Chapter 5

Modeling Bulk Market for Electricity in India

5.1 Introduction

Objective of this chapter is to examine the result of having a spot market for electricity in India. The Central Electricity Regulatory Commission (CERC) of India has initiated discussion on the establishment of a power exchange CERC (2006). Many scholars have been involved by the CERC for deciding about the broad principles under which the exchange should operate. The process of reform in the power sector was initiated in 1990 by allowing the private sector investment along with 100 percent foreign direct investment. This was done to address the severe shortage in generating capacity. The liberalisation programme of power sector followed the typical World Bank (WB) model for developing countries inspired by the US experience in Independent Power Producers (IPP) Programme as discussed earlier. This involved writing of power purchase agreement (PPA) between the distribution/load serving utility of a particular region/state (i.e., State Electricity Boards) and the IPP. This model of the WB miserably failed in many countries including India except for little anecdotal success (Bell 2003). This policy is being pursued in India since more than a decade without any significant success. The capacity additions by the private sector remain much below the expected levels. Phadke (2006) argued that the peculiar characteristics of supply of and demand for electricity leads one to believe that liberalised electricity markets may work more effectively in developing countries compared to developed countries. One of the most important reasons for this is the differences in demand response due to change in price. In developed countries with high level of per capita income, firms are able to exercise market power because demand for electricity is quite inelastic with respect to price. But in case of developing countries with low per capita income demand for electricity is claimed to be fairly elastic with respect to price though there is lack of empirical evidence for this claim. This would imply, consumers in developing countries are less vulnerable to exercise of market power.

In this chapter, we show that there is indeed an opportunity for investors. Our calculation of spot market operation, with assumtion that plants are being dispatched on the basis of their marginal cost, indicate that plants are able to generate enough surplus to cover the overnight cost and other operation and maintenance cost. Though this exercise is apparently very simple we do not find any such study conducted earlier. We assume no transmission constraint in inter-regional exchange of power which is quite reasonable as there is no congestion faced by the transmission system. India's electricity system consists of five grid zones and each zone is interconnected. Therefore, we take the whole India as one market.

5.2 Data

In order to do the above mentioned analysis, we need cost and demand information. More specifically, we need heat rates of each plant operating in India, price of fuels used by them and the calorific values of these fuels.

5.2.1 Cost

We make use of heat rate to calculate the fuel cost of all the thermal plants operating in India. List of all the plants (384 plants) along with their capacity and fuel type is available on CEA website . Heat rate of some of the plants were available through CEAs publication(CEA 2004), but for most of the plants, it was collected from the tariff orders given by respective electricity regulatory commissions[1]. Even this source could not complete our search for the heat rates. We used base line data provided for calculating Green House Gas (GHG) emissions by Ministry of New and Renewable Energy, Government of India for getting heat rate of some plants for which there were no other sources[2]. Information on calorific value and the price of fuels were available in (CEA 2004). We arrive at per unit fuel cost of each plant by the following formula.

$$\text{Fuel cost per unit}(c_i) = \frac{\text{Heat Rate}}{\text{Calorific Value}} \times \text{Price per Unit of Fuel}$$

