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LONG-TERM ISSUES IN THE POWER SECTOR

ANALYSIS OF DEMAND, INVESTMENT, AND EFFICIENCY EFFECTS OF DISTORTIONS IN RETAIL ELECTRICITY TARIFFS

Final Report

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SUMMARY

S.1 STUDY OBJECTIVES AND SCOPE

Economic growth in India will continue to be critically dependent on the efficient development of the power sector. This sector is facing an ambitious capital investment program at a time when the shortage of public financing is clearly a major constraint to accelerating development.

Electricity tariff policies, if carefully designed and properly implemented, have the potential for making significant contributions to the national welfare by simultaneously achieving multiple desirable objectives: (1) contributing to the fiscal and budgetary objectives of the Government of India (GOI) and the States, and thereby facilitating the massive amounts of capital mobilization required to meet the growing power needs of the country, (2) providing the correct price signals for stimulating energy conservation and demand management, and (3) increasing the efficiency of public and private resource allocation in the power sector.

With the preceding as a brief background, the objective of this study is to assess, from an economic perspective, the effects of distortions in retail electricity tariffs upon consumer demand for electricity, the resultant implications for sector investment requirements, and their effects on overall sector efficiency.

When we talk about "investment," we interpret it in the broadest context of capital investment and fuel-related expenditures of not only public sector power supplying entities -- at the central and state levels -- but also of private investment and fuel-related expenses incurred by consumers to meet their requirements for electricity.

The approach used in this study was to first undertake a quantitative analysis of the issues involved in the specific context of four State Electricity Boards (SEBs). Based on these analyses, implications for all-India are developed.

The four SEBs selected for this purpose were Harayana State Electricity Board and U.P. State Electricity Board in the Northern Region, and Maharastra and Gujarat State Electricity Boards in the Western Region. Together, these four Boards account for about 30 percent of all of India's electricity sales. These four SEBs are also sufficiently diverse; they provide the opportunity to analyze the range of tariff distortions that are representative of the situation in most other SEBs.

S.2 EXTENT OF TARIFF DISTORTIONS AND SUBSIDIES

The magnitude of subsidies implied by the tariff distortions in the power sector in India today is nothing short of staggering. Exhibits S-1 through S-4 help to illustrate the order-of-magnitude subsidies, in an economic sense, that are associated with the provision of electricity supply by the four case study SEBs selected. To illustrate, consider the situation of the Maharastra State Electricity Board.

Exhibit S-1 indicates the tariff yield for Maharastra by consumer segment as well as corresponding estimates of the economic cost (long-run marginal cost -- LRMC) of supply.[1] The systemwide average realization in 1989-90 was 88 paise/kWh, with class-specific yields ranging from a low of 9 paise/kWh for agriculture, to a high of Rs. 1.27/kWh for the industry segment.

By contrast, the LRMC (the economic cost of supply) is estimated to be Rs. 1.77/kWh, or about twice as high as the present (i.e., 1989-90) yield. For a projected 1990-1991 sales of 32,983 GWh, and the consumption shares shown in Exhibit S-1, the above conditions imply an economic subsidy of Rs. 29,476 million annually. Of this total, nearly half (Rs. 12,646 million/year) is attributable to the agriculture segment, Rs. 5,471 million per year to the domestic segment, and Rs. 1,489 million per year to the industry segment. The "other" customer category represents sales-for-resale (licensees, bulk supply) and street lighting loads.

Exhibit S-5 provides a summary of the magnitude of existing subsidies for each of the four SEBs and extrapolates them to all of India based upon the assumption that the four SEBs in Exhibit S-5 represent 30 percent of all SEB sales in India, a situation that reflects 1989-90 conditions.

The data in Exhibit S-5 indicate that the annual economic subsidy in the provision of electricity supply by all the SEBs in India is on the order of Rs. 266+ billion, or about $15 billion per year. Of this total, approximately half is incident in the irrigation and agriculture customer class, with the remainder spread across the other beneficiary segments.

From a purely financial point of view, the annual subsidy is estimated to be about Rs. 52 billion ($3 billion per year). Estimates of the financial subsidy are based on the conservative assumption that the average financial revenue requirement is Rs. 1.00/kWh.

In discussions with power sector officials, we learned that the Rs. 1.00/kWh figure barely covers all costs today, with perhaps a negligible contribution to self-financing. If the self-financing ratio were set at 35 percent, the Rs. 1.00/kWh figure would have to be raised. Additionally, if a rate of return on net revalued assets of even 5 percent real were to be

[1] Estimates of LRMC were developed by London Economics, consultants to the World Bank. A brief description of their methodology for estimating marginal costs is contained in Appendix 4.

Exhibit S-1
Estimate of Economic Subsidies by Consumer Segment
Maharastra State Electricity Board
(1990-91)

Consumer Segment	Share of Sales(%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	9.7%	0.55	2.26	5,471
Commercial	2.4%	1.03	2.07	823
Industrial				
LT	4.7%	0.92	1.67	1,163
HT	32.9%	1.27	1.30	326
Agriculture	21.3%	0.09	1.89	12,646
Railway	1.3%	1.15	1.37	94
Other	27.7%	1.09	2.07	8,954
Total	100.0%	0.88	1.77	29,476

Exhibit S-2
Estimate of Economic Subsidies by Consumer Segment
Gujarat State Electricity Board
(1990-91)

Consumer Segment	Share of Sales(%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	9.6%	0.69	2.39	2,686
Commercial	0.0%		2.18	0
Industrial				
LT	7.6%	1.18	1.76	725
HT	33.9%	1.24	1.35	614
Agriculture	32.0%	0.22	2.00	9,374
Railway	1.6%	1.12	1.42	79
Other	15.3%	0.95	2.18	3,097
Total	100.0%	0.81	1.82	16,575

Source: RCG/Hagler, Bailly, Inc. estimates based upon historical data provided by CEA, and estiamtes of marginal cost by London Economics.

Exhibit S-3
Estimate of Economic Subsidies by Consumer Segment
Harayana State Electricity Board
(1990-91)

Consumer Segment	Share of Sales(%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	14.3%	0.56	2.40	1,793
Commercial	2.4%	1.23	2.20	159
Industrial				
LT	19.9%	1.16	1.79	854
HT	6.3%	0.96	1.41	193
Agriculture	40.0%	0.30	2.03	4,715
Railway	0.0%		1.50	0
Other	17.1%	0.56	2.20	1,911
Total	100.0%	0.62	2.03	9,624

Exhibit S-4
Estimate of Economic Subsidies by Consumer Segment
Uttar Pradesh State Electricity Board
(1990-91)

Consumer Segment	Share of Sales(%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	12.1%	0.69	2.40	4,185
Commercial	7.2%	0.91	2.20	1,879
Industrial				
LT	13.5%	1.13	1.79	1,802
HT	21.7%	1.16	1.41	1,097
Agriculture	37.5%	0.22	2.03	13,729
Railway	4.3%	1.19	1.50	270
Other	3.7%	0.71	2.20	1,115
Total	100.0%	0.71	1.90	24,077

Source: RCG/Hagler, Bailly, Inc. estimates based upon historical data provided by CEA, and estiamtes of marginal cost by London Economics.

Exhibit S–5
Summary of Existing Subsidies
(1990–91, Million Rs.)

SEB	Economic Subsidy	Financial Subsidy	% Share of Economic Subsidies						
			Domestic	Commercial	Industry		Agriculture	Other*	Total
					LT	HT			
Maharastra	29,476	4,117	17.6	2.6	3.7	0.3	40.3	35.4	100.0
Gujarat	16,575	3,128	16.0	0.0	4.2	3.0	55.7	21.0	100.0
Harayana	9,624	2,612	18.8	1.6	8.9	1.9	49.5	19.2	100.0
U.P.	24,077	5,801	17.5	7.8	7.5	4.2	57.4	5.7	100.0
Total	79,752	15,657							
Projected to All–India	265,839	52,188							

* Includes licencees, railways, and other.

Source: RCG/Hagler, Bailly, Inc.

required, then the revenue requirement estimate quoted above would need to be increased to somewhat between Rs. 1.10/kWh and Rs. 1.25/kWh, thereby substantially raising the estimated financial subsidy amount beyond the Rs. 60 billion per year estimate mentioned above.

To put the magnitude of subsidies at the all-India level in perspective, it should be noted that the Rs. 266 billion per year in economic subsidy, and the Rs. 52+ billion per year financial subsidy translate to five-year subsidies of greater than[2] Rs. 1,330+ billion and Rs. 260+ billion, respectively. By comparison, the provisional outlays for the power sector in the Eighth Plan (1990/91-1994/95) are reported to be about Rs. 690 billion.

S.3 DEMAND AND INVESTMENT EFFECTS AND EFFICIENCY GAINS POTENTIAL

Investment Savings

Exhibit S-6 presents estimates of the potential for investment cost savings as a consequence of raising retail electricity tariffs from today's average levels to the respective economic price levels (i.e., to pure efficiency price levels) for each consumer class, over a five-year period. For the four SEBs analyzed in this report, the investment cost savings are estimated to be Rs. 142 billion. This number is a present value calculated over the 10-year period 1990-91 through 1999-00, and at a discount rate of 12 percent. Of the total amount, Rs. 133 billion represent reductions in capital outlays for grid expansion, and the balance of Rs. 9 billion comprise savings in capital in the private sector for the installation of captive generation plant.

The all-India estimates shown in Exhibit S-6 are extrapolated from the four SEB totals based on the assumption that these four SEBs account for approximately 30 percent of all-India sales, an assumption that reflects the situation in recent years. Thus, the all-India numbers should be interpreted as being indicative of the order-of-magnitude implications at the national level.[3] The data in Exhibit S-6 indicate that the all-India investment savings potential by phasing-in economic price levels over a five-year period are on the order of Rs. 473 billion. Of this amount, about 94 percent is attributable to reductions in grid investment requirements, with the balance in savings coming from reduced investments in customer-owned captive generation plant.

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[2] Since the subsidy calculations are based upon projected 1990/91 sales levels.

[3] Whereas the magnitude of tariff distortions in the four SEBs analyzed in this study are for the most part representative of the magnitude of distortions to be found in the other SEBs, the customer shares may vary somewhat more, as do the absolute levels of tariff realizations across the other states (Appendix 3).

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Exhibit S-6

Investment Savings Potential by Increasing Retail Tariffs from Today's Average Levels to Economic Price Levels over Five Years

(Present Value 1990-91 through 1999-00; in Rs. Billions)

	Four SEBs	All India
Grid	(133)	(443)
Self-Generation	(9)	(30)
Total Investment Savings	Rs. 142 billion	Rs. 473 billion

Exhibit S-7

Potential for Efficiency Gains by Increasing Retail Tariffs from Today's Average Levels to Economic Price Levels over Five Years

Present Value 1990-91 through 1999-00; in Rs. Billions)

	Four SEBs	All India
Consumer Benefit	(89)	(296)
Grid Generation Costs (Capital & Fuel)	(186)	(619)
Self-Generation Costs (Capital & Fuel)	(45)	(150)
Net Benefit	Rs. 142 billion	Rs. 473 billion

Demand Effect

An estimate of the demand effect -- in terms of megawatts of reduced generation capacity requirements -- can be approximated as follows. The analysis described in Chapter 3 of this report indicates that the total demand effect because of phasing in economic pricing is a reduction of 167 billion kWh over the 10-year period, or approximately 17 billion kWh per year in a levelized sense. At a load factor of 70 percent, this implies a reduction of 2,800 average MW in consumer demand. Assuming a reserve margin of 15 percent, this implies a reduction in generation capacity requirements of slightly over 3,200 MW.

To put this estimate of the demand effect in perspective, consider that under the baseline demand forecast utilized in the analysis, the projected sales growth in the four SEBs together over the 10-year period is 66 billion kWh, or about 11,000 MW of incremental demand. In other words, the 2,800 average MW demand reduction because of economic pricing represents an approximate 25 percent reduction in demand. We believe that this percentage is also indicative of the demand (i.e., kWh) effect at the all-India level as well.

Increase in Net National Benefits

Exhibit S-7 summarizes estimates of efficiency gains as a consequence of phasing in economic pricing over a five-year period. The present value of the net economic benefit is estimated very conservatively to be Rs. 142+ billion for the four SEBs analyzed in this study. Of this total, Rs. 186 billion represent savings in capital and fuel by the grid, and Rs. 45 billion represent savings in capital and fuel by consumers who have captive generation, whereas there is a loss in consumer benefit of Rs. 89 billion because of the price-induced reduction in consumption levels.

The analysis indicates that at the all-India level, the present value of efficiency gains (net national benefits), by raising average retail tariffs to economic price levels, is on the order of Rs. 473+ billion. This amount is calculated as follows. Savings associated with reductions in grid supply cost (capital and operations) are Rs. 619 billion and Rs. 150 billion represent comparable savings in customer-owned captive generation facilities. Some of these savings, Rs. 296 billion, are offset by reduced consumer benefits.

Additional Potential for Investment Savings and Efficiency

The estimates noted above do not reflect the significant potential for additional efficiency gains that are not captured in the analysis. Such benefits can be captured by improvements in the structure of retail tariffs and can be realized on top of the gains already noted that stem from simply raising the average level of retail tariffs to economic levels. More specifically:

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- Additional reductions in demand (kW) on-peak can be achieved by raising the demand charge share of the effective price of a kWh of electricity to be closely aligned to the economic cost structure, i.e., the demand charge share should represent about 45 to 55 percent of the effective cost per kWh for all but the very high load factor consumers, as opposed to the situation now where the demand charge share typically ranges between 5 percent and 15 percent of the effective price per kWh faced by industrial consumers.

- The present analysis does not reflect still further efficiency gains and investment cost reduction potential that can most definitely be tapped by introducing time-of-day (TOD) pricing for the large industry segment to start with and to be eventually expanded in coverage to include medium-sized industry and large commercial customers as well. There is ample evidence and experience from around the world, including some developing country experience as well, which indicates that the introduction of time-of-day pricing and other forms of pricing, including interruptible tariffs, demand subscription service, and dynamic pricing to foster electricity demand management, should be aggressively pursued in India.

  The potential for reducing peak demand from the introduction of special-purpose load management tariffs of the type noted is significant, and has been conservatively placed at 5 to 10 percent peak load reduction [19].

The design, implementation, and demonstration of such tariffs on a broad scale in the context of one or two SEBs merits serious and immediate consideration for funding and follow-on by bilateral and multilateral development agencies. This assistance could perhaps be structured in the form of a technical cooperation agreement with one or more SEBs that are committed to pursuing these options aggressively.

In conclusion, the results of this report serve to underscore the need for and benefits from rationalizing retail electricity tariffs in India based upon the concept of efficiency pricing. Industry HT customers are, in many instances, paying close to marginal costs. For most other customer segments, a five-year phase-in period should provide adequate time to bring tariffs in alignment with economic costs. The most problematic issue arises in the agriculture sector where tariff yields are 5 to 10 percent of the economic cost of supply and where there appears to be strong politically driven factors that have caused the present situation. Certainly the more affluent farm segment -- that has diesel pumpsets to back up electric pumpsets -- has demonstrated its willingness to pay the economic cost of supply.

Other consumers in this segment -- especially the poor farmers -- could be adversely affected by tariff rationalization. An alternative that could be considered is to provide an off-peak pumping tariff that largely reflects off-peak marginal energy costs. These have been estimated to be about 45 to 50 paise/kWh in the four SEBs selected for this study. Such a tariff would have to be enforced by a mechanism which could be as simple as a time switch, or by the implementation of a more sophisticated but not very expensive system

based on radio-controlled time switches. Agriculture customers who want service round-the-clock should have to pay the regular tariff applied on a metered basis.

Finally, the study has been hampered by the lack of data on the extent and incidence of power shortages in the major consumer segments. Major data gaps exist with respect to information about the ownership of small generation by residential and commercial customers that are used primarily for reliability purposes. In addition, we do not know what percentage of such consumers experience significant energy shortages. Therefore, we recommend that proceedings be set up to monitor and collect such data on a regular basis. Once available, these data would provide the basis to extend the methodological framework of this study to address a more diverse range of consumer circumstances regarding their experience with power shortages.

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CHAPTER 1: INTRODUCTION

1.1 STUDY OBJECTIVES AND SCOPE

Economic growth in India has and will continue to be critically dependent upon the efficient development of the power sector. This sector is facing an ambitious capital investment program at a time when the shortage of public financing is clearly a major constraint to accelerating development.

The power sector in India absorbs a substantial share of the nation's development budget. The data in Exhibit 1-1 reveal that capital expenditures in the power sector have been at about 18 to 20 percent of total plan outlays in the last fifteen years; these levels are projected to be maintained during the current Eighth Plan period (1990/94), and presumably beyond into the Ninth Plan period as well.

Electricity tariff policies, if carefully designed and properly implemented, have the potential for making significant contributions to the national welfare by simultaneously achieving multiple desirable objectives: (1) contributing to the fiscal and budgetary objectives of the Government of India (GOI) and the States, and thereby facilitating the massive amounts of capital mobilization required to meet the growing power needs of the country, (2) providing the correct price signals for stimulating energy conservation and demand management, and (3) increasing the efficiency of public and private resource allocation in the power sector.

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The approach used in this study was to first undertake a quantitative analysis of the issues involved in the specific context of four State Electricity Boards (SEBs). Based on these analyses, implications for all India are developed.

The four SEBs selected for this purpose were Harayana State Electricity Board and U.P. State Electricity Board in the Northern Region, and Maharastra and Gujarat State Electricity Boards in the Western Region. Together, these four Boards account for about 30 percent of all of India's electricity sales. These four SEBs are also sufficiently diverse; they provide the opportunity to analyze the range of tariff distortions that are representative of the situation in most other SEBs.

Exhibit 1-1

PLAN OUTLAYS FOR THE POWER SECTOR
(Rs billion)

	Power Sector	Total Plan	Power as a Percentage of the Total Plan Expenditure
First Plan (1951/52-1955/56)	2.60	21.66	12.0%
Second Plan (1956/57-1960/61)	4.60	49.93	9.2%
Third Plan (1961/62-1965/66)	12.52	89.38	14.0%
Annual Plans (1966/67-1968/69)	12.23	68.79	17.8%
Fourth Plan (1969/70-1973/74)	29.31	162.73	10.0%
Fifth Plan (1974/75-1978/79)	74.00	394.[illegible]0	18.8%
Sixth Plan (1980/81-1984/85)	182.98	1100.90	16.6%
Seventh Plan (1985/86-1989/90)	293.35	1677.40	17.5%
Eighth Plan (1990/91-1994/95)	690.00 /1	3600.00	18.2%

/1 Provisional

Source: World Bank, Resident Mission New Delhi.

1.2 ORGANIZATION OF REPORT

This report is organized as follows. The remainder of this chapter contains an overview of the historical and current situation as regards electricity tariffs, and a review of related variables of particular relevance to the subject matter of this report. Next, Chapter 2 describes the theoretical reasoning and methodological framework employed in the study to quantitatively analyze the key issues in this study. Following this, Chapter 3 presents our analysis and findings.

1.3 REVIEW OF HISTORICAL SITUATION

As a prelude to the methodology and analysis described in the following chapters of this report, this section sets the stage by highlighting and interpreting relevant historical data on the inter-related areas of influence: electricity tariffs and subsidies, consumption patterns, and power supply adequacy.

Electricity Tariffs and Subsidies

A necessary condition to ensure an adequate, reliable, and economical supply of power over the long run is that electricity tariffs meet a few basic criteria.

First, and at a minimum, tariffs should be maintained at levels to ensure that the supplier's financial requirements are met. These requirements are understood to include all investment and operating costs including depreciation, principal repayments, and debt service, as well as a provision for self-financing a substantial portion of the future expansion. In addition to these costs, tariffs should enable the recovery of a rate of return that reflects the true opportunity cost of capital to the nation.

Second, tariff levels by customer segment should reflect the respective cost burdens incurred in supplying power to each segment. This is simply the fairness and equity principle of pricing.

Third, the structure of tariffs, in contrast to the average level, should reflect the economic cost (i.e., the long-run marginal cost) of supply to each customer segment. This will help to foster the optimal amount of energy conservation and the minimize the mis-allocation of resources.

Finally, "equity" and other socio-political considerations may enter into the tariff setting process. In any event, the economic cost structure provides the reference benchmark and the point of departure for tariff adjustments related to non-economic objectives. Thus, the efficiency implications (costs) of such deviations can be readily established to facilitate comparisons with the potential benefits of subsidies inherent in any departure from pure efficiency pricing.

Exhibits 1-2 through 1-5 depict tariff yields (realization) in recent years by customer segment in the four SEBs selected for analysis in this report. The corresponding all-India tariff realizations are also shown in these exhibits. Tariff yield, also sometimes referred to as tariff realization, is understood to mean the billed revenue per unit of sales.

The data indicate that tariff yields (in constant 1985-86 Rupees) are the lowest for the irrigation and agriculture segment (7 to 18 paise/kWh, with the all-India average at just under 10 paise/kWh), followed by domestic tariff yields (45 to 50 paise/kWh), commercial yields (70 to 85 paise/kWh), and industrial tariff yields (85 to 98 paise/kWh).

The data in Exhibits 1-2 through 1-5 also reveal the following pattern in tariff realization on an all-India basis. Industrial tariff yields have increased somewhat in real terms from 1985-86 levels, though not significantly during the last two or three years.

Tariff yields for the other three segments -- commercial, domestic, agriculture -- have declined in real terms from their 1985-86 levels. This trend is most alarming in the case of agriculture tariffs, where the all-India realization decreased in real terms by approximately 45 percent, from about 18 paise/kWh to 10 paise/kWh. At an exchange rate of Rs. 18 to one U.S. dollar, this implies a yield of about 0.5 cents/kWh, a price level that is perhaps unmatched elsewhere, except possibly in situations where a hydro-dominant utility must spill water because of inadequate storage capacity.

The magnitude of subsidies implied by the tariff distortions in the power sector in India today is nothing short of staggering. Exhibits 1-6 through 1-9 help to illustrate the order-of-magnitude subsidies, in an economic sense, that are associated with the provision of electricity supply by the four case study SEBs selected. To illustrate, consider the situation of the Maharastra State Electricity Board (MSEB).

Exhibit 1-6 indicates the tariff yield for Maharastra by consumer segment as well as corresponding estimates of the economic cost (long run marginal cost -- LRMC) of supply.[1] The systemwide average realization in 1989-90 was 88 paise/kWh, with class-specific yields ranging from a low of 9 paise/kWh for agriculture, to a high of Rs. 1.27/kWh for the industry segment.

By contrast, the LRMC (the economic cost of supply) is estimated to be 1.77/kWh, or about twice as high as the present (i.e., the 1989-90) yield. For a projected 1990-91 sales of 32,983 GWh, and the consumption shares shown in Exhibit 1-7, the above conditions imply an economic subsidy of Rs. 31,382 million annually. Of this total, nearly half (Rs. 12,646 million/year) is attributable to the agriculture segment, Rs. 5,535 million per year to the domestic segment, and Rs. 1,272 million per year to the industry segment. The

[1] Estimates of LRMC were developed by London Economics, consultants to the World Bank. A brief description of their methodology for estimating marginal costs is contained in Appendix 4.

