Least Cost Power Planning : Case Study of Maharashtra State

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Abstract :

Power sector in India and other developing countries is engulfed in many crises viz. capital, environmental and social crisis. Of these, capital crisis is the most talked about. But little has been done to address the root causes of this crisis. This paper, through a case study of Maharashtra state (in western India) demonstrates that integrating DSM options and decentralised generation in the power planning can provide substantial relief from capital as well as the environmental crisis. An integrated least cost plan (LCP) is developed for Maharashtra for the decade 1991-2001. The results of LCP are compared with the conventional plan. This work received inspiration and has benefited by the DEFENDUS plan developed by Prof. AKN Reddy and others for Karnataka state.

The official energy demand forecasts have numerous problems, such as opaque methodology, socially unacceptable assumptions regarding the sectoral growth rates. Hence, a frozen efficiency (FE) demand forecast was developed by incorporating desired development focus. This indicated a energy and power demand growth rate of 6.4% p.a.. To meet the incremental demand of 5,278 MW, similar to the conventional plan the FE scenario banks on only centralised supply sources. The capacity addition plan is based on screening curves evolved after detailed costing of relevant supply options. FE scenario needs a capacity addition of 7,760 MW, with a annual cost of Rs.71.47 billion /yr.

The LCP starts off using the FE demand forecast for the terminal year. Based on the integrated screening curves, economical DSM and decentralised supply options are chosen. The remaining demand is met by the centralised supply options. About 40% of incremental demand is met by DSM options, 15% by the decentralised generation options and the rest, i.e., 45% by traditional centralised sources. The total cost of the LCP is Rs. 47.66 billion /yr. Despite meeting same level of energy services as the FE scenario, least cost plan results in 33% saving in lifecycle cost. Least cost plan also reduced use of fossil fuel equivalent to 12 million tons of coal per year.

Introduction :

Maharashtra with installed capacity of more than 11,000 MW is the largest power generating state in India. Maharashtra State Electricity Board (MSEB), a monopoly state owned integrated utility, has developed most of this capacity.[1] Maharashtra is also the most industrialised state in the country. Table 1 shows the historical development of power sector and changing share in consumption of different consumer categories. Compared to other state electricity boards in India, MSEB's financial performance is relatively better with Rs. 161 Cr. profit in 1993. But, it is becoming increasingly difficult for MSEB or state government to satisfy the growing financial needs of power sector. Like other states, private investment in the power sector is said to be the only solace and most of the efforts are directed to attract more private investment. But there is little attempt to address the root causes of capital crisis, i.e., low internal resource generation, increasing electricity intensity (kWh per unit of GDP), and the sole dependence on costly centralised supply sources.

Table 1 : Power sector profile of Maharashtra state.

Year	Installed Capacity (MW)#	Bus-bar demand MW	Bus-bar demand Million kWh /Yr.	T&D losses (% supply)
1969-70	1,584	1,314	8,089	12.6%
1979-80	3,858	2,471	15,599	17.2%
1989-90	7,925	5,631	35,515	17.6%

Share of consumption by consumer categories (% of utilisation)

Year	HT industry	LT industry	Irrigation Pumpsets (IPS)	Households (HH)	Commercial (CL)
1969-70	59.8	9.7	4.3	9.4	7.0
1979-80	50.5	9.2	10.4	12.5	8.4
1989-90	41.6	7.0	21.2	16.2	7.1