Figure 5.1: Fuel cost per MW of Indian thermal plants in the year 2005-06

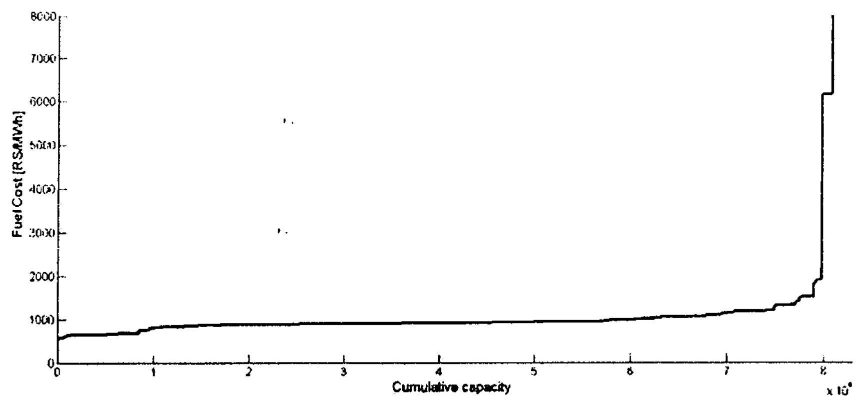


Figure 6.2 shows cumulative capacity versus fuel cost of the power plants in India. The figure indicates quite clearly that fuel cost of majority of the plants in India is around 1000[Rs/MWh]. The outstanding point in the figure indicates fuel cost of little more than 6000[Rs/MWh] represents diesel generation sets with very small capacities.

[1]Tariff Orders of regulatory commissions regarding purchase of power from a particular plant coming under its jurisdiction has details of cost parameters. Plants owned by central government and plants that have interstate exchange of power come the jurisdiction of the Central Electricity Regulatory Commission(CERC) and the rest of the plants are subject to the jurisdiction of the respective state electricity regulatory commission (SERC).

[2]It needs to be emphasised here that such crucial information could be managed easily by the organisation like CEA. This would save time for the researchers

5.2.2 Demand

We arrive at an all India monthly demand for the year 2005-06 by adding demands of each region. The information on demand is obtained from five Regional Load Dispatch Centres (RLDCs) representing North, West, South, East and Northeast region respectively. Websites of RLDCs and Regional Power Committees (RPCs) are rich source of information regarding the functioning of the grid and contain very detailed data on frequency and voltage of the grid for every 15 minute blocks for each day. We got the data of maximum demand realised and total units of electricity consumed in each month for all regions. Based on these two information, we design

Table 5.1: Load pattern of India for each month for 2005-06 (in MW)

Month	Ist	2nd	3rd	4th	5th	6th	7th	8th	9th	10th
April	82149	78654	75158	71662	68167	64671	61176	57680	54185	50689
May	80768	77749	74731	71712	68694	65675	62657	59638	56620	53601
June	82848	79221	75594	71967	68340	64713	61086	57459	53832	50206
July	72356	69111	65866	62620	59375	56130	52885	49639	46394	43149
August	69227	66145	63064	59982	56900	53819	50738	47656	44575	41493
September	70287	66569	62850	59132	55413	51694	47976	44257	40539	36820
October	76421	72842	69263	65684	62105	58526	54948	51369	47790	44211
November	77683	73762	69841	65921	62000	58079	54158	50237	46316	42396
December	79790	76550	73310	70070	66831	63591	60351	57111	53871	50631
January	80676	77722	74768	71815	68861	65907	62954	60000	57046	54093
February	81980	78609	75238	71868	68497	65126	61756	58385	55015	51644
March	85454	81955	78457	74958	71459	67960	64461	60963	57464	53965

Source: Calculated from Annual Reports of Regional Load Dispatch Centres

a load duration curve for each month. Each month is assumed to have 10 demand levels(load) represented ℓ. The duration of (τ) for each ℓ is valid for 73 hours [3].Thus, ℓ represents 120 levels of demand (load) for a given year.

[3]For an arithmetic progression(AP) we know $2S = n[2a + (n-1)d]$, $2S = 10[2a + 9d]$ if $n = 10$ therefore $d = (S/5 - 2a)/9$.Where S is the sum, n is the number terms (known variable) and d is common difference of the AP. Once we know d we can easily find all the terms of the series. We divide all the terms by 73 to get the capacity demanded.

