmission network is congested. See Bushnell, 1999, Bushnell and Stoft, 1997, Joskow and Tirole, 2000, Oren, 1997, Joskow and Schmalensee, 1983, Chao and Peck, 1997, Gilbert, Neuhoff, and Newbury, 2002, Cardell, Hitt, and Hogan, 1997, Borenstein, Bushnell, and Stoft, 1998, Wolfram, 1998, and Bushnell and Wolak, 1999.

realized capacity could be less than expected capacity so that revenue-adequacy condition is violated.

Loop Flows: As shown by Bushnell and Stoft (1997) for a network with loop flow, an addition in transmission capacity might have a negative social value. Additionally, the initially feasible FTR set can depend on random exogenous variables.

Information Asymmetries: The separation of transmission ownership and system operation in the FTR model creates a moral hazard "in teams" problem. For example, an outage can be claimed to result from poor line maintenance (by the transmission owner) or from imprudent dispatch (by the system operator). Moreover, since transmission investment is not static in reality, there is no perfect coordination of interdependent investments in generation and transmission. In fact, stochastic changes in supply and demand conditions imply uncertain nodal prices. In addition, equal access to investment opportunities is not a good assumption because deepening investments of the incumbent's network can only be efficiently implemented by the incumbent.

Hogan (2002b) analyzes the implications of loop flows on transmission investment raised by Bushnell and Stoft (1997). Hogan makes a preliminary attempt to analytically provide some general axioms to properly define LT FTRs. Hogan's model relies on an institutional structure where there are various established agents (generators, Gridcos, marketers, etc.) interested in the transmission grid expansion. Under an initial condition of non-fully allocation of FTRs in the grid, the awarding of incremental LT FTRs should satisfy the following basic criteria:

1. An LTFTR increment must keep being simultaneously feasible (*feasibility rule*)12.
2. An LTFTR increment remains simultaneously feasible given that certain currently unallocated rights (or proxy awards) are preserved.
3. Investors should maximize their objective function (*maximum value*).
4. The LTFTR awarding process should apply both for decreases and increases in the grid capacity (*symmetry*).

As shown by Bushnell and Stoft (1996) and Bushnell and Stoft (1997), under these conditions allocation of new PTP-FTR obligations will not reduce social welfare. Hogan explains however that defining proxy awards is a difficult task. One possibility would be to define every possible use of the current grid

12 A set of FTRs is simultaneously feasible if the associated net power flows are also simultaneously feasible.

as a proxy award. However, this would imply that any investment beyond a radial line would be precluded, and that incremental award of FTRs might require adding capacity to every link on every path of a meshed network.

A better possibility would be then to define as a proxy award the best use of the current grid along the same direction that the (positive or negative) incremental FTR was awarded. "Best use" could be defined in terms of a preset proxy references so that proxy awards maximize the value of such references. Another possibility is to define "best" in terms of the maximum value of investors' preferences.

Then, given a proxy rule, an auction is carried out in order to attract investment for transmission expansion. In case the investors' preference criterion is chosen, the auction model maximizes investors' preferences to avoid LTFTRs in the direction of the expansion subject to the simultaneously feasibility conditions and the "best" rule.

Notwithstanding, Hogan (2003) recognizes that LTFTRs only provide efficient results under assumptions of no existence of market power and non-lumpy marginal incremental expansions of the transmission network. He then believes that regulation plays an important role in the development of large and lumpy projects, and in mitigation of market power abuse.

Hogan's response to contingency concerns is twofold.13 On one hand, only contingency conditions that are outside the control of the system operator could lead to revenue inadequacy of FTRs, but such cases do not describe the most important contingency conditions. On the other hand, most of the remaining contingencies are foreseen in a security-constrained dispatch in a meshed network with loops and parallel paths. If one of "n" transmission facilities were lost, the remaining power flows would still be feasible in an "n-1" contingency constrained dispatch.

Hogan (2003) recognizes that information asymmetries and agency problems are present in a reformed electricity industry with an ISO, independent transmission providers and decentralized market players. However he believes that the main issue on transmission investment is deciding the boundary between merchant and regulated transmission expansion projects. It is not clear to him how asymmetric information can affect such a boundary.

The second alternative to electricity transmission expansion seeks to solve the transmission expansion problem through regulation only and within a different institutional framework through. System operation and ownership of the transmission company are carried out by a "Transco" that is regulated through benchmark or price regulation so as to provide it with incentives to

13 See Hogan (2002a), Hogan (2002b), and Hogan (2003)

invest in the development of the grid, while avoiding congestion. Léautier (2000), Grande and Wangesteen (2000), and Harvard Electricity Policy Group (2002b) propose mechanisms that compare the Transco performance with a measure of welfare loss due to its activities. Joskow and Tirole (2002) propose a surplus-based mechanism to reward the Transco according to the redispatch costs avoided by the expansion, so that the Transco faces the entire social cost of transmission congestion.

Another regulatory alternative is a two-part tariff cap that solves the opposite incentives to congest the existing transmission grid in the short run, and to expand it in the long run (see Vogelsang 2001). Incentives for investment in network expansion of are achieved through the rebalancing of the fixed part and the variable part of the tariff. This approach tries to deepen into the analysis of the cost and demand functions for transmission services, which are not very well understood in the literature. However, in order to carry out this task, it has to assume a monotonic increasing behavior of the transmission cost function. As argued by Hogan (2002b), this assumption is not in general valid since an expansion in a certain transmission link can derive in a total decrease of the network capacity. Additionally, in order to study the cost and production characteristics of a Transco, Vogelsang finds it useful to define the Transco's output (or throughput). As argued in the FTR literature (Bushnell and Stoft, 1997, Hogan, 2002a, Hogan, 2002b), this problem is very difficult since the physical flow through a meshed transmission network cannot be traced due to its multi dimensionality.

The third alternative method for transmission expansion seeks to derive optimal transmission expansion from the power-market structure of electricity generation, and considers conjectures made by each generator on other generators' marginal costs due to the expansion (see Sheffrin and Wolak 2001, Wolak 2000, and London Economics International 2002). The basic idea is to estimate the generator's bidding behavior before and after a transmission upgrade. This method also uses a real-option analysis to derive the net present value of both transmission and generation projects through the calculation of their joint probability.

