Electricity Demand and Supply in Mexico

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August 21, 2002

1 Introduction

Wherever consumers obtain electricity supply from an integrated network, altering supply to any one consumer generally affects the cost of supplying remaining consumers connected to the network. In particular, an anticipated expansion of demand in one location could affect the type and level of capital investment in many parts of the network. This consideration is particularly important in a country such as Mexico that is likely to experience not only a rapid expansion in total demand for electricity over the next decade but also a geographical pattern of demand growth that differs somewhat from the historical experience.

In this paper, we first present a model for forecasting electricity demand in Mexico. The model has two components. Forecasts of the aggregate demand for electricity are derived by fitting a time series model to the aggregate production data. Using data disaggregated to the regional level we also estimate a model of regional demand shares. The two models are then combined to yield a forecast of demand at the regional level.

In section 3 of the paper, we present a simplified model of the Mexican electricity transmission network. We use the model to approximate the marginal cost of supplying electricity to consumers in different locations and at different times of the year. In the final section of the paper, we examine how costs and system operation will be affected by proposed investments in generation and transmission capacity and the forecast growth in regional electricity demands.

The analysis presented in the paper has implications for a number of critical policy issues. In particular, our model reveals that the marginal costs of supplying customers differ from electricity prices. Subsets of consumers are either being taxed or subsidized, albeit often in a hidden or implicit way. Since such taxes or subsidies affect the efficiency of resource use, they ought to be important to policy discussions regarding the electricity industry.

The marginal cost of supplying electricity in different locations or under different load conditions also has implications for how regulatory reform is likely to affect different types of customers and therefore the political feasibility of reform. The largest obstacle to such reforms is that they are likely to induce substantial cost reductions, primarily through the elimination of excess employment in the industry. Current employees in the industry therefore constitute a powerful vested interest opposed to reform. Altering the system so that prices more closely reflect marginal costs is also likely, however, to make some consumers worse off and they, too, are likely to oppose reform.

Our demand forecasts also raise some critical policy issues. They imply that large investments in the Mexican electricity industry will be needed over the next decade. If the electricity industry remained fully publicly owned, the government of Mexico would need to raise significant revenue to fund these investments. Mexico has many alternative valuable uses for scarce tax revenues, however, and most of these alternatives are far less amenable to private sector involvement than is electricity supply. It therefore is not surprising that the government has turned to the private sector to supply much of the needed generating capacity. The route the government has taken, however, is to rely on build, lease and transfer (BLT) projects. Under these schemes, the private sector builds the new plant, leases it under a long term contract with the government-owned utility, and ultimately transfers the plant to government ownership at a specified future date. This approach leaves the government firm in charge of operating the plant. It also leaves the government firm bearing all the risks associated with inaccurate forecasts of future electricity demand.

Another approach would be to reform and restructure the industry in a way that allows a competitive wholesale electricity market to develop. Private investors then would not only finance investments in the industry, but also would transfer risks from consumers to the capital markets where they can be borne more efficiently. The reforms would need to split the existing publicly owned firms into many separate firms to ensure that the industry remains competitive enough to protect the interests of Mexican consumers. The transmission, distribution and generation functions of the existing firms would also need to be separated. New entrants to the industry would not have any confidence that they could obtain non-discriminatory access to the transmission and distribution networks if the operator of that system continues to own generating plant.

Another advantage of developing a competitive wholesale market is that prices would more closely reflect the true marginal costs of supply. In particular, a competitive wholesale electricity market would eliminate cross-subsidies hidden in deviations between prices and marginal costs of service.

2 Forecasting regional electricity demands

Electricity demand is measured by the metered final consumption of end users. To supply power to consumers, however, generating plants also have to supply sufficient energy to compensate for the losses incurred in the process.[1] Hence, any forecast of power needs must take account of losses that in some cases are

[1] In the year 1999, for example, Mexican electricity consumption by sectors represented 144,922GWh, or about 80% of the total 180,977GWh produced in the country. Net imports of electricity into Mexico in 1999 were only 524GWh. Consumption within the generating plants was about 8,887GWh, or 5% of total production. The remaining 27,621GWh (approximately 15% of domestic production) represents transmission and distribution losses in the system and losses due to theft.

hard to identify. In particular, losses in Mexico arise not only from resistance losses on the transmission and distribution wires, but also from theft. The approach we take is to forecast total power generation. This implicitly assumes that there is a constant relationship between losses and total demand.[2]

2.1 Modeling aggregate electricity demand

The methodology used to make aggregate demand forecasts is based on the Chang and Martinez-Chombo (2002). The model is fit to total power generation data from Comisión Federal de Electricidad (CFE) over the period January 1987 to November 2001. Essentially, the logarithm of total power generation (Q) is related to GDP (y), the relative price of electricity (p), and a variable (z), based on temperature records, that accounts for seasonal variations. Details of the model and the estimated equations can be found in Appendix A.

2.2 Using the model to forecast aggregate demand

In order to use the estimated model to forecast electricity demand, we need to forecast the determinants, y, p and z. We use the average pattern holding over the sample period for the temperature variable z. To forecast y, we use the GDP growth forecast for 2002 and 2003 made by specialists and collected and reported by the Central Bank of Mexico.[3] Beyond 2003, we assume that the annual GDP growth rate converges gradually to an equilibrium level that gives an average growth of 5.2% for the rest of the decade. This is the average growth rate assumed by the CFE in its projections of electricity sales and has the virtue of making our forecasts more comparable to those of the CFE.[4]

In order to forecast p, we note that the Mexican government has a stated policy of applying a monthly adjustment to electricity prices that is aimed at compensating for the effect of inflation. In practice, the adjustments have not kept the relative price of electricity constant. Indeed, as we show in Appendix A, the relative price trends to drift over time. The rate of price adjustment has also varied for different types of customers.[5] Evidently, politics has played a role in setting electricity prices. Since we do not have a model of the political process, we simply assume that real electricity prices will fluctuate around the mean observed in the previous six years. We preserve the monthly seasonal component of p by estimating a regression (also presented in Appendix A) that allows the mean value of p to differ systematically from one month to the next.

[2]Given the lack of storability of electricity, the consumption of electricity (losses plus demand from agents) is always equal to its generation.

[3]Private Expectation Survey, Bank of Mexico, May 20, 2002. The consensus forecast is reported at http://www.banxico.org.mx/eInfoFinanciera/FSinfoFinanciera.html

[4]Secretaría de Energía. "Prospectiva del sector eléctrico 2001-2010". Page 96.

[5]Since January 2001, the montly adjustment for the residential sector has been 1.00526. This corresponds to an annual increment of 6.5%. For the service sector, the average monthly adjustment was 1.00682, yielding an annual increment of 8.5%. The adjustment factor for the electricity price charged to industry is indexed to the price of power generation fuels. This information was obtained from the CFE, http://www.cfe.gob.mx/www2/Tarifas

Table 1: Power needs forecast 2002 - 2010

	GDP	Total Power Generation			
		With price increase		Without price increase	
Year	Growth (%)	GWh	Growth (%)	GWh	Growth (%)
1991		118,348			
1992	3.54	121,604	2.75		
1993	1.94	125,864	3.50		
1994	4.46	137,684	9.39		
1995	-6.22	142,503	3.50		
1996	5.14	151,890	6.59		
1997	6.78	161,385	6.25		
1998	4.91	170,983	5.95		
1999	3.84	180,917	5.81		
2000	6.92	191,340	5.76		
2001	-0.38	191,340	-0.14		
2002	1.50	199,857	4.60	203,830	6.68
2003	4.30	207,724	3.94	215,895	5.92
2004	5.45	220,942	6.36	229,921	6.50
2005	5.91	234,428	6.10	244,585	6.38
2006	6.20	247,401	5.53	258,742	5.79
2007	5.96	260,008	5.10	272,487	5.31
2008	5.85	273,247	5.09	286,950	5.31
2009	5.90	288,510	5.59	303,660	5.82
2010	5.90	306,221	6.14	323,103	6.40
Average Growth Rates					
1991-2001	3.09		4.94		4.94
2001-2010	5.20		5.38		6.01
1991-2010	4.09		5.15		5.45

Note: The electricity price increase results from the reduction of subsidies to households. We calculate this will result in a 6.97% increase in p.

Substituting the forecast values of y, p and z into the estimated model, we arrive at the forecast of annual electricity demand in Mexico from 2002 to 2010 as reported in Table 1. Our model actually delivers monthly total power generation forecasts. These have been aggregated to yield the corresponding annual values. For some of the subsequent analysis, however, we will be interested in the monthly variations.

For comparison, we have included the results before and after the recent price adjustment that reduced federal subsidies in the residential sector. This one time increase in residential electricity prices is estimated to be around 30%.[6] To translate the residential price increase into an effect on p, we note that this sector represented 23.23% of total electricity sales over the last five years. Hence, the overall increase in electricity prices from the subsidy reduction will be about 6.97%. Our estimated model implies that a price increase of that magnitude will reduce the average annual growth rate of electricity generation in the period 2001-2010 from 6.01% to 5.38%, with the effects concentrated in the first two years.[7]

2.3 Forecasting regional demand shares

Mexico has large contrasts in climate, topography, resource availability, economic development and population density among its different regions. These contrasts have direct implications for the optimal siting of power generating plant and the distribution of electricity demand around the country. Regions with insufficient natural energy resources, underdeveloped infrastructure, or a large demand for power, are likely to import electricity generated elsewhere. Conversely, regions with substantial hydroelectric generating capacity, or substantial reserves of fossil fuels, are likely to have surplus power available for export. Differences in climates also mean that peak demands for electricity do not necessarily occur at the same time, allowing regions to save on generating capacity by exchanging power with neighboring regions.

To capture the regional differences in the Mexican electricity demand we began with data on electricity sales in the 14 administrative regions of the CFE. Although sales do not necessarily reflect demand,[8] they are likely to be a better indicator than local production. In most of the cases, regional power consumption will differ from regional power generation because of trading among regions through the transmission system. In order to link electricity supply and demand we also need to account for losses. In this section of the paper,

[6] According to a report in the newspaper *Reforma* on February 9, 2002, Banxico estimated the reduced subsidy would increase residential electricity prices by 30%.

[7] This estimated reduction in power needs is probably an upper bound. Although household electricity demand is likely to be more elastic than demand in the services sector (where lighting is the dominant use), it would be less elastic than demand in industry. Using the overall elasticity may thus overstate the responsiveness of demand to price. In addition, a price increase for households is likely to raise electricity losses through theft.

[8] Electricity demand and sales can differ because of billing lags and the theft of electricity. If the latter factors do not differ systematically across regions, however, the pattern of sales ought to approximate the geographic distribution of demand.

Figure 1: Administrative regions of the CFE

we compute and forecast regional sales shares as a first approximation to the regional power consumption. The next section focuses on estimation of the losses. The administrative regions of the CFE are illustrated in Figure 1.

To forecast regional sales, we hypothesized that sales *shares* would change only slowly through time as the relative industrialization and population growth rates shift from one region to the next. In particular, we estimated a set of equations that allowed the shares S_{it} of demand in region i in period t to vary from one month to the next and to grow at a declining or accelerating rate. Details of the modeling strategy are provided in Appendix A.

The regions with the highest (region 8) and second highest (region 10) positive growth in demand share both include suburban parts of Mexico City. The positive relative growth in both of these regions is, however, slowing down. By contrast, the third fastest growing region (region 4, the north gulf including Monterrey) has an accelerating growth rate. Baja California has an even stronger accelerating growth rate, although its current growth rate is below that of the north gulf. Other regions with a reasonably strong, and statistically significant, growing share of demand include Norte (region 3) and Golfo Centro (region 5), both of which border region 4. Unlike region 4, the growth rate of their demand shares is tending to decline, although the deceleration is not significant in region 3. The Yucatan peninsula (region 13), like region 3 has a positive but weakly decelerating growth in demand share.

The central Mexico City region served by Luz y Fuerza exhibits the strongest declining share of demand and there is little evidence that the trend is changing over time. Since this is already the most developed area in Mexico, it is not surprising that the market has relatively fewer opportunities to grow. The share of demand in region 11 (Sureste, the gulf coast east of Mexico City) is falling almost as fast as for Mexico City, but there is stronger evidence that the rate of decline is slowing. Region 7 (Jalisco) is the only other region with a strong and statistically significant declining share of demand, but it also reveals stronger evidence that the rate of decline is slowing.

The estimated monthly changes in shares (presented in Table 23 in Appendix A) allow the regions to be placed into groups with similar patterns of demand variation across months. Regions 1 (Baja California) and 2 (Noroeste) have a tendency to show smaller demand shares February–April and larger shares June–November. Regions 5 (Golfo Central) and 13 (Peninsula) also have significantly smaller demand shares February–April, but do not share the tendency of the two northwestern regions to have significantly higher demand shares in the second half of the year. Region 11 (Oriente), which lies between regions 5 and 13 on the Gulf coast, has demand shares that do not differ significantly from month to month. The remaining northern regions, 3 (Norte) and 4 (Golfo Norte) are like regions 1 and 2 in that they have significantly larger demand shares May–November, but they do not have significantly lower shares in first half of the year.

The remaining central (6, 9 and 14) and southern Pacific coastal (7, 8, 10, 12) regions tend to have smaller, not larger, demand shares in the second half of the year. In regions 7 (Jalisco), 10 (Centro Sur), 12 (Sureste) and 14 (Centro, Luz y Fuerza) the months with significantly lower demand shares last April–November. In regions 8 (Centro Occidente) and 9 (Centro Oriente) the period with significantly lower demand is only July–October. The northernmost of these regions, 6 (Bajio), only has a significantly lower demand share from August–November. Regions 6, 8 and 9 are also the only ones to have significantly larger demand shares in the early part of the year. In region 6 it lasts January–June, while in regions 8 and 9 the period of above average demand share is shorter, lasting February–April.

The estimated regional share model can be used to forecast demand shares by month and year. We can obtain an idea of how the different growth paths influence demand shares by examining forecast annual demand shares for 2005 and 2010. These are presented in Table 2. They suggest that by 2005 the demand in Golfo Norte will be approximately equal to, if not slightly above, the demand in the Mexico City area served by Luz y Fuerza. The share of the Luz y Fuerza region is expected to decline further by 2010. The regions surrounding Mexico City (Bajio, Centro Occidente, Centro Oriente and Centro Sur) will, however, all see growing shares of demand. Baja California, like Golfo Norte, is also likely to see a substantial increase in its share of demand by 2010.

We obtain a forecast of regional electricity demand by combining the overall demand forecast derived in the previous section of the paper with the forecasts of regional shares. Table 3 gives the resulting regional demands (in GWh annually) and total and average annual growth rates for demand in each region.

The substantial differences in forecast regional electricity demand growth rates may have important policy implications. A high overall rate of growth of demand for electricity will require substantial investment in the industry.

Table 2: Actual 1999 and forecast electricity demanad shares by administrative region (%)

	Region	1999	2005	2010
1	Baja California	5.83%	6.65%	7.39%
2	Noreste	7.09%	7.22%	7.13%
3	Norte	7.94%	8.14%	8.17%
4	Golfo Norte	15.28%	17.02%	18.72%
5	Golfo Centro	4.66%	4.56%	4.49%
6	Bajio	8.79%	8.89%	8.95%
7	Jalisco	5.86%	5.69%	5.72%
8	Centro Occidente	5.57%	5.93%	6.08%
9	Centro Oriente	4.42%	4.56%	4.65%
10	Centro Sur	3.70%	3.58%	3.59%
11	Oriente	6.25%	5.47%	5.05%
12	Sureste	2.96%	2.95%	3.00%
13	Peninsular	2.87%	2.98%	3.08%
14	Luz y Fuerza	18.78%	16.36%	13.97%
	Total	100.00	100.00	100.00

Table 3: Power demand and demand growth (from 1999) by region

	1999	2005		2010		Annual
Region	GWh	GWh	% Inc	GWh	% Inc	growth
1 Baja California	8,165	13,312	63.0	20,031	145.3	8.50
2 Noroeste	10,331	14,460	40.0	19,335	87.2	5.86
3 Norte	11,458	16,298	42.2	22,153	93.3	6.18
4 Golfo Norte	21,908	34,105	55.7	50,743	131.6	7.94
5 Golfo Centro	6,589	9,142	38.8	12,170	84.7	5.74
6 Bajio	12,849	17,809	38.6	24,247	88.7	5.94
7 Jalisco	8,454	11,402	34.9	15,506	83.4	5.67
8 Centro Occidente	7,785	11,874	52.5	16,466	111.5	7.05
9 Centro Oriente	6,429	9,140	42.2	12,601	96.0	6.31
10 Centro Sur	5,398	7,165	32.7	9,737	80.4	5.51
11 Oriente	9,128	10,968	20.2	13,684	49.9	3.75
12 Sureste	4,206	5,918	40.7	8,127	93.2	6.17
13 Peninsular	4,144	5,967	44.0	8,337	101.2	6.56
14 Luz y Fuerza	27,445	32,763	19.4	37,868	38.0	2.97
Total	144,285	200,324	38.8	271,005	87.8	5.90

This problem could be exacerbated, however, if the geographical distribution of future demand differs greatly from the current distribution. The above average growth of demand in the northern regions, for example, is likely to require a substantial increase in generating plant in the north or a substantial upgrading of the transmission links either from further south in Mexico or from the US.

3 A model of the electricity supply system

In this section, we discuss a model of the Mexican electrical network that allows us to approximate the spatial and temporal variations in the marginal cost of supplying electricity in 1999. Discussion of some of the more technical issues, including an outline of the equations included in the model, can be found in Appendix B.

The model calculates the least cost pattern of electricity production and transmission required to meet a discrete number of demand loads on the system. The demands are chosen to be "representative" of different times of the year. The geographic dispersion of demand also is approximated in a discrete way by assuming that the demand for a particular region is concentrated at a single "node." The model delivers an estimate of the "usual" short run marginal cost of supplying electricity in different regions and at different times of the year.

The aggregated demand data and the broad assumptions about other technical characteristics of the system make the marginal costs obtained from the model approximations to the true marginal cost. They are useful for indicating how prices might change were they to more closely reflect marginal costs. The model also is useful for examining longer run issues, such as the effects of investment and demand growth on average system costs. Our model would not be useful, however, for dispatching generators to ensure least cost operation of the system or for predicting how costs or system operations are likely to be affected by an emergency.

3.1 Approximating spatial and temporal variation

Geographical structure. In principle, the cost of supplying electricity will differ at every single connection point to the transmission network. For our current purposes, it is impractical to calculate all these nodal prices. We instead consider a discrete approximation to the physical layout of the network and the location of major centers of supply and demand.

In general, there is no unique method to determine the boundaries of the geographic regions. The appropriate level of aggregation can depend on the objective of the analysis. For example, a highly aggregated model may be sufficient when the objective is to identify electricity trade among countries, states or utility districts. Small or isolated regions can be subsumed into larger regions without having much of an impact on the questions of interest.

The number of regions included in the model, and the size of each, also depends on the available data. We based the geographical division of the country

Table 4: Generating capacity, production and estimated demand by transmission region, 1999

Transmission Region	Generators at year end 1999 Total	Type[a]	Total MW	Output GWh	Demand GWh
1. Sonora Norte	4	T	807	3,876	4,691
2. Sonora Sur	6	3T, 3H	746	3,343	3,261
3. Mochis	8	2T, 6H	1,167	3,050	2,288
4. Mazatlán	1	T	616	3,467	992
5. Juárez	1	T	316	1,561	4,197
6. Chihuahua	7	5T, 2H	1,118	6,289	3,698
7. Laguna	5	T	643	3,619	6,168
8. Rió Escondido	5	3T, 2H	2,710	18,359	2,238
9. Monterrey	10	T	1,215	5,841	19,214
10. Huasteca	1	T	800	4,732	3,922
11. Reynosa	2	T	521	2,680	3,090
12. Guadalajara	9	1T, 8H	1,352	2,147	9,620
13. Manzanillo	2	T	1,900	11,194	1,355
14. Ags-SLP	4	1T, 3H	720	3,963	7,384
15. Bajío	13	3T, 9H, 1R	1,447	8,895	17,197
16. Lázaro Cárdenas	3	1T, 2H	3,395	16,043	414
17. Central	20	7T, 13H	3,526	19,023	43,089
18. Oriental	17	3T, 12H, 1N, 1R	4,719	29,835	14,796
19. Acapulco	4	1T, 3H	681	1,498	2,212
20. Temascal	3	2H, 1R	358	1,736	1,521
21. Minatitlan	1	H	26	119	2,989
22. Grijalva	7	H	3,928	17,342	2,918
23. Lerma	2	T	164	902	924
24. Mérida	4	T	277	1,261	2,415
25. Chetumal	1	T	14	12	275
26. Cancún	7	T	529	1,471	1,199
27. Mexicali	5	2T, 3R	684	4,680	3,061
28. Tijuana	2	T	830	2,785	5,118
29. Ensenada	2	T	69	9	906
30. Cd. Constitución	6	5T, 1R	120	402	190
31. La Paz	2	T	156	709	825
32. Cabo San Lucas	1	T	30	59	153
Total	164	83T, 73H, 1N, 7R	35,585	180,901	172,319

a. T = oil, coal or gas thermal, H = hydroelectric, N = nuclear,
R = plant using "renewable" wind and geothermal energy sources.