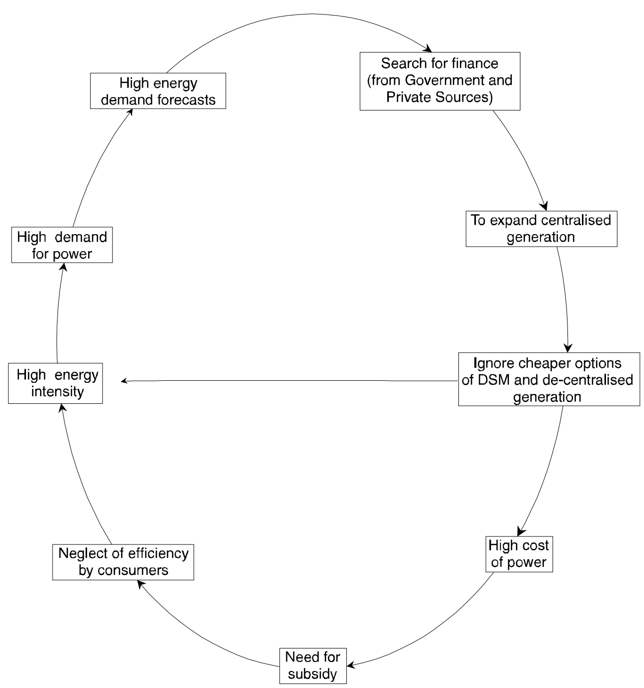
- Maharashtra has two private, and one co-operative licensees for distribution and one generating licensee, apart from the state owned MSEB. The data refer to the state situation.

Though government efforts are mostly directed towards capital crisis, this is not the only crisis faced by the power sector. Since, last few years power sector projects are facing increasing public opposition due to environmental and social considerations. Addressing these shortcomings has proved to be difficult, resulting in cost and time over-runs. With high transmission and distribution losses, low plant load factors, poor quality and reliability of supply; technical performance of SEBs also leaves much to be desired.

There exists large inequality in sharing of benefits due to power development. The people paying price for power development in terms of displacement or loss of livelihood are usually disadvantaged sections of the society who do not benefit from power development. Even after four decades of power development with increasing budgetary support, it has not been possible to provide even single light point connections to nearly 35% household in Maharashtra. This huge population is left out of direct benefits of power development. On the other hand, MSEB has been extending enormous subsidy (US $ 590 million in 1995) to agricultural consumers, claiming this to be the social obligation. But distribution of this subsidy is highly skewed, with rural elite (mainly sugarcane growers) appropriating large share of this subsidy. Poor farmers in drought prone areas pay substantially higher tariff then sugarcane growers. Moreover, due to over exploitation of water by small section of farmers, poorer sections of society face increasing water scarcity. This is another facet of the inequality related to the power development.

Despite such crisis the government efforts are primarily directed only towards the capital crisis. At the same time, overestimated energy demand forecasts result in shortage psychosis among power planners. This reinforces the centralised bias of the planning. For constructing new mega power projects, planners look forward to huge capital investment from the government and now also from the private investors. Whereas, the economical but smaller decentralised projects, efficiency improvement, and demand side management (DSM) options are neglected. This results in high cost of power and low efficiency of power use, leading to increasing energy intensity of the society. The subsidy provided to compensate the high cost of power removes consumer's incentive for efficiency improvement, in turn, leading to in-efficient power use. This, further results into higher demand for power. This conventional model of power planning (inter-linked with the conventional model of development) is seen to be leading us into a vicious circle shown in figure 1. The circle is complete with the demand forecasts echoing the high growth scenario.

Figure 1 : The vicious Circle



The figure shows how the power sector in India is trapped in a vicious circle. Starting from high growth scenario assumption and ending in a high growth forecast. In the process deepening the capital crisis.

To move away from this vicious circle, actions on many fronts will be needed. Adoption of integrated resource planning, based on the choice of least cost options will be a major step in this direction. Often the potential of decentralised generation and DSM options is highly underestimated, while their costs are over-estimated. This paper elaborates the benefits of integrated resource planning through a case study for the state of Maharashtra. The study is motivated by work of Prof. A K N Reddy and other [Reddy A K N et.al, 1991] and has also benefited by the methodology and worksheets developed by them for DEvelopment Focused ENDUse oriented Services directed (DEFENDUS) scenario for Karnataka state. This work was carried out in 1991 and was revised in 1994. Present paper is an abridged version of a detailed report with the same title.