The results of this model show that benefits of transmission expansion are small until added capacity surpasses a certain upper limit that, in turn, is determined by the possibility of induced congestion by the strategic behavior of generators with market power. Transmission expansion will only yield benefits until it is large enough with respect to a given generation market structure. The addition of cost uncertainty (due to environmental factors and local opposition to transmission projects) implies that many small upgrades are preferable to large greenfield projects.14

14 See London Economics International (2002), chapters 3 and 5.

The main contribution of this approach is that it explicitly models the existing interdependence of generation investment and transmission investment. However, this approach relies on a transportation model with no network loop flows. As argued by Hogan (2002a), the use of a transportation model in the electricity sector is not adequate because it does not consider discontinuities in transmission capacity due to the multi-dimensional character of a meshed network.

Incentive Pricing for the Mexican Electricity Transmission System

In last section we analyzed different models for a structure of incentives for long-term investment in a transmission network. With the exception of the Vogelsang's two-part tariff mechanism (Vogelsang, 2001), the three alternatives propose different general approaches that do not provide implementation details as to the specific type of pricing for transmission services.

For example, the LTFTR option is a way to hedge consumers from nodal price fluctuations in the long run. However, as argued by Pérez-Arriaga et al (1995), revenues from nodal prices only permit to recover 25% of total costs. Therefore, LTFTRs should be complemented with a certain fix pricing structure or, as in Rubio-Odériz and Pérez-Arriaga, 2000, a complementary charge that permits recuperation of fixed costs.15 This fact is recognized by Hogan (1999) who believes that complete reliance on market incentives for transmission investment is undesirable. Rather, Hogan (2003) argues that merchant and regulated transmission investments might be combined so that regulated transmission investment is limited to projects where investment is "large" relative to market size, and "lumpy" so that it only makes sense as a single project as opposed as many incremental small projects.

Pricing for electricity transmission should satisfy certain desirable properties that are consistent with the regulatory scheme that supports it. A set of relevant principles is provided in Transpower (2002). A first principle is that pricing for the different cost components of transmission should not conflict with each other (integrated approach). So, sunk and fixed costs should be allocated in such a manner that they do not preclude the variable charge from

15 In the US, transmission fixed costs are recuperated through a regulated fixed charge, even in those systems that rely on nodal pricing and FTRs. Typically, this charge is regulated by a cost of service methodology.

reflecting nodal prices.16 Likewise, new investment costs should be allocated to the beneficiaries of such new investment.17

A second principle is that the allocation of sunk and fixed costs should not distort production and consumption schedules or investment decisions. In other words, fixed cost allocation should not reduce social welfare. A third property is that variable costs are based on marginal costs. In a system where a power flow model is used to determine nodal prices, variable charges should be determined by nodal price differences that reflect (short run) transmission congestion. A fourth principle is that transmission charges must preclude cross subsidies.

In the remaining of the present section we concentrate on transmission pricing methods applied to the Mexican transmission network within the context of these guiding principles. In 4.1 we review a proposal based on the "benefit factors" approach. In 4.2 we propose our own model that is further applied to the Mexican transmission grid. Such a model derives from the regulatory alternative (second alternative) described in section 3.

The Benefit-Factors Approach

Instituto de Investigaciones Eléctricas (2003) proposes a method for calculating CFE's transmission charges based on the benefit-factors method of Rubio-Odériz and Pérez-Arriaga (2000).18 Assuming the existence of a nodal pricing system, Rubio-Odériz and Pérez-Arriaga (2000) propose to base the complementary charge according to the economic benefit that each transmission network facility causes to each agent. For a consumer, the benefit is measured as the reduction in its total electricity charges before and after a new transmission corridor is added, while for a generator it is the increment in its profits. Rubio-Odériz and Pérez-Arriaga only consider positive benefits (no agent can receive a payment for a negative benefit).

Under this approach, the total allowed transmission revenue is annually determined and regulated, typically by the regulatory agency. The calculation of this amount considers both the capital, operation and maintenance costs of the existing transmission infrastructure, as well as the cash flow necessary to cover the expansion costs to meet demand from future generators and consumers (demand is also forecasted during the planning process).19 Regulation of the annual revenue is accompanied by regulation of the quality

16 For Transpower (2002) sunk costs are basically capital costs that are "unavoidable" in the long run, while fixed costs are operating and maintenance costs that are "avoidable" in the long term.

17However, Bushnell and Stoft (1997), and Hogan (2002b) show that the definition of the beneficiaries of a transmission expansion is not an easy task.

18 This method is design for consumers above a tension of 69 KV.

19 In 2000, the CFE's monthly total transmission revenue was around USD 0.5 billion.

of transmission services. The authorized annual revenue is monthly disaggregated by transmission corridor.

The variable part of the authorized revenue is recovered through a variable charge that is directly determined by the difference in nodal prices, and it is merely a congestion charge. The "complementary" part of the authorized revenue is equal to the total authorized revenue less the variable-charge revenue. The complementary amount is recovered through the complementary charge according to the particular benefit that each consumer obtains through network expansion.

Some assumptions of this model might be criticized. In first place the non-negative-benefits assumption. The authors consider this assumption as valid because "…normally, an agent with negative benefit would have market power (due to network constraints) without the line being considered for complementary charge".20 However, Hogan (2002b) show that negative benefits could sometimes occur due to the power flow nature only. Likewise, Hogan (2002a) shows that the assumption of no negative benefits could violate the "Revenue Adequacy" condition of congestion management through FTRs. This property is in fact implied by simultaneous feasibility of electricity flows. These issues are somewhat recognized by Rubio-Odériz and Pérez-Arriaga (2000) in their concluding last paragraph.

Additionally, there seems not to exist an objective way to determine the complementary charge, especially for long-term transmission projects. The problem of how to determine the beneficiaries of a certain transmission expansion project is as subjective as the "joint-cost" allocation dilemma. More importantly, the authors of the benefit approach develop an ad-hoc mechanism and do not seem to resolve the proxy-award issue raised by Hogan (2002b). In this sense, they do not comply with the Transpower's second principle for electricity transmission. Namely, that transmission pricing should not reduce social welfare. Examples can be shown where a certain transmission expansion project (such as the building of a parallel line) and its subsequent complementary charge could diminish total transmission capacity and, hence, reduce social welfare (see Bushnell and Stoft, 1997, and Hogan, 2002b).21 Even more, an annual determination of the transmission revenue could in practice be at odds with the determination of the net present value of long-term transmission projects.