Figure 2: Mexican electricity transmission network, 1999

on the 32 "transmission regions" defined by the CFE. The regional data examined above was based on the CFE accounting records. In order to calculate costs or examine optimal investments, we need to relate the demand data to the physical supply system, primarily the generating plants and transmission lines. The engineering data supplied by CFE is organized by transmission region. This subdivision highlights the high voltage transmission network that connects the most important industrial and population centers of the country. The geographical distribution of such regions and the 1999 transmission network (with its capacities in MW) are illustrated in Figure 2. Table 4 gives basic data on generating capacity located in the 32 transmission regions.

The number of transmission regions exceeds the number of accounting regions, and the boundaries of the two sets of regions sometimes overlap. We constructed the demand shares per transmission region by disaggregating the shares for the 14 administrative regions into the 32 transmission regions based on population data of the main Mexican cities.[9] The right-hand column of Table 4 shows our allocation of the 1999 demand data. The remainder of the analysis will be based on the transmission regions with demand imputed in this manner.

By the end of 1999, the Mexican electric supply system had 164 active fixed generating plants[10] with a total effective capacity of 35,584 MW. While 44% of

[9]To allocate the forecast future demand shares to the transmission regions, we used the population growth projections of the *Consejo Nacional de Población* (CONAPO), http://www.conapo.gob.mx, the main governmental institution in Mexico involved in demographic analysis.

[10]Officially, 170 plants were said to be available in December 1999, but not all of them

the plants were hydroelectric and 46% thermal, the capacity shares were more unequal, with these two types of plant supplying 27% and 63% of the total capacity respectively. Capacity data for each plant were collected from annual public reports of the CFE.[11] We approximated the current annual "availability" of each plant by its maximum annual production in the last three years of operation.

Temporal structure. An important feature of most electricity systems is that the demand load on the system varies over time. In particular, extreme weather conditions can significantly affect the demand for electricity.[12] Our analysis of the regional variation of demand showed that, in the north of Mexico, electricity consumption is considerably higher during the second half of the year. In the southern half of the nation, demand shares tend to be lower during this period.

The demand for electricity for cooking also displays a distinct daily pattern that also tends to coincide with the daily fluctuation in demand for electricity from electrified commuter rail systems. Industrial demand for electricity tends to be higher during daylight hours, although 24 hour operation of some large plants can also raise the demand for electricity during off-peak periods. The demand for electricity for lighting (for which there are no good substitutes) is, of course, highest during the night, but drops substantially in the early morning hours. Electrical water heaters can be operated at night when the demand for electricity is otherwise relatively low, but in this application natural gas is a strong competitor for electricity.

In addition to the daily and seasonal fluctuations in demand, there are also substantial weekly patterns. Most obviously, demand is lower on the weekends than during the week.

The seasonal, weekly and daily fluctuations in demand matter because the costs of supplying electricity can change substantially as a function of both the total system load and its geographic distribution. The generating plant have different costs of production, while there are also costs associated with generating electricity in one location and transmitting it large distances to be consumed elsewhere. Furthermore, the difficulty[13] of storing electrical energy makes it difficult to arbitrage price differences over time. We therefore need to approximate the pattern of demand fluctuations over time in order to obtain a realistic idea of how costs vary over time. As with the geographical diversity discussed above, however, a discrete approximation to the time variability allows us to simplify the model.

Again, the optimal level of detail will depend on the purpose for which the

operated at some time during that year.

[11]The relevant CFE reports are titled "Informe de Operacion."

[12]The seasonal pattern of electricity demand also is affected by the fact that many businesses have annual and other holidays at the same time.

[13]In some situations, pumped storage can be used to store a limited amount of energy. More generally, the availability of hydroelectricity increases the intertemporal substitutability of electricity supply.

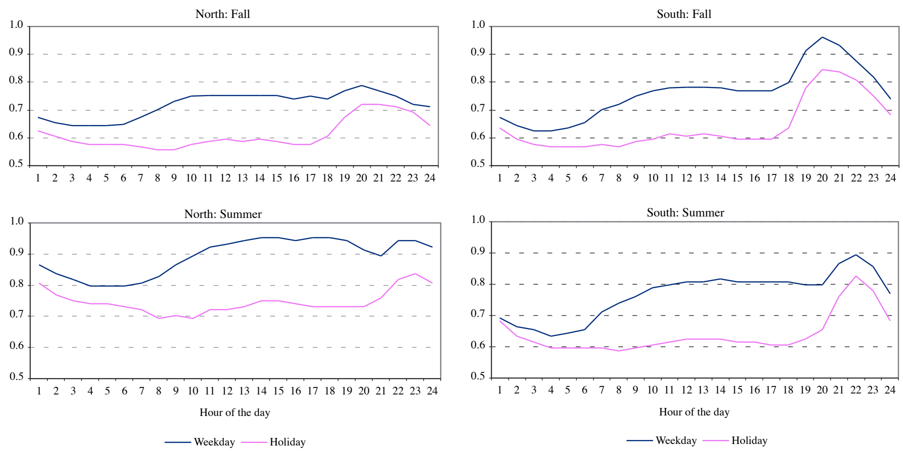

Figure 3: Representative daily load curves, normalized to the maximum annual demand, 1999

model is being constructed. As with the geographical information discussed above, however, the detail we can include in the model is limited by the data that are available to us.

The Secretary of Energy[14] published average *daily* load curves for the year 1999. These curves are available separately for the North and South areas of the country,[15] for two seasons, Summer (May to August) and Fall (November to February), and for weekdays and holidays. The curves, graphed in Figure 3, represent the average demand per hour during a typical day expressed as percentage of the maximum annual demand.[16] For the remaining months (March, April, September and October) we constructed a daily load curve that was a weighted average of the two published curves, having as weights the electricity demands in the Summer and Fall seasons. We assume that all the transmission regions within an area (North or South) have the same daily pattern of electricity demand and thus the same daily load curve shape.

We derived the total demands (weekdays plus weekends and holidays) in each of the 32 transmission regions in each season by aggregating the *monthly* demands. The daily load curves were used to allocate demand in each season to weekdays versus weekends or holidays. Finally, demands in a weekends-holidays "season" were obtained by aggregating the weekend or holiday components across seasons. In summary, the data allows us to calculate, in each of the 32 transmission regions, the electricity demands for four seasons:

[14] "Prospectiva del sector eléctricol 2000-2009", Secretary of Energy.

[15] The North region includes the North and Northeast areas. The South region includes the Occidental, Central, Oriental and Peninsular areas.

[16] None of the load curves in Figure 3 attain the value since they represent "average" loads in each season.

1. Fall, covering working days for the 4 months from November to February;
2. Summer, for working days for the 4 months from May to August;
3. Shoulder, for working days for the 4 months of March, April, September and October; and
4. Weekends-Holidays, that includes non-working days during the whole year.

To capture the intraday demand dynamics, we could, in principle, use the average daily load curves in each season to construct hourly electricity demand.[17] However, to keep the model manageable, we approximate the hourly demand fluctuations using step functions. The details of this approximation procedure are provided in Appendix A.

For constructing the hourly demand in 2005, we assumed that the daily load curves are the same as those in 1999. This approach was used because of the limited nature of our investigation. In principle, one could estimate the change in the load duration curves over time based on changes in the prices of electricity (including changes in peak relative to off-peak prices), economic growth (as measured by GDP) and weather conditions. In effect, the demand estimation carried out above would be repeated for different load patterns on the system. The estimated variation in demands by time of day (as determined by system load) could then be used to make forecasts in place of the aggregate forecasts with an unchanging pattern of demand that we have used.

3.2 Generation and transmission technologies

To calculate the costs of supply, we need information about the generation and transmission technologies. With regard to the generating plants, we need to know not only generating costs but also capacities and the average level of availability. For the transmission links, we need to know the overall capacity and, to calculate the loss factors, the number of circuits per link.

Generating plant costs. Regardless of the type of generating technology, we assume that the cost function of a plant can be represented by two components. The first component is an annual fixed cost. It includes the fixed components of the operation and maintenance costs of the plant, such as the labor force required to keep the plant operational even if it is not generating electricity. We assume that the fixed costs, given in dollars per MW, are a linear function of the total capacity of the plant set at the beginning of the year. The variable cost is the second component of the generating cost of each plant. It includes the cost of fuel and some other operation and maintenance costs, mainly on the cost of labor, that vary with the amount of electricity that the plant is generating. We assume that this cost is a linear function of the MWh generated by the plant. The variable cost per MWh is constant during a given period, but could vary

[17] Even this involves a simplifying assumption that all days in a season have the same demand pattern that can be scaled up or down according to the monthly demand.

from one period to the next as a result of seasonal fluctuations in fuel prices in particular.

We based the operation and maintenance costs for thermal plants on cost estimates provided by the CFE (COPAR, 1999) for "typical plants" in Mexico classified by size of the plant and type of technology.[18]

The fuel cost of thermal plants was calculated using the average technical efficiency of each plant (fuel/MWh). In turn, we obtained the average efficiency of a plant by dividing its overall fuel consumption for the year 1999 by its power output in the same year. The monthly cost in pesos was then obtained by multiplying the required fuel input by the monthly fuel prices. The seasonal prices, for example the price for the peak period May-August, were computed as the average price in the months falling into that period. The relevant information was obtained from the CFE.[19]

The hydroelectric plants do not have a fuel cost as such but are required to pay "resource levies" on the cubic meters of water they use. We shall take these "resource levy" payments as part of the variable cost.

The CFE publications do not provide "typical" operation and maintenance costs for hydroelectric plants. This may be because such plants are more heterogeneous than the thermal plants. They vary in size and efficiency much more than do the thermal plants, and the MWh of electricity generated only approximates water use. The CFE publications do, however, provide costs for ten existing large hydroelectric plants and we use these to extrapolate the costs for other plant sizes. Specifically, we extrapolated the fixed component of the operating and maintenance costs of large hydro plants by regressing the log of costs for the ten hydro plants on the log of their capacities.[20] The relationship reported on page 5.5 of COPAR(1999)[21] was used to compute the variable cost, that is the operation and maintenance costs and resource levies. This equation was estimated using regression analysis with a larger sample than the ten plants whose costs were reported. Finally, we assumed small hydroelectric plants (less than 50 MW) had constant costs (an average fixed cost of 152,802 pesos per MW per year and a variable cost of 10.58 pesos per MWh).

The generating costs do not include any capital cost (that is, interest payments or depreciation). Implicitly, we are anticipating that investment projects would be evaluated on a cash flow basis. Any time a firm could expect market prices to exceed the "short run" costs as calculated here, there would be a positive cash flow that could be offset against the negative up-front costs of a new investment.

In particular, in periods or regions where the demand is pushing against

[18] "Costos y Parametros de Referencia", COPAR, CFE 1999. In practice, costs are also likely to depend on the age of the plant, but this information was not available to us.

[19] The source for annual power generation and fuel consumption was "Informe de Operacion 1999" and "Unidades Generadoras en Operacion 1999", CFE. The fuel prices were obtained from "Evolucion de Precios Entregados y Fletes de Combustibles 1999-2000", CFE.

[20] The estimated equation for annual fixed costs in pesos/MW was $C_F = 782,784K^{-0.4151}$ where K is the capacity of the plant in MW.

[21] The equation was $C_v = 0.3122Q^{-0.1271}$ where C_V is average costs in pesos/MWh and Q is the output of the plant in MWh.

capacity, prices would be expected to rise to ration the demand to the available capacity. This would provide "rents" in excess of the costs excluding interest payments and depreciation. In a competitive market, such rents would attract entrants once the *net* present value of the cash flows flowing from an investment would be positive when discounted at the appropriate risk adjusted rate.[22] The additional capacity would in turn drive prices closer to the short run costs, making entry less attractive to subsequent firms until demand expands further or some old plant is retired.[23] The latter decision in turn will also depend on a net present value calculation comparing the likely revenue in excess of variable operating costs with the fixed maintenance and other costs of keeping the plant operational for another year.

While this argument has been couched in terms of a competitive market, a similar set of calculations ought to drive the investment decisions of a publicly owned firm, such as CFE. The main change would be that the word "rents", interpreted as the "anticipated difference between price and short run costs," would be replaced by the "appropriately calculated shadow price of additional capacity."

Transmission. The model allows trade in electricity through the high voltage transmission network (see Figure 2 above). Since the possibility of not using a link at all during the year is not a relevant option, we ignore any managerial, maintenance or capital costs associated with transmission and distribution. We nevertheless need to compute the transmission losses associated with electricity flows, which in turn requires information about the capacity and other technical characteristics of the links. Specifically, the losses on a transmission link depend on the length, the voltage and the number of circuits per link. This information was collected from the Secretary of Energy.[24] We approximated the non-linear transmission losses by piecewise linear functions. Details are provided in Appendix B.

Other losses. The transmission losses are only part of the source of losses in the system. In 1999, for example, the Mexican electricity system generated 180,917 GWh of electricity, but only 145,127 GWh were recorded as sales. Almost 25% of the electricity generated was either lost in the transmission or distribution network for technical reasons or was consumed without monetary compensation. As we shall see later, only about 3 of this 25% can be accounted

[22] The model does not, however, explicitly incorporate any decisions regarding investments in new generation and transmission capacity. In this sense, it is a short run model where the optimal generation schedule is based on marginal cost of operating existing plants and a given transmission network. We shall, however, examine the model in 1999 and again in 2005, when additional investments have been made in both generating and transmission capacity and when demand is higher.

[23] Since new capacity is added in discrete "lumps," the gap between *equilibrium* prices in a competitive wholesale electricity market and short run marginal costs could be expected to fluctuate over time. Nevertheless, our model is likely to under-estimate the average equilibrium prices in a competitive wholesale market.

[24] "Prospectiva del sector eléctricol 2000-2009", Secretary of Energy.

for by losses in the high voltage transmission network. Consumption within the generating plants was about 8,887GWh, or 5% of total production. We cannot directly measure some sources of losses, including in particular theft of electricity by consumers and losses on the lower voltage transmission and distribution networks. We therefore calibrate the model by including an additional factor that substitutes for these unmeasured losses.

The Luz y Fuerza company reported that in 1999 losses approximated 30% of its total sales.[25] Since Luz y Fuerza sales accounted for about 19% of total sales that year, losses in the Mexico City region served by Luz y Fuerza account for almost another 6 of the 25% of losses. Luz y Fuerza reports that its losses are mainly in distribution and unbilled consumption. The latter, in turn, includes waived debts as well as theft of electricity. We apportioned the remaining losses (about 11% of production) on the basis of regional population. A justification is that the resistance losses in the transformer stations and distribution network, and the losses through undetected leaks and theft, are all likely to increase along with regional population and the number of customers.

3.3 The Linear-Optimization Model

We now combine the various components of the model to derive estimates of the least-cost pattern of generation and transmission required to meet the representative demands in each period and region. Minimizing the cost of generation is the basic objective, but setting this as an objective on its own would make no sense. The cost could be minimized by generating zero electricity. The constraints that have to be met ensure that the solution to the problem is nontrivial. The solution process also yields values for the "co-state" variables, or the "multipliers" which measure the effects on minimized costs of imposing the various constraints. In particular, the multipliers on the demand constraints can be interpreted as the marginal costs of supplying demand at each node in each time period.

The main constraints that prevent zero generation of electricity from solving the cost minimization problem are that the amounts of electricity supplied need to satisfy the demands of consumers at every node and for every hour in each of the periods. The minimized cost thus represents the cost of meeting the specified demands.[26]

Since electricity can be transmitted over the high voltage network, demands in each region do not have to meet the demand for electricity in that region. Exchanging electricity through the high voltage network, however, incurs transmission losses as discussed above. Many regions are linked by more than one set of transmission lines. As part of the solution, the model simulates the interregional power flows along the high voltage transmission network. The model also calculates how to allocate the required down time for maintenance of generating plant in order to minimize the overall annual costs of production.

[25] "Unidades Generadoras en Operacion 1999", CFE, March 2000, pp 99.

[26] This section discusses the cost function and constraints in general terms. Appendix B provides a more precise algebraic formulation of the cost function and the various constraints.

Another set of constraints results from the need to maintain plant on a regular basis. Each plant must be off-line a certain amount of time during each year. Random technical problems may also take plant out of operation for hours or several days. Hydroelectric plant may also need to be taken off-line for days or even months to conserve limited supplies of water.

We focus on the planned maintenance schedule as a key determinant of the availability of both generating capacity and electrical energy. We represent this restriction as a limit on the total MWh that the plant can generate in the whole year, while allowing the model to schedule the down time optimally across periods.

As the equations in Appendix B reveal, we treat large "base" plants in a different way to the remaining plants. The large base plants tend to be operated around the clock when they are used at all. They also typically require a substantial block of time for planned maintenance. Effectively, they can only be off line for complete days and not for just hours.

In addition to generating electricity to satisfy "normal" demand loads, the system needs sufficient reserves of capacity to meet unexpected increases in demand or unexpected equipment failures. In most electricity supply systems, consumers are willing to accept some voltage or frequency fluctuation in return for a lower price of electricity. Consumers with a strong need for stable supply can purchase their own on-site generation plant and many find this worthwhile in countries with weaker systems that are more prone to instability. Nevertheless, one of the advantages of an integrated network is that it can supply reserve capacity to cope with emergencies at a relatively low cost.

One can view reserve capacity, or consumers who agree to have their supply interrupted in return for a payment, as "options contracts." Under specified circumstances, the producer or consumer will be called upon to supply a specified amount of output or demand reduction, in return for a specified payment.[27] The "ancillary services" provided under such contracts can assist with controlling voltage, frequency and power flow or with restarting the system in the event of a failure (when blackouts occur). Contracts to provide ancillary services can be priced just as financial and commodity options are priced. Firms supplying the services could earn revenue even if they are not actually called upon to produce energy. In fact, Australia is gradually introducing a set of such options markets and already has an operational market for frequency control services.

In a centralized system managed by a publicly owned monopoly, the amount of reserve capacity should in principle balance the capital cost of excess capacity against the benefits to consumers of a more stable power supply. It is unclear to us how one could in practice obtain the required information about the benefits of reserve capacity in the absence of an ancillary services market. We can, however, calculate the consequences of maintaining a specified level of excess reserves.

[27] The specified circumstances are analogous to the "strike price" for a financial option, the volume of output or demand reduction is analogous to the number of options contracts purchased, and the specified payment is analogous to the cost of the options contracts.

To capture the need to maintain reserve capacity to meet unexpected peak demand, we calculate the generating capacity and associated transmission amounts for a set of "virtual" periods of extreme demand. The notion is that such periods last for a brief period and thus do not require a substantial amount of additional energy to be produced. They do, however, require plant capacities to be higher than would be the case if demand was always at its "normal" level.

4 Base case results

According to data reported by the CFE,[28] generation costs accounted for 38% of the total cost of supplying electricity in 1999. Depreciation and capital costs accounted for 15.2% and 1.6% respectively.[29] The remaining 45% of expenditures covered administration and the costs of operating the distribution and transmission networks. The expenditure amounts in pesos were: generation costs, 35,448 million pesos; depreciation 14,020 million pesos, financial costs 1,457 million pesos and total cost, 92,397 million pesos.