Exhibit 1-2

Agriculture Tariff Yields

(1985-86 Rs./kWh)

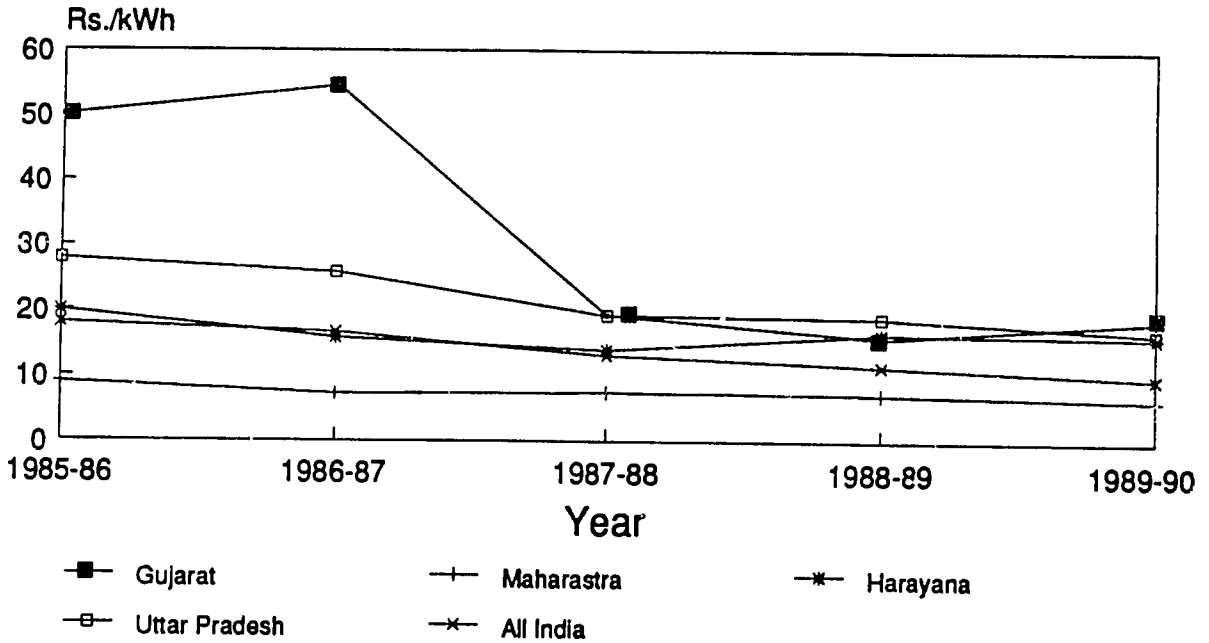


Exhibit 1-3

Industrial Tariff Yields

(1985-86 Rs./kWh)

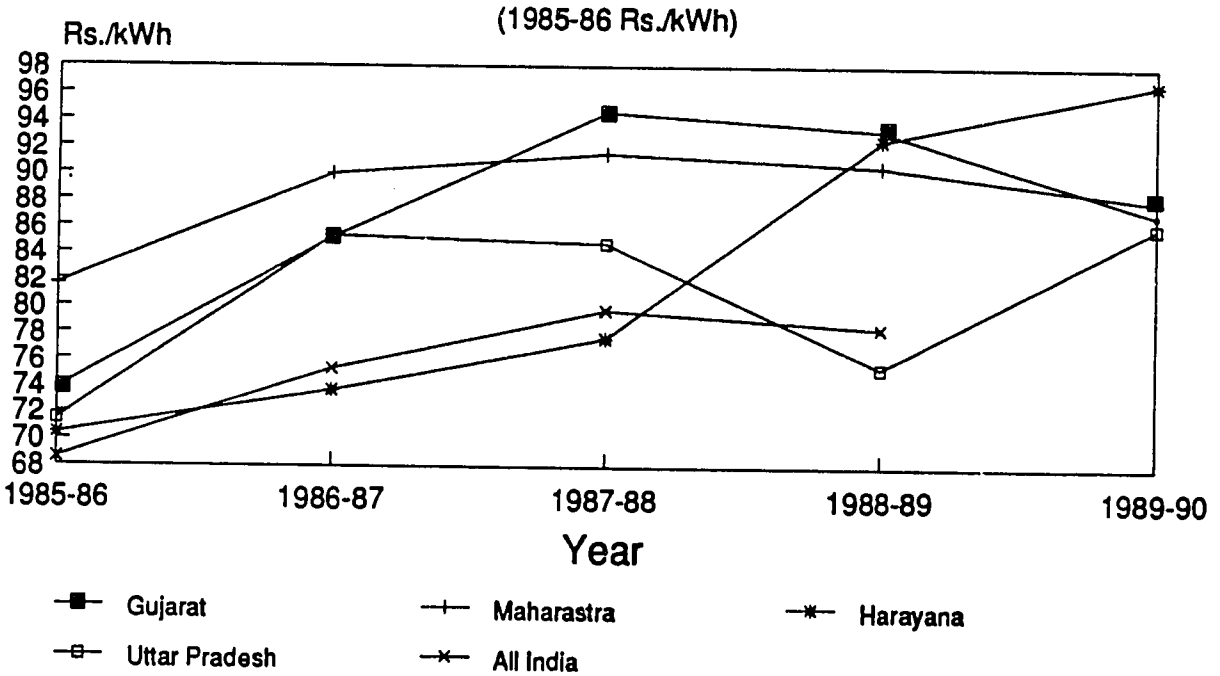


Exhibit 1-4
Commercial Tariff Yields
(1985-86 Rs./kWh)

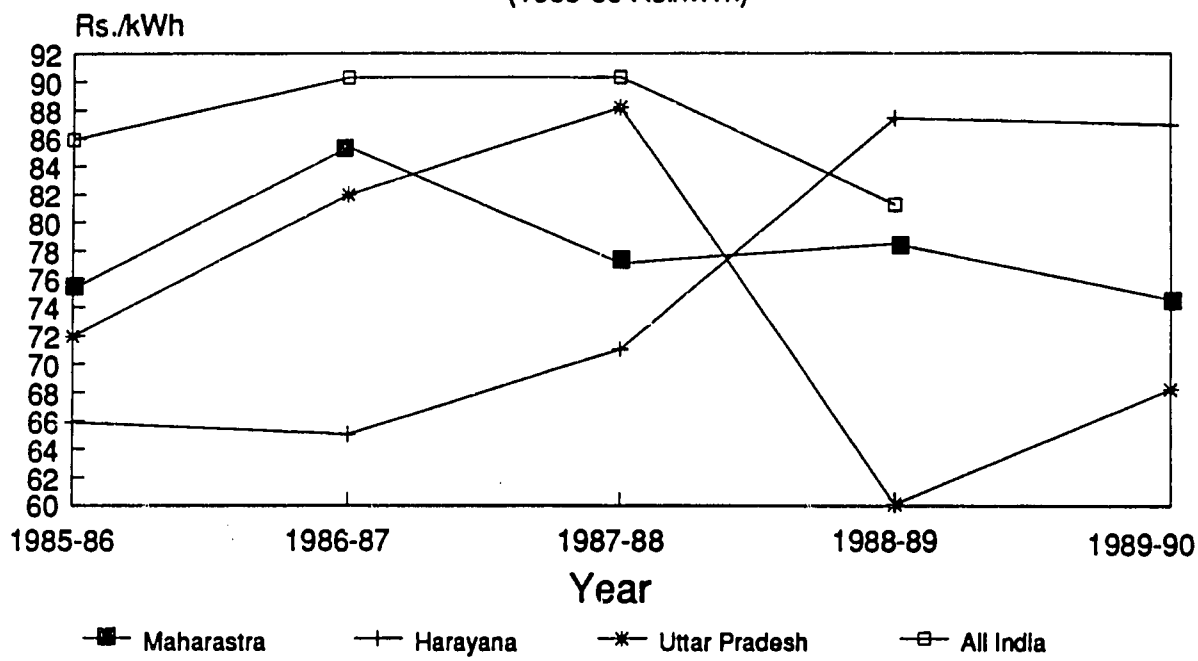


Exhibit 1-5
Domestic Tariff Yields
(1985-86 Rs./kWh)

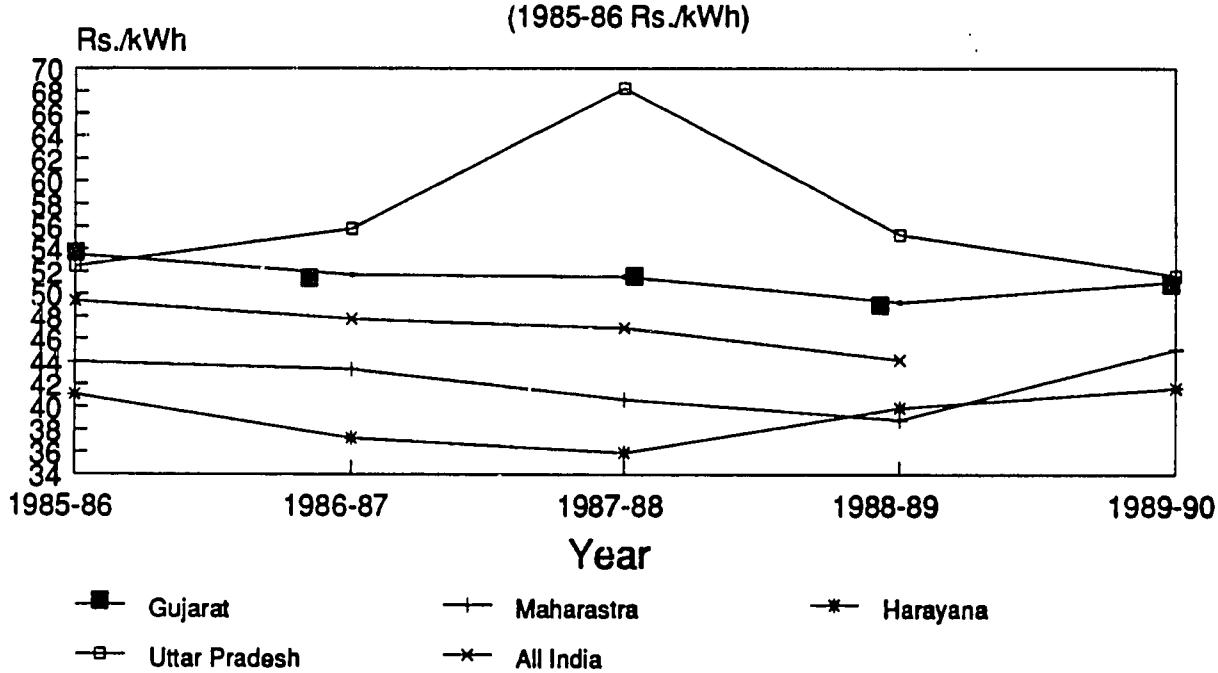


Exhibit 1-6
Estimate of Economic Subsidies by Consumer Segment
Maharastra State Electricity Board
(1990-91)

Consumer Segment	Share of Sales (%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	9.7%	0.55	2.28	5,535
Commercial	2.4%	1.03	2.08	831
Industrial				
LT	4.7%	0.92	1.67	1,163
HT	32.9%	1.27	1.28	109
Agriculture	21.3%	0.09	1.89	12,646
Railway	1.3%	1.15	1.36	90
Other	27.7%	1.15	2.08	11,009
Total	**100.0%**	**0.88**	**1.77**	**31,382**

Exhibit 1-7
Estimate of Economic Subsidies by Consumer Segment
Gujarat State Electricity Board
(1990-91)

Consumer Segment	Share of Sales (%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	9.6%	0.69	2.37	2,654
Commercial	0.0%	0.00	2.16	0
Industrial				
LT	7.6%	1.18	1.74	700
HT	33.9%	1.24	1.33	502
Agriculture	32.0%	0.22	1.97	9,216
Railway	1.6%	1.12	1.41	76
Other	15.3%	0.81	2.16	3,399
Total	**100.0%**	**0.79**	**1.79**	**16,548**

Source: RCG/Hagler, Bailly, Inc. estimates based upon historical data provided by CEA, and estimates of marginal cost by London Economics.

Exhibit 1-8
Estimate of Economic Subsidies by Consumer Segment
Harayana State Electricity Board
(1990-91)

Consumer Segment	Share of Sales (%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	14.3%	0.56	2.39	1,783
Commercial	2.4%	1.23	2.18	155
Industrial				
LT	19.9%	1.16	1.78	841
HT	6.3%	0.96	1.39	185
Agriculture	40.0%	0.30	2.02	4,687
Railway	0.0%		1.49	0
Other	17.1%	0.62	2.18	1,817
Total	100.0%	0.63	2.02	9,468

Exhibit 1-9
Estimate of Economic Subsidies by Consumer Segment
Uttar Pradesh State Electricity Board
(1990-91)

Consumer Segment	Share of Sales (%)	Yield (Rs./kWh)	Long-Run Marginal Cost (Rs./kWh)	Economic Subsidy Million Rs.
Domestic	12.1%	0.69	2.39	4,161
Commercial	7.2%	0.91	2.18	1,850
Industrial				
LT	13.5%	1.13	1.78	1,775
HT	21.7%	1.16	1.39	1,010
Agriculture	37.5%	0.22	2.02	13,653
Railway	4.3%	1.19	1.49	261
Other	3.7%	0.72	2.18	1,093
Total	100.0%	0.71	1.88	23,802

Source: RCG/Hagler, Bailly, Inc. estimates based upon historical data provided by CEA, and estimates of marginal cost by London Economics.

"other" customer category represents sales-for-resale (licensees, bulk supply) and street lighting loads. Exhibit 1-10 provides a summary of the magnitude of existing subsidies for each of the four SEBs and extrapolates them to all of India based upon the assumption that the range of customer shares and class-specific subsidies in the four SEBs are fairly typical of the situation in the other SEBs. Further, it is assumed that the four SEBs in Exhibit 1-10 represent 30 percent of all SEB sales in India, a situation that reflects 1989-90 conditions.

The data in Exhibit 1-10 indicate that the annual economic subsidy in the provision of electricity supply by all the SEBs in India is of the order on Rs. 271+ billion, or about $15 billion per year. Of this total, approximately half is incident in the irrigation and agriculture consumer class, with the remainder spread across the other beneficiary segments.

From a purely financial point of view, the annual subsidy is estimated to be about Rs. 60 billion ($3+ billion per year). Estimates of the financial subsidy are based on the conservative assumption that the average financial revenue requirement is Rs. 1.00/kWh.

In discussions with power sector officials, we learned that the Rs. 1.00/kWh figure barely covers all costs today, with perhaps a negligible contribution to self-financing. If the self-financing ratio were set at 35 percent, the Rs. 1.00/kWh figure would have to be raised. Additionally, if a rate-of-return on net revalued assets of even 5 percent real were to be required, then the revenue requirement estimate quoted above would need to be increased to somewhere between Rs. 1.10/kWh and Rs. 1.25/kWh, thereby substantially raising the estimated financial subsidy amount beyond the Rs. 60 billion per year estimate mentioned above.

To put the magnitude of subsidies at the all-India level in perspective, it should be noted that the Rs. 271 billion per year in economic subsidy, and the Rs. 60+ billion per year financial subsidy translate to five-year subsidies of greater than[2] Rs. 1,355+ billion and Rs. 300+ billion, respectively. By comparison, the provisional outlays for the power sector in the Eighth Plan (1990/91-1994/95) are reported to be about Rs. 690 billion.

Consumer Demand Patterns

Exhibits 1-11 and 1-12 summarize growth rates in electricity consumption (i.e., grid sales). During the period 1960/1970, total grid sales grew by 12.1 percent. Between 1970/71 and 1985/86, total sales grew at about 6.7 percent. In the more recent past (1985/86 through 19888/89), grid-supplied consumption has grown at an average annual rate of 8.6 percent. The data in Exhibit 1-11 also reveal that growth rates have been the highest in the irrigation and agriculture segment, followed by the domestic and

[2] Since the subsidy calculations are based upon projected 1990/91 sales levels.

Exhibit 1-10
Summary of Existing Subsidies
(1990-91, Million Rs.)

SEB	Economic Subsidy	Financial Subsidy	% Share of Economic Subsidies						
			Domestic	Commercial	Industry		Agriculture	Other*	Total
					LT	HT			
Maharastra	31,382	3,480	17.6	2.6	3.7	0.3	40.3	35.4	100.0
Gujarat	16,548	6,081	16.0	0.0	4.2	3.0	55.7	21.0	100.0
Harayana	9,468	2,542	18.8	1.6	8.9	1.9	49.5	19.2	100.0
U.P.	23,802	5,793	17.5	7.8	7.5	4.2	57.4	5.7	100.0
Total	81,200	17,896							
Projected to All-India	270,667	59,653							

* Includes licencees, railways, and other.

Source: RCG/Hagler, Bailly, Inc.

Exhibit 1-11
Growth Rates in Electricity Consumption

Year	Domestic	Commercial	Industry	Irrigation & Agriculture	Total GWH
1960-61	-	-	9,696	833	13,953
1970-71	-	-	29,579	4,470	43,724
1975-76	-	-	37,568	8,721	60,246
1985-86	12,161	4,277	52,224	23,560	115,336
1988-89	18,282	6,290	59,980	38,080	147,648
Growth Rates					
60-61 to 70-71	-	-	11.8%	18.3%	12.1%
70-71 to 75-76	-	-	6.6%	14.3%	6.6%
75-76 to 85-86	-	-	3.3%	10.4%	6.7%
85-86 to 88-89	14.6%	13.7%	4.7%	17.4%	8.6%

Source: Based upon data in references [10], [11], [12].

Exhibit 1-12
Trends in Relative Consumption Shares (%)

Class	1960-61	1970-71	1980-81	1987-88
Domestic	8.9	8.8	11.2	14.7
Commercial	5.1	5.9	5.7	5.9
Industry	74.5	62.4	58.4	52.5
Irrigation & Agriculture	5.0	14.5	17.6	20.7
Bulk Supply	--	--		9.4
Railways	2.7	3.1	2.7	2.4
Other	2.6	4.5	4.4	4.3
Total	100.0	100.0	0.0	100.0

Source: Reference [10].

commercial segments. By contrast, the industry segment has grown between 4 and 6 percent annually over the last two decades.

Exhibit 1-12 shows how relative consumption shares have evolved from 1960/61 to the present. Industry's share has fallen from 75 percent in 1960/61 to about 53 percent in 1988/89. Over the same period, the share of agriculture class sales increased from 5 percent to 21 percent. The share of domestic sales experienced an increase from 9 percent to about 15 percent.

It is no coincidence that sales to the agricultural segment have grown at rates that are not only highest in relative terms but also extremely high in absolute terms. Tariffs for this class have been extremely low. Furthermore, tariffs have declined in real terms. Thus, electricity is very nearly a "free good" to consumers in this class.

Chakravarty [8] provides quantitative evidence of the increase in direct energy intensity in the agriculture sector (Exhibit 1-13). This intensity -- of electricity and diesel fuel use -- has increased from 11.10 TOE per million Rupees of agricultural output (or 11.54 TOE per hectare of gross cropped area) in 1971-72 to 23.4 TOE per million Rupees of output (31.18 TOE per hectare of gross cropped area) by 1984-85. The annual growth rates in energy intensity are 5.90 percent using the first measure of energy intensity, and 7.95 percent based on the acreage measure of energy intensity, as compared to the average annual growth rate of 2.30 percent in sector output.

From an economic perspective, the costs of electricity subsidies should be stacked up against the benefits to society to gauge whether the nation is better off as a consequence. In this regard, it is increasingly being recognized in research and policy circles that traditional policies that have been used to promote agricultural development are not sustainable in the long run; that there is a need to devise policy responses which can lead to more efficient use of energy and resource inputs as well (e.g., see references [1], [7], [8]), [9].

From an overall economy-wide perspective, the low tariff levels across all sectors of the economy have surely been a contributory factor in making the economy more electricity intensive than necessary. Exhibit 1-14 shows this trend. Starting with 1960/61, up to now, the GNP per kWh per input has declined from 58 Rs./kWh to 19 Rs./kWh by 1988-89. Equivalently, the power intensity of the economy (as measured by the number of kilowatt-hours of electricity per Rupee of GDP) has risen three-fold, from 17 to 53 kWh input/Rs. GDP output.

An indicator of the overall electricity intensity of an economy that is commonly used for making broad inter-country comparisons is the "income elasticity." Exhibit 1-15 reveals that this elasticity coefficient for India has been around 1.5 since 1975, and was significantly higher prior to that time. An income elasticity greater than 1.0 in general, and equal to 1.5, is not out of line with those observed in many other developing nations.

Exhibit 1-13
Commercial Energy Consumption and Energy Intensity in Indian Agriculture

Year	Value of Output in Agriculture (at 70-71 prices) (Rs. billions)	3 Yrs. Moving Avg. of Direct Energy in TONNES of Oil Equivalent	
		(Per Rs. million of Agri. Output)	(per Hectare Gross Cropped Area)
1971-72	175.49	11.10	11.54
1972-73	163.15	12.07	12.48
1973-74	176.19	13.30	13.73
1974-75	172.49	13.76	14.76
1975-76	192.92	14.86	16.18
1976-77	182.04	15.10	17.11
1977-78	204.24	15.93	18.49
1978-79	211.03	17.40	20.13
1979-80	185.49	18.89	21.98
1980-81	207.52	20.03	23.50
1981-82	217.57	20.79	25.22
1982-83	210.10	21.44	26.66
1983-84	232.55	22.54	28.88
1984-85	235.89	23.40	31.18
Annual Growth Rate	2.30%	5.9%	7.95%

Source: Chakravarty [8].

Exhibit 1-14
GNP and Electricity Usage Intensity

Fiscal Year	GNP/kWh 1980-81 Rs./kWh	kWh per 80-81 Rs. of GNP
1960-61	58	17
1965-66	37	27
1970-71	29	34
1975-76	25	40
1985-86	20	49
1986-87	20	51
1987-88	19	54
1988-89	19	53

Source: RCG/Hagler, Bailly, Inc.

Exhibit 1-15
Income Elasticity Measure of Electricity Intensity in the Indian Economy

Time Period	Real GNP Growth Rate	Electricity Consumption	Income Elasticity
FY60-FY65	2.90%	12.44%	4.29
FY65-70	4.82%	10.00%	2.07
FY60-70	3.86%	11.21%	2.91
FY70-75	2.95%	6.40%	2.16
FY75-85	4.66%	6.73%	1.45
FY85-88	5.72%	8.63%	1.51
FY75-88	4.90%	7.17%	1.46

Source: RCG/Hagler, Bailly, Inc.

However, this elasticity has not declined during the course of the 13-year period 1975-1988. Over the same period, most developed countries have been able to substantially reduce their electricity intensity to levels significantly below 1.0.

Income elasticities over 1.0 pose a dilemma for planners. To achieve 1 percent economic growth under these conditions requires a more than 1 percent growth in the output of the power sector, which is one of the most capital-intensive sectors of the economy. To ensure that limited capital is employed most effectively, planners need to assess how much capital should be channelled to efforts aimed at reducing the electricity intensity of the economy -- e.g., by labor and capital substitution and by restructuring the industry mix -- and how much capital should be deployed to simply increase the supply of electricity to sustain the desired level of economic growth.

Power Supply Adequacy

Power supply shortages and unreliability were mostly sporadic in India in the 1950s and into the early 1960s. However, towards the end of this period the deficit situation was gradually deteriorating because generation capacity addition targets for the power sector in the five-year plans were consistently not achieved for a variety of reasons. As a consequence, the expansion program has been playing "catch-up" with demand ever since. By the 1970s power shortages had become a chronic national problem that now afflicts most states to varying degrees. Lost industrial output caused by power shortages is estimated very conservatively to have reduced GDP by 1.5 to 2+ percent [2].

Exhibit 1-16 displays the projected national power balance during the period 1989-1990. The data reveal that with the exception of the northeast, all regions experienced power deficits. Exhibit 1-17 indicates estimates of all-India energy deficit trends from 1974-1975. Because these are averages, they mask the considerable variations in deficits across regions and across customer segments.

When faced with a power shortage situation, broadly speaking, there are four shortage management strategies available. They are:

- Establish a new connections policy so that new service connections are offered only if there is sufficient generation capability.

- Connect everyone who wants service, but ration the shortfall by pricing mechanisms such as interruptible service tariffs, special load management tariffs, and the implementation of tariffs based on the notion of a capacity reservation charge.