20 See Rubio-Odériz and Pérez-Arriaga (200), p. 451.

21 In such a case, reduction of social welfare could only be reverted by making the agent that generates the negative externality (the one that expands the transmission network) pay to the affected agents (those holding original FTRs). See Bushnell and Stoft (1997).

A Combined Merchant-Regulatory Mechanism for Electricity Transmission Expansion

We now propose an alternative pricing scheme for the Mexican transmission network. Building on Hogan (2002b) and Vogelsang (2001) we propose a pricing regulatory method in the context of a combined merchant-regulatory mechanism for electricity transmission expansion. As discussed in section 3, there is not yet in theory or practice a single mechanism that guarantees an optimal expansion of the electricity transmission network. However, the distinct study efforts suggest a second-best standard that combines the merchant and the regulated transmission models, so that “small” transmission expansion projects rely on the merchant approach while “large and lumpy” projects are developed through incentive regulation.

Figure 1 suggests that an LTFTR method could be used “inside” the 32 transmission regions of the country, while a price-cap rule could be applied to develop the large lumpy links among such regions. This approach could be used since the current CFE’s shadow market is already based on nodal pricing, the systems inside each of the 32 regions are relatively meshed, and the large links joining transmission regions are approximately node-to-node radial lines.22 The application of this method could later be adapted to a possible reform of the Mexican electricity market that allowed more competition from private players.

In this paper we concentrate our analysis on incentive regulation of the large links in figure 1. Given a “large” potential transmission expansion project (such as the one between regions 17 and 18 in figure 1), the ISO (CENACE) carries out a feasibility test to check out the redispatch impact of the project. The party interested in building such a link would decide to carry out the project given the price-cap constraint, and a “payback” constraint (as in Bushnell and Stoft, 1997) that would internalize the negative externalities generated for the expansion project.

Our modeling strategy in this paper is to abstract from loop-flow effects (and, thus, from the payback condition), so as to study two scenarios.23 One scenario is a hypothetical situation where there is a single two-node radial line that provides the transmission service in all the country. In this first scenario, a single firm would own the transmission network and would apply a uniform two-part tariff along the country.

The second abstraction would study a hypothetical situation where there are several radial transmission lines serving each of the nine electricity regions of the country. Each one of these systems would be physically separated from the other systems. In this second scenario, we analyze two

22 And also assuming this large links are DC lines only

23 Note also that through this modeling strategy we avoid (or delay) the difficult problem of defining the output of transmission under loop flows (as pointed out by Hogan, 2002b).

sub-cases. In the first, different firms that charge distinct variable and fixed fees with respect to the other regions would own the lines. In the second sub-case, a single firm would own each of the regional systems, and would charge the same variable fee across regions but with different fixed fees.

We carry out simulations for the Mexican transmission network using a price-cap regulatory method similar to Vogelsang (2001). Vogelsang shows that price structure regulation can be used to solve congestion problems of transmission lines, in the short run, as well as capital costs and investment issues, in the long run. He proposes a two-part tariff regulatory model with variable (or usage) charges, and fixed (or capacity) charges. The variable charge can be actually defined in terms of nodal prices. The transmission firm is a profit-maximizing monopolist that makes investment and pricing decisions subject to a regulation of its two-part tariff. The solution to this problem takes care of congestion problems through the variable charges. Recuperation of long-term capital costs is achieved through the fixed charge, while incentives for investment in expansion of the network are reached by a rebalancing of the fixed charge and the variable charge. Transmitted volumes for each type of service are used as weights for the corresponding different prices so that Transco's profits increase as capacity utilization and network expansion increases. In equilibrium, the rebalancing of fixed and variable charges depends on the ratio between the output weight and the number of consumers.24

We now concentrate our analysis on the firm's rebalancing of the fixed fee and the variable fee, and its subsequent impact on the firm's profits. Our, simulations are performed using the Newton method through progressive derivatives.25 Common assumptions in our distinct simulations are:

- A radial line links the production node with the consumption node.
- The inflation rate and the x efficiency adjustment factors are equal to zero.

[24] This pricing mechanism might be directly compared to the pricing mechanism in Rubio-Odériz and Pérez-Arriaga (2000). The latter bases benefits on last period's quantities, and calculates benefits as cost savings for consumers and revenue increases for generators. This is similar to the Slutzky approximations to welfare increases used in Vogelsang (2001). Also, the total amount to be distributed in the complementary charge could be based on last period's numbers, so that the Rubio-Odériz and Pérez-Arriaga mechanism would be a Vogelsang-Finsinger mechanism with weak cost-reducing and investment incentives (as in Vogelsang and Finsinger, 1979). However, if the complementary charge is based on current cost data it would produce zero profits and would therefore have no cost-reducing or investment incentives at all.

25 It is important to stress that we sometimes found local maximums that, even though they satisfied the constraints imposed to the model, they did not provide the optimal benefit for the regulated firm. We therefore review in detail all the data so as to make sure that a global maximum was reached.

- Operation costs are equal to zero.
- Previous periods transmission flows are used as Laspeyres weights

The period of analysis is 2001-2006. Year 2001 is the base year. The initial data for prices, electricity flows and necessary costs are obtained from this year. The analysis of rebalancing of fees is carried out for the 2000-2004 period. We also assume the following demand function:26 $D^{t+1} = (1+\alpha)D^t - \beta p^t$. This equation establishes a demand increase at rate α and it presents an inverse relationship between demand and prices. Another important assumption is that the firm is myopic with respect to profit maximization so that in each period it maximizes profits separately from the other periods.