The linear programming model objective function represents the generation costs alone for the period November 1998 to October 1999, which corresponds to the timing of the four seasons considered in the model. The minimized costs of production from the model for this period were 30,376 million pesos. Our estimation is for the period November 1998-October 1999 rather than calendar 1999. Furthermore, some fixed costs that are absent from the model may have been included in the accounting data. Finally, the lack of data required us to make various approximations to the demand load curves, generating costs and many other factors, so it is not surprising that our minimized costs differ somewhat from the accounting figures.

4.1 Production, transmission and consumption

Table 5 summarizes the generation, transmission and consumption results for the Base Case. The central region (17) has the highest electricity consumption in the country, with a 26% share of total gross demand. However, this region generated only around 10% of the total power supply. The concentration of population and industry in the central region resulted not only in high consumption but also in levels of losses (or power supplied at zero cost) on the order of 23% of the region's total annual electricity needs.[30] The model results imply that the central region imported 60% of its electricity. Two regions neighboring the central region, Lazaro Cardenas (16) and Oriental (18) are major exporters of power. The Oriental region is also a significant center of electricity consumption. Two other regions connected to the Central one are Bajio (15) and Acapulco (19). Both of these are, however, importers of power. Bajio (the third largest

[28] "Resultados de Explotacion, 1999."

[29] The depreciation and capital costs pertain to the transmission and distribution as well as the generation sectors of the business.

[30] As we noted above, the losses in this region were obtained from a report by Luz y Fuerza.

Table 5: Base Case, Annual Regional Results (GWh)

Region	Gross Generation[a]	Net Transmission[b]	Gross Demand[c]	Other Losses[d]
1	3,599	752	4,140	4.0%
2	3,159	-139	2,842	2.8%
3	3,080	-913	2,016	3.9%
4	3,789	-2,695	855	1.7%
5	5,110	-1,092	3,813	6.0%
6	2,644	863	3,335	5.3%
7	2,647	3,192	5,685	7.4%
8	17,192	-13,885	1,970	3.0%
9	6,192	13,116	19,019	13.9%
10	5,036	-1,134	3,536	5.2%
11	2,813	134	2,757	4.2%
12	2,146	7,418	9,545	13.9%
13	11,037	-9,229	1,177	1.6%
14	4,700	2,599	6,978	9.7%
15	8,059	9,354	16,983	13.8%
16	16,031	-14,884	354	0.4%
17	18,398	25,603	42,948	23.4%
18	28,697	-12,394	14,909	15.2%
19	1,702	294	1,985	5.0%
20	1,736	-378	1,341	2.8%
21	119	2,560	2,674	4.3%
22	17,342	-14,390	2,660	6.0%
23	964	-82	811	2.0%
24	1,386	898	2,178	4.6%
25	0	238	238	0.6%
26	1,262	-124	1,059	2.6%
27	4,315	-1,420	2,695	3.5%
28	4,197	726	4,641	6.2%
29	147	637	780	1.2%
30	475	-287	166	2.6%
31	641	189	782	10.3%
32	46	88	133	2.1%

a. As estimated by the model.
b. Positive values indicate the net electricity delivered to the region, while negative values indicate the net supply transmitted out of the region.
c. Calibrated sales and theft of electricity, plus distribution and internal generation losses.
d. Distribution and internal generation losses and losses due to theft of electricity.

importing region) is a high consumption region with a high level of electricity losses (13.7%). Acapulco on the other hand is primarily an importing region because of its low level of generation.

The hydroelectric plants located on the Grijalva river (region 22) are also a major source of energy for the central region of the country. These plants total more than 3,900 MW of capacity and more than 80% of the electricity they produce is exported north not only to the center but also to neighboring region of Minatitlan (21) and the Yucatan peninsula.

Bajio (15), Guadalajara (12) and Ags-SLP (14) constitute a significant area of consumption to the north of the Central region. These areas together form an industrial corridor that links the center of the country with the north. Manzanillo (13) is a major source of energy for these regions as well for the center. It has two thermal plants with a joint capacity of 1,900 MW. Another important regional electricity supplier is Lazaro Cardenas (16), which supplies the corridor (12-14-15) and the center (17), with a thermal plant of 2,100MW capacity and a 1,000MW hydroelectric plant.

The northern city of Monterrey (9) is the second largest consuming and importing region in the country. The large coal-fired plants in Rió Escondido (8), with a total capacity of 2,600 MW, are a major source of energy for Monterrey. Other regions neighboring Monterrey are Laguna (7) to the west, Huasteca (10) to the south-east and Reynosa (11) to the north-east. Of these, Laguna is also a moderate importing region while Huasteca is a moderate exporter. Further growth of demand in the north-east of the country is clearly going to require additional generating capacity in the region, or a strengthening of the transmission links from the south of the country or from Texas.

4.2 Scheduled maintenance

Any least cost scheduling of generation plants to meet power demands and provide reserve capacities has to allow plants to be taken out of service for maintenance. The optimal solution may involve some rolling maintenance, depending on factors such as the seasonal pattern of the regional demand and the seasonal behavior of fuel prices for different plant types. In our model, plant availabilities are choice variables, and the set of availability percentages per plant and per period are an important model output.

Table 6 summarizes the calculated availabilities by region and season. The seasonal variation in availabilities reflects the pattern of aggregate electricity demand, which attains its lowest values during the Fall and is the highest during the Summer months. There are, however, some interesting regional variations. In particular, plants in some regions are made fairly uniformly available throughout the year, enabling them to compensate for the reduced availability of other plant taken off line for maintenance when demands tend to be lower. This backup task appears to be important in Mazatlán (4), which compensates for the low availability of plant in the northwest during the Fall, and Huasteca (10) and Oriental (18), which support the low availability of plant in the north-east during the Fall. Oriental (18) and Manzanillo (13) are interesting in so

Table 6: Base Case, Allocation of availability by region and season

Region	Year[a]	Summer	Shoulder	Fall	WE-Hol
1	0.51	0.53	0.53	0.46	0.51
2	0.49	0.59	0.51	0.42	0.42
3	0.32	0.41	0.33	0.21	0.26
4	0.70	0.70	0.70	0.70	0.70
5	0.71	0.84	0.73	0.61	0.62
6	0.51	0.53	0.51	0.51	0.48
7	0.51	0.63	0.55	0.45	0.30
8	0.72	0.75	0.73	0.69	0.73
9	0.62	0.72	0.65	0.33	0.61
10	0.80	0.94	0.45	1.00	0.54
11	0.66	0.83	0.67	0.62	0.41
12	0.63	0.03	0.71	0.02	0.03
13	0.74	0.89	0.35	0.89	0.56
14	0.75	0.81	0.80	0.70	0.69
15	0.65	0.69	0.70	0.68	0.52
16	0.54	0.57	0.60	0.53	0.47
17	0.61	0.67	0.68	0.56	0.50
18	0.70	0.69	0.71	0.73	0.66
19	0.31	0.35	0.36	0.32	0.15
20	0.61	0.75	0.75	0.42	0.36
21	0.52	0.52	0.52	0.52	0.52
22	0.51	0.51	0.55	0.49	0.47
23	0.67	0.67	0.67	0.67	0.67
24	0.59	0.65	0.69	0.53	0.45
25	0.00	0.00	0.00	0.00	0.00
26	0.28	0.36	0.28	0.24	0.22
27	0.58	0.63	0.59	0.52	0.58
28	0.41	0.54	0.40	0.33	0.31
29	0.28	0.16	0.36	0.02	0.01
30	0.45	0.53	0.43	0.40	0.40
31	0.48	0.54	0.51	0.42	0.43
32	0.02	0.02	0.01	0.00	0.00
Average[a]	0.62	0.67	0.63	0.62	0.55

a. Weighted average, with generation per region or season as weights.

far as both have lowest availabilities in the Shoulder season, enabling them to provide greater capacity and output during both the Summer and Fall seasons. By contrast plant in Guadalajara (12) and Ags-SLP (14) have their highest availabilities during the Shoulder season of the year.

4.3 Calculated costs

A major motivation for constructing the model is that it allows us to examine total, average and marginal costs of electricity supply in Mexico. We wish to compare the marginal costs in particular with current electricity prices. In the next section of the paper, we study how the forecast increase in demand for 2005, and the completion of the planned new additions to generating and transmission capacity over the next few years, both affect costs.

As noted in the introduction to this section, the total generation costs calculated by the model are 30,376 million pesos for 178,664 GWh generated during the period under analysis (November 1998 to October 1999). By contrast, the CFE reported that total generation costs for 1999 were 35,448 million pesos. It therefore is possible that the calculated marginal costs are too low. The calculated marginal costs would not be affected, however, if the accounting data includes fixed costs that have been omitted from our objective function.[31]

Tables 7, 8, 9 and 10 present the calculated marginal costs of power supply for each transmission region and in each time period. For the peak periods in Summer and Fall, the marginal costs have been separated into the components associated with the demand constraints (14) and those associated with the reserve constraints (19). Although the latter could in principle bind in any period,[32] we find that they bind only in either the summer or fall periods of peak demands, and even then not for all regions in both seasons.

The weighted average system-wide marginal cost (with weights determined by consumption shares) is 32.08 cents Mexican per kWh. By contrast, the calculated total cost of generation corresponds to an average of only 17.00 cents Mexican per kWh, implying that the marginal cost is around 88% higher than the average cost.

Evidently, generation of electricity in Mexico is not a "natural monopoly" activity in the sense that average costs exceed marginal costs. This is usually the case in all countries, since plant with higher operating costs is used only to supply electricity in peak periods. The marginal costs in peak periods also reflect the cost of maintaining additional generating capacity to cope with emergencies.

The finding that the weighted marginal cost exceeds the average cost has another important implication. If wholesale prices reflected the marginal cost of generation, the revenue raised would exceed the costs of generating the elec-

[31] Some items that accountants count as costs, including depreciation and interest costs, are appropriately excluded from an economic measure of costs. These items have, however, already been excluded from the reported cost of 35,448 million pesos.

[32] In particular, it is possible that scheduled maintenance, differences in seasonal demands or transmission constraints might cause the reserve constraints to bind in periods other than those of peak demand.

tricity. In fact, the excess revenue would more than cover the reported annual "capital costs" for the CFE.[33] If the depreciation and interest charges in the CFE accounts represent a competitive return to capital, then setting wholesale electricity prices equal to the marginal costs of generation ought to attract considerable entry into the industry, were that to be permitted by law. This is another sense in which the generation of electricity in Mexico is not a natural monopoly. The essence of the natural monopoly idea is that a large incumbent firm has a cost advantage relative to smaller potential entrants making entry unattractive. Our calculations suggest that, if wholesale electricity prices reflected marginal costs, new generators would be delighted to set up business in Mexico. Entrants would need to be guaranteed the same access to the transmission network, and receive the same wholesale price for electricity supplied at the same time and location, as the incumbent producers. In reality, this would require the transmission business of the CFE to be separated from the generation business. Effective competition in the wholesale market also would require that the existing generating stations be parceled out into many competing companies and not kept as a monopoly entity.

The spatial and temporal variation of marginal costs is also of interest. Tables 7 and 8 give the costs arising from both the demand and the reserve constraints for time periods in which the reserve marginal cost is non-zero for at least one region. The "full" marginal costs include both constraints since an increase in "normal" demand within a period is assumed to increase extreme demand in the same proportion. To begin with, however, the discussion will focus on the demand constraints only. These determine the energy requirements for the system and the "usual" pattern of electricity transmissions. The reserve constraints indicate how the system behaves under extreme conditions and will be discussed later.

In the North (regions 1 to 11 and all of Baja California), the demand for electricity exhibits a strong seasonality with Summer as the peak season. This behavior of the demand is reflected in marginal costs that are higher in the summer than they are in the fall.

Within a given season, the peak hours represented by periods 1, 2, 6, 11 or 16 tend to have the highest cost. Marginal costs are raised not only by the need to use more expensive generating plant, but also by the higher transmission losses.

In some regions, relatively abundant hydroelectric resources allow the price spikes to be smoothed out or even eliminated. Since stored water can be run through the turbines at any time, the shadow value of using the water to generate electricity should be equal in all periods in which it is used. Otherwise, costs could be reduced by saving water in periods when its value is lower and using it instead when the cost of generating electricity using other technology is higher. Hydroelectric capacity is, in a sense, a substitute for storing electricity. Without it, marginal costs would fluctuate much more as the demand load on the system

[33]As noted earlier, in the 1999 CFE accounts, capital costs, primarily depreciation and interest payments, were almost equal to 43% of total generation costs.

Table 7: Marginal costs by transmission region: Summer (May–August) (cents per kWh, Mexican Pesos)

	Demand periods						
	1		2		3	4	5
Region	Dem	Res	Dem	Res			
1	27.3	152.0	27.3	9.5	27.3	26.5	26.5
2	26.1	149.6	26.1	9.1	26.1	26.1	26.1
3	24.3	139.4	24.3	0.0	24.3	24.3	24.3
4	25.4	145.8	25.4	0.0	25.4	25.1	25.1
5	23.5	238.1	23.5	0.0	23.5	23.5	23.5
6	26.3	251.5	26.3	0.0	26.3	25.9	25.9
7	27.4	262.2	27.4	0.0	27.4	27.0	27.0
8	25.0	241.9	25.0	0.0	25.0	24.6	24.6
9	26.7	258.4	26.7	0.0	26.7	26.3	26.3
10	25.5	235.6	25.5	0.0	25.5	25.5	25.5
11	26.5	261.1	26.5	0.0	26.2	26.2	26.2
12	27.1	149.5	27.0	0.0	27.0	26.9	26.9
13	25.2	139.0	25.2	0.0	25.2	25.0	25.0
14	28.3	240.9	27.9	0.0	27.9	27.9	27.9
15	28.1	245.8	27.9	0.0	27.9	27.9	27.9
16	24.5	58.8	24.5	0.0	24.5	24.5	24.5
17	27.3	238.4	26.9	0.0	26.9	26.9	26.9
18	24.7	214.0	24.7	0.0	24.7	24.7	24.7
19	27.1	0.0	27.1	0.0	27.1	27.1	27.1
20	22.4	83.9	22.4	0.0	22.4	22.4	22.4
21	21.0	71.4	21.0	0.0	21.0	21.0	21.0
22	19.7	62.0	19.7	0.0	19.7	19.7	19.7
23	86.9	190.9	33.6	0.0	33.6	33.1	33.1
24	90.3	198.3	35.0	0.0	34.9	34.5	34.5
25	96.0	210.9	37.2	0.0	37.1	36.7	36.7
26	84.4	185.3	33.9	0.0	33.9	33.9	33.9
27	125.6	188.4	123.0	0.0	123.0	123.0	121.8
28	130.3	192.8	130.3	0.0	130.3	130.3	130.3
29	133.2	196.4	133.2	0.0	133.2	133.2	133.2
30	103.4	173.5	95.4	0.0	95.1	95.1	95.1
31	111.5	187.1	102.9	0.0	102.6	102.6	102.6
32	108.8	182.6	105.1	0.0	105.1	105.1	105.1

Weighted averages across groups of regions (with the shares of group electricity needs as weights):

	1	2	3	4	5
1–26	243.4	27.1	26.5	26.4	26.4
27–29	320.7	128.1	128.1	128.1	127.7
30–32	294.2	102.0	101.7	101.7	101.7
1–32	248.6	33.7	33.2	33.0	32.9

Table 8: Marginal costs by transmission region: Fall (Nov–Feb)
(cents per kWh, Mexican Pesos)

	Demand periods					
	11		12	13	14	15
Region	Dem	Res				
1	25.1	0.0	24.1	24.1	24.1	24.1
2	24.7	0.0	23.7	23.7	23.7	23.7
3	24.1	0.0	24.0	23.6	23.6	23.1
4	25.2	0.0	25.1	24.7	24.7	24.0
5	23.4	0.0	23.4	23.4	23.4	23.4
6	24.6	0.0	24.6	24.6	24.0	24.0
7	26.1	0.0	26.1	26.1	25.9	25.9
8	23.4	0.0	23.4	23.4	23.2	23.2
9	25.0	0.0	25.0	25.0	24.8	24.8
10	24.2	0.0	24.2	24.2	24.0	24.0
11	25.3	0.0	25.3	25.2	25.0	25.0
12	27.1	0.0	27.1	26.6	26.5	25.8
13	25.2	0.0	25.2	24.7	24.7	24.0
14	28.0	196.4	27.7	27.2	27.2	27.2
15	28.5	208.3	28.3	27.7	27.5	27.0
16	24.5	0.0	24.5	24.5	24.5	24.2
17	27.7	214.7	27.4	26.9	26.6	26.2
18	24.7	0.0	24.6	24.1	23.9	23.5
19	27.1	73.9	27.1	27.1	27.1	27.1
20	22.4	0.0	22.4	22.3	22.3	22.1
21	21.0	0.0	21.0	21.0	21.0	21.0
22	19.7	0.0	19.7	19.7	19.7	19.7
23	30.9	0.0	30.4	29.7	29.7	28.8
24	32.1	0.0	31.6	31.0	31.0	31.0
25	34.1	0.0	33.6	33.0	33.0	31.6
26	31.1	0.0	31.1	31.1	31.1	31.1
27	118.1	0.0	117.8	117.8	117.8	117.8
28	126.4	0.0	126.1	126.1	125.8	125.8
29	128.7	0.0	128.7	128.4	128.2	128.2
30	91.9	0.0	91.9	88.3	87.9	87.9
31	98.3	0.0	98.3	90.6	90.6	90.6
32	100.7	0.0	100.7	92.9	92.9	92.9

Weighted averages across groups of regions (with the shares of group electricity needs as weights):

	11	12	13	14	15
1–26	120.7	26.2	25.8	25.6	25.3
27–29	123.8	123.6	123.5	123.4	123.4
30–32	97.6	97.6	90.6	90.5	90.5
1–32	120.8	31.5	30.9	30.6	30.3

Table 9: Marginal costs by transmission region:
Shoulder (March, April, Sept, Oct)
(cents per kWh, Mexican Pesos)

	Demand periods				
Region	6	7	8	9	10
1	26.5	26.5	26.5	26.5	25.4
2	26.1	26.1	26.1	26.1	25.0
3	24.3	24.3	24.3	24.3	24.3
4	25.2	25.2	25.2	25.2	25.2
5	23.8	23.8	23.8	23.8	23.8
6	26.1	26.1	26.1	25.9	25.9
7	27.2	27.2	27.2	27.2	27.2
8	24.7	24.7	24.7	24.7	24.7
9	26.4	26.4	26.4	26.4	26.4
10	25.5	25.5	25.5	25.5	25.5
11	26.2	26.2	26.2	26.2	26.2
12	27.1	27.1	27.1	27.1	27.1
13	26.5	26.5	26.5	26.5	26.5
14	28.2	28.0	28.0	28.0	28.0
15	28.4	28.1	28.1	28.1	28.1
16	24.5	24.5	24.5	24.5	24.5
17	27.5	27.3	27.1	27.1	27.1
18	24.7	24.7	24.7	24.7	24.7
19	27.1	27.1	27.1	27.1	27.1
20	22.4	22.4	22.4	22.4	22.4
21	21.0	21.0	21.0	21.0	21.0
22	19.7	19.7	19.7	19.7	19.7
23	51.3	33.5	33.0	32.1	31.7
24	53.3	34.8	34.3	33.4	33.0
25	56.7	37.0	36.5	35.5	35.1
26	50.8	33.8	33.8	33.8	33.8
27	119.6	119.6	119.5	119.5	119.0
28	127.9	127.9	127.9	127.9	127.3
29	130.3	130.3	130.3	130.3	129.7
30	93.0	93.0	93.0	90.5	87.9
31	100.4	99.8	99.8	92.9	92.9
32	102.3	102.3	102.3	95.2	95.2

Weighted averages across groups of regions (with the shares of group electricity needs as weights):

1–26	27.3	26.6	26.6	26.5	26.4
27–29	125.3	125.3	125.3	125.3	124.8
30–32	99.4	99.0	99.0	92.8	92.4
1–32	33.2	32.5	32.3	32.2	32.0

Table 10: Marginal costs by transmission region: Weekends–Holidays (cents per kWh, Mexican Pesos)

	Demand periods				
Region	16	17	18	19	20
1	25.3	25.0	24.9	24.9	24.9
2	24.9	24.6	24.6	24.6	24.6
3	24.3	24.0	24.0	24.0	24.0
4	25.2	25.2	25.1	25.1	25.1
5	23.2	23.2	23.2	23.2	23.2
6	25.1	25.1	24.2	24.2	24.2
7	26.7	26.7	26.7	26.7	26.7
8	23.9	23.9	23.6	23.4	23.4
9	25.5	25.5	25.2	25.0	25.0
10	24.7	24.7	24.7	24.7	24.7
11	25.8	25.8	25.8	25.8	25.8
12	27.1	27.0	27.0	27.0	27.0
13	25.4	25.4	25.4	25.4	25.4
14	27.7	27.7	27.7	27.7	27.7
15	27.6	27.6	27.6	27.6	27.6
16	24.5	24.5	24.5	24.5	24.5
17	26.6	26.6	26.6	26.6	26.6
18	24.0	24.0	24.0	24.0	24.0
19	27.1	27.1	27.1	27.1	27.1
20	22.3	22.3	22.3	22.3	22.3
21	21.0	21.0	21.0	21.0	21.0
22	19.7	19.7	19.7	19.7	19.7
23	32.0	31.5	31.5	30.5	30.5
24	33.3	32.8	32.8	32.8	32.8
25	35.4	34.9	34.9	33.5	33.5
26	33.0	33.0	33.0	33.0	33.0
27	119.9	119.9	118.5	118.5	118.5
28	128.3	128.3	126.8	126.8	126.8
29	130.7	130.7	129.2	129.2	129.2
30	93.3	89.7	87.9	87.9	87.9
31	100.2	92.1	92.1	92.1	92.1
32	102.7	94.4	94.4	94.4	94.4

Weighted averages across groups of regions (with the shares of group electricity needs as weights):

1–26	26.0	26.0	25.9	25.8	25.8
27–29	125.7	125.7	124.3	124.3	124.3
30–32	99.4	92.0	91.7	91.7	91.7
1–32	32.1	31.8	31.6	31.5	31.5

varies and plants with different operating costs become the marginal source of supply.