Exhibit 1–16
Projected Power Balance
(1989–1990)

Region	Demand		Availability		Deficit		Deficit/Surplus	
	Capacity MW	Energy GWh	Capacity MW	Energy GWh	Capacity MW	Energy GWh	Capacity %	Energy %
North	11,745	75,280	11,550	74,365	(195)	(915)	–1.69%	–1.23%
West	12,165	73,750	11,640	71,721	(525)	(2,029)	–4.51%	–2.83%
South	11,080	66,900	9,615	57,154	(1,465)	(9,746)	–15.24%	–17.05%
East	5,305	30,630	4,325	25,784	(980)	(4,846)	–22.66%	–18.79%
Northeast	530	2,640	615	2,837	85	197	–13.82%	6.94%
All India	40,825	249,200	37,745	231,861	(3,080)	(17,339)	–	–

Source: Based upon data in references [6], [7], [11], [12].

Exhibit 1–17
Magnitude of Power Shortages

Year	Power Deficit (%)
1974–75	14.1
1975–78	10.3
1976–77	5.8
1977–78	15.5
1978–79	10.3
1979–80	16.8
1980–81	12.6
1981–82	10.8
1982–83	9.2
1983–84	10.8
1984–85	6.7
1985–86	7.9
1986–87	9.4
1987–88	10.9
1988–89	7.7
1989–90	7.3
1990–91 (Target)	7.0

- Ration the shortfall by controlled load shedding. This strategy would involve curtailments in supply according to a pre-announced schedule. Such curtailments could take the form of rotating blackouts (i.e., complete loss of service) or stipulated partial reductions in load.

- Ration the shortfall by uncontrolled load shedding. Such power cuts represent complete loss of service without any advance notification.

From an economic efficiency perspective, the first two strategies should be employed to manage shortages. Uncontrolled load shedding imposes the highest economic costs upon electricity users.

The shortage management strategy most commonly employed in India has been a combination of the third and fourth options noted above. Furthermore, industry has tended to bear the brunt of the shortfalls, followed by the irrigation and agriculture consumer segment. As a consequence of the power supply situation, a significant amount of customer-owned generation has been installed and operated.

Exhibit 1-18 shows the installed captive generation capacity and mix. In 1987/88, slightly over 6,200 MW of generating capacity was owned and operated outside the utility sector, of which about 60 percent represented steam capacity (coal or oil fired) and 36 percent was diesel based. These data only reflect sets exceeding 100 kW capacity or sets owned by customers with contract demands in excess of 500 kVA. In particular, these data do not include the large numbers of very small and portable generating sets typically found in the commercial sector that are mostly used to provide some lighting and other minimal essential needs during outages. These data also do not reflect self-generation capacity operated by customers who are isolated from the grid.

The data in Exhibit 1-19 indicate the extent to which industry relies on self-generation to supplement the shortfall in grid power supply. Over the 30-year period starting from 1960/61, the data indicate that industry has typically had to provide between 16 to 18 percent of its requirements. Furthermore, the data show that diesel's share of self-generation has also remained at a fairly constant level, around 14 to 18 percent during the last ten years.

Exhibit 1-18
Installed Captive Generation Capacity

Year	Installed Capacity				Capacity Mix			
	Steam MW	Diesel MW	Other MW	Total MW	Steam %	Diesel %	Other %	Total %
1970-71	N/A			1,512				
1976-77	1,784	423	18	2,225	80.2	19.0	0.8	100.0
1979-80	2,022	721	57	2,800	72.2	25.8	2.0	100.0
1985-86	2,882	2,378	159	5,419	53.2	43.9	2.9	100.0
1987-88	3,732	2,278	246	6256	59.7	36.4	3.9	100.0

Source: CEA data sheets

Exhibit 1–19
Captive Generation in Industry (GWH)

Year	Purchase	Self Gen.	Total	Self Gen. by Type (% Shares)				Capacity Factor (% Annual)		
				% of Tot.	Steam	Diesel	Hydro/Gas	Steam	Diesel	Other
1960–61	9,696	3,000	12,696	23.6%						
1965–66	18,876	3,733	22,609	16.5%						
1970–71	29,579	5,347	34,926	15.3%						
1975–76	37,568	6,657	44,225	15.1%						
1976–77	–	7,240	–	–	95.3	4.1	0.6	44.1	7.9	30.5
1979–80	–	8,157	–	–	88.6	10.1	1.3	41.0	13.0	21.2
1982–83	53,064	9,989	63,053	15.8%	85.1	14.1	0.8	39.7	12.3	17.2
1983–84		10,769			82.9	16.1	1.0			
1984–85	63,019	12,303	75,322	16.3%	81.0	16.3	2.7	40.6	11.0	24.2
1985–86	66,980	12,997	79,977	16.3%	78.7	18.1	3.2	40.5	11.3	30.1
1986–87	71,496	13,528	85,024	15.9%	80.6	16.7	2.7			
1987–88	77,104	16,855	93,959	17.9%	81.5	15.5	3.0			

Data represent generation by captive sets of size exceeding 100kW (1,000 kW from 1986–87 onwards), or generation by customers with contract demand in excess of 500 kVA.

Source: CEA data sheets.

CHAPTER 2: METHODOLOGICAL FRAMEWORK

This chapter provides an overview of the economic reasoning and methodological framework that underpin the analysis of demand and investment effects carried out in the study and described subsequently in the report.

It is important to emphasize at this juncture that when we talk about "investment," we interpret it in the broadest context of capital investment and fuel-related expenditures of not only public sector power supplying entities -- at the central and state levels -- but also of private investment and fuel-related expenses incurred by consumers to meet their requirements for electricity.

More specifically, as the data in Chapter 1 reveal, chronic capacity and energy shortages have taken on a national dimension and have affected a number of states, albeit to varying degrees. Industrial and agricultural customers have tended to bear the brunt of these shortfalls under the shortage management strategies most commonly employed. In response to this experience and because of expectations for such shortages to continue for the foreseeable future, a significant amount of customer-owned generation capacity is already in-place and is expected to grow until such time as grid-supplied power (i.e., utility generation) is adequate to meet consumer demand fully.

Customer generation is higher cost in comparison to utility generation because of the inefficient scale of equipment. Whereas customer generation may make sense in the short-run from the private firms' financial interest, from the national perspective it would be more economic to provide an equivalent amount of power from the grid. Thus, customer generation imposes a significant opportunity cost on the nation, stemming from a misallocation of investment resources in the long run. The analytical framework described in this chapter is designed to capture demand, investment, and efficiency effects of pricing distortions in total from a national perspective, i.e., utility and private investment.

With this as background, the remainder of this chapter is organized as follows. Section 2.1 presents the economic reasoning in the more straightforward situation where customer electricity demand is by and large met by grid supply. Section 2.2 provides the parallel reasoning in the more complex situation where constraints in grid supplies exist, resulting in significant amounts of customer-owned capacity and electricity generation.

2.1 DEMAND, INVESTMENT, AND EFFICIENCY EFFECTS: UNCONSTRAINED GRID SUPPLY

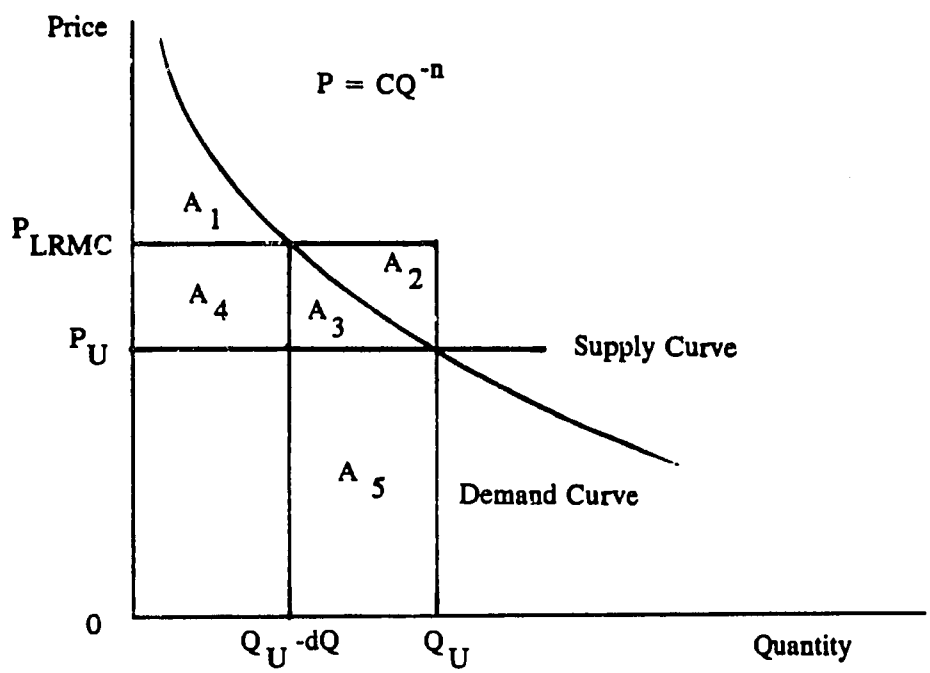
Exhibit 2-1 helps to illustrate the measurement bases employed in this report. The exhibit depicts a long-run (one year) demand curve for electricity for a given customer segment (e.g., residential) that is relatively free from any significant constraints in grid supply. This does not necessarily mean that these customers do not have any customer-owned generating capacity in-place. Rather, the extent of any customer generation in kWh is insignificant.

Under this situation the point (P_U,Q_U) lies on the demand curve, where P_U is the price of electricity (in Rs./kWh) and Q_U is the grid sales to the given customer segment today.

Also shown in Exhibit 2-1 is the price denoted P_{LRMC}, corresponding to the economic cost (i.e., long-run marginal cost) of supply to the customer segment under consideration. The "demand effect" as a consequence of moving to full long-run marginal cost (LRMC) pricing is shown in the exhibit as dQ. This effect can be readily calculated once the demand function is specified in analytical form.

Exhibit 2-1

Demand and Efficiency Effects Under Economic Pricing: No Supply Cons' aints



The corresponding "investment effect" can be approximated as follows, depending upon how an LRMC-based tariff is structured. If the capacity charge component is exclusively (or largely as is the case today) collected via a one-part tariff (i.e., a per kWh energy charge), it is reasonable to expect that the demand response in terms of customer load shape impact will be a contraction of the load curve primarily during off-peak hours. At best one can expect a uniform contraction of the hourly load shape since a pure energy tariff provides no incentive for reducing maximum demand, or coincident demand on-peak. In this case, the attendant economic benefit can be estimated by the associated fuel cost savings plus savings in capital expenditures from the reduced need for base load generating capacity to be provided by the grid.

If a two-part tariff is implemented and it preserves the economic cost structure, this would typically imply that the demand charge share of the effective total cost of a kWh is on the order of 45 to 60 percent for all but the very high and very low load factor customers. Under such a tariff structure we can expect an additional demand response in terms of a load shape impact where the customer reduces his maximum demand (kW). Adjusting these demand (kW) reductions for class coincidence will yield an estimate of the coincident (i.e., on-peak) demand reductions. The resultant economic benefit per kW can be estimated by the cost of peaking capacity. This (kW) benefit is in addition to the benefit from the energy (kWh) savings discussed earlier.

Finally, the efficiency impacts (gains) of introducing economic pricing can be estimated as follows. Efficiency refers to the maximization of total "welfare." Welfare in this economic sense may be thought of as the total net national benefit associated with the production and consumption of electricity. Sometimes also referred to as the economic surplus, it can be estimated by subtracting the gross costs from gross benefits.

Specifically, in Exhibit 2-1 the economic surplus under today's pricing and consumption regime (P_U,Q_U) is represented by the area (A_1-A_2). This can be depicted as the sum of "consumer surplus" (area $A_1+A_3+A_4$) and the "producer surplus," which is the <u>negative</u> of the area ($A_2+A_3+A_4$). The consumer surplus represents the gross benefits of consuming Q_U units of electricity (total area under the demand curve between 0 and Q_U) less the price paid for these units (area $P_U.Q_U$). The producer surplus represents the difference between the electricity revenue (area $P_U.Q_U$) less the cost of producing Q_U units (area $P_{LRMC}.Q_U$).

The economic surplus under LRMC pricing is equal to the consumer surplus A_1 (the producer surplus is zero in this case). Therefore, the economic efficiency gains potentially realizable in the power sector from the introduction of LRMC pricing is defined by A_2, the net change in economic surplus (calculated as A_1 - (A_1-A_2)).

The same economic surplus change A_2 can also be derived by subtracting the reduction in total consumer benefit in moving from Q_u to Q_u-dQ, the area (A_3+A_5), from the savings in utility generation cost represented by area ($A_2+A_3+A_5$).

2.2 DEMAND, INVESTMENT, AND EFFICIENCY EFFECTS: SIGNIFICANT CONSTRAINTS IN GRID SUPPLIES

In customer segments where grid supplies are inadequate, the incidence and extent of customer generation to supplement grid supply can be expected to be significant. Under such conditions, the underlying economic reasoning for determining the distortionary effects of interest is somewhat more involved than in the previously analyzed case of insignificant supply restrictions.

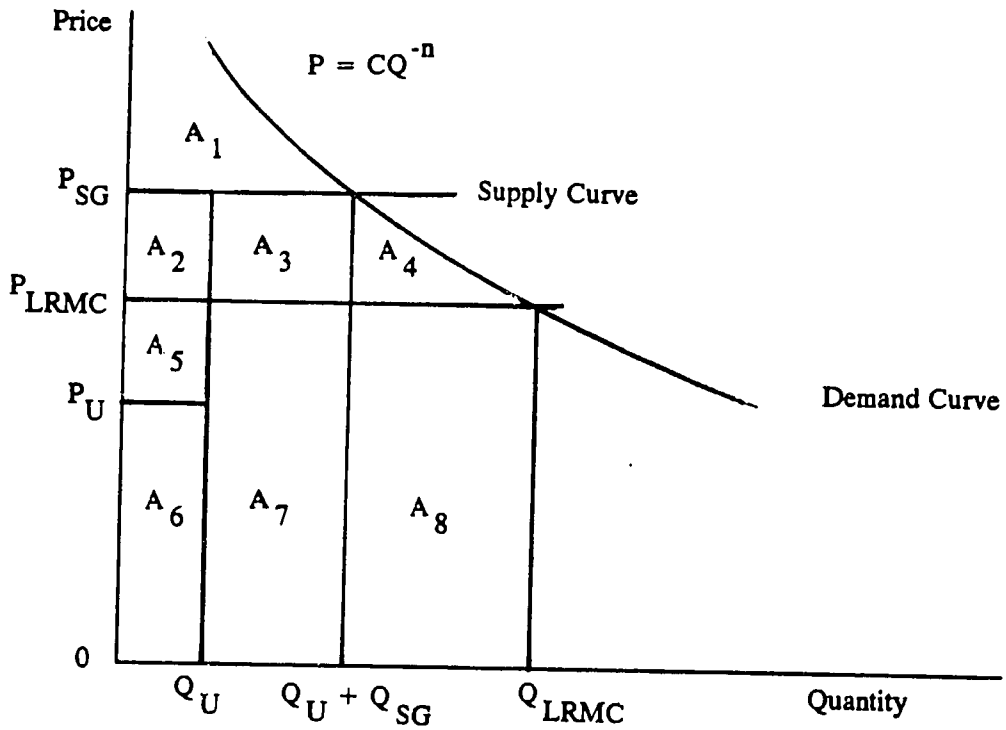
Exhibit 2-2 helps to illustrate the conceptual framework. The key difference in a constrained supply situation is that the point defined by today's price-quantity pair (P_U,Q_U) is not on the demand curve, since utility supply is constrained and therefore insufficient to meet customer demand. The balance, Q_{SG}, is made up from self generation at a unit cost P_{SG}.

Exhibit 2-2 depicts the intersection of the demand and supply curve at the point whose coordinates are (P_{SG}, Q_U+Q_{SG}). Also shown is the strict LRMC price P_{LRMC}. This price is below P_{SG} because of the more efficient scale of generation operations that the utility can employ.

It is relevant to consider whether P_{SG} should be only the variable cost component of back-up generation or if a per kWh amount to account for capital cost should also be included in P_{SG}. Clearly, consumers who are considering the purchase of new equipment to meet self-generation needs will include capital cost in P_{SG}. Even consumers with existing self-generation equipment must have considered full costs in making their original purchase decisions, although it may be argued that annual operating decisions of these consumers will be based only on annual variable operating costs. However, to the extent that operation results in physical depreciation of the generator and a reduction in its future life, it can be argued that this cost is also taken into account in the annual operating decisions of consumers with existing generators. If this depreciation rate is approximately the same as the annualized capital cost, this is a reasonable supposition, it is total cost per kWh -- including capital cost -- which is the appropriate measure of P_{SG}. In practice, the annual costs associated with self-generation -- the variable cost in our terminology -- accounts for over 80 percent of total cost in the case of all self-generating consumer groups considered in the study. To this extent, using only variable or both capital and variable costs has only a marginal impact on the final outcome of our analyses.

Exhibit 2-2

Demand and Efficiency Effects Under Economic Pricing: Significant Supply Constraints



Under full LRMC pricing, and if utility output is constrained to present consumption level (Q_U+Q_{SG}) kilowatt-hours, the demand effect is an increase in utility sales of Q_{SG}, and an offsetting decrease in customer generation, with a resultant net demand effect of zero. In spite of the fact that the demand effect is zero, there will be a beneficial investment effect since an amount Q_{SG} of consumption will be provided by lower-cost utility supplies. By contrast, if utility output is unconstrained with moving to LRMC pricing, total electricity demand will be Q_{LRMC}. In other words, in this situation, the "demand effect" is a net increase in total electricity consumption, resulting in an increase in expenditures required by the utility. In spite of this, there will be a net gain in efficiency, as discussed below.

The efficiency gains potentially achievable by eliminating the distortionary effects of today's tariff levels can be illustrated with the help of Exhibit 2-2. The economic surplus under today's prices and consumption is the area (A_1+A_2). This represents the sum of the consumer surplus ($A_1+A_2+A_5$), and the producer surplus (minus A_5). Under strict LRMC pricing with constrained output, the economic surplus is the area ($A_1+A_2+A_3$), resulting in an efficiency gain corresponding to the area A_3. With no output constraint, the economic surplus is represented by the area ($A_1+A_2+A_3+A_4$), resulting in an efficiency gain represented by the area (A_3+A_4).

Alternatively, in the case with constrained output, total consumer benefits remain unchanged in moving from P_U to P_{LRMC}, since the total consumption (from the grid and from self-generation) remains unchanged. However, the cost of self-generation decreases by the area (A_3+A_7), while the cost of utility generation increases by A_7, resulting in an overall efficiency gain of A_3.

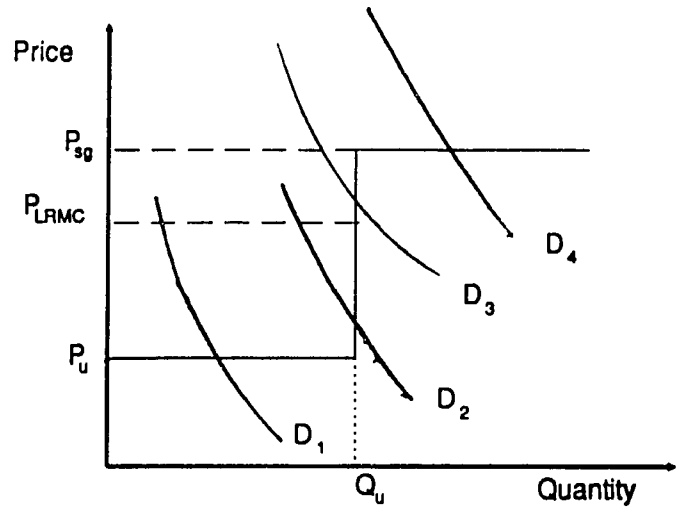
Similarly, in the unconstrained case, total consumer benefit increases are represented by the area (A_4+A_8). Self generation costs are reduced by the area (A_3+A_7) while utility generation costs increase by the area (A_7+A_8). The net change in consumer benefits is therefore represented by $(A_4+A_8)+(A_3+A_7)-(A_7+A_8) = (A_3+A_4)$.

Care must, however, be exercised in using the constrained demand framework in practice. Since individual consumers are "rationed" in such a case, estimates of benefit changes made by representing the supply position faced by a group of such consumers as a single supply curve which intersects the combined demand curve (for the consumer segment as a whole) is only justified under restrictive conditions. This is so since some individual consumer demands may be such that they do not in fact face a constrained supply, although the total demand of the consumer segment as a group may not be met. The "total supply curve" representation here would clearly be applicable if all consumers were identical, since they would all face similar rationing levels and be self-generating similar amounts.

In practice, all consumers within a consumer category would not have identical demand curves, and a direct application of the constrained grid supply model to an entire consumer category may not be appropriate. To clarify the theoretical implications of different types of consumers within a single consumer category, Exhibit 2-3 shows an electricity supply curve for a single consumer, and four alternative individual demand curves D_1, D_2, D_3, and D_4 corresponding to four different types of consumers. The utility supplies a quantity of electricity Q_u at a price P_u to each of the four types of consumers. If any of them wish to consume a greater quantity of electricity, they will have to generate it themselves at a price P_{sg} per unit.

Consumer type 1 (demand curve D_1) is a strictly unconstrained consumer who will cut back on grid consumption as price is increased from P_u to P_{LRMC}, the long-run marginal cost-based price. Consumer type 4 (demand curve D_4) self generates, and will increase to P_{LRMC}, and can be clearly treated with the constrained supply model. Consumer types 2 and 3 fall between these two extremes, as may be seen from the exhibit. Type 2 (demand curve D_2) will reduce grid consumption as price is increased to P_{LRMC}, while type 3 (demand curve D_3) will increase grid consumption as price is increased to P_{LRMC}.

Exhibit 2-3
Individual Customer Supply and Demand Curves



While the above theoretical framework completely captures the behavior of different types of consumers, it is not possible to make actual estimates of demand and investment effects on the part of consumers of types 2 and 3 because data are not available on the numbers of consumers of each type, their consumption levels, and the prices at which their demand curves intersect the vertical part of the supply curve. Therefore, simplifying assumptions must be made to make numerical estimates. Before doing so, however, it is appropriate to reiterate that the consumer behavior being modeled here is not meant to be applicable to the coping behavior of consumers faced with short-term reliability problems such as outages and brown-outs. Rather, it applies to consumer decisions to use back-up generators to generate energy to supplement grid supplies.

It is argued in Chapter 3 -- where actual estimates of demand and investment effects are made -- that significant self-generation for energy purposes only occurs in the agricultural, low-tension (LT) industrial and high-tension/power-intensive (HT/PI) industrial consumer categories. While in a strict sense this statement would mean that consumers having demand curves of the type D_3 are only present in any significant magnitude in these consumer categories, we broaden the statement to also mean that consumers with demand curves of types D_2 and D_3 are also not present in any significant magnitude in the other consumer categories (besides agriculture, LT industrial and HT/PI industrial), or that these consumers can effectively be treated as if they were consumers of type 1. In other words, energy shortages suffered by these consumers at the grid price P_u are not particularly large.

In the case of agricultural consumers, since available data (see Chapter 3) only allow us to identify the fraction of consumers of type 4, we lump all remaining agricultural consumers into type 1 and treat them with the unconstrained model. Chapter 3 shows

that the gap between P_u and P_{LRMC} is very large, while that between P_{LRMC} and P_{sg} is much smaller (approximately 20 paise compared with 160 paise). Therefore, the number of consumers of type 2 is likely to be much larger than the number of consumers of type 3 in the agricultural consumer category. Since type 2 consumer response to price increases is similar to type 1 consumers, the allocation is justifiable to some extent. However, in the case of both type 2 and type 3 consumers, their treatment using the unconstrained demand model will, to some extent, overstate the reduction in consumption in moving to LRMC prices, compared with a more theoretically correct treatment. We address this issue through sensitivity analyses in which we re-estimate the impacts assuming that the total number of consumers treated using the constrained supply model is 50 percent larger than in the base case.

In the case of industrial consumers -- both LT and HT/PI -- the procedure used in Chapter 3 is to treat all consumers in these categories as falling within type 4 and to carry out a sensitivity analysis in which 50 percent of the consumers are assumed to fall within type 1 and are treated using the unconstrained supply model. The range covered by these two cases will arguably encompass the actual situation on which no data are available.