Case 1: Monopolist with "postage stamp" fees

We analyze first a single firm that covers the whole country applying uniform fees. In the two cases that we present in this section, the transmission firm solves the following optimization problem:

$$\max \pi^t = p^t q^t + F^t N - C(q^t, K^t)$$

subject to (1)

$$(p^t q^W + F^t N^W) \leq (p^{t-1} q^W + F^{t-1} N^W)$$

$$p^t \geq 0, \qquad F^t \geq 0, \qquad F^t N^W \geq CF^t$$

where:

Ft = fixed fee in period t.

pt = variable fee in period t.

qt = real oriented energy flow in period t (in kWh).

Kt = available transmission capacity in period t.

26 For the estimation of the demand function, parameter β was obtained through a price-quantity regression. Parameter α was taken from estimations carried out by the Secretaría de Energía regarding the behavior of electricity demand, both at the national level as for each of the regions included in the national electricity system.

w = type of weight27.

N = number of consumers

CF = fixed costs

The transmission cost function c(q,K) reflects the sunk cost nature of transmission investment and has the following form:

$$C(q^t, K^{t-1}) = C(q^{t-1}, K^{t-1}),\ \forall\ q^t, q^{t-1} \leq K^{t-1}$$

$$C(q^t, K^t) = C(q^t, K^{t-1}) + f(K^{t-1}, I^t),\ for\ q^t > K^{t-1}$$

where

$$I^t = K^t - K^{t-1}$$

With respect to Vogelsang (2001), the following restrictions have been added:

The fixed fee and the variable fee must be non-negative.

Income from the fixed fee must be greater than or equal to fixed costs at each period.

The transmission firm must make the needed investments in each period so as to cover the difference between transmission capacity of the previous period, and transmission demand in the current period.

Additionally, we assume in this section that there is a single radial line in all the country. Its cost function is composed by fixed costs (that depend of the transmission capacity in period t-1,) and by investment costs. When qt ≤ Kt-1, investment costs are zero. Values corresponding to fixed costs, and investment costs were taken from Comisión Federal de Electricidad (2000).28

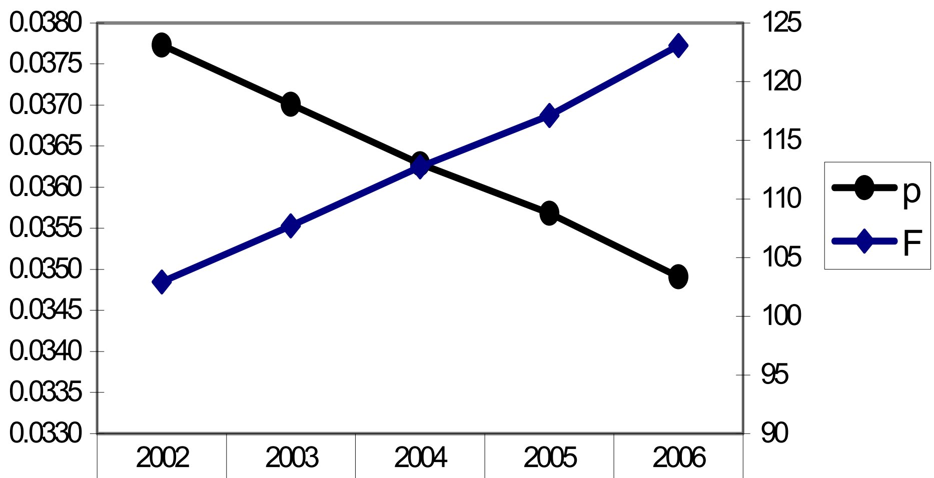
27 We use Laspeyres weights for our simulation.
28 Annex 2 presents a summary of these data.

Fixed number of consumers

In this subsection we assume a fixed number of consumers over the study period. Consumers might increase their demand for transmission services. We model, for example, the case of several established distribution companies whose number does not grow but their demand for transmission service does.

Figure 4 presents the optimal values of the simulation for fixed fees and variable fees. The fixed fee represents the amount charged to each consumer. The restriction on the fixed fee is binding in all periods. As shown in table 4, transmission capacity increases 42,927 MWh, and the length of transmission lines increases 10,165 kilometers.

Figure 4
Rebalancing of fixed fees and variable fees (fixed number of consumers).
p=variable fee; F= fixed fee
(2001 pesos per KWH)



	2002	2003	2004	2005	2006
p	0.0377	0.0370	0.0363	0.0357	0.0349
F	102.94	107.69	112.73	117.13	123.07

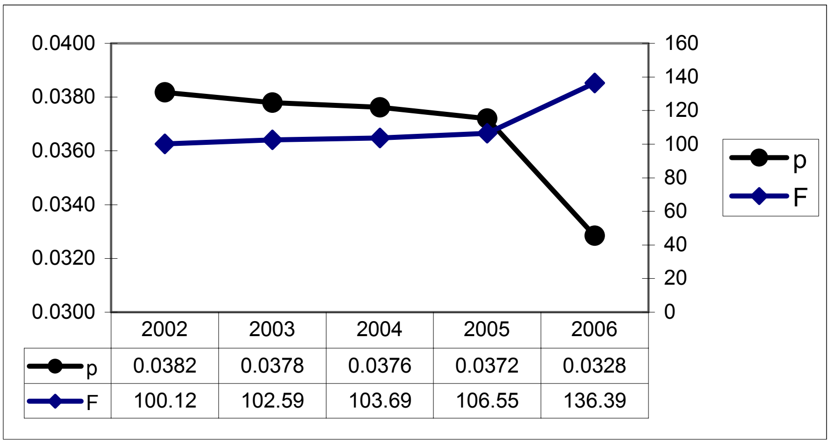
Table 4
Monopolist with "postage stamp" fees and fixed no. of consumers:
Profits, capacity and expansion of the transmission network

Year	Profits (1999 pesos)	Transmission Capacity (MWh)	Length of transmission lines (Kilometers)
2002	3,942,895,867	164,774	39,020.9
2003	3,971,421,490	172,824	40,927.1
2004	3,995,992,170	181,381	42,953.6
2005	4,018,819,838	190,470	45,106.1
2006	4,033,832,898	200,131	47,393.8

Variable number of consumers

We now assume that the number of consumers increases 3.1% every year.29 Figure 5 presents the results for the rebalancing of the fixed fee and the variable fee. As shown in table 5, transmission capacity increases 42,816 MWh, and the length of the transmission network increases 10,139 kilometers. It can also be noted that profits increase year by year since, as the number of consumers grows, the firm will have more possibilities for rebalancing the fixed and variable fees.