If hydroelectricity is available, but the amount of stored water is limited, prices may still fluctuate seasonally. The water is optimally used first to supply electricity at the peak periods. If water remains after doing that, it is used next in the near-peak periods and so on. In the off-peak periods when water is not used, the price of electricity would be lower than in the periods when water is used.

Transmission losses, and transmission constraints, also influence the regional pattern of marginal costs. It is simplest to consider first the case where none of the transmission links is congested. The marginal cost at the sending end of an active link then has to exceed the marginal cost at the receiving end by the marginal transmission loss. If the marginal costs in the two regions differ by less than the transmission loss, transmitting power between them is not worthwhile and the link will be inactive.

Laguna (7) and its neighboring regions (6, 4, 9 and 14) illustrate the effect of transmission losses. In all periods, the marginal cost is higher in Laguna than in the three regions Chihuahua (6), Mazatlán (4) and Monterrey (9) to the north, west and east. Evidently, power flows from these latter regions to Laguna. On the one hand, in all periods the marginal costs are higher in the Ags-SLP region (14) to the south than they are in Laguna. Power must therefore flow from the north to the central region along the Laguna to Ags-SLP link. The differences in marginal costs along these links reflect the marginal transmission losses.

With an annul demand of 5,685 GWh, Laguna is a medium sized consumption center, but its scarce local generating capacity means that about 60% of its electricity needs are supplied from other regions. Laguna is also a transshipment point, however, for power flowing from the north to the large demand load in the center of the country. Even though Laguna is a net importer of electricity, the link to the south has power flowing out of the Laguna region. Evidently, the excess demand for power in the central region of the country is even greater than the excess demand in Leguna.

The Monterrey region (9) has the second highest demand for electricity in the country and meets about 68% of its electricity needs with imports from other regions. The marginal costs in Monterrey therefore are higher than in the surrounding regions (8 and 10) that export power to Monterrey. On the other hand, we have already seen that the marginal costs in Monterrey are below those in Laguna so that, even though Monterrey is a net importer of electricity, power nevertheless flows from Monterrey toward Laguna in all of the model periods.

The pattern of marginal costs in Monterrey (9) versus Reynosa (11) is consistent with the direction of power flow reversing over the course of the year. In the summer and shoulder periods, the marginal costs in Monterrey are higher than those in Reynosa, implying that power flows west toward Monterrey. In the fall, and on weekends and holidays, however, the marginal costs are lower in Monterrey implying that power flows east toward Reynosa. This may be the result of the different pattern of scheduled maintenance in the two regions.

There is also a reversal in the direction of power flow between the Huasteca

(10) and Oriental (18) regions. For most of the year, the marginal cost in higher in region 10 than in region 18, implying that power flows north. In the two highest demand periods in the fall, however, the marginal cost is higher in region 18 than in region 10 implying that power flows south. As the estimated monthly deviations in demand shares presented in Table 23 show, the seasonal fluctuation in demand is less in the south than in the north and also shows a slight peak in the fall as opposed to the summer. These different seasonal patterns can explain the reversals in the direction of flow between the seasons. It is also interesting to note that even though power tends to flow south from Huasteca to Oriental in the fall, for the three lowest demand periods in the fall, the flow is either from south to north or the link is inactive. As the representative daily load curves in Figure 3 show, the fall season in the south is characterized by a much greater peak to off-peak daily fluctuation than occurs in either season in the north or in the summer in the south. Thus, demand in the south during the three lowest demand periods in the fall is still low enough that additional power is not required from the north.

The lowest marginal costs occur in the Grijalva region (22). As we noted above, there is more than 3,900 MW of hydroelectric capacity located on the Grijalva river. The total hydroelectric generating capacity in the Grijalva region is sufficient to ensure that marginal generating costs there are constant throughout the year. As one moves away from the Grijalva region to the north, marginal costs reflect more seasonal variation as transmission costs fluctuate with the load and high cost local plant is used to supply peak demands.

Limited transmission capacity also plays a role in allowing costs to fluctuate across seasons and times of the day as one moves away from the Grijalva region. The Yucatan peninsula (regions 23–26) dramatically illustrates how costs are affected when transmission links become congested. The power flowing on the weak link[34] between Grijalva and neighboring Lerma (region 23) is not sufficient to equilibrate marginal costs net of transmission costs. The higher costs are then passed on to regions further down the system. In particular, further weak links between regions Lerma and Mérida (region 24) and Mérida and Chetumal (region 25) produce additional large increments in marginal costs. On the other hand, Cancún (region 26) has marginal costs below those in Mérida and almost as low as the marginal costs in Lerma. The Cancún region has the largest concentration of generating plant in the Yucatan and evidently exports power to the Mérida region despite the high costs of satisfying the local demand. A strengthening of the Cancún to Mérida link would actually raise prices in Cancún even further as more power was exported to the west.

The large marginal cost differences between two regions linked by a binding transmission constraint represents the "shadow value" of increasing the capacity of the link. If there were competitive wholesale power markets at both ends of the link, market prices would reflect the marginal costs in each region. A new entrant building a new link (or strengthening an existing one) could earn the price differential in each period. If the discounted present value of these

[34]The capacity is 110 MW at 230 kV.

anticipated revenues were sufficient to cover the capital cost of the link upgrade, the project would be profitable and efficient to undertake. Independent entrepreneurs have already invested in such network upgrades in the wholesale electricity markets in Australia.

The value of additional links in Mexico is even more apparent in the Baja California peninsula. Currently, there are two systems in Baja that are not connected to the rest of the Mexican grid, although the system in the north of Baja is connected to the United States via California. The marginal costs of generation are in Baja California are higher than they are anywhere else in the country. The region currently depends on diesel generating plants that are expensive to operate. If market prices reflected marginal costs, there would be a large incentive to strengthen connections between Baja California and the remaining networks in both Mexico and the United States.[35]

A change in one network link is likely to have consequences elsewhere in the system. For example, strengthening the Cancún to Mérida link also would reduce the differential in marginal costs between Lerma and Mérida and therefore the implicit value of augmenting the capacity of the Lerma to Mérida link. It is not inefficient, however, for a potential investor in one link to ignore these effects on other links. As in any market, a change in supply or demand conditions can affect the prices paid or received by other consumers or producers. The price changes signal that the opportunity cost of using scarce resources has changed and that supply and demand decisions need to be adjusted accordingly. There is, therefore, no need to centrally coordinate network investment decisions on these grounds.

It might be thought that the need to maintain the physical stability of the network is a different matter. In general, the stability of voltage levels, frequencies and power flows depends on the whole network and not just individual links. Even in this case, however, if there were competitive markets in ancillary services (as discussed above) actions that stabilize, or destabilize, the network would be priced and private individuals and firms would receive appropriate signals to take these factors into account when making their decisions about supply and demand.

Concerns about imperfect competition, however, may justify oversight of network operation and expansion. Network operation is a "natural monopoly" activity in the sense that only one agency can be responsible for scheduling generators to supply demand while maintaining system operating parameters within specified bounds.[36] A network operator that also owned generating plant or transmission links would have an incentive to manipulate the dispatch of generators to increase returns to its own assets. Similarly, an owner of one

[35] The model does not consider international electricity trade with the USA. There are plans to place new generating plant in Baja California using imported LNG as fuel. These plans, if brought to fruition, would strengthen the transmission grid in Baja and turn the region into a power exporter to the US. One of the perceived advantages of siting the plant in Baja and exporting the power north is that it would enable US utilities to circumvent political constraints on siting new plants in California.

[36] Extensive and frequent use of sub-contracting, however, would allow the construction and maintenance of network facilities to be organized as a competitive industry.

network link who owned other links, or generating plants, may have an incentive to limit transmission capacity in order to drive up the rents on other assets. Regulatory oversight may be needed to prevent the abuse of monopoly if the industry is not structured to ensure adequate competition.

Tables 7 and 8 also report non-zero marginal costs associated with the reserve constraints (19). These costs represent the lowest fixed operation and maintenance costs that the system must incur in order to provide the last kW of capacity reserve required to cope with emergencies. While the reserve constraints for each region could bind in any period, in practice they do not bind in periods other than 1, 2 or 11,[37] which are peak periods of demand for some regions of the country. Summer demand in the south, and demand for the system as a whole, peaks in period 1, while period 2 corresponds to the summer peak in the north. Period 11 coincides with the fall peak in the south, which for some regions exceeds the summer peak in period 1. The generating capacities, $\bar{g}_n$, associated with the reserve constraints do not vary period by period. They are established for the year as a whole and potentially constrain generation output in each period. Ensuring that capacity is sufficient to cope with extreme demand fluctuations in the peak periods, however, is likely to guarantee also that capacity will be more than sufficient to cope with the same proportional variation in demand in off-peak periods.

In all regions except Acapulco (19), the reserve constraints bind in the peak period for the system as a whole. If there were no binding transmission constraints, we would expect to find the reserve constraints binding only in the peak period for the system as a whole. Even if demand peaked in other periods in particular regions, there would have to be surplus capacity elsewhere in system at those times since the system as a whole needs sufficient capacity to meet the highest overall demand peak. Although there are transmission losses associated with using surplus plant located in other regions to meet local demand surges, such extreme demand surges are brief. The transmission losses generally would be small relative to the cost of keeping additional generating capacity available to supply output for only short periods of time. Regional demand variations that are negatively correlated will not affect the overall system demand as much as positively correlated demand shocks. Analogously to financial markets, the *undiversifiable* component of demand variation is the relevant "risk" that gives rise to a demand for the "insurance" supplied by surplus generating capacity.

The argument that there should be only one period when the reserve constraints bind implicitly assumes, however, that there is an unrestricted ability to arbitrage costs differences between regions. Transmission losses raise the costs of arbitrage, but transmission capacity constraints can prevent arbitrage altogether. In particular, the variation in marginal costs associated with the reserve constraints in Mexico is much more extreme than the variation in marginal costs associated with the demand constraints. Evidently, many of the transmission links in the Mexican system are weak and become congested under conditions

[37]The marginal costs associated with all reserve constraints in periods other than 1, 2 or 11 are zero and have not been reported in the tables.

of extreme demand.

The Acapulco region (19) provides an obvious example of the effect of transmission constraints. The fact that the reserve constraint does not bind in this region in period 1, despite its connection with the rest of the system, implies that the 240MW link between Acapulco and the Central region (17) must be congested. Table 6 provides a further indication of this. The availability of the plant in Acapulco remains at just 35% in the summer season despite the high implicit return to providing capacity to the Central region in times of extreme demand during those months. The reserve constraint in Acapulco thus depends on local demand variation more than system-wide variation in demand, and hence binds at the local peak in the fall rather than the system peak in the summer. The associated marginal cost (in cents per kWh) is determined by the local cost of providing additional capacity and the number of hours over which that cost will be spread.

Transmission constraints also play a role in producing the remaining binding reserve constraints in periods 2 and 11. These cases are somewhat different, however, in that the reserve constraints also bind during the system peak in period 1.

The Ags-SLP (14), Bajío (15) and Central (17) regions have binding reserve constraints in the fall as well as the summer. Bajío and Central both have very high total demand, with a local peak in period 11 during the fall. The reserve constraint can be binding in both periods 1 and 11 since the transmission levels are different. In particular, the fact that the reserve constraints are not binding in regions 7, 12, 16 or 18 in period 11 implies that the transmission links from these regions to regions 14, 15 and 17 must be congested under an extreme demand load during period 11. By contrast, under an extreme demand load during the system peak period, power flows north from region 14 to region 7, for example, so the link from 7 to 14 cannot be congested in the southern direction. Local reserve capacity in regions 14, 15 and 17 that is sufficient to meet the local extreme demand in period 11, with maximum import of power from elsewhere in the network, therefore is not sufficient to meet local extreme demand in period 1 when less power is available from other regions.

A similar explanation applies to the Sonora Norte (1) and Sonora Sur (2) regions, which have binding reserve constraints in the second as well as the first summer period. These regions (as do all regions in the north) have local peak demands during period 2 rather than period 1.[38] Regions 1 and 2 are connected to the rest of the network via a relatively weak 220MW link to region 3 (Mochis). Since the reserve constraint in region 3 is not binding in period 2, the transmission link must be congested under an extreme period 2 load. Under an extreme demand load in period 1, however, the demand for power in southern regions is substantially greater than it is in period 2, leaving less available to satisfy demand in the north. The transmission link between regions 3 and 2 remains uncongested, but more local capacity is required to satisfy the

[38]Recall, however, that the differences in demand between periods 1 and 2 in the north are slight. This may explain why there are not more northern regions with binding reserve constraints in period 2 in addition to period 1.

slightly reduced extreme demand load.

Region 16 (Lázaro Cárdenas) has much stronger links (950MW, 460MW and 400MW) to the rest of the network than do the Acapulco or Sonora regions. Nevertheless, it can also be affected by transmission constraints. The marginal reserve cost in period 1 is only 58.8 cents Mexican per kWh in region 16 but 149.5, 238.4 and 245.8 in the three neighboring regions 12, 15 and 17. These differences in marginal cost greatly exceed the transmission losses and indicate congested transmission lines. Lázaro Cárdenas has its local peak in the fall and will need greatest capacity during a temporary demand surge in period 11. The link to region 12 is not congested during period 11, however, and can transmit power to region 16 from the north. As a result, the reserve capacity needed in region 16 in the summer is sufficient to also cover a demand surge during period 11.

Lázaro Cárdenas actually has the smallest reserve marginal cost of any region. As Table reftransregions reveals, this region has only three generating stations with a 1999 capacity of 3,395MW. The marginal cost of expanding the available capacity of these plants evidently is relatively small.

The Grijalva region (22) has marginal reserve costs that are almost as low as those in Lázaro Cárdenas. Table reftransregions shows that the Grijalva region has only hydroelectric plants, with capacity that can be made available at a higher level at relatively low cost. The large jump in marginal reserve cost in period 1 between regions 20 and 18 implies that the transmission link between these regions is congested under extreme demand conditions in period 1. The congested link between regions 18 and 20 prevents the Grijalva hydroelectric plants from providing further relatively low cost capacity to meet demand surges in regions further to the north and west of region 18.

From the values presented in Tables 7 and **??** it is clear that the high marginal reserve costs in periods 1 and 11 help drive the weighted average marginal cost above the average cost of generation. As we noted above when introducing the reserve constraints, in an ideally structured wholesale market for electricity at least some of these payments would take the form of payments for ancillary services. Under extreme demand loads, additional generating capacity is placed on standby in case it is needed to maintain voltage and frequency levels, or to re-start the system in the event of a blackout. Owners of plant that is cheap to keep on stand-by and fast to convert to supplying output could earn a return for providing the reserve capacity even if they are not actually called upon to supply power.

4.4 Prices and marginal costs

The model calculations show that the marginal costs of generating electricity vary by the location of the consumer and the time at which consumption occurs. In reality, the latter dependence primarily reflects different costs of supply as the total load on the system varies.[39] Prices of electricity in Mexico, however,

[39]Marginal costs also vary by time, however, because of factors such as the need to assign contiguous periods for scheduled maintenance, allowing for holiday periods or seasonal

Table 11: Average price versus marginal generation cost by region and season

Administrative region	Summer price	Summer cost	Shoulder price	Shoulder cost	Fall price	Fall cost
Baja California	0.6000	1.3445	0.5899	1.2198	0.5312	1.1992
Noroeste	0.5272	0.3372	0.4767	0.2568	0.4787	0.2395
Norte	0.4527	0.3693	0.4645	0.2588	0.5065	0.2484
Golfo Norte	0.4836	0.3770	0.4926	0.2619	0.5166	0.2483
Golfo Centro	0.4712	0.3586	0.4829	0.2554	0.4946	0.2418
Bajío	0.4842	0.3977	0.4865	0.2809	0.5207	0.3755
Jalisco	0.5602	0.3397	0.5675	0.2705	0.5871	0.2638
Centro Occidente	0.4248	0.2740	0.4294	0.2454	0.4453	0.2452
Centro Oriente	0.4887	0.3507	0.5007	0.2470	0.5130	0.2414
Centro Sur	0.5025	0.2712	0.5256	0.2712	0.5490	0.3071
Oriente	0.4617	0.3428	0.4762	0.2449	0.4873	0.2397
Sureste	0.5821	0.2364	0.6034	0.2037	0.6338	0.2036
Peninsular	0.5949	0.4653	0.6236	0.3560	0.6488	0.3101
LyF	0.5831	0.3848	0.6038	0.2714	0.6356	0.3734

typically do not vary much by location or time of demand and thus do not closely mimic the marginal generation costs. In particular, while there is limited seasonal variation in prices, there is little variation by time of day.

Electricity suppliers incur costs apart from generation, including the costs of maintaining the distribution network and providing customer service, that do not vary as systematically by time or location. Nevertheless, prices are unlikely to accurately signal the marginal costs of supply to consumers unless they vary by location and time of supply.

Table 11 presents the average electricity price paid in each administrative region in the three main seasons. For comparison, it also provides the weighted average marginal generating costs calculated from the model. The latter are derived by weighting the marginal costs in Tables 7, 8, 9 and 10 by the corresponding demands in each transmission region and each season. Since the revenue needs to cover more than generating costs, it is not surprising that prices on average exceed the marginal generating costs. It is somewhat more interesting, however, to note that the average prices vary much less by season and region than do the marginal costs. Furthermore, in many cases, the pattern of marginal cost variation across regions and seasons is not reflected in the price variations. This is particularly apparent for those regions where the reserve marginal costs are positive in periods other than the summer peak. It would appear that consumers, and potential generators of electricity, are not being given very appropriate signals about the costs or benefits of changing electricity demands or supplies at different locations on the network or at different times

availability of water supplies for hydroelectric plant.

of the year.