The sensitivity analyses described subsequently in Chapter 3 demonstrate that from an empirical viewpoint, the theoretical issue of treatment of the various types of consumers in the agricultural and industrial consumer categories does not significantly alter the estimates of overall total demand and investment effects for all consumer categories together.

2.3 APPLICATION OF THE FRAMEWORK

The previous sections developed a framework for estimating demand and investment effects in the case of electricity consumers facing unconstrained grid supply and those with constraints who self-generate a part of their electricity needs. This framework considers what happens to demand and electricity generation costs in a single year when prices are changed from some base price to an economically efficient price (P_{LRMC}). In order to estimate these impacts it is necessary to specify the relevant demand function over the price range P_U to P_{LRMC}. This is done separately for the major consumer categories -- residential, commercial, agricultural, etc. -- by specifying a constant elasticity demand function for each category. Each function is completely defined by today's (1989-90) price-quantity pair and a user-specified estimate of the own-price elasticity.

While this framework only considers a single year, it can be readily extended to a multi-year period during which demand grows from year to year. This simply requires the specification of additional price-quantity pairs for each of these future years for the base case, the elasticity of demand remaining the same. Exhibits 2-4 and 2-5 depict the elements of a two-period analysis -- for the unconstrained and constrained grid supply cases -- where (P_{Ui},Q_{Ui}) is the relevant price-quantity pair in year i.

A further refinement in the application of the framework, to more realistically depict practical possibilities, is to allow the movement from the first year (1989-90) price to P_{LRMC} to occur gradually over a five-year period. The relevant prices for calculating the demand and investment effects in these interim years are these intermediate prices rather than P_{LRMC}.

The actual estimates were made with the aid of a PC-based spreadsheet model to facilitate rapid calculation and sensitivity analyses of demand and investment effects as well as efficiency gains attributable to the introduction of LRMC pricing. Selected further details of the model and the data used in estimating demand and investment effects using the model are given in Appendix 2.

Exhibit 2-4
Two-Year Framework: Unconstrained Grid Supply

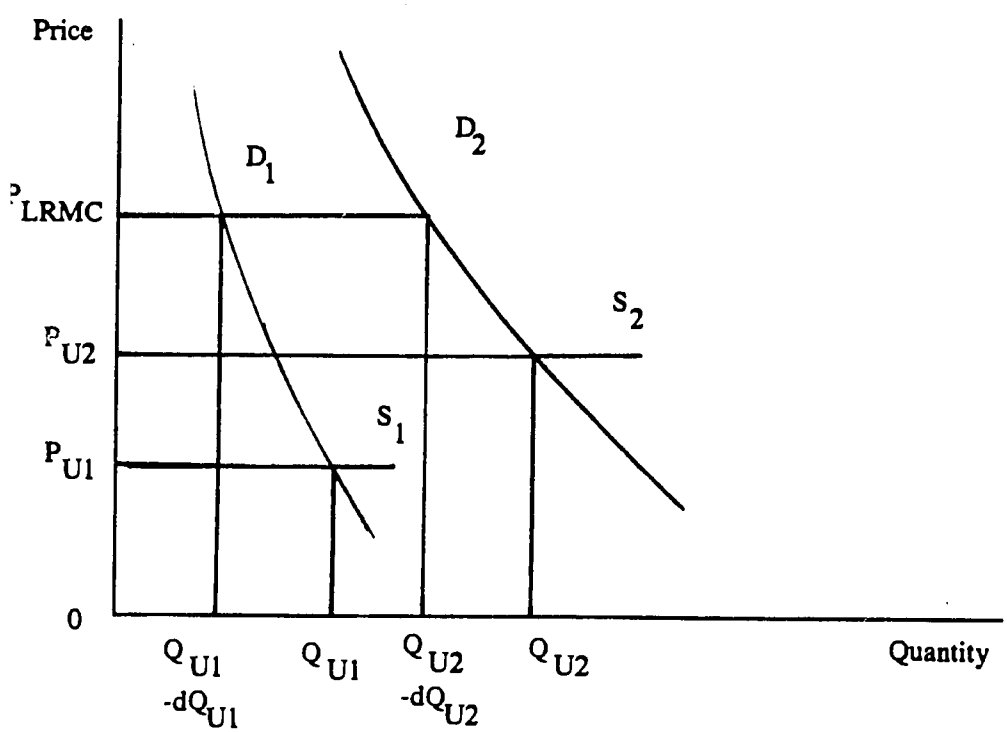


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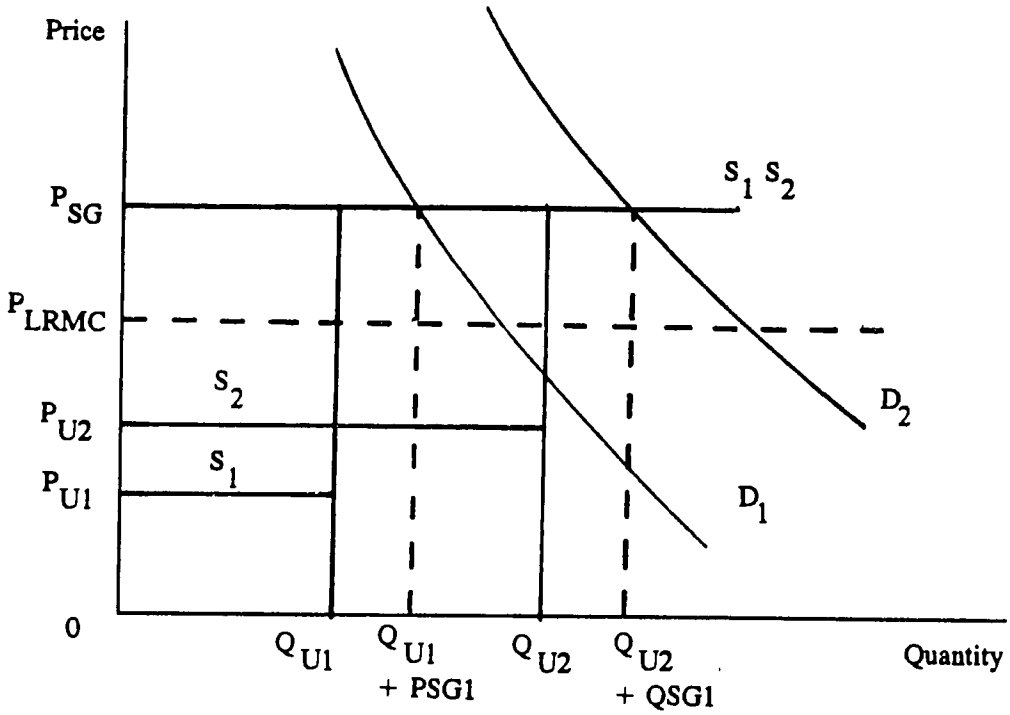
Exhibit 2-5
Two-Year Framework: Constrained Grid Supply



CHAPTER 3: ANALYSES AND FINDINGS

Chapter 2 developed a methodological framework to assess changes in electricity consumption (by consumers) and electricity generation (by the utility and by consumers) as a result of moving to economically efficient pricing from today's inefficient prices. The changes in total consumer benefits, capital costs and operating costs as a result of these consumption and generation changes were also depicted in the framework. The details of the PC-based model developed to facilitate the estimation of these demand and investment effects are given in Appendix 2. In this chapter we describe the analyses and the findings of the four state case studies -- Haryana, Uttar Pradesh, Gujarat and Maharastra -- undertaken in the present study.

3.1 MODEL INPUTS

The time frame of the analysis is 1990-91 through 1999-00 in the case of all four states considered. All financial data are specified in 1989-90 Rupees since this is the latest year for which historical data used to develop many of the model inputs are available. In this section we describe how each major model input used to estimate demand and investment effects was developed.

3.1.1 Consumption from the Utility Grid Under Today's Pricing Scenario

The "Thirteenth Electric Power Survey of India" was the principal source of the base case data on projected future consumption of electricity from the utility grid.[1] Although the Fourteenth Power Survey containing much more recent projections has been substantially completed and is expected to be finalized in the near future, detailed data from it were unavailable at this time. However, the study team was given verbal information on the major differences between the Thirteenth and the Fourteenth surveys. This information was used to adjust the estimates in the Thirteenth Survey to more realistically represent future demand trends.

Today's Pricing Scenario

The Thirteenth Survey develops estimates of annual "Net Generation Requirements" (NGRs) for each State Electricity Board (SEB), which supply electricity to the four case study states, over the period 1987-88 through 1999-00. Present and future expected electricity prices are not explicitly considered by the Thirteenth Survey in projecting these NGRs, except to the extent that the NGRs are based principally on historical consumption trends, and, as a result, have built into them the implicit assumption that

[1] *Thirteenth Electric Power Survey of India*, Central Electricity Authority, December 1987.

future price trends are "similar" to those in the past. In practice, past pricing policies have varied both by state and by consumer segment. In general, agricultural consumers have faced highly subsidized prices which have risen little -- or even declined in the case of one state -- in nominal terms, resulting in declines in real prices. In the case of industrial and commercial consumers, prices have tended to be much closer to costs and also to keep up with inflation, i.e., to be approximately constant in real terms. Residential consumers have generally fitted somewhere between these two situations.

Whatever the past price trends, there is a growing recognition that prices need to rise if SEBs are to become financially viable and have the financial ability to undertake investments necessary to meet fast growing future demands. To this extent, it is likely that future prices will at least remain constant in real terms, in contrast to the real declines in prices observed for some consumer segments in recent years. Although the Fourteenth Power Survey, like the Thirteenth, does not explicitly consider future prices in making demand projections, the substantially lower growth expected in the former survey may, arguably, be a recognition of the likely move towards more economically efficient -- i.e., higher -- pricing in the future, or at least a non-decline of prices in real terms.

The present study assumes that the price scenario underlying the projections in the Thirteenth Survey, and in the Fourteenth Survey used to modify these projections, is that prices for all consumer segments remain constant in real terms at their 1989-90 level over the period of the analysis. These prices were estimated as the actual billed revenue per kWh during 1989-90 for each consumer category for the four case study states. Exhibit 3-1 shows these data.

Exhibit 3-1
1989-90 Prices (in paise/kWh)

Consumer Category	Haryana	Uttar Pradesh	Gujarat	Maharastra
Residential	56.0	68.7	69.1	55.0
Commercial	123.0	90.8	n/a[1]	103.0
Agricultural	30.0	22.2	22.1	9.0
LT Industrial	116.0	113.0	118.3	92.0
HT/PI Industrial	95.5	115.5	124.0	127.0
Railways	-	118.6	111.6	115.0
Other[2]	55.8	71.3	95.1	108.9
System Average Price	55.8	71.3	95.1	108.9

1 Available data include the commercial category under "other."
2 The average price for the "other" category is calculated using the system average price, the prices of remaining categories and the kWh demands of all categories.

Source: Planning Commission of India, [4].

Net Generation Requirements vs. Net Generation Availability

Discussions with CEA officials responsible for the Thirteenth Survey's NGR forecasts revealed that they were based principally on historical trends in electricity consumption **from the utility grid** and, to this extent, do not include that part of demand met by consumers through self-generation. The Thirteenth Survey also provides estimates of Net Generation Availability (NGA) for each SEB, which reflects capacity and energy expected to be available to each SEB from power plants (and parts of power plants) they have direct control over, after accounting for present contractual import and export obligations.[2] The NGA does not take into account the possibility of additional intra- and inter-state transfer of power through the transmission network, beyond present contractual obligations. To this extent, shortfalls in energy (or capacity) in a particular state could be met using surpluses from other states (if available), provided the necessary transmission capacity exists for the transfer of this power.

In the case of the Northern and Western regions, within which the four states analyzed in the present study fall, while energy shortfalls are projected for some states in some years through 1994-95, the regions as a whole face almost no energy shortfalls in any year from 1990-91 to 1994-95. (No projections of NGA are made for years beyond 1994-95 in the Thirteenth Survey.) CEA officials familiar with the transmission system indicated that there are unlikely to be significant transmission bottlenecks which would hinder the transfer of power from surplus to deficit states within the Western and Northern regions. Therefore, after allowing for transfer of energy from surplus states to deficit states, grid supplies will be able to meet the NGRs in each of the four states analyzed.[3]

Although there are no significant shortfalls in energy availability at the regional level, the Thirteenth Survey does project shortfalls in peak capacity. In practice, these shortfalls are likely to be met by constraining peak period supplies to industrial and agricultural consumers, as is done today. Since these consumer segments have significant self-generation capacity today, and are projected to continue having such capacity in the future under the present pricing scenario (see Section 3.1.4), it is reasonable to suppose that they will meet peak capacity supply constraints through self-generation as they do today.

Considering the foregoing arguments together, it is reasonable to interpret the projected NGRs as the total utility grid supplies that will be available to consumers over the time horizon analyzed.

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[2] The NGA is based on planned expansion of grid supply.

[3] It is relevant to reiterate at this point that the NGRs met by utility grid supplies are net of consumer self-generated power.

In practice, however, as was mentioned earlier, the NGRs in the Thirteenth Survey were adjusted downwards to reflect more recent information from the Fourteenth Survey made available by the CEA. These adjustments were carried out by London Economics (LE) -- the contractor carrying out a related task in the overall project -- using information provided by CEA officials. In broad terms, total NGRs for energy in each of the SEB analyses are expected to be 7 percent below the levels projected in the Thirteenth Survey by the year 1994-95 and 18 percent below original projections by 2004-05. The last column in Exhibit 3-2 shows total demand (after adjusting NGRs for system losses) for selected years for each SEB. We assume that the net generation availability in the Fourteenth Survey will be sufficient to meet these demands at a regional level, and that the adjusted NGRs can be interpreted as the total utility grid supplies to customers over the time frame analyzed.

Consumer Segment-wise Demand Under Today's Pricing Scenario

Detailed consumer segment-wise demand data are not available in the case of the "adjusted" NGRs provided by LE, nor in the published version of the Thirteenth Power Survey. CEB officials did not provide such breakdowns in spite of repeated requests. Therefore, we used actual data on 1989-90 energy consumption from the grid by customer segment for each SEB to derive the share of total demand by these consumer segments. These shares were assumed to remain constant each year over the time horizon of the analysis. This procedure, in essence, assumes that grid consumption by all customer segments within an SEB grows at the same rate as total demand (NGR) of that SEB. Exhibit 3-2 shows base case data on consumption from the utility grid by each consumer segment for three representative years, estimated using the procedures and data described above.

The principal purpose of the present study is to estimate efficiency gains to be had from moving to economically efficient pricing from today's inefficient pricing policies. Specifying these efficiency gains simply in Rupee terms -- Rs. 1,500 million or Rs. 20 million (say) -- will not be meaningful unless these gains are related to some base against which it can be measured. The total economic cost of grid supply and customer self-generation under today's pricing scenario would be an appropriate base for comparison. If efficiency gains are expressed as a percentage of such a base, uncertainty associated with the base demand forecast summarized in Exhibit 3-2 will not be particularly troublesome, since this percentage efficiency gain is unlikely to be very sensitive to changes in the demand forecast.

3.1.2 Price Elasticity of Demand

A review of the available literature on price elasticity estimates for India and other countries was carried out to develop "consensus elasticity estimates," by customer segment, to be used in the study. Appendix 2 provides the details of this review, which shows that the available data are not sufficiently detailed to allow specification of

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separate customer segment elasticities for each of the four states assessed. The common customer segment elasticities used in the study for all four states are summarized in Exhibit 3-3.

Exhibit 3-2
Consumer Segment Demands Under Today's Pricing Scenario (in MkWh)

	Residential	Commercial	Agricultural	LT Industrial	HT/PI Industrial	Railway	Other	Total
Haryana								
1990-91	974	163	2,725	1,356	430	0	1,165	6,813
1994-95	1,314	220	3,679	1,830	580	0	1,572	9,195
1999-00	1,900	319	5,318	2,646	838	0	2,273	13,294
Uttar Pradesh								
1990-91	2,436	1,449	7,557	2,737	4,393	870	745	20,107
1994-95	3,422	2,035	10,615	3,844	6,171	1,222	1,046	28,355
1999-00	5,125	3,047	15,898	5,757	9,242	1,830	1,567	42,467
Gujarat								
1990-91	1,554	*	5,185	1,238	5,500	256	2,487	16,220
1994-95	1,949	*	6,506	1,553	6,900	322	3,120	20,349
1999-00	2,566	*	8,564	2,044	9,084	423	4,107	26,789
Maharastra								
1990-91	3,182	788	6,990	1,555	10,794	418	9,108	32,836
1994-95	4,140	1,025	9,095	2,023	14,044	544	11,850	42,720
1999-00	5,752	1,424	12,638	2,810	19,512	756	16,464	59,354

*The available data for Gujarat do not separate out commercial consumption, including it as part of the "other" category.

Source: RCG/Hagler, Bailly Inc. estimates based on CFA data.

Exhibit 3-3
Price Elasticity Estimates Used in the Study
(Same for all Four SEBs)

Consumer Segment	Price Elasticity
Residential	-0.35
Commercial	-0.35
Agricultural	-0.25
Low-Tension Industrial	-0.50
High-Tension/Power Intensive Industrial	-0.50
Railways	-0.25
Other	-0.35

Source: Appendix 2.

3.1.3 Consumer Segments Facing Constrained and Unconstrained Demand

Historically, the agricultural and industrial consumer segments are the ones which have borne the brunt of past power shortages through interrupted grid supplies, particularly during peak hours. These consumers are also the ones who have installed self-generation capacity to meet power shortages. Therefore, we model all other consumer segments -- residential, commercial, railways and "other" -- using the unconstrained framework described in Section 2.1.

Detailed data on the extent of ownership of back-up generators by low-tension (LT) industrial and high tension/power intensive (HT/PI) industrial consumers, and their use for energy rather than short-term reliability purposes, are not readily available. In the absence of such data, and since industrial customers self-generate a significant share of their total electricity consumption (see Section 3.1.4), we assume that all LT and HT/PI industrial customers self-generate and that they can be modeled using the supply-constrained framework described in Section 2.2. The sensitivity analyses carried out in Section 3.3 of the report test the impact of this assumption on our results by re-estimating demand and investment effects on the basis that only 50 percent of consumers in the LT and HT/PI industrial categories self-generate, treating the remaining 50 percent of consumers using the constrained demand model of Section 2.1. These analyses show that the impact on efficiency gains as a result of these changes is small compared to the total efficiency gains from moving to LRMC-based prices in each of the four SEBs.

The remaining consumer segment, agricultural, is divided into two sub-segments, one containing consumers with self-generation capability and the other containing those with no self-generation capability. The rationale for this division was also laid out in Section 2.2; it is necessary because of the "rationing" of supply to this consumer category coupled with the large subsidy of agricultural prices, which results in these two very different

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types of consumers -- both consuming from the grid at today's prices -- having very different demand curves.

The total agricultural demands projected under today's pricing scenario (Section 3.1.1 described the development of these demand data) are divided into two sub-segments -- agriculture: self-generation and agriculture: no self-generation. The proportions used in this division are based on data from a country-wide survey of back-up agricultural diesel pumping capacity by state carried out by the National Council of Applied Economic Research (NCAER). Exhibit 3-4 shows the self-generation and no self-generation fractions of total agricultural demand for each of the four states analyzed. Demand and investment effects for these two groups are estimated using the constrained and unconstrained grid supply frameworks, respectively, of Chapter 2.

It is worth emphasizing again at this juncture that when a certain consumer segment is modelled within the "unconstrained framework" for a given SEB, e.g., residential or commercial, what is meant is that the energy deficit experienced by that segment (as measured in kWh terms) is negligible or where data were not available to readily quantify the extent of any shortage. Further, this does not preclude the ownership of small generator sets by individual consumers within that segment, installed primarily for reliability purposes to meet essential needs during outages in grid supply and not for mitigating energy deficits. The difference is that generation used exclusively or largely for reliability support is intended to provide kilowatts, and will be characterized by extremely low load factors (kWh generation).

To this extent, therefore, the analysis in this report understates the potential for efficiency gains from a move to economic pricing. As regards the reliability benefit aspect, implementation of economic pricing should enable the reliability of grid supplies to be improved to levels at which most consumers with standby generation for reliability support will not find it necessary to continue doing so. This situation will result in additional efficiency gains from two sources. First, there will be less misallocated capital applied in the production of standby generator sets. Second, since consumers will experience substantially fewer outages, they will realize a significant reduction in economic costs associated with outages, e.g., damage and spoilage, business opportunity losses (e.g., see references [2], [13], [14], [15]).

Exhibit 3-4
Self-Generation and No Self-Generation
Shares of Total Agricultural Demand

	Self-Gen.	No Self-Gen.
Haryana	0.29	0.71
Uttar Pradesh	0.12	0.88
Gujarat	0.11	0.89
Maharastra	0.04	0.96

Source: NCAER, [18].

3.1.4 Extent of Self-Generation

The application of the constrained grid supply framework developed in Section 2.2 requires estimates of future self-generation extent by supply-constrained consumer segments under today's pricing and grid supply scenario. In this section we describe the procedures used to make such estimates in the case of industrial and agricultural consumers.

Industrial Consumers

Historical data on self-generation by large industrial consumers are available from a number of sources. The CEA conducts annual surveys of all self-generating industrial consumers with generators having a capacity of 1000 KVA or greater. (Prior to 1986/87 the survey included all generators with a capacity of 100 KVA or greater.) The CEA surveys reveal that industry-owned generators use a variety of fuels: steam, gas, hydro and diesel. Generators using the first three types of fuels are usually large units with efficiencies comparable to those of utility grid power plants -- they are often captive plants commissioned as part of setting up a power-intensive industry such as cement plant. Even if the efficiency of these generators is somewhat below that of utility plants, since they are located close to the final consumer, the usual transmission and distribution losses associated with grid-supplied power will not apply to them. Consequently the effective cost per unit of energy consumed from these captive (self) generators is unlikely to be higher than that of grid supplied energy. We do not consider these self-generating units in our analyses since no efficiency improvements or cost savings would result from shutting down these plants and providing an equivalent amount of power from the grid.

Exhibit 3-5 uses data from the two latest CEA surveys and actual past consumption data by HT/PI industrial consumers in the four case study states, to estimate actual self-generation (from generators larger than 1000 kVA) as a percentage of grid consumption by the group. The percentages in the table are likely to be underestimates of diesel self-generation by the HT/PI industry segment to the extent that some consumers in this group may have back-up generators of lower than 1000 kVA capacity.

Information on the use of back-up diesel generating sets by industrial consumers in Haryana and Uttar Pradesh, for generators in three different capacity ranges -- <100 kVA, 100-1000 kVA, and >1000 kVA -- for Haryana and Uttar Pradesh, is also available in a survey conducted by the Tata Energy Research Institute.

Exhibit 3-5
Self-Generation by Industrial Consumers Using Diesel Self-generators of 1000 kVA or Greater as a Percentage of Consumption from the Utility Grid (CEA/SEB Data)

	87/88	86/87
Haryana	53.7	60.4
Uttar Pradesh	4.3	4.5
Gujarat	2.8	4.5
Maharastra	1.0	1.2

Source: RCG/Hagler, Bailly Inc. estimates based on CEA and SEB data.

Institute (TERI) for the base year 85/86 [16]. Exhibit 3-6 uses these data and actual past consumption data by the HT/PI and LT industrial consumers to estimate actual self-generation as a percentage of grid consumption by the two groups. In doing so, we assume that all generators with capacity <100 kVA are used by LT industrial consumers, all with capacity >1000 kVA by HT consumers and the 100-1000 kVA generators are split evenly between the two industry groups.

Exhibit 3-6
Self-generation by Industrial Consumers Using Diesel Self-Generators as a Percentage of Consumption from the Utility Grid (1985/86 TERI Survey)

	LT Industrial	HT/PI Industrial
Haryana	30.8	92.6
Uttar Pradesh	10.3	16.5

Source: RCG/Hagler, Bailly Inc. estimates based on TERI and SEB data.