Figure 5
Rebalancing of fixed fees and variable fees (fixed number of consumers).
p=variable fee; F= fixed fee
(2001 pesos per KWH)



29 This consumer growth rate is equal to the country's growth rate in dwellings. It has been recently used by the Secretaría de Energía in its forecast studies. See Secretaría de Energía (2002), p. 56.

Table 5

Monopolist with "postage stamp" fees and variable no. of consumers: Profits, capacity and expansion of the transmission network

Año	Profits (1999 pesos)	Transmission capacity (MWh)	Length of transmission lines (kilometers)
2002	4,029,084,977	164,754	39,016.1
2003	4,149,449,558	172,768	40,913.8
2004	4,277,271,353	181,261	42,925.2
2005	4,405,660,628	190,275	45,059.9
2006	4,471,645,358	200,020	47,367.6

Case 2: A single transmission firm for each electricity area

In this section we assume there exists one regional transmission company for each of the five areas in the national electricity system. Each company is a regional monopoly and does not have any relationship with the rest of the transmission companies. That is, we assume there are no interconnections among the different electricity areas, and that each area has its own power generators that satisfy demand increases within the area. We also assume that transmission networks within each area are radial lines. Each transmission company solves program (1) within its area. There are now different increments in demand given by the Secretaría de Energía forecasts.30 Transmission capacity per area in for the 2002-2006 period is presented in table 6.

There is a conglomerate of distribution companies per each of the areas of the national electricity system. There are 32 distribution companies, and this number remains constant from one regulatory period to the other. Table 7 presents the existing distribution companies for each of the electricity areas, as well as their respective demand growth rates.

Figure 6 presents the distinct variable fees charged by the regional transmission companies. Such fees show a decreasing linear tendency. Table 8 presents the different fixed fees applied to each one of the distribution companies in each area. Fixed fees are different among distinct areas because the number of consumers and their demand also differs. The fixed charge is inversely proportional to the number of consumers; the less the number of consumers the greater the fixed charge. Likewise, constraints on the fixed charge remain binding in each case.

30 See Secretaría de Energía (2002).

Profits for each firm increase as well as capacity. Annual average growth rate of profits for all regional companies is greater than the one obtained for a monopolist with postage stamp prices (see table 9).

Table 6
Maximum transmission capacity per area MW, 2002-2006

		2002				
	NO	**NE**	**CO**	**CENTRO**	**SS**	**total**
NO	1156	140	55	0	0	1351
NE	140	3161	400	0	357	4058
CO	55	400	3418	1966	170	6009
CENTRO	0	0	1966	0	4945	6911
SS	0	357	170	4945	6432	11904
total	1351	4058	6009	6911	11904	

		2003				
	NO	**NE**	**CO**	**CENTRO**	**SS**	**total**
NO	1528	140	109	0	0	1777
NE	140	3662	863	0	1000	5665
CO	109	863	3059	2018	174	6223
CENTRO	0	0	2018	0	95	2113
SS	0	1000	174	95	0	1269
total	1777	5665	6223	2113	1269	

		2004				
	NO	**NE**	**CO**	**CENTRO**	**SS**	**total**
NO	1808	322	282	0	0	2412
NE	322	3971	1832	0	1000	7125
CO	282	1832	3101	2035	174	7424
CENTRO	0	0	2035	0	5418	7453
SS	0	1000	174	5418	9364	15956
total	2412	7125	7424	7453	15956	

		2005				
	NO	**NE**	**CO**	**CENTRO**	**SS**	**total**
NO	1836	365	230	0	0	2431
NE	365	4382	2179	0	1000	7926
CO	230	2179	3147	1982	190	7728
CENTRO	0	0	1982	0	5689	7671
SS	0	1000	190	5689	8719	15598
total	2431	7926	7728	7671	15598	

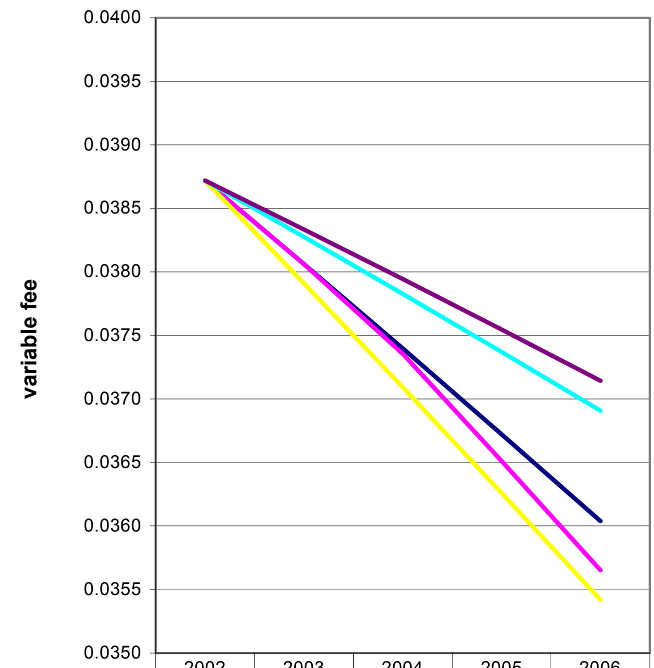
		2006				
	NO	**NE**	**CO**	**CENTRO**	**SS**	**total**
NO	1806	414	1035	0	0	3255
NE	414	4460	4173	0	1000	10047
CO	1035	4173	2795	2309	194	10506
CENTRO	0	0	2309	0	5570	7879
SS	0	1000	194	5570	8264	15028
total	3255	10047	10506	7879	15028	

Table 7
Distribution companies and demand growth

Region	*No. of distribution companies*	*Demand growth rate*
Northwest	10	5.6
Center-West	5	5.6
Northeast	7	6.7
Center	1	4.1
South-Southeast	9	3.7

*Source: * Secretaria de Energía (2002)*

Figure 6
Variable fee per area (2002-2006)