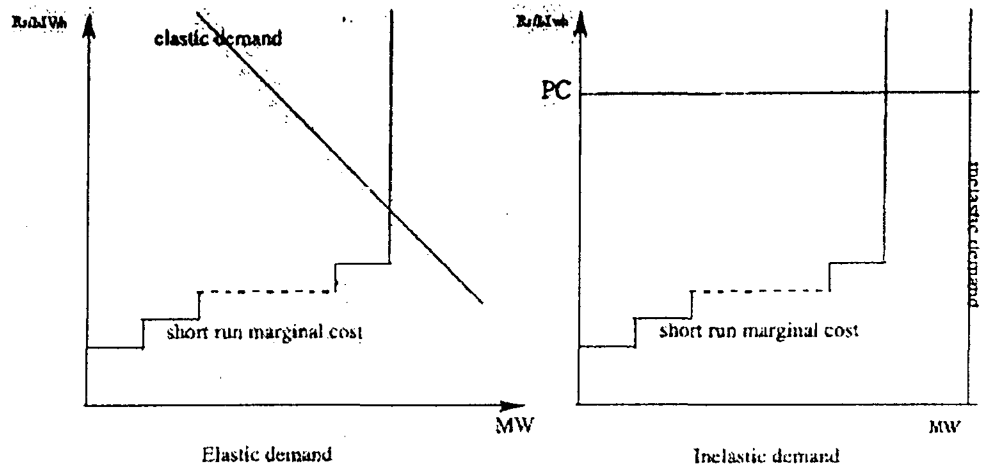
We reduce each of the demand levels obtained in this manner by percentage of hydro generation in the respective month so that we are able to take care of hydro generation. While this may not be an appropriate way of taking account of the hydro generation as hydro plants would like to use their water reserves when demand is highest so that they are able to earn highest scarcity rent. But under the assumption that generators bid on the basis of their fuel cost and they do not know the demand ex-ante this can be plausible. This means that hydro plants will bid as long as water is available in their reservoir. Table 5.1 gives the resultant load pattern of India (Net of hydro served demand)

5.3 The Model

We model an hourly spot market for electricity. In this model generating firms bid for each hour of the day on the day ahead of the actual operation. This is an energy only power exchange where generators are paid nothing in addition to the price they receive for the units of power they inject into the grid for committing their generating capacity to the grid. We assume a perfectly competitive model and system operator (SO) is knows the demand level. This implies that SO has to clear, for each hour, a perfectly inelastic demand curve. The System operator (or regulator) of the spot market has to keep dispatching the plants in an increasing order of their bidding (ask price) (i.e., plant asking for lowest price per unit of power is dispatched earliest) until demand level of that hour is met. This is in line with the regulator's objective to clear the demand at minimum cost. The ask price in this case happens to be the fuel cost per unit of generation. The ask price of the last plant dispatched in this manner becomes the price received by all the plants which are dispatched. Mathematically this is nothing but a linear programming problem. This problem can be written in the following manner.

The problem arises when demand in certain hours exceed the total available ca-

Figure 5.2: Market with Perfectly Inelastic Demand vis-a-vis downward sloping demand curve



Source: Adopted from Ehrenmann & Smeers (2008)

pacity in the market place. Such a situation does not arise in standard models because these models usually assume downward sloping demand curve. Therefore, negatively sloping demand curve intersects the vertical segment of the supply curve at the capacity limit defined by the total available supply of capacity in the market for a given hour (See First Panel of Figure 5.2). But in the case of the vertical demand curve, supply and demand curve will never intersect each other in cases when demand of the system exceeds the total available capacity in the market place (see second panel of Figure 5.2) . In such cases, it is not possible to determine an equilibrium price. One solution to this problem is to impose a price cap in the market i.e., the maximum price at which trade of electricity will take place when intersection of demand and supply curve is not possible. Ideally, this price cap should reflect value of loss of load (VOLL) as demand is curtailed in this situation (see second panel in Figure 5.2). Stoft (2002, ch. 2.2) and Ehrenmann & Smeers (2008) also discuss these issues. In fact this is one of the classical cases of market failure in electricity markets.