The electricity tariffs in Mexico fall into two main categories. One category, known as "specific rates," classifies customers by the purpose for which they use electricity. The tariffs for residential, commercial, agricultural and public services demand largely fall into this category. The second group of tariffs differentiate between customers based on the amount of energy that they consume and other characteristics of their supply including in particular the voltage level at which they draw power. The latter is important because many losses occur in the distribution network or result from transforming power to lower voltage levels. Hence, it is generally much less costly to supply power to large customers drawing directly from the high voltage transmission network.

Residential tariffs. The price of electricity for households is a step function with three price levels that depend on demand. The prices for each step change according to region and season and thus could, in principle, partially reflect cost differences.[40] All residential customers face the same rate scale in non-summer months. During the summer, however, households are charged different rates according to the average temperature of the region. A common problem with step function tariffs is that different households pay a different price for electricity that costs the same amount to supply to each of them. This leads to inefficiencies since the household paying a higher price would be willing to pay more for the marginal power consumed by the household paying the lower price but is prevented from doing so.

Agricultural tariffs. Agricultural users face two different tariffs depending on the voltage level at which they take supply. In either case, the tariff schedule is a step function with four levels. As with residential tariffs, prices vary somewhat by region and season.

Commercial tariffs. Commercial users also face a step function tariff, with the marginal price determined by the maximum demand and the total consumption within the billing period. In this case, the prices on the steps of the tariff do not vary by region or season, but are changed from one billing cycle to the next via indexation to components of the wholesale price index.

Industrial tariffs. There are 16 different schedules for the industrial sector and two additional rates for firms willing to allow their service to be interrupted at short notice.[41] All but one of the industrial tariffs includes some price differences by region and by hour of use. The latter differentiation is based on

[40]Such a price structure could not reflect all cost differences since marginal costs vary within a day or across days of the week in addition to seasons.

[41]In the latter case, companies enrolled in the program are asked, at least 15 minutes in advance, to reduce their demand for electricity. They are then credited an amount that depends on the reduction in demand. There are two categories of such service, one for demands equal or higher than 10,000 kW in peak hours and another for demands equal or higher than 20,000 kW.

base, intermediate and either semi-peak or peak demand. Charges are further differentiated depending on the voltage level at which service is provided, total energy consumed within the billing period, the overall maximum demand within the billing period or the sum of the maximum daily demands within the period or whether the firm agrees to pay a fixed charge. In this sector, the price for electricity is indexed to the variation of fuel prices and to the producer price of three industrial components of the wholesale price index.

4.5 Altered plant availability

The base case has demonstrated that hydroelectricity plays a significant role in the Mexican electricity supply system. An important problem that Mexico faces, however, is that rainfall is not always reliable and the availability of hydroelectric plants can be severely curtailed as a result of drought.

To see how the system is affected by reduced hydroelectric plant availability, we re-computed the costs of meeting the 1999 demand levels but using the availability of plants from 1998. As a result of dry weather, hydroelectric plant had much lower availability levels in 1998 than in 1999. To compensate, many of the thermal plants were run at higher availability levels.

Table 12 gives the differences in annual availabilities in the two years by regions. The differences between the two years are not only the result of different availabilities of hydroelectric plant. Using the actual availabilities from 1998, however, allows us to examine what can happen under an alternative "realistic" scenario.

Comparing Table 12 with Table 4, we see that the main regions with reduced availability in 1998 relative to 1999 are those with substantial hydroelectric generating plant. In particular, the availabilities in regions 21 (Minatitlan) and 22 (Grijalva), which have only hydroelectric plant, were 35.7% and 39.6% lower in 1998 than in 1999. Guadalajara (region 12), which had 57.8% lower availability in 1998, has 8 hydroelectric generating plant and only 1 thermal plant. Other regions with significantly lower availability in 1998 were Acapulco (region 19, with 3 hydroelectric and 1 thermal plant) and Temascal (region 20, with 2 hydroelectric and 1 renewables plant).

Low water supplies were, however, not the only problem in 1998. Three regions in Baja California with only thermal plant (Ensenada, 29, Tijuana, 28, and Cabo San Lucas, 32) each had substantially reduced availability, although the very small Ensenada, and particularly the Cabo San Lucas, plants also had fairly low availabilities in 1999.

The most significant increases in availability in 1998 relative to 1999 typically were in regions with substantial thermal generating plant. Examples include regions 7 (Laguna, with 5 thermal plants), 26 (Cancún, with 7 thermal plants), 27 (Mexicali, with 2 thermal and 3 renewable plants) and 5 (Juárez, with 1 thermal plant). On the other hand, three regions with significant numbers of hydroelectric plant also had higher availabilities in 1998 than 1999. These were Central (region 17, with 13 hydroelectric and 7 thermal plants), Bajío (region

Table 12: Difference in availability by region with reduced hydro

Region	1999	1998	% diff
1	0.51	0.53	4.7%
2	0.49	0.52	5.8%
3	0.32	0.35	10.8%
4	0.70	0.70	0.0%
5	0.71	0.79	11.4%
6	0.51	0.52	2.6%
7	0.51	0.68	34.8%
8	0.72	0.73	0.0%
9	0.62	0.64	4.0%
10	0.80	0.78	-2.3%
11	0.66	0.65	-1.2%
12	0.63	0.27	-57.8%
13	0.74	0.78	6.3%
14	0.75	0.77	2.7%
15	0.65	0.70	9.2%
16	0.54	0.56	3.2%
17	0.61	0.67	10.0%
18	0.70	0.70	0.7%
19	0.31	0.25	-20.3%
20	0.61	0.56	-9.3%
21	0.52	0.34	-35.7%
22	0.51	0.31	-39.6%
23	0.67	0.67	0.0%
24	0.59	0.58	-1.5%
25	0.00	0.01	∞
26	0.28	0.33	16.2%
27	0.58	0.65	12.1%
28	0.41	0.39	-4.7%
29	0.28	0.05	-80.8%
30	0.45	0.46	4.0%
31	0.48	0.48	0.0%
32	0.02	0.01	-36.8%
Average[a]	0.62	0.63	2.5%

a. Weighted average, with generation per region as weight.

15, with 9 hydroelectric, 3 thermal and 1 renewables plant) and Mochis (region 3, with 6 hydroelectric and 2 thermal plants).

It might be thought that if thermal plant can be made more available in drought years they could be made more available in all years. Using thermal plant to generate more electricity is, however, likely to lead to increased maintenance problems in the future. Higher availability in one year therefore is likely to lead to reduced availability in future years as plants are taken out for maintenance. Running plants harder in one year is also likely to raise the annual maintenance costs in future years. This factor has been ignored in our cost estimates presented below.

We will not discuss all the details of the altered availability scenario.[42] We shall instead focus on the major differences in costs and system operation relative to the base case.

In the scenario with 1998 availabilities, the system generates only 177,971 GWh compared with 178,664 GWh generated in the base case. Both scenarios have the same final demand levels. Hence, the difference between generation levels implies that transmission losses are lower under the altered availability scenario.

The minimized total generating cost of meeting the 1999 demands with the 1998 plant availabilities is 31,595 million pesos compared with 30,376 million pesos in the base case, even though more electricity is generated under the base case. Changing the plant availabilities raises the minimized total costs, and average costs per kWh of power provided to consumers, by about 4%. The differences in marginal costs between the two scenarios are even larger. The weighted average marginal cost (with final demands as weights) in the reduced availability case is 38.58 cents per kWh compared with 32.08 cents per kWh in the base case, which is an increase of 20.3%. The dramatic increase in marginal costs resulting from the reduced availability of hydroelectricity reflects the higher costs of marginal thermal generating plant. It is another indication that electricity generation is not a "natural monopoly" in the sense of exhibiting declining costs as output expands.

Although the weighted average marginal cost is higher under the alternative availability scenario, the *dispersion* in marginal costs across regions is less in all periods, except only for the marginal reserve costs in period 2. This result may seem surprising. Since stored water can be used to generate hydroelectricity at any time, it generally allows the dispersion in costs across time periods to be reduced. Thus, a lower availability of hydroelectric capacity might be expected to produce more variable marginal costs. In the Mexican system, however, lower availability of hydroelectricity requires a greater use of localized thermal generation to satisfy demand. With less hydroelectricity being produced and transmitted over long distances, the network becomes less congested. When links are being used at less than capacity, a marginal change in local demand can be met by a marginal change in transmission levels. The price differentials between regions then become the marginal transmission losses. These are gen-

[42] Complete results are available from the authors upon request.

erally much smaller than the marginal cost of increasing output from different local thermal plants.

The different marginal costs of *reserves* under the two scenarios also reflect the lower extent of network congestion when hydroelectricity is less available. In particular, when it is possible to meet demand fluctuations by adjusting transmission levels, cost differences can be arbitraged away to a greater extent and the network behaves more like a unified system. Except for regions 1 and 2, the reserve marginal costs are positive only in period 1 when the system-wide demand peaks. In particular, transmission links to the central regions 14, 15, 17 and 19 can carry more power in the fall than they do in the summer, allowing the local generating capacity required for the system peak to cope with the local peak in the fall. From Table 12, generators in regions 14, 15 and 17 were used much more extensively under the 1998 regime.

In regions 1 and 2, marginal reserve costs are positive during both the local peak (in period 2) and the system-wide peak (in period 1). Since the transmission constraint from region 3 to region 2 is constrained in period 2, higher demand in period 2 can be met only by increased use of local plant.

The marginal costs in the Baja California regions (27–32) are the other major difference between the base and the altered availability scenarios. The Baja California costs are lower under the alternative scenario, while costs in most other regions are higher. The major explanation, as Table 12 and Table 4 show, is that the regions within Baja California that had increased availability in 1998 tended to have higher available plant capacities in 1999 than the regions with reduced availability.

5 The anticipated situation in 2005

In this section, we combine the model of the electricity supply system with the demand forecasts to investigate how planned additions to generating and transmission capacity will enable the system to deal with the anticipated growth between 1999 and 2005. We focus on 2005 since the investment schedule until then has been approved and most of the projects are already under construction. For years beyond 2005, the investment projects are more uncertain.

Table 13 presents the expected construction of generating capacity from 2000 to the end of 2004 in each of the 32 transmission regions.[43] Table 13 also gives our estimates of the forecast evolution of electricity sales[44] and generation output by transmission region.

The state-owned CFE recently has encouraged greater private investment in electricity generation. This has taken the form of self-generation by large industrial plants with sales back to the CFE when output exceeds the firm's

[43]The data on planned additions to generating capacity and their costs are from the CFE, "Prospectiva del Sector Electrico 2001-10," the Ministry of Finance and Public Debt (SHCP), "Presupuesto de Egresos de la Federacion 2002," available at http://www.shcp.gob.mx/docs/pe2002/pef/temas/pidiregas/cfe.pdf, and the Energy Regulatory Commission (CRE), http://www.cre.gob.mx/estadisticas/stat98/electr.html.

[44]Sales and demand for electricity are different because of the losses.

Table 13: Additions to the installed generating capacity by the end of 2004[a]

Region	No.	Type[b]	Capacity (MW) Added	Capacity (MW) Total	Generation GWh	Demand GWh
1	2	CC	525	1,332	7,075	5,888
2				746	3,159	3,641
3				1,167	3,080	2,760
4				616	3,789	1,161
5	1	CC	268	584	7,334	5,628
6	2	1CC, 1Ga	583	1,701	4,019	4,859
7				643	2,288	8,518
8				2,710	17,192	2,969
9	4	3CC, 1Ga	1,545	3,211	16,512	29,840
10	2	CC	1,591	2,391	16,186	4,970
11	2	CC	1,032	1,544	10,568	4,086
12				1,352	2,146	12,432
13				1,900	9,850	1,516
14	2	O	480	1,200	7,854	9,758
15	5	4CC, 1Ge	1,390	2,837	12,582	26,657
16				3,395	16,031	612
17	1	CC	257	3,614	16,875	49,656
18	2	CC	1,576	6,268	39,281	21,186
19				681	1,496	3,437
20				358	1,736	1,783
21	1	D	25	51	3,623	3,633
22	1	H	936	4,864	21,610	3,530
23	1	CC	261	425	1,829	1,164
24	1	CC	531	808	3,392	3,124
25				14	0	281
26	1	CC	100	629	3	1,582
27	1	Ge	100	784	4,073	3,993
28	2	CC	1,065	2,181	9,122	7,423
29				55	0	1,244
30	3	2D, 1Ge	52	181	951	262
31				156	857	1,235
32				30	25	209
Total	34		12,308	48,398	244,514	228,827

a. Includes some 1999 capacity that was not available until 2000. Expected retirements (of 560MW) are not included since the location of these is unknown.
b. CC = combined cycle, D = Diesel, Ga = gas turbine, Ge = geothermal, H = hydroelectric, O = oil

Figure 4: Planned changes to the transmission network by 2005

own needs (co-generation), and also private construction under various types of contracts with the CFE. The latter category includes BLT, IPP and "turnkey" plants built by the private sector, but with all of the output produced or purchased by the CFE. Co-generators are allowed to sell only up to 25% of the capacity of their plants to the CFE, and only under very restrictive conditions.

Under the BLT, IPP and turnkey schemes, firms bid through public tender to provide new plants. The BLT plants are operated by the CFE, but leased for a period before being turned over to the CFE. By contrast, the private builder of an IPP plant also operates the plant under a long term contract to supply power to the CFE. In a turnkey project, the private firm constructs the plant for the CFE, which then owns and operates the plant.

Table 13 covers all private and public sector projects. In fact, of the expected 69,084 million pesos (in year 2001 currency) of proposed investments in generating plant between 2000 and 2004, 66,891 million pesos will be undertaken by private firms. Seven of these are co-generation projects expected to provide about 1,889 MW of capacity by the end of 2004. Of the 12,308 MW of additional capacity by the end of 2004, 7,303 MW will be built by private firms, with 6,198 MW of this in combined cycle plants. Public investment is expected in just two plants – a 114 MW hydroelectric plant and a 125 MW combined cycle plant.

In addition to new generating plant, the CFE have plans for substantial enhancements to the transmission network. These involve building new links between some regions and enhancing some of the existing links. Figure 4 illustrates the changes that are expected to be in place for the period November 2004 to October 2005.

As with the generation investments, much of the investment in the transmission system is being undertaken by the private sector. Of the 75,272 million pesos (in 2001 currency) required to undertake the transmission investments illustrated in Figure 4, 46,684 will be financed by the private sector and 28,588 by the public sector. The private schemes are BLT and turnkey projects, or else transmission investments associated with co-generation projects.

The estimated total generation costs in 2005 (in year 2000 currency) are 40,116 million pesos. The forecast power generated for the period November 2004 to October 2005 is 244,539 GWh. Recall that the corresponding numbers for 1999 were a cost of 30,376 million pesos and a total output of 178,664 GWh. The average generation cost in 2005 is 16.40 cents per kWh compared with 17.00 in 1999. The average generating costs are thus predicted to decline slightly despite a forecast growth in production of almost 6.5% per year. Whether or not the investments are justified depends on the magnitude of the investments relative to the value of the additional electricity generation for consumers. We do not have sufficient information to make this judgment. The rather low price elasticity of demand estimated in the first section of the paper implies, however, that the loss in consumer surplus associated with a reduction in electricity consumption is likely to be quite large.

If all the planned investments are completed, our model also forecasts that the demand-weighted marginal costs will decline from 32.08 cents per kWh in 1999 to 25.46 cents per kWh in 2005. This is an even larger percentage decline than for the average costs. The geographical and temporal variation of marginal costs is also forecast to change. Tables 14, 15, 16 and 17, corresponding to Tables 7, 8, 9 and 10 in the base case, present the forecast marginal costs in 2005. In particular, reserve costs are expected to be non-zero only in the summer peak period in 2005, while the marginal costs associated with the demand constraints are also expected to vary less than in 1999. Both of these results suggest that the transmission network is likely to be less constrained in 2005 than it was in 1999.

5.1 Reduced transmission investment

The level of planned investment in generating and transmission capacity from 2000–2004 is 144,356 million pesos (in 2001 currency). Of this amount, over 30,000 million pesos is slated to come from the public sector. There are also large planned expenditures for investments in the distribution system and the maintenance of existing capital. The public sector is expected to finance over 50,000 million of the more than 62,000 million pesos expected to be invested in the distribution system, while maintenance expenditure of almost 30,000 million pesos will also need to be financed by the public sector.

The proposed transmission investments rely much more heavily upon direct public expenditures than do the generation investments. If the Mexican government encounters fiscal problems in the next two years, some of the transmission investments may be postponed. We therefore considered a scenario where all the generation investments are made as planned, but some of the investments

Table 14: Marginal costs by transmission region: Summer (May–August) (cents per kWh, Mexican Pesos)

	Demand periods					
	1		2	3	4	5
Region	Dem	Res				
1	25.9	192.1	25.9	25.7	24.4	24.4
2	25.6	189.9	25.6	25.6	24.7	24.7
3	25.1	180.0	25.1	25.1	25.1	25.1
4	26.0	186.2	26.0	26.0	25.8	25.8
5	26.1	195.6	25.7	25.2	24.0	23.9
6	26.5	199.3	26.2	25.7	24.5	24.4
7	28.3	218.3	27.9	27.5	26.5	26.5
8	25.0	195.0	24.7	24.2	23.5	23.3
9	26.8	206.3	26.4	25.8	25.1	24.9
10	25.2	186.3	24.8	24.8	24.8	24.8
11	25.7	198.0	25.3	24.8	24.1	23.9
12	26.8	188.6	26.7	26.5	26.5	26.5
13	24.7	174.1	24.7	24.7	24.7	24.7
14	27.1	203.8	26.7	26.3	26.0	26.0
15	27.5	202.3	27.1	26.9	26.7	26.7
16	24.9	170.0	24.9	24.9	24.9	24.9
17	26.3	183.5	25.5	25.5	25.5	25.5
18	24.4	170.1	24.4	24.4	24.4	24.4
19	25.9	180.3	25.9	25.9	25.9	25.9
20	22.3	148.4	22.3	22.3	22.3	22.3
21	20.8	132.6	20.8	20.8	20.8	20.8
22	20.4	124.9	20.4	20.4	20.4	20.4
23	21.2	176.4	21.2	21.2	20.8	20.7
24	21.7	183.2	21.5	21.5	21.2	20.9
25	22.0	185.8	21.8	21.8	21.5	21.2
26	21.9	185.3	21.8	21.8	21.4	21.2
27	24.2	329.0	24.2	24.2	24.2	22.0
28	23.8	312.7	23.8	23.8	23.8	22.4
29	24.8	325.8	24.8	24.8	24.2	22.7
30	101.2	180.5	97.6	97.6	97.6	86.3
31	106.9	189.9	103.4	103.4	102.6	90.8
32	105.1	186.8	105.1	105.1	104.3	92.3

Weighted averages across groups of regions (with the shares of group electricity needs as weights):

1–26	215.5	25.6	25.4	25.0	25.0
27–29	343.3	24.1	24.1	24.0	22.3
30–32	293.7	102.7	102.7	102.0	90.3
1–32	225.3	26.2	26.0	25.6	25.4

Table 15: Marginal costs by transmission region: Fall (Nov–Feb)
(cents per kWh, Mexican Pesos)