Another survey that provides more aggregate data on self-generation by industrial consumers is a country-wide survey carried out by the NCAER, referred to earlier in Section 3.1.3. Data from this survey -- for the 1983/84 base year -- show that total self-generation by all industrial consumers in the Northern region was approximately 50 percent of grid consumption (in kWh). For the Western region this percentage was approximately 10 percent. These data are not directly comparable to those in Exhibits 3-5 and 3-6, as they also include large self-generators using steam, hydro and gas for their generation. However, they do corroborate the general view that the extent of self-generation in the Western region -- within which Gujarat and Maharastra lie -- is considerably less than in the Northern region containing Haryana and Uttar Pradesh. Finally, another survey by TERI in Maharastra showed that industrial consumers in the

state self-generate approximately 20 percent as much energy as they consume from the grid [17].

The foregoing information was collectively used to make consensus estimates of self-generation -- as a percentage of grid consumption -- by the LT and HT/PI industrial consumer categories. We have deliberately been conservative in making these estimates, so that the demand and investment impacts calculated using these estimates will be a lower bound. Exhibit 3-7 shows the self-generation fractions for the LT and HT/PI industrial consumer categories used in the study.

Exhibit 3-7
Self-generation Assumptions Used in the Present Study
(as a Percentage of Grid Consumption)

	LT Industry	HT/PI Industry
Haryana	25	50
Uttar Pradesh	10	15
Gujarat	10	10
Maharastra	5	5

Source: RCG/Hagler, Bailly Inc. estimates.

Agricultural Consumers

Unlike in the case of industrial consumers, there is very little information available relating to actual levels of use of back-up diesel generators by agricultural consumers for water pumping. The only source is the NCAER survey referred to earlier. Even this survey, while estimating the numbers of agricultural consumers with back-up diesel generators, did not explicitly estimate the actual level of use of these generators. However, the survey did identify that those owning such generators face considerable power shortages which are met by using the generators. For the present study we conservatively assume that these generators have a load factor of 15 percent. Since we separately identify agricultural consumers with back-up diesel generators, this assumption is equivalent to saying that this small group (see Exhibit 3-3) self-generates 15 percent as much energy as they consume from the grid.

3.1.5 Self-Generation Costs

A number of estimates of self-generation costs by industrial and agricultural consumers in India have been made in both published and unpublished reports. After a review of this literature the present study uses the following estimates of self-generation costs for the LT industrial, HT/PI industrial and agricultural consumer segments. (The estimates are based on a combination of data presented in the World Bank's 1990 *Northern Region Transmission Project* Appraisal Report, and two surveys carried out by the Tata Energy Research Institute -- one for the Northern Region and the other for Maharastra -- on actual installed self-generation capacity and its use.)

Industrial Consumers

Exhibit 3-8 shows estimated costs of self-generation using diesel generators of three different sizes: 50 kW, 200-400 kW, and 1 MW. We assume that LT industry consumers are divided equally between the 50 kW and 200-400 kW categories, while HT/PI industrial consumers are divided equally between the 200-400 kW and 1 MW categories. The weighted average costs for LT industry and HT/PI industry consumers based on these assumptions are shown later in this section after discussing self-generation costs of agricultural consumers.

Exhibit 3-8
Self-Generation Costs in 1990 for Different Sizes of Diesel Generators

	50 kW	200-400 kW	1 MW
Total capital cost (Rs/kW)	6,300	4,420	4,420
Annualized capital cost (Rs/kW/yr)[1]	925	649	649
Capital cost per kWh generated (Rs/kWh)[2]	0.70	0.49	0.49
Annual fixed operating cost (Rs/kW)			
Salaries	668	449	127
Maintenance	134	92	50
Total	802	541	177
Annual fixed operating cost per kWh generated (Rs/kWh)[2]	0.61	0.42	0.14
Average diesel cost (Rs/kWh)[3]	1.67	1.40	1.40
Lubricant cost (Rs/kWh)	0.06	0.04	0.02
Total fuel/lubricant cost (Rs/kWh)	1.73	1.44	1.42
Total self-generation cost (Rs/kWh)	3.04	2.36	2.05

[1] Assuming a 15-year life and a 12% discount rate.
[2] Using a 15% load factor.
[3] Using a financial cost of Rs. 5.00 per liter for diesel and 0.33 lit/kwh consumption for a 50 kw generator and 0.28 lit/kwh for a 200-400 kw generator.

Source: RCG/Hagler, Bailly Inc. estimates based on World Bank and TERI estimates.

Agricultural Consumers

The overwhelming use of electricity by agricultural consumers is for operating electric water pumps. When we speak of self-generation by some agricultural consumers we do not mean that such consumers generate electricity to run their pumps when grid supplies are unavailable. Rather, such consumers use back-up diesel pumps as substitutes for the electric pumps. The "self-generation" costs in such a case are the capital and operating costs of a diesel pump with the same water pumping capacity as an equivalent electric

pump. Assuming that a 7 hp diesel pump is equivalent to a 5 kW electric pump -- as was done in the World Bank's Northern Region Transmission Project Appraisal Report -- Exhibit 3-9 estimates the cost per kWh of "self-generation" for agricultural consumers using back-up diesel pumps.

Changes in Self-Generation Costs Over Time Frame of Analysis

The self-generation costs derived above were for the year 1989-90. It is reasonable to assume that capital equipment and annual fixed operating costs related to this self-generation remain unaltered in **real terms** over the time frame of the analysis. In the case of diesel oil, however, World Bank projections of future changes in **real** world price -- provided by London Economics -- were used to estimate the fuel cost per kWh each year over the time horizon of the analysis. (We assume that domestic oil price changes parallel world price changes.)

Exhibit 3-9
Equivalent Cost of Agricultural "Self-Generation"
Using a Diesel Pump in 1990

Equivalent electric motor size (kW)	5
Pump capital cost (Rs)	11,365
Annualized capital cost (Rs)[1]	2,011
Capital cost per equivalent kWh generated (Rs/kWh)[2]	0.33
Annual fixed operating costs (Rs)	2,857
Annual fixed operating costs per equivalent kWh generated (Rs/kWh)[2]	0.50
Cost of diesel fuel per equivalent kWh (Rs/kWh)[3]	1.94
Total operating cost per equivalent kWh (Rs/kWh)	2.44

[1] Assuming a 10 year life and a 12% discount rate.
[2] Using a 15% load factor.
[3] At a diesel price of Rs. 5.00 per liter (in financial terms) and a diesel usage of 2.40 liters per hour.

Source: Based on World Bank estimates.

Summary of Self-Generating Costs Used in the Analysis

Exhibit 3-10 shows the self-generation costs per kWh of the three types of consumers who self-generate -- LT industrial, HT/PI industrial and agricultural -- broken down by capacity cost, annual fixed operating cost and fuel cost. Although fuel costs were derived each year and used in the analyses, the exhibit only shows such costs for three representative years over the time horizon of the analysis.

To illustrate the use of Exhibit 3-10, the total financial cost per kWh of self-generation by the LT industrial category in 1997-98 is Rs. (0.60+0.52+1.59) = Rs. 2.71.

The summarized self-generation costs in Exhibit 3-10 show two different estimates of fuel cost per kWh of self-generation, one a financial cost and the other an economic cost. (Financial costs are based on the domestic price for fuel, whereas economic costs are based on the border price for fuel converted at the official exchange rate and adjusted using a "standard conversion factor.") The procedures used to make the financial cost estimates were described above. That used to make the estimates of economic cost costs is identical, except that the relevant fuel price used in Exhibits 3-8 and 3-9 is now the economic cost of fuel per liter rather than the financial cost. In practice, the two costs are very similar, resulting in the fuel cost per kWh for self-generation being very close in financial and economic terms.

Exhibit 3-10
Summarized Cost of Self-Generation
(in Constant 1990 Rupees/kWh)

	LT Industrial	HT/PI Industrial	Agricultural
Capital cost	0.60	0.49	0.33
Annual fixed oper. cost	0.52	0.28	0.50
Fuel cost in financial terms			
1990/91	1.59	1.43	1.94
1994/95	1.52	1.37	1.85
1999/00	2.02	1.82	2.47
Fuel cost in economic terms			
1990/91	1.57	1.42	1.92
1994/95	1.50	1.36	1.83
1999/00	2.00	1.81	2.44

Source: Exhibits 3-8 and 3-9, London Economics; RCG/Hagler, Bailly Inc. estimates.

3.1.6 Utility Long-Run Marginal Costs

London Economics (LE) provided information on capacity and energy costs by voltage level for three of the four SEBs -- Uttar Pradesh, Gujarat and Maharastra -- analyzed in the present study. Since the fourth SEB, Haryana, is part of the Northern grid to which Uttar Pradesh also belongs, we assume that the LE's estimates for Uttar Pradesh also apply to Haryana. These data are summarized in Exhibit 3-11. Exhibit 3-12 shows estimates of consumption percentages in the peak period, load factors and peak coincidence factors developed by RCG/Hagler, Bailly, Inc. These two sets of data were used to make consumer category-specific estimates of capacity and energy costs (on a per

kWh basis) for each of the four SEBs. (HT/PI Industrial and Railway consumers were taken as being served at HT voltage level and all other consumers at LT voltage level.) The formulas used to make the estimates for a particular consumer and SEB were:

Marginal energy cost = (Marginal peak energy cost). (Fraction of cons. in peak)
+ (Marginal off-peak energy cost). (1-Fraction of cons. in peak)

$$\text{Marginal cap. cost} = \frac{\text{Cost per kW per year}}{\text{(Load Factor). (8,760 hrs per year)}} \cdot \text{(Peak coincidence factor)}$$

The energy and capacity costs (per kWh) estimated using these formulas are shown in Exhibit 3-13.

Exhibit 3-11
Long Run Marginal Costs at Different Voltage Levels

	Haryana		Uttar Pradesh		Gujarat		Maharastra	
	HT	LT	HT	LT	HT	LT	HT	LT
Capacity Cost (Rs/kW/year)	4,842	6,111	4,842	6,111	4,778	6,207	4,481	5,762
Peak Energy Cost (Rs/kWh)	0.72	0.83	0.72	0.83	0.82	0.96	0.79	0.94
Off-peak Energy Cost (Rs/kWh)	0.55	0.58	0.55	0.58	0.45	0.48	0.45	0.48

Source: London Economics.

Exhibit 3-12
Consumer Category-Specific Data Used to Estimate LRMC by Category

	Percentage Cons. in Peak	Load Factor	Peak Coincidence Factor
Residential	30	0.38	0.95
Commercial	28	0.43	0.95
Agricultural	20	0.35	0.70
LT Industrial	20	0.45	0.75
HT/PI Industrial	25	0.65	0.95
Railway	20	0.45	0.75
Other	28	0.43	0.95

Source: RCG/Hagler, Bailly Inc. estimates.

Exhibit 3-13
Long-Run Marginal Costs by Consumer Category and SEB
(in Constant 1990 Rs/kWh)

	Haryana and UP		Gujarat		Maharastra	
	Capacity	Energy	Capacity	Energy	Capacity	Energy
Residential	1.74	0.66	1.77	0.62	1.64	0.62
Commercial	1.55	0.65	1.57	0.61	1.46	0.61
Agricultural	1.40	0.63	1.42	0.58	1.32	0.57
LT Industrial	1.16	0.63	1.18	0.58	1.10	0.57
HT/PI Industrial	0.82	0.59	0.81	0.54	0.76	0.54
Railway	0.92	0.58	0.91	0.52	0.85	0.52
Other	1.55	0.65	1.57	0.61	1.46	0.61

Source: RCG/Hagler, Bailly Inc. estimates based on Exhibits 3-11 and 3-12.

3.1.7 Introduction of LRMC Pricing

To realistically depict a movement to LRMC prices, the model phases in these prices for each consumer segment over a five-year period, with prices increasing each year at 20 percent of the difference between P_{LRMC} and the base case utility price, P_U, starting in 1990-91.

In constrained demand Case II, where grid supply is increased up to Q_{LRMC} along with introduction of LRMC prices, in the transition years where price has not reached P_{LRMC}, grid supply is assumed to increase up to Q_{LRMC} at the same rate as prices approach P_{LRMC}.

3.2 RESULTS OF THE ANALYSES

The sources and numerical estimates of the various data inputs into the demand and investment effects model were described in detail in the previous section. In this section we present the results of the analyzes. Before doing so, however, it is useful to briefly restate the main elements that constitute these demand and investment effects arising as a result of a move from today's pricing scenario to economically efficient prices. (They were described more fully in Chapter 2.) These are:

- The changes in quantities consumed from the grid by the various consumer categories as a result of the price changes. (In the case of self-generating consumers, increases in consumption from the grid will be totally or partially offset by reductions in self-generation.)

- The changes in total consumer benefits due to the change in quantities consumed. (The area (A_3+A_5) in Exhibit 2-1 or the area (A_4+A_8) -- for the unconstrained output case -- in Exhibit 2-2.)

- The changes in utility generation cost -- annualized capital and variable costs -- as a result of supplying changed quantities to each consumer category. (The Area $(A_2+A_3+A_5)$ in Exhibit 2-1. The area A_7 for the constrained output case and the area (A_7+A_8) for the unconstrained output case, both from Exhibit 2-2.)

- The change in customer self-generation costs as a result of cutting back on self-generation and consuming more from the grid. [The area (A_3+A_7) in both constrained and unconstrained output cases in Exhibit 2-2.)

- The net change in benefits (i.e., efficiency gains) is the change in total consumer benefits minus the change in utility generation cost minus the change in customer self-generation costs.

3.2.1 Base Case Results

The demand and investment effects model was used to estimate each of the above components annually, for each consumer category, for a move from today's pricing scenario to one based on LRMC prices. In order to be able to meaningfully draw conclusions from these large number of estimates, and to enhance the clarity of the presentation, the present values of the four streams of benefits and costs referred to above were calculated using an annual discount rate of 12 percent.

Exhibits 3-14 to 3-17 summarize the results of the analyzes for the four case study states. As mentioned earlier in Section 3.1.1, the values estimated in the exhibits are more meaningful if related to the total (economic) costs of grid and self-generation to meet load under today's pricing scenario. Estimates of the present values of these annual costs -- using a 12 percent discount rate -- for each of the four case study states for each consumer category, are shown in Exhibits 3-18. The last columns in Exhibits 3-14 to 3-17 use these estimates to calculate the changes in net benefits (or the efficiency gains in alternate terminology) for each consumer category expressed as a fraction of the total economic cost of serving that category.

The following observations can be made using the estimates in Exhibits 3-14 to 3-17:

- As expected, the quantities consumed from the grid by all non-self-generating consumer categories -- residential, commercial, agricultural-nsg, railways and other -- decline with a move to a LRMC-based price, since this price is higher than today's price for these consumer categories. Quantities consumed from the grid increase for all self-generating consumer categories -- agricultural-sg, LT industrial and HT/PI industrial -- with a move to LRMC-based price since the cost of self-generation is higher than this price.

Exhibit 3-14
Summary Results of Base Case Analysis: Haryana
(1990/91 - 1999/00)

	Total Quant. Consumed from Grid (MkWh)	Change in Total Quant. Consumed from Grid (MkWh)	PV of Change in Total Customer Benefits (Rs Mill)	PV of Change in Util. Gen. Costs (Rs Mill)	PV of Change in Cust. Gen. Costs (Rs Mill)	PV of Change in Net Benefits (Rs Mill)	Change in Net Benefits/ Total Cost
Non-Self-Generating Consumers[1]							
Residential	13,887	(5,027)	(2,761)	(6,003)	0	3,242	0.185
Commercial	2,328	(375)	(292)	(401)	0	110	0.041
Agricultural - NSG	27,598	(9,617)	(3,681)	(9,779)	0	6,098	0.207
Other	16,611	(5,726)	(3,003)	(6,257)	0	3,254	0.169
Self-Generating Consumers: Case I							
Agricultural - SG	11,272	1,437	0	1,398	(1,985)	587	0.040
LT Industrial	19,336	4,108	0	3,524	(5,509)	1,986	0.079
HT/PI Industrial	6,126	2,603	0	1,759	(2,854)	1,096	0.134
Self-Generating Consumers: Case II							
Agricultural - SG	11,272	2,523	996	2,394	(2,229)	831	0.057
LT Industrial	19,336	9,557	4,867	8,006	(6,522)	3,383	0.134
HT/PI Industrial	6,126	4,853	1,544	3,215	(3,268)	1,596	0.195
Total self-generating and non-self-generating consumers: Case I	97,159	(12,597)	(9,736)	(15,761)	(10,349)	16,373	0.140
Total self-generating and non-self-generating consumers: Case II	97,159	(3,812)	(2,330)	(8,826)	(12,019)	18,515	0.158

[1]Same for both Case I and Case II

Source: RCG/Hagler, Bailly estimates.

Exhibit 3-15
Summary Results of Base Case Analysis: Uttar Pradesh
(1990/91 - 1999/00)

	Total Quant. Consumed from Grid (MkWh)	Change in Total Quant. Consumed from Grid (MkWh)	PV of Change in Total Customer Benefits (Rs Mill)	PV of Change in in Util. Gen. Costs (Rs Mill)	PV of Change in Cust. Gen. Costs (Rs Mill)	PV of Change in Net Benefits (Rs Mill)	Change in Net Benefits/ Total Cost
Non-Self-Generating Consumers							
Residential	36,474	(11,676)	(7,063)	(13,808)	0	6,745	0.147
Commercial	21,688	(5,138)	(3,417)	(5,521)	0	2,104	0.084
Agricultural - NSG	99,566	(39,261)	(13,137)	(39,921)	0	26,785	0.253
Railways	13,026	(641)	(406)	(462)	0	56	0.005
Other	11,149	(3,264)	(1,924)	(3,528)	0	1,604	0.125
Self-Generating Consumers: Case I							
Agricultural - SG	13,577	1,740	0	1,685	(2,395)	711	0.041
LT Industrial	40,947	3,500	0	2,989	(4,667)	1,698	0.038
HT/PI Industrial	65,774	8,427	0	5,669	(9,210)	3,541	0.059
Self-Generating Consumers: Case II							
Agricultural - SG	13,577	3,058	1,211	2,889	(2,684)	1,005	0.058
LT Industrial	40,974	13,736	9,839	11,372	(5,758)	4,225	0.095
HT/PI Industrial	65,774	27,089	14,068	17,691	(11,167)	7,544	0.125
Total self-generating and non-self-generating consumers: Case I	302,228	(46,313)	(25,947)	(52,897)	(16,283)	43,233	0.134
Total self-generating and non-self-generating consumers: Case II	302,228	(16,096)	(829)	(31,288)	(19,609)	50,067	0.156

Source: RCG/Hagler, Bailly estimates.

Exhibit 3-16
Summary Results of Base Case Analysis: Gujarat
(1990/91 - 1999/00)

	Total Quant. Consumed from Grid (MkWh)	Change in Total Quant. Consumed from Grid (MkWh)	PV of Change in Total Customer Benefits (Rs Mill)	PV of Change in in Util. Gen. Costs (Rs Mill)	PV of Change in Cust. Gen. Costs (Rs Mill)	PV of Change in Net Benefits (Rs Mill)	Change in Net Benefits/ Total Cost
Non-Self-Generating Consumers							
Residential	20,225	(6,357)	(3,903)	(7,643)	0	3,739	0.144
Agricultural - NSG	60,160	(23,409)	(7,839)	(23,971)	0	16,132	0.250
Railways	3,341	(170)	(104)	(119)	0	15	0.006
Other (including commercial)	32,419	(8,352)	(5,305)	(9,101)	0	3,796	0.100
Self-Generating Consumers: Case I							
Agricultural - SG	7,435	934	0	908	(1,304)	396	0.041
LT Industrial	16,135	1,351	0	1,156	(1,832)	677	0.038
HT/PI Industrial	71,700	6,005	0	3,940	(6,656)	2,716	0.045
Self-Generating Consumers: Case II							
Agricultural - SG	7,435	1,662	660	1,577	(1,485)	568	0.059
LT Industrial	16,135	5,425	3,926	4,501	(2,313)	1,738	0.099
HT/PI Industrial	71,700	26,761	16,014	17,021	(8,479)	7,472	0.123
Total self-generating and non-self-generating consumers: Case I	211,445	(29,999)	(17,151)	(34,830)	(9,793)	27,472	0.125
Total self-generating and non-self-generating consumers: Case II	211,445	(4,441)	3,449	(17,735)	(12,278)	33,461	0.153

Source: RCG/Hagler, Bailly estimates.

Exhibit 3-17
Summary Results of Base Case Analysis: Maharastra
(1990/91 - 1999/00)

	Total Quant. Consumed from Grid (MkWh)	Change in Total Quant. Consumed from Grid (MkWh)	PV of Change in Total Customer Benefits (Rs Mill)	PV of Change in Util. Gen. Costs (Rs Mill)	PV of Change in Cust. Gen. Costs (Rs Mill)	PV of Change in Net Benefits (Rs Mill)	Change in Net Benefits/ Total Cost
Non-Self-Generating Consumers							
Residential	43,742	(15,380)	(8,160)	(17,445)	0	9,276	0.176
Commercial	10,832	(2,049)	(1,425)	(2,091)	0	666	0.056
Agricultural - NSG	92,251	(46,328)	(10,295)	(45,095)	0	34,801	0.375
Railways	5,752	(209)	(126)	(139)	0	13	0.003
Other	125,215	(21,944)	(15,700)	(22,353)	0	6,653	0.048
Self-Generating Consumers: Case I							
Agricultural - SG	3,844	486	0	444	(675)	232	0.049
LT Industrial	21,372	900	0	727	(1,216)	489	0.024
HT/PI Industrial	148,395	6,252	0	3,928	(6,900)	2,972	0.027
Self-Generating Consumers: Case II							
Agricultural - SG	3,844	924	391	825	(780)	346	0.073
LT Industrial	21,392	6,739	5,763	5,266	(1,574)	2,072	0.101
HT/PI Industrial	148,395	50,923	35,354	30,940	(8,928)	13,343	0.120
Total self-generating and non-self-generating consumers: Case I	451,402	(78,272)	(35,715)	(82,026)	(8,791)	55,102	0.126
Total self-generating and non-self-generating consumers: Case II	451,402	(27,324)	5,794	(50,093)	(11,283)	67,170	0.154

Source: RCG/Hagler, Bailly estimates.

Exhibit 3-18
Total Cost of Meeting Base Case Consumer Demand
(Present Value: 1990/91 - 1999/00)
(in Rs Millions)

	Economic Cost of Grid Supply	Self Gen. Cost	Total Cost
HARYANA			
Non-Self-Generating Consumers			
Residential	17,558	0	17,558
Commercial	2,698	0	2,698
Agricultural - NSG	29,513	0	29,513
Railways	19,252	0	19,252
Other			
Self-Generating Consumers			
Agricultural - SG	12,055	2,540	14,594
LT Industrial	18,233	7,061	25,294
HT/PI Industrial	4,550	3,654	8,205
Total	**103,860**	**13,255**	**117,115**
UTTAR PRADESH			
Non-Self-Generating Consumers			
Residential	45,817	0	45,817
Commercial	24,973	0	24,973
Agricultural - NSG	105,789	0	105,789
Railways	10,227	0	10,227
Other	12,837	0	12,837
Self-Generating Consumers			
Agricultural - SG	14,426	3,042	17,468
LT Industrial	38,388	5,951	44,339
HT/PI Industrial	48,541	11,705	60,247
Total	**300,997**	**20,698**	**321,696**

(Continued on next page)

Exhibit 3-18 (Continued)

Total Cost of Meeting Base Case Consumer Demand
(Present Value: 1990/91 - 1999/00)
(in Rs Millions)

	Economic Cost of Grid Supply	Self Gen. Cost	Total Cost
GUJARAT			
Non-Self-Generating Consumers			
Residential	25,976	0	25,976
Agricultural - NSG	64,564	0	64,564
Railways	2,564	0	2,564
Other	37,924	0	37,924
Self-Generating Consumers			
Agricultural - SG	7,980	1,700	9,680
LT Industrial	15,238	2,394	17,632
HT/PI Industrial	51,941	8,685	60,626
Total	**206,186**	**12,779**	**218,966**
MAHARASTRA			
Non-Self-Generating Consumers			
Residential	52,631	0	52,631
Commercial	11,938	0	11,938
Agricultural - NSG	92,825	0	92,825
Railways	4,195	0	4,195
Other	137,995	0	137,995
Self-Generating Consumers			
Agricultural - SG	3,868	873	4,741
LT Industrial	19,001	1,574	20,576
HT/PI Industrial	102,707	8,928	111,635
Total	**425,161**	**11,376**	**436,536**

Source: RCG/Hagler, Bailly Inc. estimates.