Electricity demand in future as well as the potential and cost of all supply options are estimated for Maharashtra for period of 1991 to 2001. Using this analysis, a conventional plan is developed followed by an integrated least cost plan. Adoption of the least cost plan can reduce the centralised capacity addition by more than 50%, for the decade of 1991 to 2001, while providing the same amount of services as the conventional plan. This can also achieve reduction in annual cost by 33% and substantial reduction of environmental damage.

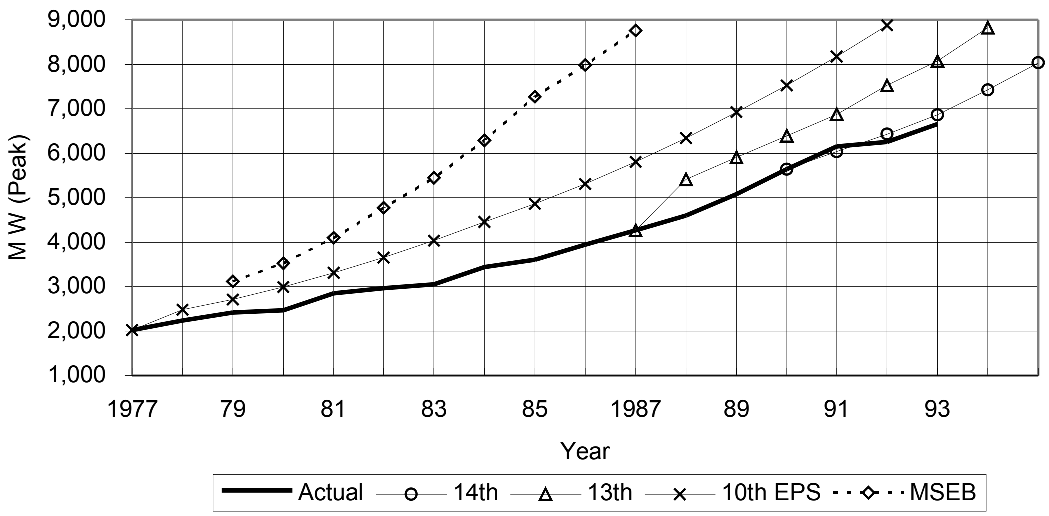
The enormous political and institutional initiatives needed for this change are not under-estimated, rather, it is argued that the huge benefits offered by this planning paradigm are in themselves great incentives to bring into effect these initiatives.

1. Base case energy demand forecasts :

Energy demand forecast is a starting step and the very basis of power planning. Hence, reliable demand forecasts are critical for successful planning. These forecasts are done by SEBs and the Power Survey Office of the Central Electricity Authority (CEA)[2]. The CEA forecasts are published as "Electric Power survey" (EPS).

These official energy demand forecasts (OEDF) have numerous shortcomings in many respects. OEDF are opaque and the conclusions are presented as rock-solid figures. The assumptions or methodology is not transparent and at times faulty assumptions are used. For example, the 14th EPS assumed a peaking availability (at the bus-bar) of generating plants in Western India at 59.5% for year 1994-95, while availability of 60.4% was achieved in 1991-92 itself [CEA, 1991, WREB, 1992]. Such lacuna overestimate the capacity addition needs. The OEDFs are based on just the continuation of past trends, resulting is continued acceptance of inequality and inefficiency. Lack of integration with other government policies and considerations (e.g. resource crunch or development objectives of household electrification) is another major lacuna in OEDF. The validity of OEDF has been questionable. [World Bank, 1991] OEDFs are used as a bargaining tool by power sector and different states to stake claims for increased budgetary support. Figure 2 shows how OEDFs had overestimated the demand in last two decades.[3]

Figure 2 : Historical demand forecasts and actual power demand in Maharashtra



The 10th, 11th and the 14th EPS (demand forecasts by CEA) show progressively declining forecasts and the actual demand is far less. Forecast by MSEB is way off the mark. These unrealistically high demand forecasts result in shortage psychosis and search for mega plants.