	Demand periods				
	11	12	13	14	15
Region					
1	24.1	24.1	23.5	23.5	23.5
2	24.5	24.4	23.8	23.8	23.8
3	25.0	24.8	24.2	24.2	24.2
4	25.9	25.7	25.1	25.0	24.8
5	23.6	23.6	23.6	23.6	23.6
6	24.1	24.1	23.9	23.9	23.9
7	26.4	26.2	26.2	26.0	25.7
8	23.3	23.2	23.2	23.2	23.2
9	24.9	24.8	24.8	24.8	24.8
10	24.1	24.0	24.0	23.9	23.9
11	23.9	23.8	23.8	23.8	23.8
12	26.8	26.4	25.8	25.7	25.5
13	24.7	24.4	24.0	24.0	23.9
14	26.3	25.9	25.8	25.6	25.2
15	27.5	27.1	26.4	26.1	25.9
16	24.9	24.4	23.7	23.5	23.5
17	26.8	26.4	25.6	25.2	24.7
18	24.7	24.4	23.8	23.8	23.6
19	26.4	25.9	25.9	25.5	25.0
20	22.3	22.3	22.3	22.3	22.2
21	20.8	20.8	20.8	20.8	20.8
22	20.4	20.4	20.4	20.4	20.4
23	21.2	21.2	20.7	20.7	20.5
24	21.6	21.5	21.0	20.9	20.6
25	21.9	21.8	21.3	21.2	20.9
26	21.9	21.8	21.2	21.2	20.9
27	22.8	22.0	22.0	22.0	22.0
28	22.4	22.4	22.4	22.4	22.4
29	22.7	22.7	22.7	22.7	22.7
30	94.2	86.2	86.2	86.2	86.2
31	99.1	90.7	90.6	90.6	90.6
32	100.7	92.2	92.1	92.1	92.1
Weighted averages across groups of regions (with the shares of group electricity needs as weights):					
1–26	25.5	25.2	24.8	24.6	24.4
27–29	22.5	22.3	22.3	22.3	22.3
30–32	98.5	90.2	90.1	90.1	90.1
1–32	25.9	25.5	25.1	24.9	24.7

Table 16: Marginal costs by transmission region:
Shoulder (March, April, Sept, Oct)
(cents per kWh, Mexican Pesos)

	Demand periods				
Region	6	7	8	9	10
1	24.4	24.4	24.4	24.4	24.4
2	24.7	24.7	24.7	24.7	24.7
3	25.1	25.1	25.1	25.1	25.1
4	26.0	26.0	26.0	26.0	26.0
5	24.3	24.3	24.3	24.0	23.9
6	24.7	24.7	24.7	24.5	24.4
7	27.1	27.1	27.1	26.7	26.7
8	24.0	24.0	24.0	23.6	23.4
9	25.6	25.6	25.6	25.2	25.0
10	24.8	24.8	24.8	24.8	24.8
11	24.6	24.6	24.6	24.2	24.0
12	27.0	26.8	26.8	26.8	26.8
13	26.4	26.4	26.4	26.4	26.4
14	26.6	26.5	26.4	26.1	26.1
15	27.5	27.2	27.1	26.9	26.9
16	24.9	24.9	24.9	24.9	24.9
17	26.6	26.3	25.6	25.6	25.6
18	24.5	24.5	24.5	24.5	24.5
19	25.9	25.9	25.9	25.9	25.9
20	22.3	22.3	22.3	22.3	22.3
21	20.8	20.8	20.8	20.8	20.8
22	20.4	20.4	20.4	20.4	20.4
23	21.2	21.2	20.8	20.8	20.7
24	21.6	21.6	21.2	21.2	20.9
25	21.9	21.9	21.5	21.5	21.2
26	21.9	21.9	21.4	21.4	21.2
27	24.3	24.3	23.6	22.0	22.0
28	23.9	23.9	23.2	22.4	22.4
29	24.2	24.2	23.5	22.7	22.7
30	95.5	95.5	86.4	86.4	86.4
31	100.6	100.5	90.9	90.9	90.9
32	102.3	102.2	92.4	92.4	92.4

Weighted averages across groups of regions (with the shares of group electricity needs as weights):

1-26	25.6	25.5	25.3	25.2	25.1
27-29	24.0	24.0	23.3	22.3	22.3
30-32	100.0	99.9	90.3	90.3	90.3
1-32	26.1	26.0	25.7	25.5	25.4

Table 17: Marginal costs by transmission region: Weekends–Holidays (cents per kWh, Mexican Pesos)

	Demand periods				
Region	16	17	18	19	20
1	23.9	23.9	23.8	23.8	23.8
2	24.4	24.4	24.1	24.1	24.1
3	24.8	24.8	24.5	24.5	24.5
4	25.7	25.7	25.3	25.3	25.3
5	23.5	23.5	23.4	23.4	23.4
6	23.9	23.9	23.9	23.9	23.9
7	26.2	26.2	26.2	26.2	26.2
8	23.2	23.2	23.2	23.2	23.2
9	24.8	24.8	24.8	24.8	24.8
10	24.0	24.0	24.0	24.0	24.0
11	23.8	23.8	23.8	23.8	23.8
12	26.5	26.4	26.1	26.1	26.1
13	25.4	25.4	25.4	25.4	25.4
14	25.8	25.8	25.8	25.8	25.8
15	26.5	26.5	26.4	26.4	26.4
16	24.4	24.4	24.4	24.4	24.4
17	25.5	25.1	25.1	25.1	25.1
18	23.8	23.8	23.8	23.8	23.8
19	25.9	25.9	25.9	25.9	25.7
20	22.3	22.3	22.3	22.3	22.3
21	20.8	20.8	20.8	20.8	20.8
22	20.4	20.4	20.4	20.4	20.4
23	20.8	20.7	20.7	20.7	20.5
24	21.2	21.0	20.9	20.8	20.6
25	21.5	21.3	21.2	21.1	20.9
26	21.4	21.2	21.2	21.0	20.9
27	22.8	22.0	22.0	22.0	22.0
28	22.4	22.4	22.4	22.4	22.4
29	22.7	22.7	22.7	22.7	22.7
30	86.2	86.2	86.2	86.2	86.2
31	90.7	90.7	90.7	90.7	90.7
32	92.2	92.2	92.2	92.2	92.2

Weighted averages across groups of regions (with the shares of group electricity needs as weights):

1-26	24.8	24.7	24.7	24.7	24.7
27-29	22.5	22.3	22.3	22.3	22.3
30-32	90.2	90.2	90.2	90.2	90.2
1-32	25.2	25.1	25.0	25.0	25.0

in the transmission system do not eventuate.

Excluding all transmission investments expected to be completed beyond the end of 2002 made it impossible to meet the forecast demands for 2005 with the planned additions to generating capacity. If planned transmission investments beyond 2002 do not eventuate, therefore, additional investment in generating capacity would be needed to meet the forecast demand growth.

We then examined the transmission investments expected to be completed by the end of 2003. Five major transmission projects should be completed in that year. There are three new links between nodes 1 and 5 (380MW), nodes 9 and 14 (568MW) and nodes 10 and 14 (1,500MW). There are also two significant upgrades between nodes 18 and 20 (an additional 1,600MW of capacity) and nodes 20 and 22 (an additional 1,000MW of capacity).

The projects to upgrade the links between regions 22–18 increase the amount of power that can be transmitted from the hydroelectric plants in the Grijalva river region (22) to the central part of the nation. We found that these projects are critical. If they are not completed by the end of 2004, the forecast demands from November 2004 to October 2005 cannot be met without building more generating capacity.

On the other hand, if the upgrade projects are completed on time while the three new links slated for completion in 2003 are not, the resulting system (with all new generating plant completed on schedule) is capable of satisfying the forecast demand in 2005. The resulting average cost of generation is 16.57 cents per kWh instead of 16.40 cents per kWh if all planned transmission investments are completed. On the other hand, the weighted marginal cost (at 25.34 cents per kWh) is actually lower if the new links are not built. The marginal costs are more variable across regions and seasons when the system is less well-connected. In the two regions with the largest demands (the central and Monterrey areas), however, the marginal costs are lower in the system with weaker links. These results show that marginal and average costs do not necessarily move in the same direction as a result of new investments. In particular, if prices reflected marginal costs, stronger transmission links could make some consumers worse off by facilitating increased arbitrage and equilibration of marginal costs across the network.

Another interesting consequence of not building the 1,500MW link from region 10 to region 14, while nevertheless adding all the new generating capacity planned for region 10, is that the reserve constraint does not bind in region 10 in any season. This result illustrates how transmission and generating investments interact. Without the accompanying transmission investment, some of the investment in new generating capacity can be wasted.

6 Conclusion

Our analysis implies that substantial investment is needed to meet the growing demand for electricity over the next decade. The Mexican government has turned to the private sector to help finance much of the needed investment.

It is questionable, however, whether the best method that has been chosen to encourage private investment. In particular, BLT, IPP and turnkey projects leave the public sector bearing most of the risks. One of the major functions of privately-owned firms, and the trade in stocks, is to share risks optimally and facilitate the financing of large, long-term risky investments. The risk adjusted return required to compensate investors for the risks they are bearing also signals the appropriate return for evaluating investments. In the absence of such information, it is much harder for publicly owned firms to decide whether investments are worthwhile.

Another potential defect of BLT and turnkey projects is that they leave the publicly owned firm in charge of operations. One of the major inefficiencies associated with public ownership is that the firm does not have a strong incentive to minimize operating costs. Even investors in IPP projects may have a reduced incentive to control costs if the contract price for their output depends on their costs, as it typically does.

The second major conclusion from our analysis is that there are substantial differences between electricity prices in Mexico and the marginal costs of supply. In particular, the regional and temporal variation of prices is not closely related to the corresponding variations in marginal costs. As a result, consumers are not receiving accurate information about the costs of meeting their demands and are not receiving accurate signals about the benefits of changing their location, or the timing of their electricity demands, so as to reduce the costs for the system as a whole.

Allowing private entry into the wholesale market for electricity, and setting prices through an auction mechanism, may also assist in making prices more reflective of costs. Before introducing such reforms, however, the existing publicly-owned suppliers would need to be separated along functional lines (with transmission and distribution separated from generation) and the remaining generating assets allocated to many competing firms. It may even be counter-productive to introduce a wholesale market for electricity that is not competitive. The price signals sent to consumers and potential entrant producers would be distorted measures of the costs and would encourage inefficient consumption and production decisions.

The third major conclusion from our analysis is that the hydroelectric generating plant in Mexico is quite valuable as a mechanism to smooth temporal and geographical variations in marginal costs of generation. In effect, the storage of water substitutes to some extent for the inability to store electricity. The benefits of hydroelectricity are limited, however, by weaknesses in the existing transmission network. The major hydroelectric generating plants are located in the Grijalva river region in the south of the country and the transmission links to other regions can often become congested. Upgrading the transmission links is thus a major priority. The public sector is expected to remain the major investor in the transmission network for the immediate future, however, and there is a risk that the needed investments may be sacrificed for fiscal reasons that have nothing to do with the needs of the electricity industry.

Appendix A: Modeling electricity demand

As we noted in the text, the aggregate demand forecast is derived by relating the logarithm of total power generation to GDP, the relative price of electricity, and a variable, based on temperature records, that accounts for seasonal variations.

Income. The GDP can be viewed as a proxy either for "household income" or for "industrial input demand." The data was converted from a quarterly to a monthly frequency using the relationship between industrial production and GDP. Specifically, the GDP for each quarter was allocated to each month in the quarter using the relative values of industrial production for each of those months in the quarter. The variable included in the analysis, denoted y_t, is the natural logarithm of the estimated monthly GDP. Information other than the electricity data obtained from the CFE was obtained from the *Instituto Nacional de Geografía e Informática*. [45]

Electricity prices. The relative price of electricity was calculated by dividing an implicit price for electricity by the producer price index. The implicit price for electricity was in turn obtained by dividing CFE monthly revenues by the quantity of electricity that CFE sold in each month. We use lagged prices in the regression to allow for the lags between consumption and billing (when most of the consumers realize how much they consumed). The variable included in the analysis, denoted p_t, is actually the natural logarithm of the relative price lagged three periods.[46] When forecasting the relative price of electricity, we need to preserve the monthly seasonal component. To do so, we estimated the following regression:

$$p_t = \alpha_o + \sum_{i=1}^{11} \alpha_i D_i + \omega_t, \tag{1}$$

where α_0 represents the mean value of p in December, D_i is an indicator variable for months i other than December and hence α_i represents the difference in the average value of p in month i relative to its value on December. The sample covers the period from February 1996 to November 2001. The estimates from this regression are reported in Table 18.

Seasonality. The aggregate demand for electricity is known to depend on seasonal factors in addition to GDP and the relative price of electricity. Since weather is the main determinant of seasonality in electricity demand, temperature variables should capture seasonality in a more parsimonious way than a set of monthly indicator variables.[47]

[45] Instituto Nacional de Geografía e Informática (INEGI), http://www.inegi.gob.mx

[46] Although most bills are issued every two months, there is an additional one month grace period for paying the bill.

[47] Factors such as holidays, or even variations in the number of days in each month may, however, also contribute to seasonal effects that are not readily captured by temperature changes.

Table 18: Estimated montly component of relative electricity prices

Parameter	Coefficient	t value
α_0	0.1897	(133.7234)
α_3	-0.0074	(-2.7073)
α_4	-0.0120	(-4.4114)
α_5	-0.0110	(-3.9850)
α_6	-0.0123	(-4.5365)
α_7	-0.0096	(-3.5232)
α_8	-0.0085	(-3.1285)
α_9	-0.0061	(-2.2384)
α_{10}	-0.0080	(-2.9543)
α_{11}	-0.0061	(-2.2607)
$\bar{R}^2$	0.30	
Observations	70	

Some studies attempt to model the effects of weather on electricity demand by including the average temperature as an explanatory variable. The effect of temperature on electricity demand is, however, likely to be non-linear with both very cold and very hot days raising the demand. Some studies attempt to allow for this by using the number of heating and cooling days within a period as explanatory variables.

Chang and Martinez-Chombo (2002), allow for a very general functional relationship $g(\tau_t)$ between the demand for electricity and the temperature τ_t at time t. In this paper, we use a quadratic to approximate g:

$$g(\tau_t) = \pi_0 + \pi_1 \tau_t + \pi_2 \tau_t^2 \tag{2}$$

In particular, the second order term allows electricity demand to increase in response to both abnormally high and abnormally low temperatures.

While electricity consumption is measured monthly, weather data is measured much more often. In addition, the electricity demand covers the country as a whole while weather data varies from one region to the next. For each month in their sample period, Chang and Martinez-Chombo (2002) gathered data on temperatures measured in six cities every three hours. The cities were chosen partly to represent different regions of the country and partly based on the quality of their weather records.[48] For each city i, and each month t in the sample, there will be roughly 240 temperature readings $\tau_{ip}, p \in t$. A probability density function $f_{it}(\tau_{ip})$ is then fit to these temperatures using a kernel density estimator.[49] The *expected* effect on electricity demand at location i of the

[48] The cities chosen for the study were Mexico City, Monterrey, Oaxaca, Mérida, Culiacán and Colima.

[49] A normal kernel was used, with a fixed bandwidth chosen to minimize the approximation mean integrated square error for normal kernels.

temperatures experienced in month t will then be given from (2) by:

$$\int_{p\in t} g(\tau_{ip})f_{it}(\tau_{ip})d\tau_{ip} = \pi_0 + \pi_1 \int_{p\in t} \tau_{ip} f_{it}(\tau_{ip})d\tau_{ip} + \pi_2 \int_{p\in t} \tau_{ip}^2 f_{it}(\tau_{ip})d\tau_{ip} \quad (3)$$

The production data available relate, however, to aggregate demand in the whole CFE network rather than the demand in particular locations. Two new variables are defined as the weighted sum of the two expected values on the right hand side of 3:

$$z_{1t} = \sum_{i=1}^{6} S_{it} \int_{p\in t} \tau_{ip} f_{it}(\tau_{ip})d\tau_{ip} \quad (4)$$

$$z_{2t} = \sum_{i=1}^{6} S_{it} \int_{p\in t} \tau_{ip}^2 f_{it}(\tau_{ip})d\tau_{ip} \quad (5)$$

where the weights S_{it} correspond to the shares of electricity consumption in the regions for which city i is representative.

Even having the two variables z_{1t} and z_{2t} as defined in 4 and 5 will lead to a large number of parameters when we estimate the dynamic adjustment model. We therefore used z_{1t} and z_{2t} to derive a single variable z_t to capture the seasonal component of total power generation. Specifically, total power generation Q_t was decomposed into an annual moving average[50] and a "short run" deviation, denoted q_t, from that moving average. The short run component was then related to temperature using the following regression (observations $N = 179$, $\bar{R}^2 = 0.8657$, t-values of the coefficients are in parentheses):

$$\begin{array}{rcl} q_t & = & \underset{(-5.57)}{-0.1833} + \underset{(0.899)}{0.1333} \cdot z_{1t} + \underset{(2.395)}{0.3522} \cdot z_{2t} + \varepsilon_t \end{array} \quad (6)$$

The variable z_t was then defined as the predicted value of q_t based on (6).

Long run relationships. Variables that are systematically related to each other in the long run display a consistent pattern in their trends. Deviations from these long run relationships constitute stationary shocks that gradually disappear over time.

For most time series of economic variables, trends primarily result from permanent shocks that accumulate over time and lead to "unit roots" in the series. While the series itself displays a trend, *changes* in the series from one period to the next are driven by shocks drawn from a stationary distribution. Table 19 presents results of tests for the presence of unit roots in the natural logarithms of total power generation (denoted Q_t), GDP and the relative price of electricity. If a unit root is absent, the series itself is stationary, and the test statistic presented in Table 19 should be below the 5% critical values listed in the bottom row of the table. The tests for the presence of stochastic trends

[50] For a given month t, the moving average was calculated as $(1/13)\sum_{l=-6}^{6} Q_{t+l}$.

can be affected if the series have trends that are deterministic functions of time or if the variables are strongly serially correlated. The tests were performed using two different criteria (Akike and Schwartz) to select the number of lags included to eliminate serial correlation. Two separate sets of tests allowing for the presence or absence of a deterministic time trend also were conducted. In eleven of the twelve results, the evidence indicates the presence of a unit root in the series.

Although each of the variables Q, y and p is non-stationary, if the demand for electricity is a stable function of these variables the relationship between them will be stationary (the variables will be "co-integrated"). One of the innovative features of the model of electricity demand presented in Chang and Martinez-Chombo (2002) is that the authors allow the long run relationship between the dependent variable, in this case Q, and its determinants, in this case y and p, to change gradually over time in a deterministic fashion. This modification may be especially important in a country such as Mexico that has recently undergone substantial economic change. In particular, the recent rapid growth of the Mexican economy, and the change in industry structure resulting from the NAFTA, both are likely to have changed the relationship between electricity demand and its key determinants. Following Chang and Martinez-Chombo (2002), the time varying elasticities of total power generation with respect to GDP and the relative price, γ_t and δ_t in the equation:

$$Q_t = \pi + \gamma_t y_t + \delta_t p_t + \phi z_t + u_t, \tag{7}$$

are approximated by a Fourier Flexible Form (FFF) function, using the Schwartz criterion to select the number of terms in the functions. The estimates were derived using the method of canonical co-integrating regression (CCR) suggested by Park and Hahn (1999). The results are reported in Table 20.[51]

We found that the long run elasticity of Q_t with respect to the GDP, γ_t, can be approximated by a series function that includes a constant coefficient $\beta_{\gamma,k,1}$) and a linear trend (with slope $\beta_{\gamma,k,2}$). The parameter estimates imply that γ_t has been decreasing over time from 0.426 at the beginning of the sample to about 0.4099 at the end of the sample. This is consistent with industrialization and economic growth leading to more widespread use of grid electricity.

In the case of the relative price of electricity, the results in Table 20 imply that the elasticity, δ_t, of power generation with respect to p can be approximated by a linear trend ($\beta_{\delta,k,2}$) and a trigonometric function ($\cos(4\pi i), i = 1 \ldots n$). The estimated coefficients on the relative price variables imply that, while electricity demand was insensitive to price at the beginning of the sample by the end of the period the elasticity of demand with respect to price was about -0.5006. Such a change might again be consistent with a growth in the relative importance of industry in the economy, which probably has more options to alter demand in response to price variations.

[51] Although z_t is stationary, it is included in the co-integrating regression to help control for seasonality in Q, y and p. In the estimation of the adjustment process presented below, we allow z_t and its lags to enter separately from u_t, so including z_t in equation 7 does not restrict the dynamic adjustment of Q to z.