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- For the SEBs as a whole, in Case I, total consumption from the grid for all consumers together shows declines ranging from a low of 13.4 percent for Haryana to a high of 17.3 percent for Maharastra. For Case II, consumption from the grid also show declines, but only about half as much as in the case of Case I, because substantially higher increases in consumption by self-generating consumers partially offset reductions by non-self-generating consumers. The decreases range from 3.9 percent for Haryana to 6.0 percent for Maharastra.

- The present value of the change in net benefits in the exhibits represents the potential efficiency gains that would result from moving to LRMC-based prices from today's inefficient prices. Although the four case study states are very different with respect to the mix of consumers, prices charged for electricity today, and the extents of self-generation, the total efficiency gains -- expressed as a fraction (percentage) of the total economic cost of meeting demand under today's prices -- are very similar for all four states (for Case I and Case II separately). The average savings are about 13 percent to 15 percent.

- Efficiency gains are larger in Case II since this case envisages that the full economically efficient quantities are supplied, while Case I still requires some measure of constrained supply and rationing of consumers, preventing maximum efficiency in resource allocation.

- The consumer category with the largest potential efficiency gains -- as a fraction of the total cost of meeting that category's demand under today's prices -- is the agricultural - non-self-generation category with efficiency gains ranging from 20.7 percent for Haryana to 37.5 percent for Maharastra. Since prices for this consumer category are highly subsidized today, moving to LRMC prices results in substantial cut-backs in consumption by this group. (From Exhibits 3-14 to 3-17, declines in quantities consumed range from 34.8 percent (for Haryana) to 50.2 percent (for Maharastra). These cut-backs result in substantial savings of utility generation costs, which more than offset declines in consumer consumption benefits.

- The consumer category with the next-largest potential efficiency gain is the residential category with net benefits ranging from 14.4 percent (for Gujarat) to 18.5 percent (for Haryana).

- The potential efficiency gains in the case of self-generating consumers are not, in general, as large as those in the case of non-self-generating consumers. Only the HT/PI industrial category in Case II -- where supplies under LRMC pricing are unconstrained -- show much potential for gains. These gains range from 2.7 percent to 13.4 percent.

- The above observations on efficiency gains refer to the gains to society as a whole and not to consumers or the utility separately. In practice, consumers with no

self-generation will cut back on their consumption with a move to higher LRMC-based prices and lose the benefits of this cut-back consumption (including any consumer surplus associated with this consumption). The electricity bills of these consumers need not necessarily decrease with lower consumption since the price per kWh has been raised. In the case of self-generating consumers, the direct financial implications of the move to LRMC pricing will also include savings in self-generation costs. We do not make estimates of these changes in consumer and utility costs since they merely reflect a redistribution between consumers and the utility and do not effect the overall societal efficiency gains.

Exhibits 3-19 and 3-20 which show selected data from Exhibits 3-14 to 3-17 and other estimates from the model runs, can be used to show the demand and investment effects associated with a move to LRMC-based prices. The following observations can be made using the data in the exhibits pertaining to Case I:

- **Total demand effect:** Estimated as a decline in total consumer benefits in each of the four states, range from Rs. 9,736 million for Haryana to Rs. 35,715 million for Maharastra.

- **Total investment effect:** Made up of decreases in utility generation cost and consumer self-generation cost. Utility generation cost savings range from Rs. 15,761 million for Haryana to Rs. 82,026 million for Maharastra. Self-generation cost savings range from Rs. 8,791 million for Maharastra to Rs. 16,283 million for Uttar Pradesh.[4]

- **Overall efficiency gains:** Estimated as the utility generation cost saving plus consumer self-generation cost saving minus the decrease in total consumer benefits. These gains range from Rs. 16,373 million for Haryana to Rs. 55,102 million for Maharastra.

- **Utility generation cost disaggregation:** Changes in utility generation cost include both changes in capacity cost and fuel cost. Exhibit 3-19 shows these savings in disaggregated form for Case I. From the exhibit, the capacity cost savings as a percentage of total utility savings is very similar for all four SEBs, and is approximately 71 percent. These capacity and fuel savings are calculated using the capacity and fuel cost per kWh components of LRMC costs shown in Exhibit 3-13. The capacity cost component in this LRMC calculation assumes a zero (or very low) off-peak capacity cost, and is essentially based on the capacity cost of a peaking plant such as a gas turbine. In practice, consumer reduction in capacity will occur both in the peak and off-peak periods with a move to LRMC prices, particularly since there are no time-of-day tariffs. As a result, there could be

[4] "Investment effect" as used here include both capacity and fuel costs of grid consumption and self-generation.

Exhibit 3–19

Net Efficiency Gain from Phasing–In Economic Pricing Over Five Years

Case I

(Present Value 1990–91 through 1999–00; in Rs. Millions)

	SEB				
	Haryana	Uttar Pradesh	Gujarat	Maharastra	Total
Change in total consumer benefits	(9,736)	(25,947)	(17,151)	(35,715)	(88,549)
Change in utility generation costs	(15,761)	(52,897)	(34,830)	(82,026)	(185,514)
– of which change in capacity costs	(11,517)	(37,805)	(25,526)	(58,397)	(133,245)
– of which change in fuel costs	(4,243)	(15,092)	(9,304)	(23,629)	152,268
Change in self generation costs	(10,349)	(16,283)	(9,793)	(8,791)	(45,216)
– of which change in capacity costs	(2,019)	(3,246)	(1,974)	(1,819)	(9,058)
– of which change in fuel costs	(8,330)	(13,073)	(7,819)	(6,972)	(36,158)
Change in net benefits	16,373	43,233	27,472	55,102	142,180

Exhibit 3–20

Net Efficiency Gain from Phasing–In Economic Pricing Over Five Years

Case II

(Present Value 1990–91 through 1999–00; in Rs. Millions)

	SEB				
	Haryana	Uttar Pradesh	Gujarat	Maharastra	Total
Change in total consumer benefits	(2,330)	(829)	3,449	(5,794)	6,084
Change in utility generation costs	(8,826)	(31,288)	(17,735)	(50,093)	(107,942)
– of which change in capacity costs	(7,079)	(24,551)	(14,960)	(39,349)	(85,939)
– of which change in fuel costs	(1,747)	(6,737)	(2,775)	(10,744)	(22,003)
Change in self generation costs	(12,019)	(19,609)	(12,278)	(11,283)	(55,189)
– of which change in capacity costs	(2,371)	(3,963)	(2,513)	(2,367)	(11,214)
– of which change in fuel costs	(9,648)	(15,646)	(9,765)	(8,916)	(43,975)
Change in net benefits	18,515	50,067	33,461	67,170	169,213

significant capacity savings in the off-peak period, and these savings per kW are likely to be significantly higher than the cost per kW for a peaking plant.

To correctly estimate capacity savings, it would be necessary to use the estimated reductions in grid consumption (in kWh) year-by-year, and corresponding changes in kW estimated using appropriate load factors, and redevelop a capacity expansion plan under this reduced demand scenario. It would then be necessary to recalculate LRMC prices to check that they were not very different from those used to originally estimate changes in consumption. If these prices were very different, further iterations would have to be carried out. Such an assessment of savings in capacity costs is outside the scope of the present analysis, and we merely observe that the capacity cost savings we have estimated here are lower-limit estimates of potential savings.

Order-of-Magnitude Effects for All-India

Exhibit 3-21 presents estimates of the potential for investment cost savings as a consequence of raising retail electricity tariffs from today's average levels to the respective economic price levels (i.e., to pure efficiency price levels) for each consumer class, over a five-year period. For the four SEBs analyzed in this report, the investment cost savings are estimated to be Rs. 142 billion. This number is a present value calculated over the 15-year period 1990-91 through 1999-00, and at a discount rate of 12 percent. Of the total amount, Rs. 133 billion represent reductions in capital outlays for grid expansion, and the balance of Rs. 9 billion comprise savings in capital in the private sector for the installation of captive generation plant.

The all-India estimates shown in Exhibit 3-21 are extrapolated from the four SEB totals based on the assumption that these four SEBs account for approximately 30 percent of all-India sales, an assumption that reflects the situation in recent years. Thus, the all-India numbers should be interpreted as being indicative of the order-of-magnitude implications at the national level.[5] The data in Exhibit 3-21 indicate that the all-India investment savings potential by phasing-in economic price levels over a five-year period are on the order of Rs. 475 billion. Of this amount, about 94 percent is attributable to reductions in grid investment requirements, with the balance in savings coming from reduced investments in customer-owned captive generation plant.

An estimate of the demand effect -- in terms of megawatts of reduced generation capacity requirements -- can be approximated as follows. Exhibits 3-14 through 3-17 together indicate that the total demand effect because of phasing in economic pricing is

[5] Whereas the magnitude of tariff distortions in the four SEBs analyzed in this study are for the most part representative of the magnitude of distortions to be found in the other SEBs, the customer shares may vary somewhat more, as do the absolute levels of tariff realizations across the other states (Appendix 3).

a reduction of 167 million kWh over the 10-year period, or approximately 17 million kWh per year in a levelized sense. At a load factor of 70 percent, this implies a reduction of 2,800 MW in consumer demand. Assuming a reserve margin of 15 percent, this implies a reduction in generation capacity requirements of slightly over 3,200 MW.

To put this estimate of the demand effect in perspective, consider that under the baseline demand forecast utilized in the analysis, the projected sales growth in the four SEBs together over the 15-year period is 66 billion kWh, or about 11,000 MW of incremental demand. In other words, the 2,800 MW demand reduction because of economic pricing represents an approximate 25 percent reduction in demand.

Exhibit 3-22 summarizes estimates of efficiency gains as a consequence of phasing in economic pricing over a five-year period. The present value of the net economic benefit is estimated very conservatively to be Rs. 142+ billion for the four SEBs analyzed in this study. Of this total, Rs. 186 billion represent savings in capital and fuel by the grid, and Rs. 45 billion represent savings in capital and fuel by consumers who have captive generation, whereas there is a loss in consumer benefit of Rs. 132 billion because of the price-induced reduction in consumption levels.

The analysis indicates that at the all-India level, the present value of efficiency gains (net national benefits), by raising average retail tariffs to economic price levels, is on the order of Rs. 473+ billion. This amount is calculated as follows. Savings associated with reductions in grid supply cost (capital and operations) are Rs. 619 billion, and Rs. 150 billion represent comparable savings in customer-owned captive generation facilities. Some of these savings, Rs. 296 billion, are offset by reduced consumer benefits.

Again, these estimates do not reflect the significant potential for additional efficiency gains that are not captured in the analysis. Such benefits can be captured by improvements in the <u>structure</u> of retail tariffs and can be realized on top of the gains already noted that stem from simply raising the <u>average level</u> of retail tariffs to economic levels. More specifically:

- Additional reductions in demand (kW) on-peak can be achieved by raising the demand charge share of the effective price of a kWh of electricity to be closely aligned to the economic cost structure, i.e., the demand charge share should represent about 45 to 55 percent of the effective cost per kWh for all but the very high load factor consumers, as opposed to the situation now where the demand charge share typically ranges between 5 percent and 15 percent of the effective price per kWh faced by industrial consumers.

- The present analysis does not reflect still further efficiency gains and investment cost reduction potential that can most definitely be tapped by introducing time-of-day (TOD) pricing for the large industry segment to start with and to be eventually expanded in coverage to include medium-sized industry and large

Exhibit 3-21

Investment Savings Potential by Increasing Retail Tariffs from Today's Average Levels to Economic Price Levels over Five Years

(Present Value 1990-91 through 1999-00; in Rs. Billions)

	Four SEBs	All India
Grid	(133)	(443)
Self-Generation	(9)	(30)
Total Investment Savings	Rs. 142 billion	Rs. 473 billion

Exhibit 3-22

Potential for Efficiency Gains by Increasing Retail Tariffs from Today's Average Levels to Economic Price Levels over Five Years

Present Value 1990-91 through 1999-00; in Rs. Billions)

	Four SEBs	All India
Consumer Benefit	(89)	(296)
Grid Generation Costs (Capital & Fuel)	(186)	(619)
Self-Generation Costs (Capital & Fuel)	(45)	(150)
Net Benefit	Rs. 142 billion	Rs. 473 billion

commercial customers as well. There is ample evidence and experience from around the world, including some developing country experience as well, which indicates that the introduction of time-of-day pricing and other forms of pricing, including interruptible tariffs, demand subscription service, and dynamic pricing to foster electricity demand management, should be aggressively pursued in India.

The potential for reducing peak demand from the introduction of special- purpose load management tariffs of the type noted is significant, and has been conservatively placed at a 5 to 10 percent peak load reduction [19]. The design, implementation, and demonstration of such tariffs on a broad scale in the context of one or two SEBs merits serious and immediate consideration for funding and follow-on by bilateral and multilateral development agencies. Initially, this assistance could perhaps be structured in the form of a technical cooperation agreement between two SEBs that are committed to pursuing these options aggressively.

3.3 SENSITIVITY ANALYSIS

While the best available data were used to make the estimates in the previous section, it must be recognized that a degree of uncertainty exists in the case of some of these data. In this section we estimate how these data uncertainties affect the observations on demand and investment effects made in the previous section by comparing efficiency gains and changes in grid consumption under four alternative scenarios with those in the base case. The four scenarios considered are:

- **Scenario 1:** The price elasticities used in the base case were shown in Exhibit 3-3. Appendix 1, which developed these elasticities, deliberately used "lower end" estimates so as to ensure that the potential efficiency gains estimated in the base case were conservative. In Scenario 1 we use somewhat higher price elasticities for each consumer segment. These elasticities are shown in Exhibit 3-23.

- **Scenario 2:** In this scenario we assess the impact of a 50 percent **increase** in our estimates of self-generation extents for the three consumer categories which self-generate: LT industrial, HT/PI industrial, and the self-generating sub-group of agricultural consumers.

Exhibit 3-23
Price Elasticity Estimates Used in the Sensitivity Analyses
(Same for all Four SEBs)

Consumer Segment	Base Case Price Elasticity	Sensitivity Case Price Elasticity
Residential	-0.35	-0.50
Commercial	-0.35	-0.50
Agricultural	-0.25	-0.40
LT Industrial	-0.50	-0.65
HT/PI Industrial	-0.50	-0.75
Railways	-0.25	-0.25
Other	-0.35	-0.50

Source: Exhibit 3-3, RCG/Hagler, Bailly, Inc. assumptions.

- **Scenario 3:** In this scenario, we assess the impact of a 50 percent **decrease** in our estimates of self-generation extents for the three consumer categories that self-generate.

Exhibit 3-24 shows the extents of self-generation by the three self-generating consumer categories under Scenarios 1 and 2.

Exhibit 3-24
Extent of Self-Generation in Scenarios 2 and 3 (% of Grid Consumption)

	Agricultural			LT Industrial			HT/PI Industrial		
	Base Case	Scen 2	Scen 3	Base Case	Scen 2	Scen 3	Base Case	Scen 2	Scen 3
Haryana	15	22.5	7.5	25	37.5	12.5	50	75.0	25.0
Uttar Pradesh	15	22.5	7.5	10	15.0	5.0	15	22.5	7.5
Gujarat	15	22.5	7.5	10	15.0	5.0	10	15.0	5.0
Maharastra	15	22.5	7.5	5	7.5	2.5	5	7.5	2.5

Source: Exhibit 3-7, Section 3.1.4, RCG/Hagler, Bailly Inc. assumptions.

- **Scenario 4:** In the base case analyses agricultural consumers were divided into two categories -- those that self-generate and those that do not -- and these two groups were treated differently in our demand and investment effects model. Exhibit 3-4 showed the percentage shares of total agricultural demand by each category for each of the four SEBs. In this scenario we check the sensitivity of the results to this division by re-estimating efficiency gains and changes in consumption from the grid under the assumption that the percentage of self-generating consumers in each SEB is 50 percent higher than assumed in the base case.

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- **Scenario 5:** In this scenario we test the impact of our model assumption that all LT and HT/PI industrial consumers are treated as self-generators -- more precisely, in the terminology of our model (see Chapter 2), as consumers of Type D_4. We do this, as explained in Chapter 2, by testing the impact of assuming that 50 percent of consumers in each of these consumer categories are of type D_1 (unconstrained demand consumers) and only 50 percent are of type D_4. However, since available data relating to self-generation presented in the report show self-generation as a percentage of total grid consumption by the entire LT and HT/PI consumer classes, we assume that the total quantum of self-generation (in kWh) for any year remains unchanged at the original base case value, even when assuming that only 50 percent of consumers self generate.

- **Scenario 6:** In this scenario we estimate the impact on efficiency gains of assuming that the domestic and agricultural consumer categories are only charged 50 percent of LRMC-based prices rather than full LRMC prices as in the base case. As in the base case these prices are assumed to be phased in at a uniform rate over five years.

Exhibit 3-25 shows the results of the sensitivity analyses for each of the six scenarios described above. The following observations can be made based on the estimates shown in the exhibit.

- Higher demand elasticities -- as used in Scenario 1 -- result in significantly higher efficiency gains. The increases are in the 40-50 percent range and are, in general, of the same order as the percentage increases in elasticities.

- Efficiency gains are relatively insensitive to changes in various self-generation parameters in Scenarios 2, 3 and 4, although fairly large changes in grid consumption occur as a result of the changes in the same self-generation parameters.

- Changes in total consumption from the grid (in kWh) are quite sensitive to changes in elasticity and to changes in self-generation parameters, generally changing by more (in percentage terms) than the percentage changes in elasticity and generation parameter.

- The scenario 5 sensitivity results indicate that the approximations necessitated in the analysis vis-a-vis treatment of customers in demand category D_3 (see Chapter 2) do not alter the findings and conclusions of our analysis.

In summary, the overall conclusions relating to efficiency gains as a result of moving to LRMC-based prices are quite robust and apply within a fairly wide range of variations in the input parameters with the largest uncertainties.

Exhibit 3-25
Sensitivity Analyses of Results

	Base Case	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6
Haryana							
Total efficiency gains: Case I (Rs millions)	16,373	21,422	18,208	14,539	15,422	15,790	13,396
Total efficiency gains: Case II (Rs millions)	18,515	24,442	20,607	16,408	17,685	17,342	15,660
Total efficiency gains: Case I (% of total cost)	14.0	18.3	14.7	13.2	13.0	13.3	11.3
Total efficiency gains: Case II (% of total cost)	15.8	20.9	16.7	14.9	14.9	14.6	13.2
Pct. Change in grid consumption: Case I	(13.0)	(20.6)	(8.8)	(17.2)	(10.2)	(12.4)	(5.4)
Pct. Change in grid consumption: Case II	(3.9)	(7.5)	1.3	(9.1)	(0.6)	(5.8)	4.2
Uttar Pradesh							
Total efficiency gains: Case I (Rs millions)	43,233	58,680	46,203	40,263	41,762	43,909	36,043
Total efficiency gains: Case II (Rs millions)	50,067	68,639	53,523	46,569	48,744	47,926	42,877
Total efficiency gains: Case I (% of total cost)	13.4	18.2	13.9	12.9	12.9	13.6	11.2
Total efficiency gains: Case II (% of total cost)	15.6	21.4	16.1	15.0	15.1	14.9	13.3
Pct. Change in grid consumption: Case I	(15.3)	(22.6)	(13.1)	(17.6)	(14.2)	(17.0)	(9.8)
Pct. Change in grid consumption: Case II	(5.3)	(7.4)	(2.5)	(8.2)	(3.9)	(11.2)	0.2
Gujarat							
Total efficiency gains: Case I (Rs millions)	27,472	37,271	29,364	25,557	26,673	27,726	23,117
Total efficiency gains: Case II (Rs millions)	33,461	46,328	35,725	31,172	32,748	31,154	29,106
Total efficiency gains: Case I (% of total cost)	12.5	17.0	13.0	12.0	12.1	12.7	10.6
Total efficiency gains: Case II (% of total cost)	15.3	21.2	15.9	14.7	14.9	14.2	13.3
Pct. Change in grid consumption: Case I	(14.2)	(20.9)	(12.2)	(16.1)	(13.3)	(15.4)	(9.6)
Pct. Change in grid consumption: Case II	(2.1)	(1.9)	(0.4)	(4.6)	(1.0)	(8.6)	2.5

Exhibit 3-25 (continued)
Sensitivity Analyses of Results

Maharastra	Base Case	Scen 1	Scen 2	Scen 3	Scen 4	Scen 5	Scen 6
Total efficiency gains: Case I (Rs millions)	55,102	74,354	46,948	53,255	54,493	55,666	48,282
Total efficiency gains: Case II (Rs millions)	67,170	92,852	69,450	64,863	66,618	62,173	60,351
Total efficiency gains: Case I (% of total cost)	12.6	17.0	12.9	12.4	12.5	12.8	11.1
Total efficiency gains: Case II (% of total cost)	15.4	21.3	15.7	15.1	15.2	14.2	13.8
Pct. Change in grid consumption: Case I	(17.3)	(23.8)	(16.5)	(18.2)	(17.1)	(18.0)	(14.0)
Pct. Change in grid consumption: Case II	(6.1)	(5.8)	(4.9)	(7.2)	(5.7)	(12.1)	(2.7)

* Source: RCG/Hagler, Bailly Inc. estimates.

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APPENDIX 1: ELECTRICITY PRICE ELASTICITY ESTIMATES

This appendix summarizes the results of empirical studies on consumer demand response to changes in the price of electricity. The list of references and the estimates cited are not intended to be exhaustive. Rather, the focus is on highlighting estimates of demand response that are indicative of those found in the literature, with particular emphasis on developing country studies. This review provides the basis for selecting the price elasticity estimates by customer segment that are used in the analysis described in the main body of the report.

A review of the Indian literature as well as discussions with individuals who are recognized for their knowledge about that literature revealed that there is very little quantitative information on the subject; and what little is available is dated. Consequently, it is difficult to draw accurate conclusions concerning the price elasticity of electricity demand for electrical energy in India, based solely on Indian studies.

It is thus necessary to examine estimates of demand response to price changes in other countries as well. On this subject, there is considerable information. Table 1 highlights price elasticity estimates obtained for several developing countries in Asia, Latin America, and Africa, as well as in the United States, and for a group of industrialized countries.

Table 1 reveals one general pattern. On average, long-run price elasticities established by econometric studies are lower in developing countries than in the developed countries across all consumer segments. More specifically, the price elasticities reported in Table 1 for developing countries are about one-half of the estimates reported for developed countries.

The influence of several market and economic factors potentially explains why electricity demand in developed countries has been observed to be more price elastic than demand in developing countries in general. In the residential sector, for example, some of the significant factors that economists have argued as being responsible in determining demand response are: the number of close substitutes for meeting the energy-driven service needs of consumers, and the share of electricity expenditures in the household budget.