2. FROZEN EFFICIENCY (FE) SCENARIO :

This section describes the construction of FE scenario, which is used as a reference (base-line) scenario. The benefits of the least cost planning methodology are evaluated against this reference scenario. To overcome shortcomings of OEDF, a demand forecast is evolved under FE scenario. Based on the conventional centralised supply options a capacity addition plan is also worked out.

The FE scenario forecast differs from the official EDFs, as it incorporates the intended development focus, introduced through interventions in the form of planned growth of connections and adjustment in consumption norms. However, as its name suggests, it does not incorporate any efficiency measures. The plan horizon of one

decade from the base year of 1990-91 (1991 in short) is considered. Development of FE scenario forecast consists of two steps :
1) Estimation of 'True Demand' for the base year 1991 and
2) Estimation of energy and power demand for the terminal year 2001.

2.1 Estimation of 'True Demand' for Base Year 1991 :

'True' demand is the demand unrestrained by the supply constraints. No restrictions on energy or power demand were imposed in Maharashtra in 1991 or even in the preceding years but occasional load shedding to curtail peak load was resorted. Also when the generation falls short of demand the grid frequency drops, resulting in reduced consumption of inductive loads. Thus, the load shedding and frequency variation were two factors constraining the demand. Their effect on demand is studied.

The effect on energy consumption is worked out as per following steps:
i) Using hourly load (bus-bar demand) data for a distributed sample of 101 days the average load curve for 1991 is drawn.
ii) The data of hourly load shedding was available from MSEB for 5 months, from February 1991 to June 1991.[4] The hourly data of frequency change was not readily available. Analysis of the load shedding data and the estimated frequency variation, based Western Regional Electricity Board report [WREB, 1992:57] indicated an unmet energy demand of only 0.4%. Hence, the unrestricted energy demand is estimated by increasing the energy consumption for all categories by 0.4%.

The frequency variation has an effect similar to that of load shifting, due to suppression of peak load and boosting base load demand. [5] The grid frequency is not controlled by Maharashtra state alone and variations in frequency are likely to continue in the next decade. Hence, power demand is not corrected for the frequency variation.

2.2 Estimation of Energy Demand in the Terminal Year 2001 :

The FE scenario assumes no improvement in efficiency but assumes implementation of the planned growth rates. Future demand projection is possible knowing the 'true demand' for the base year 1991 and following two factors for different categories of consumers:
(1) expected growth rate of number of consumers and
(2) change in the consumption norms (average annual energy consumption per connection).
The FE scenario forecast incorporates the intended development focus through these factors. The deviations considered in these factors from the past trend and the underlying logic are explained below.

<u>2.2.1 Growth rate of number of consumers</u> : With the present growth rate of household electrification (between 1989 to 1992) of about 6.9% p.a., all the households would not be electrified by the terminal year of the plan. To electrify all houses by the turn of century, a higher growth rate of 9.2% is assumed. The IPS growth is assumed to continue at the prevailing rate of about 7.5% p.a. until the IPS number reaches 26.6 lakhs. This represents the maximum limit for wells with sustainable ground water extraction.[6][Dhokarikar B., 1989] After this point, no additional IPS connections has been assumed. The policy of encouraging LT industries, as recommended by the Advisory Board to the Government of Maharashtra is considered here. [GoM, 1989] The growth rate of power intensive HT industries is assumed to be 6.0% p.a. instead of 6.2% in the preceding decade. On the other hand, growth rate of employment intensive LT industries is expected to increase from 5.5% to 8.0% p.a. Growth rates of commercial and other miscellaneous sectors is assumed to remain nearly same.