Table 19: Augmented Dickey-Fuller (ADF) tests for stationarity

Variable Lag selection criterion[a]	Demeaned series	lags	Detrended series	lags
Total power generation, Q_t				
AIC	0.4167	12	-2.641	12
SC	0.4167	12	-4.798	7
GDP, y_t				
AIC	0.6244	16	-1.110	16
SC	0.6244	16	-1.110	16
Relative prices, p_t				
AIC	-2.013	14	-1.4549	14
SC	-1.330	4	-1.9035	5
5% critical values	-2.86		-3.41	

a. Akike (AIC) and Schwartz (SC) criterion

Table 20: Estimated co-integrating relationship for total power generation

Variable	Coefficients	(t values[a])
Constant (π)	7.0766	(4.7866)
z_t (ϕ)	1.0632	(20.4203)
Parameters of the TVC: γ_t		
k	0^b	
$\beta_{\gamma,k,1}$	0.4261	(5.9735)
$\beta_{\gamma,k,2}$	-0.0161	(-2.2235)
Parameters of the TVC: δ_t		
k	2	
$\beta_{\delta,k,2}$	-0.5025[c]	(-6.5293)
$\beta_{\delta,k,3}$	0.0047[d]	(2.3271)
SC = -6.7665	R^2 =0.9839	DW =2.01
observations $N = 176$		
Long run variance of the CCR errors		
Ω^*_{11}	0.0010	
Unit root test for estationary of the errors u_t of the regression[e]		
τ^*	10.6039	Critical value 1%: 13.28

a. Computed using CCR standard errors.
b. Indicates that there are no trigonometric terms.
c. Coefficient of the linear trend.
d. Coefficient of the trigonometric term $\cos(4\pi r)$.
e. $\tau^* \sim \chi^2(4)$ for H_0 : errors are stationary. Park and Hahn (1999) statistic.

The final panel of Table 20 presents the results of a test of whether the errors from the regression, u_t, contain a unit root. Since the value of the test statistic is below the 1% critical value, it would appear that, once the model allows for time varying coefficients, power generation, GDP and the relative price of electricity are cointegrated.

Short run adjustments. Equation 7 represents the long run relationship between total power generation , GDP and relative price of electricity. The dynamic adjustment of the model is driven in part by deviations of power demand from the long run relationship. The short run dynamic adjustment process can be represented by a so-called "error-correction model" (ECM). This equation relates the change in electricity demand (which is a stationary variable) to the lagged error term u_{t-1} and other stationary variables. For a stable adjustment process, we would expect the coefficient of u_{t-1} to be negative. Then, if electricity demand is above its long run equilibrium relationship with GDP and the relative price, demand will tend to fall and conversely. In addition, the adjustment could occur gradually. For example, an increase in the electricity price initially may influence the length of time that equipment is used. If the higher price persists, however, firms may buy new equipment that requires lower electricity input. Including the lagged change in electricity demand as another explanatory variable can accommodate such a lagged adjustment process. The estimated ECM can be written as:

$$\begin{aligned}\Delta Q_t = &\sum_{l=1}^{p_1} b_{1,l}\Delta Q_{t-l} + \sum_{l=1}^{p_2} b_{2,l}u_{t-l} + \\ &\sum_{l=0}^{p_3} b_{3,l}\Delta y_{t-l} + \sum_{l=0}^{p_4} b_{4,l}\Delta p_{t-l} + \sum_{l=0}^{p_5} b_{5,l}z_{t-l} + \varepsilon_t\end{aligned} \tag{8}$$

There is little theoretical reason for expecting one dynamic pattern of adjustment rather than another. To determine the lags of each variable included in the model, we first estimate a general model with $p_1, p_2, p_3, p_4, p_5 = 12$. Lags were then progressively eliminated beginning with those having coefficients $b_{j,l}$ that were least statistically significantly different from zero. The lags retained in the model, and reported in Table 21, all have coefficients that are not statistically different from zero at the 5% level. Table 21 also reports a Box-Pierce statistic that tests for the presence of serial correlation in the error term ε. The p-value of more than 0.29 suggests that sufficient lags have been included in the model to eliminate the serial correlation.

The parameter estimates in Table 21, and the negative coefficient on the error term u_{t-1} in particular, imply that a gap between power generation and its long run determinants sets up an adjustment process that eventually restores the long run relationship. If power generation is above the long run equilibrium level ($u > 0$), generation in subsequent periods will decline ($\Delta Q < 0$). Further adjustments will occur in subsequent periods as prior movements in ΔQ continue to produce continuing movements as a result of the significant $b_{1,l}$ coefficients.

Table 21: Estimated dynamic adjustment equation for $\Delta\hat{Q}_t$

Parameter	Variable					
	ΔQ_{t-l} $(j=1)$		u_{t-l} $(j=2)$			
	Coeff.	(t val.)	Coeff.	(t val.)		
$b_{j,1}$	-0.1695	(-3.86)	-0.4631	(-7.78)		
$b_{j,4}$	0.1231	(2.94)				
$b_{j,5}$	0.1480	(3.78)				
$b_{j,12}$	0.5263	(12.74)				
	Δy_{t-l} $(j=3)$		Δp_{t-l} $(j=4)$		z_{t-l} $(j=5)$	
	Coeff.	(t val.)	Coeff.	(t val.)	Coeff.	(t val.)
$b_{j,0}$	0.3469	(8.02)	-0.1662	(-2.39)	0.5835	(7.30)
$b_{j,3}$	0.1717	(5.00)				
$b_{j,4}$			-0.1295	(-2.41)		
$b_{j,5}$			0.1514	(2.76)		
$b_{j,8}$	0.1430	(2.79)				
$b_{j,11}$					0.3130	(3.91)
$b_{j,12}$	-0.2340	(-5.35)	0.1065	(2.07)	-0.2910	(-3.40)
$\bar{R}^2$	0.9115					
Box-Pierce χ^2_{40}	44.3359	p-value 0.2938				

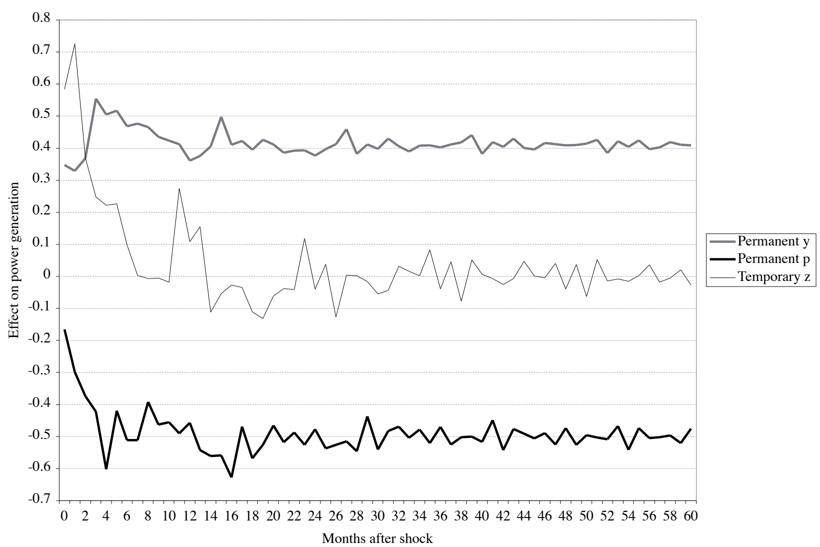

Figure 5: Implied dynamic adjustment of power generation to shocks

Eventually, however, the adjustments will decay to zero.

The dynamic adjustment process implied by the estimated ECM is illustrated in Figure 5. This graphs the response of Q to a one percent *permanent* shock to GDP, y, and relative prices of electricity, p, and a 1% temporary shock to z. The adjustments graphed in 5 have been calculated setting the long run elasticities of power demand with respect to y and p to their values at the end of the sample period. In reality, we would expect these elasticities will continue to change over time, making the adjustment process a function of the time when the shocks occur.

As Figure 5 illustrates, $\Delta Q \rightarrow \gamma_T = 0.4099$ for a permanent 1% shock to y, $\Delta Q \rightarrow \delta_T = -0.50057$ for a permanent 1% shock to p, and $\Delta Q \rightarrow 0$ for a temporary shock to the stationary variable z. In all cases, there is a seasonality to the response with "patterns" in the adjustment process being "mirrored" with 12-month lags. The annual seasonality is also evident in the large estimated coefficients at lag 12 in Table 21. Any change in income, prices or weather that induces a home or business to alter their stock of electrical equipment or appliances is likely to have continuing effects on power demand in similar seasons in subsequent years.

The response of total power generation to a permanent increase in GDP is, for the first two months, somewhat below the ultimate long run response. Generation then "overshoots" the long run response for the remainder of the first year. Thereafter, the pattern is more or less repeated on an annual frequency with ever smaller fluctuations around the ultimate long run effect.

An increase in the relative price of electricity produces a different type of adjustment process. Whereas a permanent increase in y causes Q to jump almost immediately to values in the proximity of the long run effect, the response to price changes is more gradual. Such a delay in the responsiveness of demand to price changes may be explained in part by the infrequent billing schedule, and perhaps by the fact that a significant amount of electricity appears to be taken illegally. It is also possible that the seasonal component in prices makes it difficult for consumers to clearly identify price changes. In addition to displaying a more gradual adjustment of Q toward its long run value, the price response path displays much less "overshooting" than does the response to y. Again, however, the adjustment pattern set for months 4 through 16 has a tendency to be repeated, albeit with oscillations of declining magnitude, in months 16 through 28, 28 through 40 and so on.

A temporary shock to the temperature variable z also ultimately produces an adjustment path that tends to repeat in an annual cycle. In this case, however, the initial period of response lasts about 10 months instead of 4. The response of Q to z, like its response to a GDP shock, is rapid. On the other hand, like the response to p, the response to z does not involve sustained "overshooting".

Regional demand shares. The regional shares of aggregate demand are, by definition, bounded between 0 and 1. In addition, as the share of demand in any one region increases toward 1 (or decreases toward zero) we would expect further increases (respectively, decreases) to be much less likely. A natural way of representing such behavior in a way that is also likely to yield normally distributed error terms (which range from $-\infty$ to $+\infty$) is to use a logistic functional form:

$$\ln\left(\frac{S_{it}}{1-S_{it}}\right) = X_{it}'\varphi_i + e_{it} \tag{9}$$

Since we do not have data on regional GDP or industrial production we used monthly indicator variables, time and time^2 as components of X. The monthly indicators capture differences in the seasonal patterns of demand across regions. The linear trend terms indicate regions where electricity demand is growing faster (the coefficient of time is positive), or slower (the coefficient is negative), than in the nation as a whole. The coefficient on time^2 indicates whether the trend is accelerating (the quadratic and linear coefficients have the same sign) or decelerating (the coefficients have opposite signs). When making forecasts, we proportionally adjust the estimated shares in each region to ensure that they always sum to 1.0 in all periods.[52]

Table 22 gives the estimated quadratic equations for the regional demand shares. Table 23 presents the estimated monthly effects on the demand shares for January through November *relative to* shares in the month of December.

Daily demand variation. Since the load on the system is the most important feature of the demand fluctuations, we first convert the load curves in Figure 3 to load duration curves. A daily load duration curve is analogous to a probability distribution function and plots the number of hours in the day that electricity demand exceeds a given load. For the minimum load of the day, the load duration curve will have a value of 24 hours. For the maximum load of the day, the load duration curve will be 0 hours. Essentially, the load duration curve orders times of the day not according to where they come by the clock but by what the demand load on the electricity system was at that time. A step function approximation to the load duration curve then divides the day into periods of roughly constant levels of demand.

In the present model, we need to divide each day into time periods that cover the same hours of the day in both the north and the south of the country. The bottom two panels in Figure 3 show that, during the summer season, the peak demand is in the afternoon hours in the north, but in the evening hours in the south. It therefore is not possible to define a time period that yields a coincident peak in both regions. More generally, since the load curves are different shapes it is difficult to group hours into a small number of blocks of roughly constant demand. Instead of approximating the individual load duration curves, we partitioned the curves in such a way that the durations of the steps coincide in both regions.

[52]Although the error terms in the share equations will be correlated, there is no value in estimating the equations as a seemingly unrelated set since they have identical regressors.

Table 22: Estimated time variations in shares[a]

Region	Constant	Time	Time^2	Adjusted R^2
1 Baja	-3.0915	$4.5\text{x}10^{-}4$	$1.4\text{x}10^{-}5$	0.8791
California	(0.0233)	($6.1\text{x}10^{-}4$)	($5.1\text{x}10^{-}6$)	
2 Noroeste	-2.5813	$-2.9\text{x}10^{-}4$	$-2.8\text{x}10^{-}6$	0.9211
	(0.0178)	($4.6\text{x}10^{-}4$)	($3.9\text{x}10^{-}6$)	
3 Norte	-26098	$1.1\text{x}10^{-}3$	$-3.5\text{x}10^{-}6$	0.8229
	(0.0134)	($3.5\text{x}10^{-}4$)	($2.9\text{x}10^{-}6$)	
4 Golfo	-1.9964	$1.7\text{x}10^{-}3$	$2.7\text{x}10^{-}6$	0.9493
Norte	(0.0094)	($2.4\text{x}10^{-}4$)	($2.0\text{x}10^{-}6$)	
5 Golfo	-2.9886	$1.2\text{x}10^{-}3$	$-1.4\text{x}10^{-}5$	0.3729
Centro	(0.0012)	($3.8\text{x}10^{-}4$)	($3.2\text{x}10^{-}6$)	
6 Bajio	-2.3829	$7.2\text{x}10^{-}4$	$-4.9\text{x}10^{-}6$	0.6792
	(0.0236)	($6.1\text{x}10^{-}4$)	($5.1\text{x}10^{-}6$)	
7 Jalisco	-2.6334	$-1.8\text{x}10^{-}3$	$7.3\text{x}10^{-}6$	0.6491
	(0.0153)	($4.0\text{x}10^{-}4$)	($3.3\text{x}10^{-}6$)	
8 Centro	-3.2295	$6.3\text{x}10^{-}3$	$-2.5\text{x}10^{-}5$	0.8312
Occidente	(0.0267)	($7.0\text{x}10^{-}4$)	($5.8\text{x}10^{-}6$)	
9 Centro	-3.1237	$7.4\text{x}10^{-}5$	$7.5\text{x}10^{-}6$	0.6684
Oriente	(0.0204)	($5.3\text{x}10^{-}4$)	($4.4\text{x}10^{-}6$)	
10 Centro	-3.3450	$3.5\text{x}10^{-}3$	$-1.8\text{x}10^{-}5$	0.6740
Sur	(0.0230)	($6.0\text{x}10^{-}4$)	($5.0\text{x}10^{-}6$)	
11 Oriente	-2.5389	$-2.1\text{x}10^{-}3$	$1.0\text{x}10^{-}5$	0.1412
	(0.0334)	($8.7\text{x}10^{-}4$)	($7.3\text{x}10^{-}6$)	
12 Sureste	-3.3673	$-7.0\text{x}10^{-}4$	$-1.6\text{x}10^{-}7$	0.3661
	(0.0265)	($6.9\text{x}10^{-}4$)	($5.8\text{x}10^{-}6$)	
13 Peninsula	-3.5776	$1.0\text{x}10^{-}3$	$-4.6\text{x}10^{-}6$	0.3233
	(0.0199)	($5.2\text{x}10^{-}4$)	($4.3\text{x}10^{-}6$)	
14 Centro	-1.0879	$-2.8\text{x}10^{-}3$	$6.1\text{x}10^{-}7$	0.9009
Luz y Fuerza	(0.0166)	($4.3\text{x}10^{-}4$)	($3.6\text{x}10^{-}6$)	

a. Estimated standard errors are given in parentheses.

Table 23: Monthly deviations in demand shares relative to December[a]

Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
1 Baja	0.004	-0.029	-0.043	-0.04	0.012	0.057	0.197	0.295	0.322	0.233	0.089
California	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.0250)
2 Noroeste	-0.079	-0.121	-0.083	-0.045	0.012	0.065	0.206	0.235	0.277	0.224	0.18
	(0.019)	(0.019)	(0.019)	(0.019)	(0.019)	(0.019)	(0.019)	(0.019)	(0.019)	(0.019)	(0.0190)
3 Norte	0.008	0.01	0.026	0.092	0.123	0.148	0.164	0.168	0.147	0.103	0.044
	(0.014)	(0.014)	(0.014)	(0.014)	(0.014)	(0.014)	(0.014)	(0.014)	(0.014)	(0.014)	(0.0140)
4 Golfo	0.025	-0.006	0.022	-0.016	0.04	0.087	0.141	0.162	0.152	0.136	0.071
Norte	(0.010)	(0.010)	(0.010)	(0.010)	(0.010)	(0.010)	(0.010)	(0.010)	(0.010)	(0.010)	(0.0100)
5 Golfo	0.011	-0.027	-0.04	-0.044	-0.014	-0.01	0.007	-0.013	-0.019	0.01	-0.005
Centro	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.0160)
6 Bajio	0.05	0.072	0.063	0.13	0.138	0.125	-0.003	-0.062	-0.088	-0.089	-0.049
	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.025)	(0.0250)
7 Jalisco	-0.008	0.002	-0.022	-0.04	-0.042	-0.062	-0.076	-0.099	-0.112	-0.084	-0.05
	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.016)	(0.017)	(0.017)	(0.017)	(0.0170)
8 Centro	0.052	0.045	0.087	0.081	0.013	-0.025	-0.09	-0.123	-0.139	-0.081	-0.069
Occidente	(0.028)	(0.028)	(0.028)	(0.028)	(0.028)	(0.028)	(0.028)	(0.029)	(0.029)	(0.029)	(0.0290)
9 Centro	0.044	0.047	0.079	0.051	-0.025	-0.06	-0.094	-0.098	-0.103	-0.062	-0.003
Oriente	(0.022)	(0.022)	(0.021)	(0.021)	(0.021)	(0.021)	(0.021)	(0.022)	(0.022)	(0.022)	(0.0220)
10 Centro	-0.021	0.001	-0.005	-0.026	-0.067	-0.11	-0.145	-0.136	-0.166	-0.139	-0.067
Sur	(0.024)	(0.024)	(0.024)	(0.024)	(0.024)	(0.024)	(0.024)	(0.025)	(0.025)	(0.025)	(0.0250)
11 Oriente	0.032	-0.01	0.012	-0.024	-0.013	-0.029	-0.045	-0.045	-0.059	-0.041	-0.021
	(0.035)	(0.035)	(0.035)	(0.035)	(0.035)	(0.035)	(0.035)	(0.036)	(0.036)	(0.036)	(0.0360)
12 Sureste	-0.017	-0.018	-0.054	-0.009	-0.066	-0.054	-0.122	-0.119	-0.098	-0.123	-0.085
	(0.028)	(0.028)	(0.028)	(0.028)	(0.028)	(0.028)	(0.028)	(0.029)	(0.029)	(0.029)	(0.0290)
13 Peninsula	-0.041	-0.053	-0.063	-0.022	0.033	-0.001	0.019	0.004	0.018	-0.002	0.013
	(0.021)	(0.021)	(0.021)	(0.021)	(0.021)	(0.021)	(0.021)	(0.021)	(0.021)	(0.021)	(0.0210)
14 Centro	-0.039	0.012	-0.024	-0.054	-0.107	-0.138	-0.183	-0.197	-0.18	-0.137	-0.069
Luz y Fuerza	(0.017)	(0.017)	(0.017)	(0.017)	(0.017)	(0.017)	(0.017)	(0.018)	(0.018)	(0.018)	(0.0180)

a. Estimated standard errors are given in parentheses.

Figure 3 shows that the north has a higher peak demand in the summer, while the south has a higher peak demand in the remaining periods. Thus, we arranged the hours according to the load duration curve for the north in the summer period while we used the load duration curves for the south for the remaining periods. Table 24 shows, however, that we defined period 1 in the summer season and period 6 in the shoulder season to correspond with the daily peak periods for the south. Total demand in the south (which includes the central region) is so much larger than in the north, and the differences between peak and second highest demand in the north are so small, that the overall system peak demand corresponds with the southern one.