If one or more close substitutes are available -- in terms of price, quantity, and other non-price factors such as service quality, convenience, etc.-- then the demand for electricity will be more price elastic than otherwise. In the case of developed countries, natural gas is available to large segments of the residential population, and at

Table 1
Selected Estimates of Long-Run Price Elasticity *

Country	Reference	Data	Residential	Commercial	Industrial	Agriculture	Total
India	1.Uri [1]	Pooled TS-CS (1960-1971)	-0.22	-0.03	-0.14	-0.20	-0.21
	2.Murty [2]	TS (1953-1977)	-	-	-1.49	-	-
	3.Sarkar & Kadekodi [4]	Simulations based upon general equilibrium model	-	-	-	-	-0.57 for final consumption, and -0.33 for intermediate consumption
Indonesia	Pitt [5]	CS(1976-1978)	-	-	-1.34 food processing; -2.82 metal products fabrication	-	-
Korea	Chang (cited in reference [12])	TS(1967-1974)	-0.66	-	-	-	-0.11
Jamaica	Ramcharran [7]	TS (1970-1986)	-	-	-0.43 small industry -0.52 large industry	-	-
Dominican Republic	Westley [14]	TS (1960-1982)	-0.50	-0.45	-0.65	-	-
Costa Rica	Westley [15]	Pooled TS-CS (1970-1979)	-0.50	-0.50	-	-	-
Colombia	Quoted in reference [16]	TS (1958-1976)	-	-	-0.14 to -0.34 overall mean -0.25	-	-
Mexico	Berndt and Samaniego [17]	Pooled TS-CS (1970-1978)	-0.47	-	-	-	-
Paraguay	Westley [16]	Pooled TS-CS (1970-1977)	-0.50	-0.50	-	-	-
Burkina Faso	Glakpe and Fazzolore [6]	TS(1960-1977)	-0.29	-	-0.85	-	-
Ghana	Glakpe and Fazzolore [6]	TS(1960-1977)	-0.20	-	-0.46	-	-

Table 1 cont.

Country	Reference	Data	Residential	Commercial	Industrial	Agriculture	Total
Ivory Coast	Glakpe and Fazzolore [6]	TS(1960–1977)	–0.78	–	–0.66	–	–
Niger	Glakpe and Fazzolore [6]	TS(1960–1977)	–1.24	–	–0.75	–	–
Nigeria	Glakpe and Fazzolore [6]	TS(1960–1977)	–0.31	–	–0.68	–	–
Togo	Glakpe and Fazzolore [6]	TS(1960–1977)	–1.02	–	–0.70	–	–
Industrial–ized Countries	Pindyck [9]	Pooled TS–CS (1960–1979)	–	–	–0.54 to –0.63	–	–
USA	1.NERA [8]	–	–0.52 to –1.89	–0.31 to –1.70	–0.50 to –1.78	–	–
	2. Based upon data in references [10] and [11]	–	–0.50 to –1.20	–	–1.25 to –1.94	–	–
	3.Based upon data in [3]	–	–0.45 to –1.25	–	–0.75 to –1.75	–	–
	4.Based upon data in [13]	–	–0.43 to –1.50	–0.54 to –1.47	–0.11 to –2.59 However, for most industries –0.50 to –2.00	–	–

* TS denotes time series data
CS denotes cross–sectional data

competitive prices to meet space conditioning, water heating, and cooking needs. Substantial possibilities for substituting electricity with natural gas also exist in the commercial and industrial sectors in developed countries.

As regards the second factor, goods and services in the household's consumption budget, higher expenditure shares of the household budget are generally associated with higher price elasticities. The reasons for this are obvious. At first glance, the presence of this influence would argue for a lower price elasticity in the case of developing countries than in developed countries. However, a related factor is often operative in many developing countries and may offset this effect.

Electricity prices have been kept at levels well below their true cost. In addition, in the vast majority of developing countries, electricity tariffs have barely kept up with general inflation [18]. This means that electricity prices have gone down in real terms in a majority of instances, starting from levels that were already low. During the same period, however, the costs of many other basic necessities in these very instances have gone up substantially, e.g., food items, petroleum products, housing, appliances. Thus, the relative price of electricity vis-a-vis many other goods and services in the consumption bundle has gone down. The presence of this trend is likely to make electricity demand less price elastic than otherwise.

Yet another factor that is likely to be significant in explaining why electricity demand is less price elastic in developing countries has to do with consumer expectations about future price levels and increases. If experience is a guide, rational consumers in developing countries are likely to form the expectation that electricity prices are more likely to go down in real terms or stay even at best, but go down in relative price terms in any event. Further, such consumers are only too well aware of the absence of any regular periodicity in the historic pattern of electricity price increases, and may sense a lack of demonstrated resolve by the power authorities in sustaining prices via regular tariff adjustments -- e.g., annual increases. Under such conditions, the demand response to a given price increase is likely to be much weaker than otherwise, since there is little incentive to employ substitute labor or capital to facilitate a reduction in electricity consumption over the long term.

Finally, in the case of business and industry, to the extent that such enterprises operate in a weakly competitive or essentially non-competitive environment, electricity demand is likely to be less elastic because of a lack of market pressure to stay cost competitive. These influences are at work in a large number of developing countries, where it is not unusual to find a large share of heavy industry in the public sector, and where the incentive structure for management does not appear to be clearly or strongly linked to maintain profitability by cost control and product innovation. Even in the case of private sector enterprises, for example, the car industry in India, price competition or competition through product innovation is virtually non-existent.

With the preceding observations as a background, we have selected the following estimates of long-run price elasticity for the analysis in this report.

Long-Run Price Elasticity

Customer Class	Base Case	Sensitivity Case
Residential	-0.35	-0.50
Commercial	-0.35	-0.50
LT Industry	-0.45	-0.65
HT Industry	-0.50	-0.75
Agriculture	-0.25	-0.40
Railways	-0.25	-0.25
Other	-0.35	-0.35

Price elasticity estimates selected for the base case analysis are on the conservative side in our opinion. In other words, we believe that significant and sustained price increases if implemented should yield a demand response that is higher in magnitude than that implied by the price elasticities shown above. This means that the demand effects, investment effects, and efficiency gains as estimated in the report for the base case understate the real potential.

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APPENDIX 2: DEMAND AND INVESTMENT EFFECT MODEL EQUATIONS

Grid supply price-quantity pairs under today's pricing scenario

$(\overline{P}_t^G, \overline{Q}_t^G)\ \forall t$

Demand curve for consumer segment being analyzed

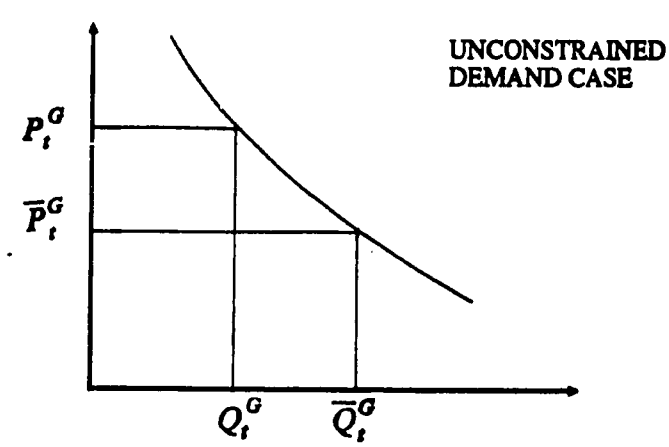
$Q_t P^\eta$

Where Q = Total quantity consumed (grid and self-generation if applicable)
P = "Appropriate" price
η = elasticity of demand
C = constant

Movement to LRMC prices under all scenarios defined by

$$P_t^G = 0.2\ t\ (P_{LRMC} - \overline{P}_t^G) + \overline{P}_t^G \qquad t = 1,2,3,4$$
$$P_{LRMC} \qquad t \geq 5$$

1. <u>Unconstrained Demand Case</u>



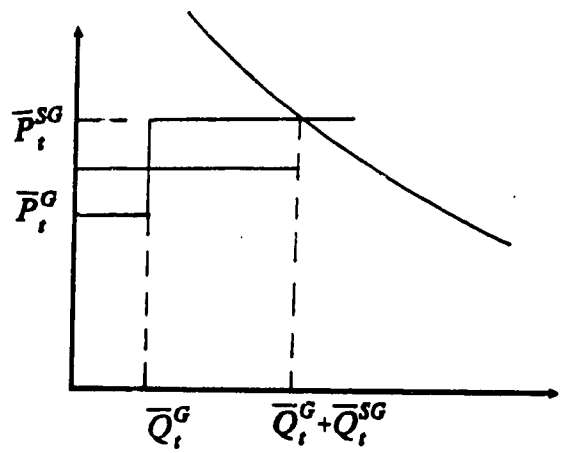
Change in quantity consumed from grid

$$= \Delta Q_t^G$$
$$= (Q_t^G - \overline{Q}_t^G)$$
$$= \frac{\overline{Q}_t^G}{(\overline{P}_t^G)^\eta} \times (P_t^G)^\eta - \overline{Q}_t^G$$
$$= \overline{Q}_t^G \left[\left(\frac{P_t^G}{\overline{P}_t^G} \right)^\eta - 1 \right]$$

Change in total consumer benefits (Δtcb)

$$= \int_{\overline{Q}_t^G}^{Q_t^G} PdQ = \frac{1}{C_t^n} \int_{\overline{Q}_t^G}^{Q_t^G} Q^{\frac{1}{\eta_{dQ}}} = \frac{\eta\ (\overline{P}_t^G x \overline{Q}_t^G)}{(1+\eta)} \left[\left(\frac{P_t^G}{\overline{P}_t^G} \right)^{\eta} - 1 \right]$$

2. <u>Constrained Demand Case I</u>



$\overline{Q}_t^{SG}$ = *Quantity self generated at today's prices*
$\overline{P}_t^{SG}$ = *Self generation price*
In the LRMC pricing scenario, quantity supplied by the grid Q_t^G *is defined by*

$$Q_t^G = \begin{cases} \overline{Q}_t^G + 0.2t\ \overline{Q}_t^{SG} & t = 1,2,3,4 \\ \overline{Q}_t^G + \overline{Q}_t^{SG} & t \geq 5 \end{cases}$$

$$\Delta Q_t^G = Q_t^G - \overline{Q}_t^G = \begin{cases} 0.2t\ \overline{Q}_t^{SG} & t = 1,2,3,4 \\ \overline{Q}_t^{SG} & t \geq 5 \end{cases}$$

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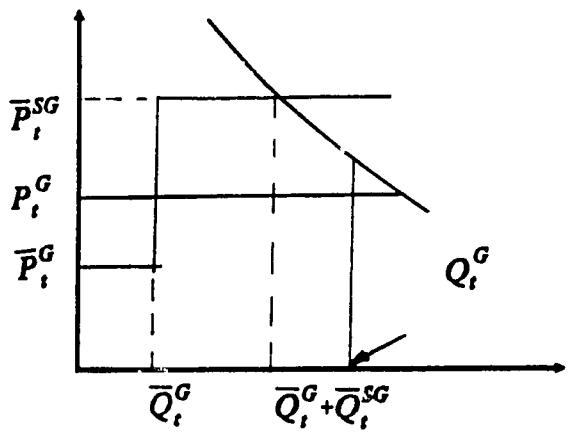
ΔTCB = *O* (*<u>Total</u> quantity consumed remains unaltered*)
$\Delta UC = \Delta Q_t^G \ x\ P_{LRMC}$
$\Delta SGC = \Delta Q_t^{SG} \ x\ \overline{Q}_t^{SG}$
$\Delta NB = \Delta TCB + \Delta UC + \Delta SGC$

3. Constrained Demand Case II

CONSTRAINED DEMAND
CASE II



$$Q_t^G = 0.2t\ C_t\ (P_t^G)^\eta \qquad t = 1,2,3,4$$
$$C_t\ (P_t^G)^\eta \qquad t \geq 5$$

where $[C_t(P_t^G)^\eta$ *is the quantity on the demand curve corresponding to the force* $P_t^G]$

$$C_t = \frac{(\overline{Q}_t^G + \overline{Q}_t^{SG})}{(\overline{P}_t^{SG})^\eta}$$ *where the point* $[\overline{P}_t^{SG},(\overline{Q}_t^G+\overline{Q}_t^{SG})]$ *lies on the demand curve.*

$$\Delta Q_t^G = Q_t^G - \overline{Q}_t^G = 0.2\ t\ C_t(P_t^G)^\eta - \overline{Q}_t^G \qquad t = 1,2,3,4$$
$$C_t(P_t^G)^\eta - \overline{Q}_t^G \qquad t \geq 5$$

$$\Delta Q_t^{SG} = -\Delta Q_t^G \quad \text{when } \Delta Q_t^G < Q_t^{SG}$$
$$-Q_t^{SG} \quad \text{when } \Delta Q_t^G \geq Q_t^{SG}$$

$$\Delta UC = \Delta Q_t^G \times P_{LRMC}$$

$$\Delta SGC = \Delta Q_t^{SG} \times \overline{P}_t^{SG}$$

$$\Delta TCB = O \quad when\ \Delta Q_t^G \leq \overline{Q}_t^{SG}$$

$$\int_{\overline{Q}_t^G + \overline{Q}_t^{SG}}^{Q_t^{SG}} PdQ \ when\ \Delta Q_t^G > \overline{Q}_t^{SG}$$

$$= O \qquad when\ \Delta Q_t^G \leq Q_t^{SG}$$

$$\frac{n}{n+1} \frac{\overline{P}_t^{SG}}{(\overline{Q}_t^{SG} + \overline{Q}_t^{SG})^{\frac{1}{\eta}}} \left[(Q_t^G)^{\frac{1}{\eta}+1} - (\overline{Q}_t^G + \overline{Q}_t^{SG})^{\frac{1}{\eta}+1} \right]$$

$$when\ \Delta Q_t^G > \overline{Q}_t^{SG}$$

$$\Delta NB = \Delta TCB + \Delta UC + \Delta SGC$$

Change in utility costs (ΔUC)

$$= \Delta Q_t^G \times P_{LRMC} = \left[\left(\frac{P_t^G}{\overline{P}_t^G}\right)^{\eta} - 1 \right] \overline{Q}_t^G \times P_{LRMC}$$

Change in Net Benefits (ΔNB) = ΔTCB + ΔUC

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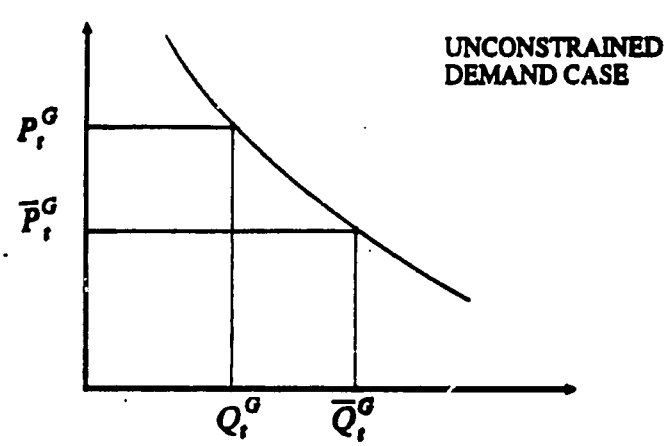

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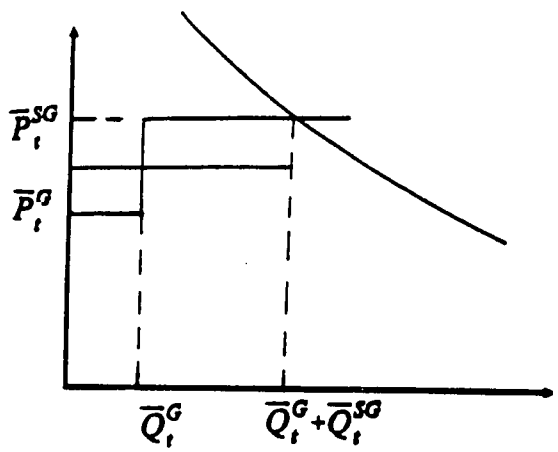
2. <u>Constrained Demand Case I</u>



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$\Delta TCB = O$ (*<u>Total</u> quantity consumed remains unaltered*)
$\Delta UC = \Delta Q_t^G \ x\ P_{LRMC}$
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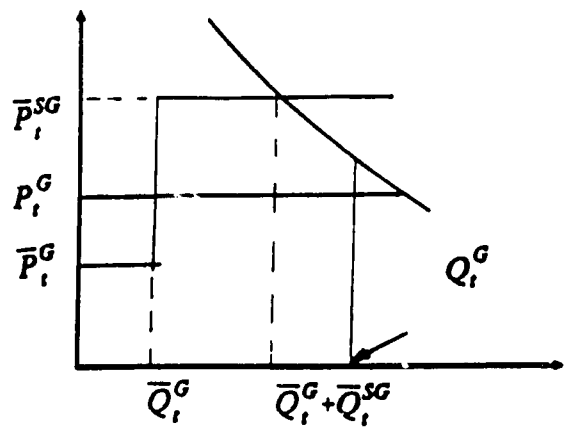
3. Constrained Demand Case II

CONSTRAINED DEMAND
CASE II



$$Q_t^G = 0.2t\ C_t\ (P_t^G)^\eta \qquad t = 1,2,3,4$$
$$C_t\ (P_t^G)^\eta \qquad t \geq 5$$

where $[C_t(P_t^G)^\eta$ is the quantity on the demand curve corresponding to the force $P_t^G]$

$$C_t = \frac{(\overline{Q}_t^G + \overline{Q}_t^{SG})}{(\overline{P}_t^{SG})^\eta}$$ *where the point $[\overline{P}_t^{SG},(\overline{Q}_t^G+\overline{Q}_t^{SG})]$ lies on the demand curve.*

$$\Delta Q_t^G = Q_t^G - \overline{Q}_t^G = 0.2\ t\ C_t(P_t^G)^\eta - \overline{Q}_t^G \qquad t = 1,2,3,4$$
$$C_t(P_t^G)^\eta - \overline{Q}_t^G \qquad t \geq 5$$

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Change in Net Benefits (ΔNB) = ΔTCB + ΔUC

Appendix 3
Average Rate of Realization in Major States: 1988–89

(Paise/kWh)

	Average Cost of Generation and Supply*	Average Rate of Realization		
		Domestic	Agriculture	Industry
Andhra Pradesh	61.44	56.67	4.50	108.12
Bihar	131.90	63.33	9.41	131.02
Gujarat	105.40	66.56	20.82	116.25
Haryana	88.36	59.00	28.01	115.36
Himachal Pradesh	117.26	45.50	20.00	70.59
Karnataka	77.74	64.50	11.55	100.50
Kerala	61.29	47.66	22.04	48.47
Madhya Pradesh	81.64	49.00	24.61	101.32
Maharastra	91.11	43.50**	9.00	112.54
Orissa	72.43	89.33	22.05	62.47
Punjab	84.45	60.33	9.18	62.84
Rajasthan	88.50	58.22$	29.46	90.99
Tamil Nadu	90.01	56.67	11.20	88.36
Uttar Pradesh	101.34	75.00	22.67	108.16
West Bengal	122.14	57.00	26.86	91.06
Assam	224.76	65.00	30.00	82.76
Meghalaya	85.42	50.00	22.06	54.84
Total	**91.04**	**53.93*** **	**15.70**	**87.85**
Consumption of power % during 1988–89		15	24	48

* Without State Electricity Duty
** For Bombay and Pune, 42.50 for other areas
*** Relates to 1987–88

SOURCES: Reference [10].

APPENDIX 4: OVERVIEW OF LONG-RUN MARGINAL COST METHODOLOGY

This appendix provides a description of the methodology employed by London Economics in developing the estimates of LRMC that are utilized in this report.

4.1 OVERALL APPROACH AND ISSUES

The first step in analyzing the efficiency of retail tariffs is to determine the LRMC of supplying each major consumer group. These LRMCs need to be disaggregated so that the different ways that consumers impose costs on the system can be distinguished. In particular, costs need to be disaggregated into:

(i) capacity-related costs;

(ii) energy-related costs; and

(iii) consumer-related costs

Capacity related costs are costs which vary with the system's peak demand and comprise both generating and transmission/distribution capacity. Energy-related costs vary with the level of demand in kWh and comprise principally the fuel costs of generating plant. Consumer-related costs are imposed by individual consumers irrespective of their level of demand. They typically include meter reading, billing and revenue collection costs.

The LRMCs of generation and transmission are first estimated for the Northern and Western regions. The additional marginal distribution and consumer-related costs are then estimated for the major customer categories in Maharashtra State Electricity Board (MSEB), Gujurat State Electricity Board (GSEB), and Uttar Pradesh State Electricity Board (UPSEB).

The rest of this section outlines first, the methodology adopted, second, the data used in the analysis and third, the results of the marginal cost analysis and comparisons of LRMC with current tariffs.

The LRMC methodology is described in detail below. It should be noted that it has been applied to power systems which are in a state of disequilibrium. This has occurred for two reasons: first, the inherited plant mixes in the systems are non-optimal; and, second, the amount of unmet energy exceeds optimal levels (which is not to say that the appropriate response is to build more capacity).

The marginal capacity cost is calculated from the discounted cost of incremental capacity introduced onto the system less any fuel cost savings divided by the discounted projected incremental peak demand served. This result is then annuitised to provide a per annum estimate. Marginal energy costs were derived from the INGRID 2 model by examination of the dispatch of plant at different phases of the load duration curve.

LRMC is calculated at each voltage level of supply. The levels identified in this analysis were:

- generation level (at the busbar)
- EHT level: 66 kV or above
- HT level: 11/33 kV
- LT level: below 11 kV.

Unserved Energy: The estimation of marginal costs should include the cost of unserved energy. However, given the difficulties in determining unserved energy with certainty, we were concerned not to over-state our estimates of LRMC and so adopted the conservative approach of ignoring the costs of unserved energy. The analysis shows that while this assumption is reasonable for the Ninth Plan, its effect has been to bias the LRMC estimates downwards in the Eigth Plan period.

Regional LRMC vs State LRMC: The estimation of marginal generation and energy costs has been undertaken at the regional level. Clearly the marginal costs of generation and energy might be different at the State level. This simplification was considered necessary in order to extend the scope of the analysis within the time available for the study to include the tariffs of three SEBs.

Economic Adjustments: To estimate costs in economic terms, we used the numeraire of rupees available to consumers rather than convertible foreign exchange available to the government. This is the appropriate numeraire for the calculation of LRMCs for comparison with published tariff rates and for tariff setting. The use of this numeraire required projects' estimated foreign exchange costs to be increased by 1.25 to reflect the shadow foreign exchange rate, as recommended by the World Bank. The domestic portion of expenditure was multiplied by a conversion factor of 0.9; this was a general adjustment to capture the distortions caused by taxes, minimum wage legislation and inefficiencies throughout the economy. This conversion factor was applied to all domestic expenditure because the available data did not permit the identification of individual expenditure items (such as non-skilled labour) to which specific adjustment factors could be applied.

Losses on the Transmission and Distribution Network: The three SEBs provided estimates of average losses (as a percentage of net generation) on their transmission and distribution networks. These were adjusted to take account of the difference between technical and non-technical losses. Only technical losses were taken into account in determining the LRMC at each voltage level, although, non-technical losses need to be included when determining tariffs' revenue adequacy. Peak losses were used for the

estimation of costs incurred in meeting peak demand. It is assumed that there is a moderate improvement in the level of technical losses to the year 2000, though given the very low level of investment in the network, this assumption may be considered optimistic.

4.2 ESTIMATION OF THE LRMC OF CAPACITY

In the current analysis, it was assumed that all investment costs associated with additions to generation and network capacity are incurred in order to meet increments in system peak demand. Insufficient load data were available to identify capacity that might contribute towards a reduction in the loss of load probability at off-peak times. To calculate LRMC at the busbars, the following steps were taken:

Step 1: the NPV of incremental investments and fixed O&M was calculated with a 12% discount rate to reflect the opportunity cost of capital to the GOI.