<u>2.2.2 Consumption norm</u> : The average annual energy use per consumer (consumption norm) of commercial sector, LT industry and HT industry has stagnated over past decade. This trend is expected to continue in the plan period. Consumption norm of household (HH) consumers is increasing at 3.4% p.a. since 1982. In 1991-92 it was 716 kWh/HH/Yr. The FE scenario envisages a faster addition of low consumption rural households to the grid. This would results in stabilising the overall consumption norm of households till year 2001.[7] The consumption norm of IPS is increasing, but for multiple reasons it has been assumed to remain constant in the future. These reasons include, 1) with suggested consumption based tariff, wasteful use of electricity would reduce, 2) due to un-metered supply of IPS, the present IPS norm is an estimate and most likely a higher side estimate, 3) it is essential to restrict the growing consumption norm of IPS to limit the impact on water sources and MSEB's revenue.

Based on above mentioned growth rates for number of consumers and consumption norm, year wise energy demand is worked out. A modified version of the spread sheet prepared by Reddy et.al. [Reddy A K N et.al., 1991] was used for this purpose. The FE scenario forecast expects energy demand (at bus-bar) to increase at 6.4% p.a. and reach 72,573 million kWh (MU) by year 2001. The FE scenario predicts energy demand growth of 6.4% p.a. against 7.2% p.a. growth prediction of OEDF. This difference in growth rates is largely accounted by the difference in the assumptions for the IPS consumption in the two forecasts.

2.3 Estimation of Power Demand in the Terminal Year :

The power demand would increase at the same rate as the energy demand unless the shape of the load curve undergoes some changes. Hence, possibility of change in shape of load curve needs to be evaluated. Due to non-availability of historical 'yearly average load-curves', the shape of daily load-curves for the maximum-demand days for past five years is analysed [data from Parikh et al, 1991]. The shape of the load curve has not significantly changed over last five years despite changed share of consumption by different categories of consumers. Load-curves for different consumer categories and analysis of the effect of increased household and IPS consumption on the load profile is not available. As a result, forecast of change of load pattern is not possible. As a best approximation, the shape of load-curve is assumed to remain unchanged.

To arrive at the FE load forecast, the load duration curve (LDC) for base year is first constructed using the hourly bus-bar load data for 101 sample days mentioned earlier[8]. The LDC for terminal year is derived by scaling up the base year LDC in accordance with the expected increase in energy consumption. The shape of LDC is expected to remain unchanged, and only the area under the curve would increase. The FE scenario predicts a peak load of 11,469 MW by 2001.

2.4 Capacity Addition Plan for FE Scenario :

In the conventional plan only a few centralised supply options are considered for the capacity addition planning. In Maharashtra, only four centralised supply options are prominent. These are coal thermal, gas / oil based open cycle gas turbines (GT) or combined cycle gas turbines (CCGT) and reversible hydro generators at the pumped hydro storage schemes (PSS). For planning purpose these supply options are classified as base load, intermediate load or as peaking load options depending on the range of load factor in which their operation is most economical.

Development of screening curves : Here the method of screening curves is used to prepare optimal capacity addition plan. For screening the supply options, cost of supply options are worked out as a function of "net plant load factor" (PLFn).[9] The annual cost of a supply option is the sum of annuatised investment cost and the fuel cost at different PLFn levels. It is worked out in Indian Rupees per year per kW reliable bus-bar output (i.e. Rs./$kW_{bus\text{-}bar}$/yr.). The annual cost can also be seen as the revenue requirement for one kW reliable bus-bar output.[10]

The screening curves used for screening purpose, plot this cost (on Y-axis) against the PLFn (on X-axis). The Y-intercept of the curve (line) is the capacity cost of the option. This is the sum of the annuatised investment cost and the fixed O&M cost. The slope of line is the running cost; representing the unit cost of fuel. The screening curves for the options analysed are shown in figure 3 (a) and detailed method of calculation is given in appendix I. Compared to the options of CCGT and the coal thermal plants, the GT plants have low investment cost (i.e., low Y-intercept) and high fuel cost (i.e. high slope). Implying that, GT are more economical than CCGT or coal plants for low PLFn, i.e. for peaking operation. But the PSS option is more economical than even the GT option as a peaking plant. For intermediate load operation, between PLFn of around 33% to 66%, the CCGT is most economical. For base load operation, above the PLFn of 66% the coal plants are ideal. The economical option for different load periods is marked by bold lines. This forms a least cost envelop of the centralised options. The PSS, CCGT and coal thermal plant represent the least cost peak load, intermediate load and base load plants respectively.