Assuming perfect competition, the spot price of the electricity in the energy only market should be determined by intersection of the supply and demand bids. As it is not possible to obtain a reasonable demand function, we assume that demand is insensitive to price i.e., vertical demand curve. We consider a load duration curve defined by ℓ segments of demand D_ℓ for a duration of $\tau(\ell)$. Demand in spot market is the horizontal summation of the demand of each load serving entity or distribution company (DISTCO) $(\bar{Z}_{j,\ell})$ that will participate in the spot market, represented by j, i.e. $D_\ell = \sum_j \bar{Z}_{j,\ell}$. The solution of this equilibrium can be found by solving the following optimal dispatch problem.

$$\begin{aligned} &\min_{x_{i,\ell}} \quad \sum_{\ell \in L} \tau(\ell) \left(\sum_{i \in I} c_i \, x_{i,\ell} + \text{VOLL} \; y_\ell \right) \\ &s.t. \begin{cases} \sum_{i \in I} x_{i,\ell} + y_\ell = D_\ell & \qquad \pi_\ell \\ 0 \le x_{i,\ell} \le \bar{X}_i & \qquad \phi_{i,\ell} \end{cases} \end{aligned} \tag{5.1}$$

In the optimization problem (5.1), the subscript i refers to identity of power plants. A power plant is defined by its variable cost of the production c_i and a maximal capacity $\bar{X}_i$. The production of this power plant during the load's segment ℓ is the variable $x_{i,\ell}$. The objective function of (5.1) is the sum of the operating cost over different plants and time segments. The next term of the objective function is the shortage cost (when demand is not met) which is assumed to be equal at a value of loss load (VOLL) of 9000 [Rs/MWh]. VOLL can also be taken as the price cap that is fixed by the System Operator of the spot market. It is possible to get the quantum of demand curtailed in the spot market at any time segment by reverting to y_ℓ. First constraint states that production of the power plants plus shortage must be equal to the total system demand in each segment of the load duration curve. In a perfectly competitive market, spot prices are determined by the marginal cost of the last unit of power generated. In this problem, it is given by the dual variable associated to the first constraint (π_ℓ). The second constraint expresses that the generation from any plant is non-negative and can never exceed its existing maximal capacity $\bar{X}_i$.

Using standard duality theory, we convert this linear optimization problem into the following complementarity conditions.

$$0 \leq c_i + \phi_{i,\ell} - \pi_l \quad \perp \quad x_{i,\ell} \geq 0 \tag{5.2}$$

$$0 \leq \sum_{i \in I} x_{i,\ell} + y_\ell - D_\ell \quad \perp \quad \pi_\ell \geq 0 \tag{5.3}$$

$$0 \leq \text{VOLL} - \pi_\ell \quad \perp \quad y_\ell \geq 0 \tag{5.4}$$

$$0 \leq \bar{X}_i - x_{i,\ell} \quad \perp \quad \phi_{i,\ell} \geq 0 \tag{5.5}$$

In this model we have two dual variables, π_ℓ and $\phi(i, \ell)$. The dual variable π_ℓ gives the marginal cost of meeting the demand in load segment ℓ. This is on account of the fact that equality of the demand and supply can be achieved only if π_ℓ is positive. The dual variable $\phi_{i,\ell}$ gives exactly, for each demand segment ℓ, the total revenue earned over and above the total variable cost by MWh produced by the plant i. Therefore the total revenue over and above total variable cost earned by unit MW of technology i can be written as

$$R_i = \sum_{\ell \in L} \tau(\ell)\,(x_{i,\ell}, \phi_{i,\ell}) \tag{5.6}$$

It is evident from condition (1.5) that if $\phi_{i,\ell}$ is positive plants are producing at maximum capacity and conversely if $\phi_{i,\ell}$ is zero some capacity of plants with technology i may remain idle. This implies that when $\phi_{i,\ell}$ is zero, plant i is the price setter in the spot market. That is exactly the reason why they will not make revenue over and above their marginal cost (scarcity rent). This leads us to make a judgement that positivity of $\phi_{i,\ell}$ for plant i implies that during that time segment price is set by a plant that has higher variable cost than the plant i. Since price is higher than variable cost for the plants who have positive $\phi_{i,\ell}$ they earn revenue over and above their variable cost.