Figure 6 illustrates the step function approximations to the load duration curve for the north in the summer season and the load duration curves in the south for the remaining seasons. We used five steps in the approximations for each of four seasons, yielding a total of twenty time periods in our model. Figure 6 also graphs the load curves for the south during the summer season, and for the north during the remaining seasons, with clock time rearranged in the same manner as was done to obtain the load duration curves. The different shapes of the northern and southern load curves are reflected in the fact that the rearranged southern curve in the summer, and the rearranged northern curves in the other seasons, do not appear as load duration curves ordered from highest to lowest demand. Finally, Figure 6 also shows how we approximated the rearranged loan curves using the same time periods as for the load duration curve approximations in each period. The durations and sizes of each the steps in the approximations were determined to maximize the fit between the approximations and the real load curves subject to the constraint that the areas under the step function approximations equaled the areas under the real load curves. As Figure 6 shows, five steps allowed us to fit the shapes of the curves reasonably well. The worst fit is for the south in the summer season.

The step function approximations were converted back to demands in each transmission region using the following procedure. Use SL to denote the season length (in days). An aggregated seasonal step load duration function in hours per season is obtained by multiplying the daily period length of each step (PL) by the number of days in the season ($PL \times SL$). The share of total power demand that is consumed at a specific period of time t in season s in the Northern ($k = N$) or Southern ($k = S$) regions the country can be computed from this seasonal step function as follows:

$$d_{s,t}^{k} = \frac{RLS_{k,s,t} \cdot SL_{s,t} \cdot PL_{s,t}}{\sum_{t \in s} RLS_{k,s,t} \cdot SL_{s,t} \cdot PL_{s,t}},$$

where $RLS_{k,s,t}$ is the relative demand load in region k, period t, and season s. Table 24 provides numerical values for these variables in our approximation.

To compute the level of power demand for each transmission region i in a particular time period and season, we used the formula:

$$d_{i,s,t} = \delta_{i,s} \cdot d_{s,t}^{k} \cdot \bar{d}_s$$

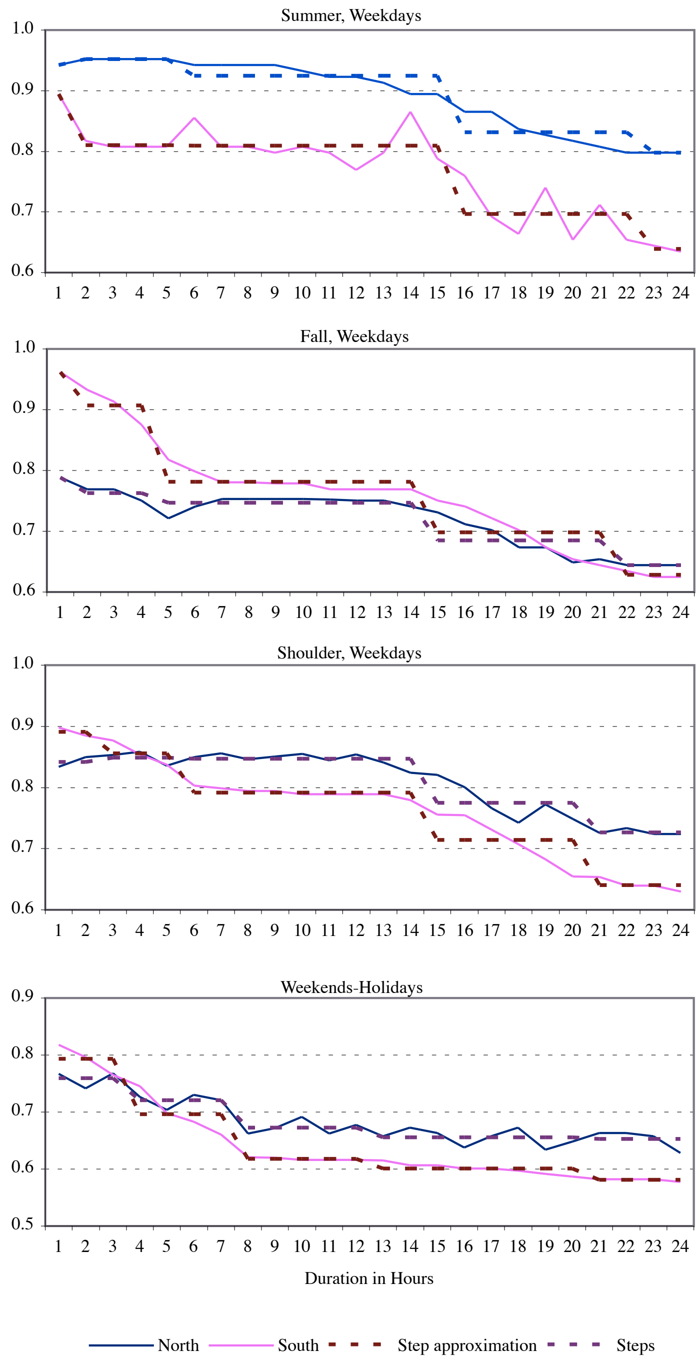

Figure 6: Step function approximations to the 1999 load curves

Table 24: System Load Curve (%)

Period No.	*Period Length*	*Season*	*Season Length*	*Relative Load Steps*	
				North	*South*
(t)	($hrs., PL$)	(s)	($days, SL$)	(RLS_N)	(RLS_S)
1	1	Summer	82	0.94	0.89
2	4	(May-Aug)		0.95	0.81
3	10			0.93	0.81
4	7			0.83	0.70
5	2			0.80	0.64
6	1	Shoulder	87	0.84	0.89
7	3	(March, April		0.85	0.86
8	10	Sep., Oct.)		0.85	0.79
9	7			0.78	0.71
10	3			0.73	0.64
11	2	Fall	83	0.79	0.96
12	3	(Nov.-Feb.)		0.79	0.91
13	9			0.75	0.78
14	6			0.68	0.70
15	4			0.64	0.63
16	3	Weekends-	113	0.76	0.79
17	4	Holidays		0.72	0.70
18	5			0.67	0.62
19	8			0.66	0.60
20	4			0.65	0.58

where $\delta^k_{i,s}$ is the share of total demand in region k and season s originating in transmission area i and $\bar{d}_s$ is the aggregate demand in GWh in season s. Including a set of multiplicative scaling factors $Z_s > 0$ in this formula allows us to calibrate demand to compensate for the (unknown) power losses per season:

$$d_{i,s,t} = \delta_{i,s} \cdot d^k_{s,t} \cdot \bar{d}_s \cdot Z_s.$$

Appendix B: Modeling electricity supply

Since details of system operation at hourly or finer time scales are not relevant to our main objectives, most of the stochastic components are eliminated from the problem.[53] We instead examine a deterministic linear programming model based on expected values of demand and supply variables. We also modify the model, however, to incorporate "normal" levels of excess capacity that are maintained to cope with unusual emergencies.

Generating costs. The generating plant costs were based on data provided by the CFE as discussed in the text. The total cost of generation for N plants in the system during the year is approximated by

$$\mathrm{C} = \sum_{n=1}^{N} b_n \bar{g}_n + \sum_{n=1}^{N} \sum_{t=1}^{T} h_t c_{nt} g_{nt}, \tag{10}$$

where $n = 1, ...N$ indexes the plants, $t = 1, ...T$ denotes the period (where now one period represents a set of hours of the day throughout a season), and h_t is the number of hours in period t (number of hours per day times number of days per season). The annual fixed cost per MW of total capacity of plant n is b_n. The total capacity of plant n, $\bar{g}_n$, is set for the whole year and constrains the variable output levels, g_{nt}, of each plant n in each period t:

$$0 \leq g_{nt} \leq \bar{g}_n, \quad \forall t, n \tag{11}$$

$$0 \leq \bar{g}_n \leq G_n, \quad \forall t, n \tag{12}$$

where G_n is the *designed* capacity of the plant. The variable cost of plant n in period t is c_{nt}.

Transmission losses. Transmission losses on a link are a function of the power flowing between two nodes and the resistance of the line. Specifically, transmission losses rise with the square of the current being transmitted on a link:

$$L_{ij} = 3 R_{ij} \tau_{ij}^2 \tag{13}$$

[53]For stochastic programming models of power markets look at Wallace, Stein W. and Fleten Stein-Erik. (2002) "Stochastic programming models in energy," Working Paper 01-02, Department of Industrial Economics and Technology Management, Norwegian University of Science and Technology. http://ideas.uqam.ca/ideas/data/Papers/wpawuwpge0201001.html

where the subscripts (i, j) indicate the nodes that are connected by the line, L_{ij} equals the losses (in MW/km), R_{ij} is the resistance of the line (ohm/km) and τ_{ij} is the current (in kamps, where 1 kamp = 1,000 amps). The relationship between current and power for a three-phase alternating current circuit is given by the formula:

$$P = \sqrt{3} \cdot E \cdot I \cdot pf$$

where P is the power (in watts), E is the voltage (in volts), I is the current (in amps), and pf is the "power factor" of circuit. The latter term determines the relationship between direct and alternating current and, for our calculations, was assumed to be 0.6 (its typical gross value). In general, the engineers try to maintain the system so that there are minimal fluctuations in the voltage E, so this, too, can be subsumed in a constant.

Finally, the resistance depends on the physical characteristics of the transmission lines.[54] Table 25 shows the typical resistance we used to compute the losses specified in (13). These figures are based on data collected by Scherer (1977, 213) and EIRRG (1998).[55]

Table 25: Typical resistance of transmission lines

Nominal Voltage	115 kv	230 kv	400 kv
R (ohm/km)	0.068	0.050	0.033

To include transmission losses in the linear programming model, we approximate equation 13 with linear functions as is illustrated in Figure 7 in the case of a two step approximation.

For a two step approximation, the piecewise linear function that minimizes the difference between equation 13 and its approximation has a break point at half the total transmission capacity of the line. The slope of the first linear function represents the average losses (in percentage terms) for transmission up to half of the line capacity, while the slope of the second function captures the average losses for the remaining transmitted current. A similar interpretation can be given for the slopes of the linear pieces when more than two steps are involved in the approximation.[56] Table 26 presents some characteristics of the transmission lines as reported by the Secretary of Energy together with the estimated loss coefficients we calculated. The numbering of the transmission regions in this table corresponds to the numbers assigned in Figure 2 and Table 4 above.

[54] Lower resistance can be obtained by using additional circuits or heavier gage wire, but this raises the capital costs of the towers needed to support the wires and the land needed for the right of way. Implicitly, another optimization problem underlies the design of the transmission network

[55] The resistance of the 115kv lines was taken from Scherer (1977) pp. 213. For the 400kV lines, the resistance was linearly extrapolated from lines with nominal voltages of 345kV and 500kV, EIRRG (1998) http://www.nrcce.wvu.edu/special/electricity/elecpaper5.htm.

[56] For links with more than one transmission line, the number of steps in the transmission loss function can be increased.

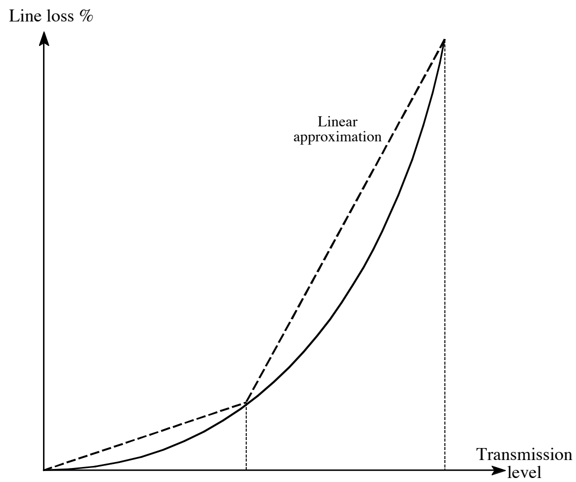

Figure 7: Approximation of quadratic transmission losses

Table 26: Characteristics of the transmission lines

Link	Voltage	Total Cap.	Loss coefficients			
	kV	MW	Step 1	Step 2	Step 3	Step 4
1-2	230	330	0.016	0.0479		
2-3	230	220	0.0245	0.0735		
4-3	230	350	0.0462	0.1387		
4-7	230	240	0.0261	0.0784		
4-12	400	260	0.0173	0.0520		
6-5	230	230	0.0250	0.0751		
6-8	400	140	0.0117	0.0351		
7-6	230	235	0.0426	0.1279		
7-9	400	260	0.0103	0.0308		
	230		0.0241	0.0723		
7-14	230	200	0.0352	0.1057		
8-9	400	2100	0.0234	0.0703		
	230		0.0447	0.1341		
	400		0.0158	0.0474		
9-10	400	900	0.0224	0.0672		
9-11	400	250	0.0073	0.0220		
	230		0.0221	0.0664		
10-18	400	750	0.0233	0.0700		
12-14	400	650	0.0158	0.0474		
	400		0.0162	0.0485		
12-15	400	750	0.0134	0.0402		
	230		0.039	0.0926		
	400		0.0083	0.0249		
13-14	400	1700	0.0157	0.0470		

continued on next page

Table 26 Continued

Link	Voltage kV	Total Cap. MW	Loss coefficients Step 1	Step 2	Step 3	Step 4
	400		0.0173	0.0520		
	230		0.0250	0.0749		
15-14	230	600	0.0202	0.0606		
	230		0.0350	0.1049		
15-17	400	750	0.0216	0.0647		
	230		0.0398	0.1194		
	230		0.0310	0.0929		
16-15	400	450	0.0204	0.0611		
16-12	400	400	0.0235	0.0706		
16-17	400	950	0.0193	0.0580		
18-17	400	3100	0.0105	0.0316		
	400		0.0263	0.0790		
	400		0.0239	0.0718		
	400		0.0206	0.0618		
	230		0.0463	0.1390		
	230		0.0507	0.1521		
18-20	400	2100	0.0146	0.0437	0.0728	0.1020
	400		0.0135	0.04040	0.0673	0.0943
	230		0.0200	0.0599	0.0998	0.1397
19-17	230	240	0.0199	0.0597		
20-21	400	1400	0.0174	0.0522	0.0871	0.1219
20-22	400	1000	0.0136	0.0407	0.0678	0.0950
21-22	400	2200	0.0149	0.0448	0.0746	0.1045
22-23	230	110	0.0188	0.0564		
23-24	230	150	0.0134	0.0403		
	115		0.0090	0.0270		
	115		0.0162	0.0487		
	115		0.0083	0.0249		
24-26	230	100	0.0104	0.0312		
	115		0.0105	0.0314		
	115		0.0105	0.0449		
24-25	115	45	0.0135	0.0405		
27-28	230	250	0.0233	0.0700		
28-29	230	180	0.0187	0.0560		
30-31	115	60	0.0168	0.0504		
31-32	115	40	0.0160	0.0480		
24-26	230	100	0.0104	0.0312		
	115		0.0105	0.0314		
	115		0.0105	0.0449		
24-25	115	45	0.0135	0.0405		
27-28	230	250	0.0233	0.0700		
28-29	230	180	0.0187	0.0560		
30-31	115	60	0.0168	0.0504		
31-32	115	40	0.0160	0.0480		

The general regional demand constraint can be written:

$$\sum_{n \in N(i)} \eta_n g_{nt} + \sum_{j \in S(i)} \sum_{l}^{\ell(i,j)} \tau_{ji,t}^{l} = \sum_{j \in S(i)} \sum_{l}^{\ell(i,j)} (1+\rho_{ij}^{l})\tau_{ij,t}^{l} + d_{it}, \quad \forall i, t \tag{14}$$

where $i = 1, ..., D$ denotes the region, $N(i)$ denotes the set of generation plants located in region i, η_n is the fraction of electricity generated by plant i that is sent out to the electrical system (so $(1-\eta_n)g_{nt}$ is consumed within the plant), $S(i)$ denotes the set of regions connected to region i, $\ell(i,j)$ denotes number of steps in transmission loss function for the link between i and j, $\tau_{ji,t}^{l}$ is the power transmission flow from region j to region i in period t and on step l of the loss function, ρ_{ij}^{l} is the loss factor on step l of the transmission loss function of link (i,j), and d_{it} is the hourly electricity demand at region i in period t.

The demand restrictions allow transmission to incur in either direction. Since all variables in the model are required to be non-negative, we double the number of transmission variables. The links (i,j) and (j,i) represent the same physical wires but the different indices indicate opposite directions of the flow. The physical wires limit the amount of electricity that can be transmitted between two regions. Thus, if $\bar{\tau}_{ij}$ denotes the transmission capacity between regions i and j in MW:

$$\sum_{l}^{\ell(i,j)} \tau_{ji,t}^{l} + \sum_{l}^{\ell(i,j)} \tau_{ij,t}^{l} \leq \bar{\tau}_{ij}, \quad \forall t, \quad (i,j) \in L \tag{15}$$

where L is the set of transmission links in the system. Since all the variables are non-negative, (15) implies $0 \leq \tau_{ij,t}^{l} \leq \bar{\tau}_{ij}^{l}, \quad \forall t, \forall i, j \in S(i), \forall l$. Furthermore, since transmissions involve losses, the program will not choose to have power flowing in both directions at once, that is, only one of $\sum_{l}^{\ell(i,j)} \tau_{ij,t}^{l}$ or $\sum_{l}^{\ell(j,i)} \tau_{ji,t}^{l}$ will be strictly positive.

Availability constraints. The plant availability restrictions can be represented algebraically as follows:

$$\sum_{t=1}^{T} h_t g_{nt} \leq 8760\alpha_n G_n, \quad \forall n, \tag{16}$$

where $8,760$ is the number of hours in a year and α_n is the faction of hours that plan n is available for generation in the whole year.

For the subset of large "base" plants, we imposed additional restrictions:

$$g_{nt}^{b} \leq g_{ns}^{b}, \ \forall s, \text{ with } s = 1, ...S, \tag{17}$$

$$\sum_{s=1}^{S} h_s g_{ns}^{b} \leq 8760\alpha_n^{b} G_n^{b}, \tag{18}$$

where the superscript b indicates a "base" plant, S is the number of seasons in a year and h_s is the number of hours in season s. With this restriction, the allocation of the optimal maintenance schedule for base plants is over seasons and not over periods. Whereas a non-base plant could be off line for just two or three hours every day, planned maintenance of a base plant must affect availability in all periods within a season. Thus, maintenance of base plant must affect availability for complete days at a time.

Reserve constraints. These constraints require that plant capacities $\bar{g}_n$ be large enough to meet brief periods of extreme demands. Since the periods are brief, they do not require substantial additional energy production. We denote the transmission levels in such extreme demand periods by $\hat{\tau}_{ij,t}$ and modify the demand constraints (14) to become:

$$\sum_{n\in N(i)} \bar{g}_n + \sum_{j\in S(i)} \sum_{l}^{\ell(i,j)} \hat{\tau}^l_{ji,t} \geq \sum_{j\in S(i)} \sum_{l}^{\ell(i,j)} (1+\rho^l_{ij})\hat{\tau}^l_{ij,t} + (1+\Psi)d_{it}, \quad \forall i,t \quad (19)$$

where Ψ is the percentage increment in demand that would be covered in an emergency. The reported average load for all of Mexico in 1999 was 20,827 MW while the maximum load observed in that year was 29,580 MW.[57] Using our assumed load curves, such a difference between the annual average load and the maximum demand in a year corresponds to a 13% gap between the average demand for the peak season and the peak demand for the year. Hence, we set Ψ =13%.[58] While (19) is required to hold for every period, in practice the constraint would not be binding in most periods. The plant capacities $\bar{g}_n$ are fixed for all periods. Reserve capacity sufficient to cover extraordinary demand levels at the peak would also more than cover extraordinary demand during the off-peak periods.

In addition to satisfying (19), the "virtual" extreme demand transmission levels $\hat{\tau}_{ji,t}$ must satisfy constraints analogous to (15):

$$\sum_{l}^{\ell(i,j)} \hat{\tau}^l_{ji,t} + \sum_{l}^{\ell(i,j)} \hat{\tau}^l_{ij,t} \leq \bar{\tau}_{ij}, \quad \forall t, \quad (i,j)\in L \quad (20)$$

where L is the set of transmission links in the system.

[57]Source: "Prospectiva del sector electrico 2001-2010", Secretary of Energy, pp 66.

[58]For the year 2005, we use the same percentage increase to represent unexpected demand. According to the CFE, the projected average and maximum load for the year 2005 will be 41,159 and 29,293 MW respectively. The ratio of these two figures is similar to that for the year 1999. Source: "Prospectiva del sector electrico 2001-2010", Secretary of Energy, pp 106.

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