Capacity addition plan using screening curves : The results of the screening curve analysis are as expected by the thumb rule logic. But an advantage over the thumb rule is the benefit of identification of exact point of transition and the possibility of using the screening curves in conjunction with the LDC to arrive at the least cost capacity addition plan. The graphical representation of this method is shown in figure 3. The figure shows :
(a) the screening curve for four supply options considered, and
(b) the LDC forecast for the terminal year, as per the FE scenario.
To start with, the optimum level of supply by the base load plants is calculated. Coal plants are the most economical for PLFn above 66%. This break even point for base load coal plants (point A) is projected on the LDC (point A'). The height of line A'A'' represents the optimal level of supply by coal plants. If we plan for higher coal capacity, then for some duration these plants would operate at PLFn below 66%. Which would be un-economical. On the other hand, if supply from coal plants is lower than A'A'', then the intermediate load plants would have to operate at PLFn higher than their economical PLFn range. Hence line A'A'' represent the optimum level of supply by coal plants. Similarly, the optimum level of supply by intermediate load plants and peaking plants is calculate. These are represented by heights of B'B'' and C'C'' respectively. Subtracting the already available capacity form this optimal level of supply would give the required capacity additions.

Figure 3 : Screening curve and LDC used for the capacity addition calculation.

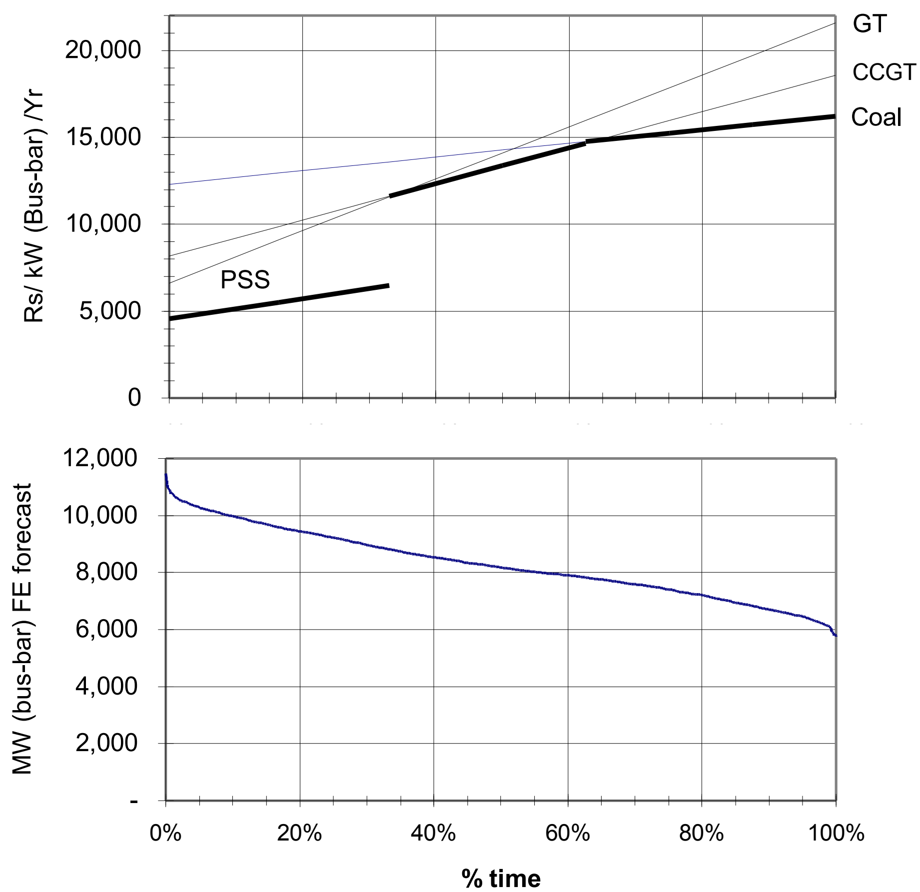


Figure shows development of capacity addition plan using screening curve and load duration curve. Figure (a) shows the screening curve representing the annualised plant cost on Y-axis and PLFn (refer end note 9) on X-axis. Figure (b) shows the LDC forecast for Maharashtra for terminal year of FE scenario. The dark line on figure (a) represent the economical PLFn range for different plants. These dark lines together form a least cost supply envelop of the centralised options. The optimal level of supply of coal, CCGT and PSS plants is indicated on figure (b) by lines A'A'', B'B'' and C'C'' respectively.

Using this methodology the optimum supply mix is calculated for the FE projection for terminal year (2001). The results are indicated in table 2, which shows the optimum level of bus-bar supply (energy in MU and power in MW) by various types of plants. The exercise aims at optimising the addition of new capacity to meet the incremental demand. It assumes that the present (1991) level of installed capacity will continue to supply the present level of demand. Hence, only the incremental demand (also shown in table 2) is considered for planning.