	2002	2003	2004	2005	2006
Noroeste	0.0387	0.0381	0.0374	0.0367	0.0360
Centro-occidente	0.0387	0.0381	0.0374	0.0365	0.0357
Noreste	0.0387	0.0379	0.0371	0.0363	0.0354
Centro	0.0387	0.0383	0.0378	0.0374	0.0369
Sur-sureste	0.0387	0.0383	0.0379	0.0375	0.0371

Table 8
Fixed fee per distribution companies (2002-2006)
(2001 pesos)

REGION / YEAR	*2002*	*2003*	*2004*	*2005*	*2006*
Northwest	31,296,289.9	32,700,628.6	34,189,512.9	35,767,760.4	37,440,454.6
Center-West	106,691,620.1	111,479,125.7	116,880,510.5	123,594,822.2	130,783,986.7
Northeast	87,298,224.1	92,175,782.61	97,400,425.42	102,995,685.2	108,986,655.6
Center	626,430,086.1	645,143,036.1	664,703,017.4	685,145,915.9	706,509,060.8
South-Southeast	35,221,909.7	36,133,183.9	37,082,076.5	38,070,036.5	39,098,565.3

*Source: * Secretaria de Energía (2002)*

Table 9
Profits per area (2001 pesos)

REGION/YEAR	*2002*	*2003*	*2004*	*2005*	*2006*
Northwest	547,671,236	553,803,306	559,664,969	565,189,518	570,303,318
Center-West	948,616,026	958,408,358	967,599,919	975,618,425	982,632,539
Northeast	951,968,458	959,962,574	966,567,559	971,510,034	974,485,500
Center	1,199,421,100	1,216,103,487	1,232,706,342	1,249,183,936	1,265,486,848
South-Southeast	659,145,496	665,640,655	672,189,658	678,781,749	685,405,164

*Source: * Secretaria de Energía (2002)*

Case 3: Monopolist with discriminatory tariffs

In this subsection we analyze the behavior of a single independent transmission company that operates in all the areas of the national electricity system, but that can discriminate the prices it applies in each of the areas. The Baja California and South Baja California regions are not included because these regions are not physically interconnected with the rest of the country's transmission network.31

31 The regional tariffs of last section would apply to these two regions.

The transmission firm now solves the problem:

$$\max \quad \pi^t = p^t q^t + F^t N - C(q^t, K^t)$$

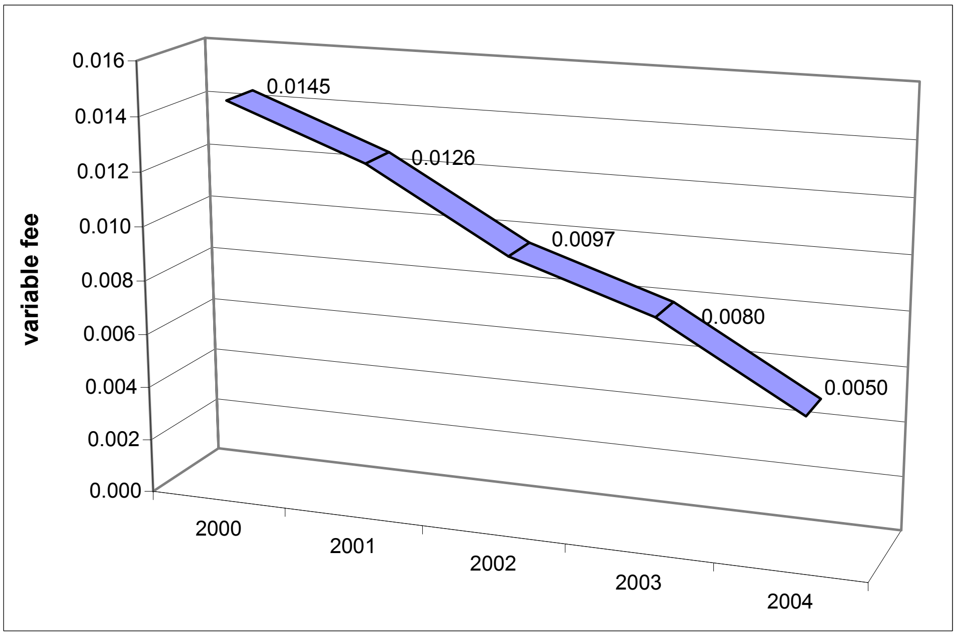
subject to (2)

$$\sum_i p_i^t q_i^W + \sum_h F_h^t N_h^W \leq \sum_i p_i^{t-1} q_i^W + \sum_h F_h^{t-1} N_h^W$$

$$p_i^t \geq 0, \qquad F_h^t \geq 0, \qquad F_h^t N^W \geq CF_h^t$$

In the new restriction of this problem, the sub-index of the fixed charge runs over consumer groups in each area. In each different transmission region the same variable charge is applied but with different fixed charges. That is, the firm uses a discriminatory two-part tariff for differentiated goods where product differentiation arises from different consumer groups in each area. Figure 7 presents the uniform variable fee for all the transmission areas.

Figure 7
Variable fee for a monopolist with discriminatory tariffs (2002-2006)
(2001 pesos)



As in previous cases, we observe that the variable charge has a decreasing tendency. The difference is that such a tendency is no longer linear.

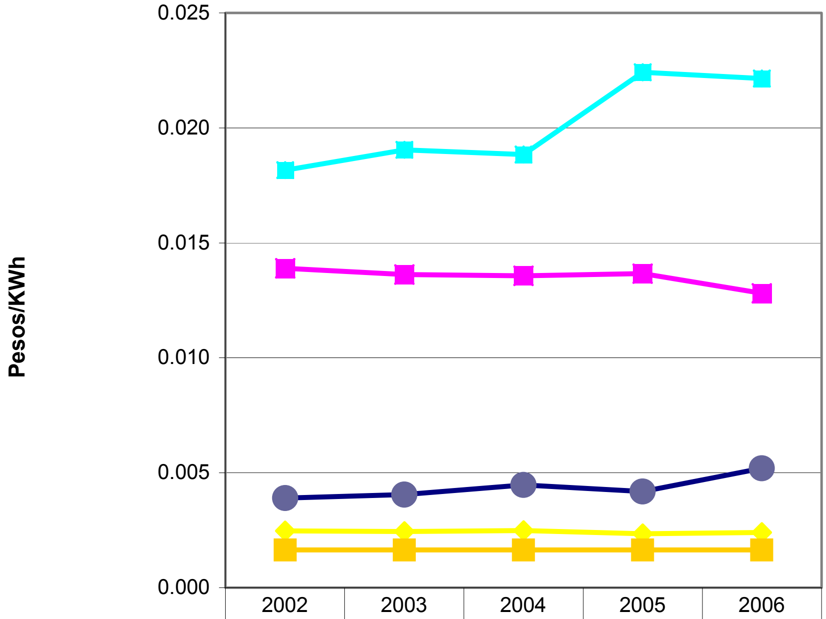
Additionally, the variable charge in this case is lower than in the previous cases. Another relevant result is that, in all the analyzed areas, investment obtained through a single monopoly that permits pricing discrimination is lower than in the other cases.