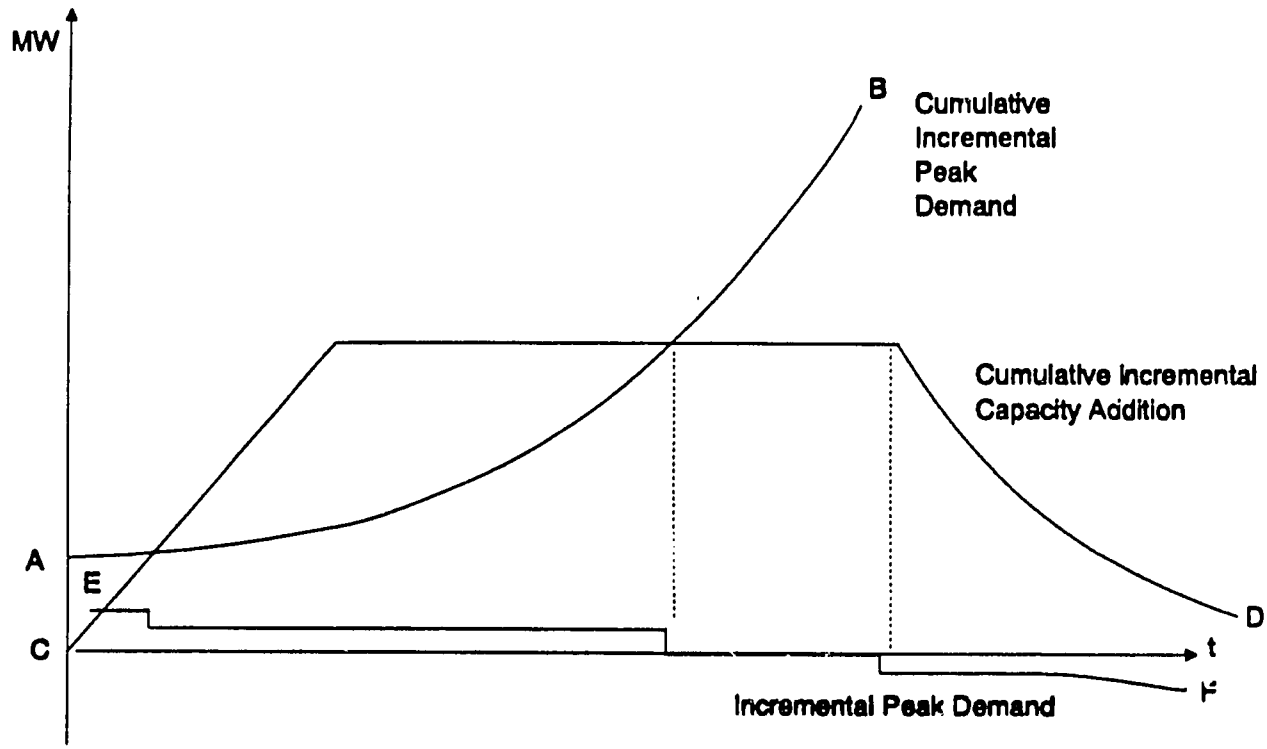
Step 2: next the NPV of fuel cost savings associated with the addition of new capacity to the system was estimated. For supply systems which are in disequilibrium, an increase in demand and commissioning of new capacity in a least-cost expansion program can lower the average fuel cost of supplying all consumers. The analysis shows that the average fuel costs in the three regions are expected to fall during 1990-2000. Fuel cost savings were estimated as the cost of meeting the demand served by the new system (existing plant together with new plant under the Eighth and Ninth Plans investment programs), minus the cost incurred by the old system (existing plant only) in meeting this demand. In order to prevent biasing this result upwards, the average cost of the new system in meeting its higher level of generation was used to estimate the cost that it would incur in meeting the (lower) level of generation that the old system meets. These were based upon INGRID 2 results.

Step 3: the incremental peak demand served by new capacity added to the system was calculated. This involved the following:

- calculating in each year the incremental MW (on a sent out basis) added to the system;
- reducing this to account for the contribution that this capacity made towards the system security: a 15% system security margin was assumed;
- calculating the increment in peak demand in each year; in addition, estimating the level of unserved peak MW that the system started with in 1990;
- incremental peak demand served is not automatically equal to the increment to peak demand: if there is inherited unserved peak MW, then if sufficient new capacity is added, served peak MW will be greater than the increment in peak demand in that year; conversely, if no new capacity is added in a year, no increase in peak demand can be met. Exhibit 4-1 below illustrates this. When the cumulative incremental capacity added (adjusted for its contribution towards system security), line AB is below the

cumulative incremental demand (line CD) to be served (where the intercept on the latter is the amount of unserved peak MW), the incremental peak served is equal to the incremental capacity added. If the condition is reversed, incremental peak demand served is equal to the incremental peak demand.

Exhibit 4-1



Decrements in peak demand served occur once capacity begins to be retired.

The NPV of the stream of incremental peak demand served was calculated.

Step 4: the generator busbar level of capacity cost was calculated as the sum of the NPV of investment, fixed O&M costs and fuel savings divided by the NPV of the incremental peak demand served.

Step 5: per annum cost is calculated by annuitising the NPVs associated with each type of plant based upon assumed plant lives. No distinction was made between civil and other expenditure, and differential annuity rates were not applied to fixed O&M costs. It was not possible to allocate fuel savings to each type of project; thus this stream was annuitised using an average plant lifetime based upon a capacity-weighted average of the different types of plant added to the system. This provided a final Rs/kW per annum cost at the generation level.

At the EHT level, capacity costs consist of a generation and an EHT network component. The generation component was calculated as above, except that incremental peak demand served was reduced to take account of losses on the EHT network during peak hours. This gave a stream of incremental peak MW served at the EHT level. The EHT component was calculated as the NPV of investment and fixed O&M costs from increased EHT capacity divided by the NPV of EHT incremental peak demand served. Both of these figures were then annuitised, using appropriate lifetimes, to give a Rs/kW/p.a. cost.

A similar procedure was used to calculate the incremental LRMCs at the HT and LT levels.

4.3 ESTIMATION OF THE LRMC OF ENERGY

LRMCs for energy were calculated at both peak and off-peak times to distinguish between the different costs of serving incremental units of energy at these times.

Calculation of marginal energy costs requires identifying the marginal plant at peak and off-peak times. This was achieved by using the results from INGRID (described below). From this, for each region, the marginal plant(s) at each phase of the load duration curve were identified for each season and an annual estimate for each phase was formed. This process was done for base year (1990), end of Eighth Plan (1995) and end of Ninth Plan (2000) to give indications of how the marginal energy costs changed over time.

INGRID 2 provided indications of the marginal plant at peak, intermediate and baseload hours. Estimates of marginal energy costs at peak times were based upon the plants that were marginal at peak times. For off-peak times, a time-weighted average of the marginal costs at intermediate and base times was used to calculate the marginal costs at off-peak times.

This approach produced peak and off-peak estimates of the marginal cost for energy at the generator busbar level. At each voltage level, the peak marginal energy cost was calculated by scaling up peak marginal cost at generator busbar by the losses that occur on the network during peak times. Thus at EHT level, peak marginal energy cost is generator busbar marginal energy cost scaled up for losses on the EHT network. At the HT level, marginal energy costs at generator busbar must be scaled up by losses on both the EHT and HT networks at peak times, and so on.

INGRID Model Structure

INGRID2 is a linear programming-based computer model written in the modelling language GAMS. The model is designed to represent each quarter of the year in order to capture the seasonal variation in demand, plant availability and energy availability at hydroelectric stations. Plant is dispatched in merit order to meet state load duration curves

which are approximated by three blocks representing base, intermediate and peak demand phases.

The objective function of INGRID2 is to minimize total variable cost, which is defined as the sum of operating costs for all stations plus the value of any unserved energy across all states. Transmission of energy between states and regions is constrained by the capacity of inter-state tie lines. Transmission constraints within each state are ignored.

INGRID2 uses two types of data: historical data for 1989/90 for the Seventh Plan scenarios, and forecast data for the Eighth and Ninth Plan scenarios.

1989/90 demand data were based on CEA published load generation balance data. This provided quarterly peak demand and energy consumption. The division of demand into base, intermediate and peak phases was based on 1989/90 chronological demand data for each state provided the SEBs.

Demand in the Eighth and Ninth Plan periods was based on the 13th Electric Power Survey (EPS) demand forecasts. Peak demands and energy requirements were reduced by 10% in anticipation of reduced demand forecasts in the 14th EPS. The distribution of energy and peak demand between base, intermediate and peak phases across quarters was based on the observed distribution in 1989/90.

Station characteristics, such as gross MW capability, quarterly availability, generation, specific coal consumptions and heat rates for 1989/90 were taken from published 1989/90 CEA sources. CEA also provided data on the share of central sector plant to each state. Data on auxiliary consumption and partial unavailability of thermal stations came from the most recent Performance Review of Thermal Power Stations. Energy availability for hydroelectric generation was taken to be actual generation by the plant in the period. The fuel prices used were administered prices provided by the relevant Indian authority - for example, coal prices were provided by Coal India.

The inventory of stations for the Eighth and Ninth Plans were based on:

- plant in existence in 1989/90;
- GoI sanctioned plants;
- CEA cleared and new plant from the Working Group on Power for the Eighth Plan; and
- information on implementation delays provided by the CEA.

The planning norms used by The Working Group were adopted for availability and auxiliary consumption for plant to be commissioned. Specific fuel consumptions and heat rates, which were not available from The Working Group or the CEA, were based on

existing plant at the same site as far as possible. Otherwise, they were derived from the characteristics of geographically and technically related stations. CEA data on energy availability for hydroelectric stations were used. The quarterly distribution of thermal plant availability and hydroelectric energy availability was not available from the CEA. It was therefore estimated by London Economics, on a region by region basis, from the observed distribution in 1989/90.

INGRID2 contains data on the number and average length of tie lines between states, subdivided by voltage into 132 kV, 220 kV and 400 kV. The length of each line is defined as the distance between adjacent sub-stations or nodes on opposite sides of the state boundary. The steady state transmission capacity of each type of line is that used by The Planning Commission, assuming standard single-circuit outage operating conditions. Losses are related linearly to the line type, length and quantity of energy transferred.

Data on the 1989/90 transmission network were taken from the most recent grid maps provided by the CEA. Data on planned transmission investments were taken from The Working Group on Power for the Eighth Plan and data provided by the CEA.

The model's results are affected by its structure and the quality of available data, and must be taken into account when formulating conclusions. The major model limitations are as follows:

- The treatment of transmission is simplistic. In the real world, the use of transmission lines is restricted by a number of technical factors. The sharing of power flows is determined by fixed features such as the line's length and impedance and will not be optimum. The use of the system may also be constrained by the ability to control voltage or to maintain stability. Line losses are not related solely to line length, type and energy transferred as represented in the model, but are much more complicated, varying from minute to minute. Accurate modelling of these effects is well beyond the scope of this study. In order to be able to model the order of magnitude of the possible cost savings, without having to carry out extremely time consuming detailed power system load flow and stability studies, some sweeping simplifications were made. Further, INGRID2 does not examine transmission constraints within a state, which could significantly influence the scope and inter-state energy transfers.

- The load duration curve approach used does not allow accurate modelling of time related elements such as starting up, back down and dynamic constraints on stations. This will slightly understate the benefit of trading.

- The paucity of chronological data from the Southern and Northern regions prevented a more disaggregated treatment of demand than the three-phase load duration curve approach adopted. The measure of peak demand used should, ideally, reflect the level of system integration being modelled. When no inter-state energy transfers are allowed, peak demand for a state should be system maximum demand in that state. If states within a region are integrated, peak demand in each state should be demand in

the state occurring at the same time as system maximum demand occurs in the region. However, the chronological data for the Southern and Northern regions were insufficient to support such analysis, and peak demands in the Western region are largely coincident. In practice, therefore, peak demand in the states was based on the regional demand profile. No quarterly load duration forecasts were available for Eighth and Ninth Plan periods, so observed 1989/90 demand patterns were assumed. These limitations will tend to understate the value and volume of trading.

- INGRID2 assumes that no out-of-merit generation is required to preserve system stability. However, this is required given the large transmission distances involved. INGRID2 can simulate this by imposing generation regimes on groups of stations, but no data were available to support this feature. The net effect could bias the modelling results either way.

- Reliable information on constraints on generation from hydroelectric plant imposed by river flow and irrigation was not available, particularly for the Eighth and Ninth Plan periods - although INGRID2 can impose minimum or maximum generation levels for such plant if the data are forthcoming. Hence, INGRID2 maximizes the output and minimizes the duration of operation of all hypoelectric stations, and tends to operate them in phases of the load duration curve when demand is highest. Although this overstates the value of hydro, its effect on the value and opportunity to trade would not be large.

- Plant specific data on fuel quality, specific fuel consumption, auxiliary consumption and availability were not available on a plant by plant basis for stations yet to be commissioned. Hence, availabilities were based on the norms adopted by The Working Group on Power for the Eighth Plan. Specific coal consumption and heat rates were based, as far as possible, on data for existing stations at the same site, or data from geographically and technically related stations.

- Similarly, quarterly variation in energy availability for hydroelectric plant, and availability for thermal plant was not available. They were therefore estimated on the basis of actual regional patterns observed in 1989/90.

4.4 KEY DATA INPUTS AND ASSUMPTIONS IN THE LRMC ANALYSIS

The Generation Investment Program

The CEA provided data on the introduction of new capacity in the Eighth and Ninth Plans. Due to resource constraints, the size of the Eighth Plan total program has been reduced to Rs 69,000 crores and about 10,000 MW of new capacity deferred to Ninth Plan. The CEA identified the most likely plant to be deferred in the Eighth Plan. In addition, the CEA indicated that the proposed Ninth Plan program would be set back by one year.

The CEA provided 1990 data on investment expenditure on a project-specific basis. Indicative capital costs were also provided by the CEA. These were, for coal plant, an estimate of Rs 20,000/kW installed (US $1081/kW), and for a combined-cycle gas plant Rs 10,000/kW installed (US $540/kW). The CEA's project-specific cost estimates were cross-checked against these indicative estimates. Exhibit 4-2 below illustrates this cross-check for coal plant and CCGTs constructed in the Northern Region during the period 1991-2000 by providing:

- capital (both total and per annum) in financial terms excluding fixed O&M expenditure;
- the equivalent economic cost (derived using the methodology described below)

The results are similar to CEA's indicative costings.

Exhibit 4-2

Indicative capital costs

	Coal		CCGT	
	Rs/kW	Rs/kW/yr	Rs/kW	Rs/kW/yr
(1) Financial cost				
No O&M	18189	2258	8977	1202
(2) Economic cost				
O&M included	21478	2666	12147	1626

Estimation of the foreign exchange component required the identification of schemes that were known to, or were likely to, use imported equipment. Once these were identified, average foreign exchange costs, based upon an analysis of World Bank Staff Appraisal Reports, were applied to each project and an overall estimate, in percentage terms, for generation investment in each region was calculated. In the Northern region, this was 9.4%; and in the Western region, 11.6%

The operating characteristics of new plant assumed in the analysis are identical to those used in the INGRID2 model runs.

Annual fixed O&M costs for each type of new generating plant in each year were assumed to be a fixed percentage of the cumulative investment in each type of capacity. For coal and gas plant, this was assumed to be 2.5%, and for nuclear and hydro plant 1.1%

Standard lifetimes were assumed for new plant. These were 30 years for coal and nuclear plant, 15 years for open-cycle gas turbines, 20 years for combined-cycle gas turbines, and 50 years for hydro plant. For existing plant, retirement dates were based upon rules provided by the CEA.

Transmission and Distribution Investment Program

The CEA provided information identifying aggregate investment requirements during the Eighth Plan in transmission and distribution taking into account the deferrals in generation projects. No information was given for Ninth Plan expenditure on transmission and distribution. The allocation of funds between HT (below 66 kV down to 11 kV) and LT was based on information provided on individual SEBs. The final analysis assumed an even split of distribution investment between HT and LT. The Eighth Plan program indicated a ratio of investment markedly in favor of generation. This was adjusted to some extent in our assumptions for the Ninth Plan period so that a more desirable 4:2:2 ratio of generation:transmission:distribution investment prevailed. This leads to a particularly large increase in distribution investment. The relatively low investment in transmission and distribution in the Eighth Plan was not regarded as sustainable in the long run.

A proportion of planned network expenditure is generally for replacement purposes, and thus should be excluded but, given the low levels of network investment, it was assumed that the entire network expenditure contributed towards network expansion.

Transmission and distribution investment costs were also adjusted by appropriate standard conversion factors to convert them into economic terms. The foreign exchange proportion was assumed, for each region, to be equal to that in generation investment.

Annual fixed O&M costs at each voltage level were assumed to be 1% of the cumulative investment in the network at that voltage level.

Losses on the Transmission and Distribution Network

The SEBs provided estimates of average losses (as a percentage of net generation) on their transmission and distribution networks. Unfortunately, this did not distinguish between technical and non-technical losses: our assumptions for non-technical losses on each SEB's network are shown in Exhibit 4-3. It was assumed that there was a moderate improvement in the level of technical losses to the year 2000. It should be noted that this may be optimistic given the very low level of investment in the network - particularly at the distribution level.

The foregoing loss estimates, together with estimates of sales at each voltage level, were used to calculate the incremental losses at each voltage level. Only technical losses were taken into account in determining the LRMC at each voltage level, although non-technical losses need to be included when determining the revenue adequacy of the tariffs. We have

Exhibit 4-3

	System losses		
	1991	1995	2000
UPSEB losses data			
(a) Losses as % net generation			
All losses			
EHT	7.5%	6.3%	5.3%
HT	6.7%	5.6%	5.3%
LT	10.7%	9.0%	8.4%
Total	25.0%	21.0%	19.0%
Non technical losses			
EHT	1.0%	1.0%	1.0%
HT	2.0%	2.0%	2.0%
LT	4.0%	4.0%	4.0%
Total	7.0%	7.0%	7.0%
Technical losses			
EHT	6.5%	5.3%	4.3%
HT	4.7%	3.6%	3.3%
LT	6.7%	5.0%	4.4%
Total	18.0%	14.0%	12.0%
(b) Incremental losses			
All losses			
EHT	7.5%	6.3%	5.3%
HT	8.1%	6.7%	6.2%
LT	19.2%	15.3%	14.0%
Technical losses			
EHT	6.5%	5.3%	4.3%
HT	5.7%	4.3%	3.9%
LT	10.1%	7.4%	6.5%

Exhibit 4-3 (cont'd.)

	System losses		
	1991	1995	2000
GSEB losses data			
(a) Average losses			
All losses			
EHT	8.0%	7.6%	6.8%
HT	4.6%	4.4%	3.9%
LT	7.4%	7.0%	6.3%
Total	20.0%	19.0%	17.0%
Non technical losses			
EHT	1.0%	1.0%	1.0%
HT	1.8%	1.8%	1.8%
LT	2.3%	2.3%	2.3%
Total	5.0%	5.0%	5.0%
Technical losses			
EHT	7.0%	6.6%	5.8%
HT	2.9%	2.6%	2.2%
LT	5.1%	4.8%	4.0%
Total	15.0%	14.0%	12.0%
(b) Incremental losses			
All losses			
EHT	8.0%	7.6%	6.8%
HT	6.0%	5.7%	5.0%
LT	12.9%	12.2%	10.8%
Technical losses			
EHT	7.0%	6.6%	5.8%
HT	3.7%	3.4%	2.8%
LT	9.0%	8.3%	6.9%

Exhibit 4-3 (cont'd.)

	System losses		
	1991	1995	2000
MSEB losses data			
(a) Average losses			
All losses			
EHT	5.0%	5.0%	5.0%
HT	3.7%	3.7%	3.7%
LT	5.9%	5.9%	5.8%
Total	14.5%	14.5%	14.5%
Non technical losses			
EHT	0.5%	0.5%	0.5%
HT	1.0%	1.0%	1.0%
LT	1.5%	1.5%	1.5%
Total	3.0%	3.0%	3.0%
Technical losses			
EHT	4.5%	4.5%	4.5%
HT	2.7%	2.7%	2.7%
LT	4.4%	4.4%	4.4%
Total	11.5%	11.5%	11.5%
(b) Incremental losses			
All losses			
EHT	5.0%	5.0%	5.0%
HT	4.8%	4.8%	4.8%
LT	11.4%	11.4%	11.4%
Technical losses			
EHT	4.5%	4.5%	4.5%
HT	3.5%	3.5%	3.5%
LT	8.5%	8.5%	8.5%

assumed that peak losses are 85% greater than average losses and off-peak losses are 70% of average system losses.

Demand

Regional energy requirement forecasts used in the analysis were based on the 13th Electricity Power Survey (EPs) estimates adjusted downwards as recommended by the CEA. By the end of the Eighth Plan, the adopted level was 7% below the 13th EPS estimate, and was 13.5% below at the end of the Ninth Plan. This adjustment was made in anticipation of the lower forceast which is expected in the forthcoming 14th EPS. An improvement in the system load factor was assumed such that by the end of the Ninth Plan it had reached 65% in all regions considered.

The CEA also provided historical information on demand by customer categories in individual SEB's. It was assumed that the customer shares of total demand remained constant over the period under analysis. Exhibit 4-4 indicates the assumed split of sales between the EHT, HT and LT voltage levels for each SEB.

Exhibit 4-4

Overall distribution of sales by voltage level (%)

	EHT	HT	LT
UPSEB	12.4	13.1	74.6
GEB	18.3	19.3	62.5
MSEB	22.7	4.0	53.3

Information on typical load profiles for consumer categories was very poor. Some information on load factors for each consumer class was available to allow the estimation of sales shares at times of system peak. Exhibit 4-5 shows the shares that were adopted.

Exhibit 4-5

Distribution of peak period sales by voltage level (%)

	EHT	HT	LT
UPSEB	11.2	11.8	77.1
GEB	16.5	17.4	66.1
MSEB	20.5	21.6	57.9

Customer Costs

Data on customer-related costs were taken from a Tariff Study report prepared by consultants for the Kerala State Electricity Board in June 1989. These costs comprised meter reading, billing and collection costs plus an annualized cost of a meter. Single-phase meters were distinguished from three-phase meters and current transformer meters. Marginal customer costs are shown in Exhibit 4-6

Exhibit 4-6

Marginal consumer costs 1988/89 prices	
EHT/HT consumers	Rs 382.7/consumer/year
LT 3 phase consumers	Rs 209.62/consumer/year
LT single phase consumers	Rs 100.78/consumer/year

The Office of Energy

The Agency for International Development's Office of Energy plays an increasingly important role in providing innovative approaches to solving the continuing energy crisis in developing countries. Three problems drive the Office's assistance programs: high rates of energy and economic growth accompanied by a lack of energy, especially power in rural areas; severe financial problems, including a lack of investment capital, especially in the electricity sector; and growing energy-related environmental threats, including global climate change, acid rain, and urban air pollution.

To address these problems, the Office of Energy leverages financial resources of multilateral development banks such as The World Bank and the InterAmerican Development Bank, the private sector, and bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research, adaptation, and innovation. These approaches include improving power sector investment planning ("least-cost" planning) and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. Promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective, reliable, and environmentally-sound energy systems integral to broad-based economic growth.

Much of the Office's strategic focus has anticipated and supports recently-enacted congressional legislation directing the Office and A.I.D. to undertake a "Global Warming Initiative" to mitigate the increasing contribution of key developing countries to greenhouse gas emissions. This strategy includes expanding least-cost planning activities to incorporate additional countries and environmental concerns, increasing support for feasibility studies in renewable and cleaner fossil energy technologies that focus on site-specific commercial applications, launching a multilateral global energy efficiency initiative, and improving the training of host country nationals and overseas A.I.D. staff in areas of energy that can help to reduce expected global warming and other environmental problems.

To pursue these activities, the Office of Energy implements the following seven projects: (1) The Energy Policy Development and Conservation Project (EPDAC); (2) The Biomass Energy Systems and Technology Project (BEST); (3) The Renewable Energy Applications and Training Project (REAT); (4) The Private Sector Energy Development Project (PSED); (5) The Energy Training Project (ETP); (6) The Conventional Energy Technical Assistance Project (CETA); and (7) its follow-on Energy Technology Innovation Project (ETIP).

The Office of Energy helps set energy policy direction for the Agency, making its projects available to meet generic needs (such as training), and responding to short-term needs of A.I.D.'s field offices in assisted countries.

Further information regarding the Office of Energy's projects and activities is available in our Program Plan, which can be requested by contacting:

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