The required capacity addition of different types of plants to reliably meet the incremental demand is then calculated. The peaking capability factor (PCF) defined by CEA, is used for this purpose. The PCF is the ratio of reliable bus-bar supply to the installed capacity. It takes into account the expected outages, auxiliary consumption as well as the desired level of spinning reserves (refer appendix I). The required capacity addition equals the incremental bus-bar demand divided by PCF of that option. This calculation is straight forward, except in case of PSS. PSS is a hydel battery. It consumes energy during the pumping cycle which is later made available during the peak periods. Hence, attention should be paid to the maximum feasible PSS capacity based on the availability of the excess thermal generation during the off peak period. In present case, the coal plants are capable of providing about half of the energy needed at peaking period. Hence, some GT capacity addition becomes inevitable. The backing down of new coal plants can be nearly eliminated in this case.[11]

After arriving at the optimal capacity addition of different types of plants, their expected load factor (PLFn) is calculated. The values of power and energy supply at bus-bar are used to calculate the PLFn for different options. The annual cost of the option (Rs/kW$_{bus-bar}$/yr.) at the expected PLFn is calculated from the screening curve equations. Total cost of added capacity is then calculated by multiplying the cost of each option by the planned bus-bar supply by the said option.

Table 2 : Capacity Addition Plan for 2000-01 : FE Scenario

	Base load period		Intermediate load period		Peak load period		TOTAL	
	Power (MW)	Energy (MU)	Power (MW)	Energy (MU)	Power (MW)	Energy (MU)	Power (MW)	Energy (MU)
1991 Actual	4,166	35,352	598	2,516	1,427	1,305	6,191	39,173
2001 FE scenario	7,716	65,455	1,109	4,700	2,644	2,418	11,469	72,537
Added demand	3,550	30,103	511	2,184	1,217	1,113	**5,278**	**33,364**

CAPACITY ADDITION OPTIONS

	Coal Thermal	CCGT	PSS	GT	**TOTAL**
Bus-bar supply	3,550	511	847	370	
Installed capacity addition (MW)	5,726	615	973	446	**7,760**
Expected PLFn	97%	48%	9%	14%	
Annual cost (Rs/kW/yr.)	16,111	13,159	5,080	8,772	

Note : The totals may not match due to rounding off. The PCF of the plants are; coal (62%), CCGT (83%), PSS (87%), GT (83%). The annual cost of the option refers to the annuatised cost per kW of bus-bar supply.