Figure 8 presents the data for fixed charges in each area. The constraint over the fixed charge is binding in each of the areas that have a larger increase in demand an, hence, face greater investment challenges. Fixed charges remained at lower levels than those corresponding to discrimination in both parts of the tariff.

Table 10 makes a comparison of all the four cases of the simulation in terms of profits, capacity increase, and network expansion. Case 1 clearly provides the best results in terms of transmission capacity increase and transmission expansion, while case 2 results in larger profits. This means that the price-cap regulatory method provides the best network expansion results when a single firm owns the transmission network and charges an even two-part tariff across the country.32 A policy planner seeking to maximize welfare might then prefer this solution to the case of making a partition of the network into five firms, given that the profits obtained under this last case are only relatively slightly higher than in case 1.

32 This result might contradict studies that foresee better welfare results for a firm that is allowed to charge discriminatory two-part tariffs (as in Bertoletti, P., and C. Poletti, 1997). However, the myopic profit-maximizing nature of our model explains the possibility of such a result. It then remains as a future research question the behavior of a non-myopic firm under our proposed price cap.

Figure 8
Fixed charge per area for a monopolist with discriminatory tariffs
(2002-20011)
(2001 pesos)



	2002	2003	2004	2005	2006
Noroeste	0.00390683	0.00405370	0.00447672	0.00418971	0.00519390
Centro-occidente	0.013893	0.013622	0.013568	0.013658	0.012802
Noreste	0.0024684	0.0024487	0.0024903	0.0023544	0.0024025
Centro	0.0181640	0.0190486	0.0188444	0.0224148	0.0221432
Sur-sureste	0.0016445	0.0016434	0.0016418	0.0016409	0.0016395

Table 10
Comparisons in profits, capacity, and network expansion for the four cases

	Total Profits (pesos)	Capacity increase (MWh)	Network expansion (Kilometers)
Case 1 fix no. consumers	26,049,682,377	42,927,045,660.01	10,165.7231
Case 1 var. no. consumers	27,419,831,988	42,816,298,038.15	10,139.4966
Case 2	28,061,340,345	37,427,028,092.75	8,863.2423
Case 3	5,920,638,442	28,644,674,371.59	7,236.4919

Concluding Remarks

We proposed a pricing method for incentives to expand the large interregional transmission links of the Mexican transmission network. This method must be understood within a combined merchant-regulatory framework where long term financial transmission rights are used within the 32 regions with meshed networks. The relatively radial nature of the interregional links makes sensible the use of the Vogelsang (2001) price-cap model. In this paper, we make an initial implementation assessment of this model under restrictive assumptions of no loop flow existence. Within the context of CFE's shadow market, our results suggest that the best institutional structure for expanding the Mexican transmission grid would be one of a single transmission firm that charges even tariffs along the Mexican territory.

We also discussed another pricing methodology based on the benefit-factors approach by Rubio-Odériz and Pérez-Arriaga (2000). Both this approach and ours seek different procedures to allocate the fixed cost of electricity transmission. The benefit factors approach defines a complementary charge in terms of the benefits to consumers from an expansion project, while our method relies in the rebalancing of the fixed and variable fees in order to provide adequate incentives for transmission investment. We believe that the former approach might violate the revenue adequacy condition of the FTR literature, does not consider discontinuities in transmission capacity due to loop flows, and presents serious implementation hurdles due to the subjectivity in the allocation of "benefits". We also recognize that our method is difficult to implement due to the difficulty in defining the electricity transmission output (or throughput).

We however showed that if combined with a merchant structure, based on long term financial transmission rights, our two-part tariff regulatory model could promote network expansion. This assertion must still be demonstrated in future studies where the issue of loop flows is handled by an independent system operator that requires a payback constraint from the builders of the large regulated projects. This could be achieved through simulations for the actual links of the electricty regions together with a detailed definition of the importing and exporting areas. Another possibility could be to redefine the Vogelsang's model so that the output of transmission is specified according to the implied FTRs of new transmission links. The variable charge would then depend on nodal price differences, and the fix (access) charge would be defined according to new transmission consumers.

ANNEX 1

According to the MW-Mile method used by CFE, the Transmission price for tensions greater than or equal to 69 Kv is given by:

$$Maximum\{(\text{Fixed cost} + \text{variable cost}), \text{minimum O \& M cost}\} + \text{Administrative costs}$$
(A.1.1)

A. Fixed cost is the sum of
+ cost for the use of the transmission infrastructure +
+ transmission cost associated to power losses in transmission+
+ generation costs implied by power losses in transmission.