This model assumes that

1. plants can be switched on and off without any cost.

2. there is no transmission constraint in interregional transfer of power. Transmission constraint in reality is not limiting factor of inter-regional transfer of power at present.

3. there is no loss in transmission to keep the problem simple.

4. there is no auxiliary consumption of plants

Assumption 1 may alter the order of the dispatch of plants. Assumptions 3 and 4 will not affect order of dispatch of plant because such things apply universally to all plants with very minor differences in case of auxiliary consumption. Violation of the first assumption can significantly change the result.

We solve this model for 120 load segments (10 for each month) for the year 2005-06 (given in Table 5.1). This process gives equilibrium prices under the condition of perfect competition for each 120 levels of demand (load). With the help of this prices we calculate the revenue earned by each plant during a given year which enables us to obtain operating margin or scarcity rent i.e., total revenue minus total fuel cost incurred in that year. The operating margin [Rs/MW] is then compared to the cost of new plants (overnight costs plus O&M cost) [Rs/MW] to check if new plants can recover their fixed expenses.

5.4 Result

the first step was to know the marginal costs at which the market clears or demand is satisfied (Table 5.1) i.e., equilibrium price under perfectly competitive regime (Table 5.2). When demand outstrips the total available capacity, the system operator has price ceiling of 9000 [Rs/MW] at which the trade will take place. Therefore, scarcity rent, that plants can earn in such a situation depends upon the price cap that is imposed by system operator. In Table 5.2 there are seven cases i.e., $7 \times 73 = 511$) hours of the year when trading will take place at the price cap fixed by the system operator i.e., 9000[Rs/MWh]. If we increase the price cap to a higher level, plants will collect more scarcity rent during these 511 hours.

Table 5.2: Short run marginal cost of meeting the demand levels given in Table 5.1[Rs/MWh]

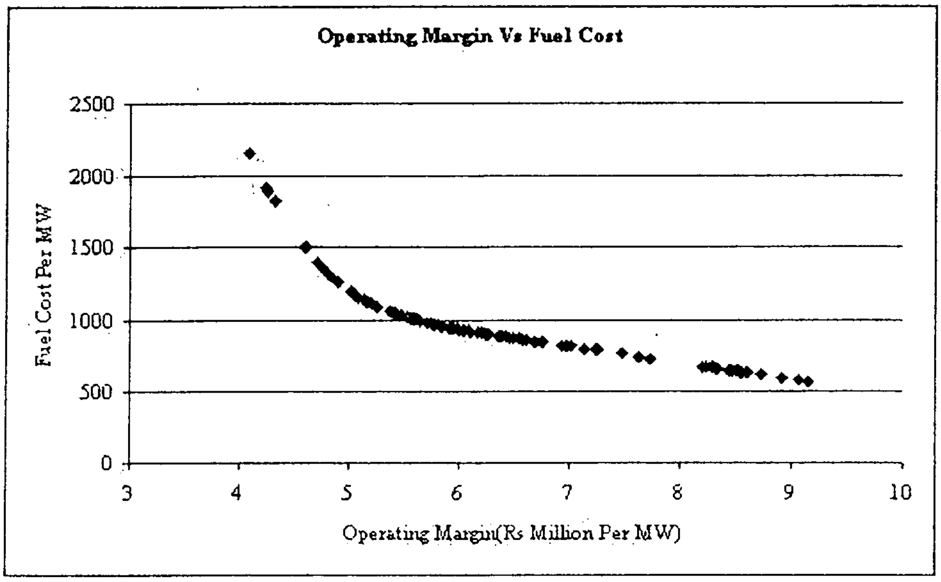
	1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th
April	9000	1910	1305	1172	1094	1045	1007	973	944	936
May	9000	1506	1305	1172	1094	1049	1035	978	949	944
June	9000	6160	1316	1172	1094	1045	999	962	944	936
July	1172	1114	1051	1035	978	948	943	933	926	908
August	1130	1061	1041	978	949	944	936	930	912	908
Sept	1141	1061	1035	976	947	937	930	912	908	903
October	1395	1182	1134	1049	1015	975	944	936	930	912
November	1506	1197	1141	1051	1015	975	944	936	926	908
Dec	6160	1395	1197	1141	1061	1045	986	949	944	936
Jan	9000	1506	1305	1172	1094	1051	1035	978	949	944
Feb	9000	1892	1305	1172	1094	1046	1013	975	944	937
March	9000	9000	1892	1305	1171	1094	1045	999	962	944