These last terms are given by the following equations:

Cost for the use of the transmission infrastructure (CTser)

$CT_{ser} = CT^{*}r_{ser}$

$$r_{ser} = \frac{\max\left\{(\sum_{j\in J} w_j(fcon_j - f\sin_j),0\right\}}{\left[\max\left\{\left(\sum_{j\in J} w_j(fcon_j - f\sin_j\right),0\right\} + \sum_{j\in J} w_j f\sin_j\right] +}$$

where:

CT = long-run total incremental cost of the network

w_j = cost per unit of capacity of transmission link j

$fsin_j$ = the maximum power flow in link j (in absolute value) between the peak demand and the minimum demand scenarios, when the demanded transmission service is NOT considered

$fcon_j$ = the maximum power flow in link j (in absolute value) between the peak demand and the minimum demand scenarios, when the demanded transmission service is considered

$J =$ set of transmission elements that operate at tensions greater than or equal to 69 Kv (calculation of power flows is carried out in an AC model)

Transmission cost associated to power losses in transmission

$$\sum_v \sum_a CMCtrans_{va} * \Delta Pser_{va}$$

where:

$\sum_v \sum_a CMCtrans_{va}$ is the monthly cost of transmission capacity for tension level "v", in region "a"

$\Delta Pser_{va}$ is the increment (or decrease) in losses at tension level "v", in region "a", due to the demanded transmission service. It is given by:

$$\Delta Pser_{va} = \sum_{j \in J_{va}} Pcon_j - \sum_{j \in J_{va}} P\sin_j$$

where:

$Pcon_j$ is the maximum power loss in the transmission element "j", between the peak demand and the minimum demand scenarios, when the demanded transmission service is considered

$Psinj$ is the maximum power loss in the transmission element "j", between the peak demand and the minimum demand scenarios, when the demanded transmission service is NOT considered

J_{va} set of transmission elements at tension level "v", in region "a"

Generation costs implied by power losses in transmission

$$CMCgen * \sum_v \sum_a \Omega ser_{va}$$

$CMCgen$ Is the monthly capacity cot of generation

Ωser_{va} is the increment (or decrease) in losses at tension level "v", in region "a", due to the demanded transmission service, estimated at peak demand. It is given by:

$$\Omega ser_{va} = \sum_{j \in J_{va}} Pmcon_j - \sum_{j \in J_{va}} Pm\sin_j$$

$Pmcon_j$ is the power loss in the transmission element "j", which results from the peak demand scenario, when the demanded transmission service is considered

$Pmsin_j$ is the power loss in the transmission element "j", which results from the peak demand scenario, when the demanded transmission service is NOT considered

J_{va} set of transmission elements at tension level "v", in region "a"

B. The variable cost (CVUR) in A.1.1 is given by:

$$CVUR = FC\left[\sum_{a}\sum_{t}^{N_a}\sum_{v} ENER_{atv} * \Delta ES_{atv}\right]$$

FC is the transmission load factor observed during the billing month; it is given by:

$$FC = \frac{EP}{24 * nd * PC}$$

EP is the energy transmitted to all the load nodes of the demanded transmission service, during the billing month

nd is the number of days during the billing month

PC is the transmission capacity for all the load nodes

$ENER_{atv}$ is the energy cost in period "t", in region "a", at the tension level "v"

ΔES_{atv} is the increment in transmission losses, due to the demanded transmission service, in period "t", in region "a", at the tension level "v". It is given by:

$$\Delta ES_{atv} = T_{at} * \left(\sum_{j \in N_a} Pcon_{je_t} - \sum_{j \in N_a} P\sin n_{je_t} \right)$$

T_{at} is the number of hours in period "t", in region "a"

$Pcon_{je_t}$ is the power loss in transmission element "j", in the demand scenario "et", of the period "t", when the demanded transmission service is considered

$P\sin n_{je_t}$ is the power loss in transmission element "j", in the demand scenario "et", of the period "t", when the demanded transmission service is NOT considered

Na is the number of periods in region "a"

C. The minimum operation costs (CMIN) in A.1.1 are given by:

$$CMIN = m*ETPR$$

where:

CMIN is the minimum cost for the demanded transmission services

ETPR is the energy transmitted measured at the load nodes at tension levels greater than or equal to 69 Kv

M = mba*fad

Mba is the base charge in pesos per KWH. It is calculated as the quotient of annual O&M transmission costs of the previous year and the transmitted KWH through the network in the previous year fad is an distance adjustment factor and it is given by:

$$fad = \min\left\{\frac{|D_p|}{|D_s|}, 1\right\}$$

where:

$D_p = \dfrac{\sum_j |\Delta f_j| * l_j}{\sum_j |\Delta f_j|}$ is the equivalent distance of the transmission service (kilometers)

$D_s = \dfrac{\sum_j |\Delta f_j| * l_j}{\sum_j |f_j|}$ is the equivalent distance of the system (kilometers)

fj is the flow in the transmission element "j", calculated without including the transmission service

lj is the length of element "j" (1 for transformers)

Δf_j is the value of the change in the flow in the transmission element "j", to the demanded transmission service

ANNEX 2

Sells per area (GWh)

Area	1989	1991	1993	1995	1997	1998	1999
Baja California	3,640	3,849	4,129	4,870	6,184	6,347	7,020
South Baja California	610	634	626	691	845	863	944
Central	22,062	22,424	24,355	25,289	27,971	29,026	30,208
Northeast	13,479	14,760	16,274	18,675	22,209	23,746	25,629
Northwest	6,796	7,359	7,641	8,561	9,872	10,020	10,541
North	7,280	7,274	7,790	9,087	10,264	11,113	11,701
Occidental	16,966	19,572	21,376	24,389	27,986	29,724	31,724
Oriental	15,584	16,304	16,166	18,514	21,198	22,337	22,983
Peninsular	2,073	2,541	2,869	3,233	3,632	3,961	4,169
TOTAL	88,490	94,717	101,226	113,309	130,161	137,137	144,919

SOURCE: Secretaria de Energía, 2000.

Average unit cost per transmission line kilometer (2001 pesos)

Type of line	Direct cost	Direct cost plus indirect cost
400 kV two circuits, 3 phase conductors	3,873,088	4,376,590
400 kV one circuit, 3 phase conductors	2,159,550	2,440,291
400 kV two circuits, 2 phase conductors	2,976,352	3,363,278
400 kV two circuits, 2 phase conductors	1,689,926	1,909,616
230 kV two circuits, 1113 MCM	1,808,795	2,043,938
230 kV one circuit, 1113 MCM	1,119,235	1,264,736
230 kV two circuits, 900 MCM	1,653,380	1,868,319
203 kV one circuit, 900 MCM	1,031,639	1,165,752
115 kV two circuits, 795 MCM	1,331,443	1,504,531
115 kV one circuit, 795 MCM	850,744	961,341
115 kV two circuits, 477 MCM	1,096,962	1,239,567
115 kV one circuit, 477 MCM	729,271	824,076

Source: Comisión Federal de Electricidad, 2000.

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