The second step is the calculation of total scarcity rent earned by each plant in India. Scarcity rent earned by each plant in the year on per MW basis is the sum of difference between the equilibrium prices per MWh and the fuel cost per MWh of all the dispatched plants for each 120 demands levels multiplied by 73 (because each demand level is expected to be for 73 hours). This is an alternative way to get the estimates of scarcity rent that we got in equation 5.6. It can be written as

$$R_i = 73\left[\sum_{d=1}^{120}(P_d - c_i)\right] \tag{5.7}$$

where i stands for plants and d stands for levels of demand. the above exercise shows that the operating margin that is the revenue net of variable cost (fuel cost) for plants with low fuel cost have high operating margin but this margin shrinks quite sharply with small increase in fuel cost from level of 1000[Rs/MWh] as can be seen in Figure 5.3.

Figure 5.3: Operating margins visa a viz fuel cost of the plants



The third step was to investigate if these scarcity rents are enough to pay for the annualized overnight cost and operation and maintenance (O&M) cost . The O&M cost is assumed at 1.02 Million [Rs/MW] on the basis of various tariff orders for NTPC plants (both coal and gas fired). Average of the annualised overnight cost of new plants that were recently given Techno-Economic clearance (TEC) from CEA is considered as the bench mark[4] for new plants. Average of the annualised overnight cost for combined cycle gas turbine (CCGT) plants and coal based thermal plants are 5.2 million and 7 million [Rs/MW], respectively. Calculation of scarcity rent (operating margin) is carried out with the intention of examining the possibility of new investments under the multilateral competitive regime.

We see that the scarcity rents earned by many plants sufficiently cover the annu-

[4]Details of plants that were recently given TEC can be viewd at `http://www.cea.nic.in/thermal/Project%20Appraisal/central-state-thermal.pdf` and `http://www.cea.nic.in/thermal/Project%20Appraisal/private-thermal.pdf`

alized overnight cost and O&M (see Table A-11 p. 216). Profitability of plants will further improve if price cap assumed at 9000[Rs/MW] in the model is increased and vice versa. In order to calculate the annualized overnight cost of the plants we take the list of the privately owned plants recently approved by the CEA for techno-economic clearance (TEC) . We assume 15% of discount rate and operating life of 30 years for coal plants while 20 years for CCGT plants. We use 15% discount rate for our calculation because this rate is used currently for calculation of tariffs under the power purchase agreement (PPA) regime. It is also important to note that the overnight cost of Indian plants are similar (little lower) in comparison to the one reported by International Energy Agency (IEA) for Organisation for Economic co-operation and Development(OECD) countries in its report on "Projected Costs of Electricity Generation" (IEA 2005). But the O&M costs differ by 50%, reflecting wage differentials that exist between India and OECD countries.

However, the current institutional norms of bilateral contracts are not favorable for hassle free investment by private sector. But when generation is free to either write a bilateral contract with load serving entities (and not the government which owns the load serving entities as it happens now) or participate in the power exchange for selling the output of their plants, then we can expect that new investment will bridge some of the gaps in the installed capacity that exists today.