FE scenario goal for the terminal year is to provide additional bus-bar supply of 5,278 MW and 33,364 MU per year. For meeting this goal, the conventional plan based on the 'least cost centralised capacity expansion' principle needs capacity addition of 7,760 MW. The annual cost of this capacity works out to be Rs 71.47 billion /yr. (1992 Indian Rs).

3. Integrated least cost plan :

Earlier section discussed the development of FE scenario. The developmental aspects of DEFENDUS approach, such as, priority to electrification of poor households (HH) and LT industry, restriction on number and consumption norm of IPS are included in FE scenario. But FE scenario considered only the limited options of centralised supply to meet the demand. This section evolves the least cost plan (LCP) by considering a much wider array of options for meeting demand. These options include decentralised supply and efficiency improvement, apart from the centralised supply options. The results of the FE scenario and the LCP scenario are compared at the end.

Following steps are carried out to integrate various options and evolve a least cost plan.
1) Estimation of potential of DSM and decentralised supply options,
2) Estimation of costs of DSM and decentralised supply options,
3) Construction of integrated screening curves to compare costs of DSM and decentralised supply options against the centralised supply options,
4) Based on these integrated screening curves, selection of DSM options which are cheaper then supply options,
5) Modification of FE load duration curve forecast for the terminal year to account for the change in load due to adoption of selected DSM options.
6) Capacity addition plan to meet the modified LDC goal, based on the integrated screening curves (consisting of decentralised and centralised supply options).

3.1 Estimation of potential of DSM options :

Estimation of DSM potential is an important step in development of the integrated least cost plan. Many studies have attempted estimation of DSM potential for different sectors (industrial/domestic etc.) or geographical regions (India/ Karnataka etc.). This section estimates the DSM potential for all sectors for Maharashtra state. For potential estimation reliable the end use pattern, end use efficiency, load shapes and seasonal variation in demand needs to be considered. In Maharashtra consumers are classified as household, commercial, industrial, agricultural and miscellaneous consumers. Information about the efficiency improvement potential in industrial and agricultural sectors is available through many studies. A number of industrial energy audits have been carried out by government and privates agencies. Possibilities of efficiency improvement in agricultural pumpsets have also been well documented. But the household consumption patterns and DSM potential do vary significantly among different regions. Hence, a detailed analysis of DSM potential is carried out for this sector. Reduction in peak demand due to DSM options, is also worked out.

3.1.1 Industry : The industrial sector in India is very inefficient in energy use. It consumes roughly 15-30% more energy for a unit output than standard norms prevalent in the western countries [TERI, 1991; Reddy A K N et.al., 1991]. A number of studies have estimated energy savings of the order of 15 to 20 % by use of efficient equipment. [Devki R&D, 1988, Nadel S et.al., 1990; World Bank, 1991(b)] Additional savings of 15% are achievable through change of industrial process.[Rao G. et al.,1991] Even in relatively efficient western industries, pumping and air handling electricity consumption can be reduced by 50% to 75%, over the existing stock averages by cost effective measures. [Nilson L, Larson E, 1991:363] As a conservative estimate, it is assumed that only 15% savings in HT industry and 20% in LT industry are possible. It is further assumed that by 2001 just 80% penetration of these improvements can be achieved. In effect, 12% savings in HT industry and 16% in LT industry are expected to be realised by 2001.

<u>3.1.2 Commercial and other Sectors</u> : Around half of electricity consumed by the commercial sector is used for lighting. [World Bank, 1991] More than 30% savings are possible in lighting consumption in a cost effective manner. The second largest end-use in commercial sector is air cooling and air circulation. Significant savings are also possible in this end-use. It is assumed that only 15% savings are possible in the commercial sector. The penetration of these improvements is assumed to be 80% by the end of the plan. Similarly, assumptions of 10% improvement with 80% penetration are made for Railway and Miscellaneous sectors.

<u>3.1.3 Irrigation Pump Sets (IPS)</u> : The efficiency of IPS is dismally low. Use of low-friction pipes and low-friction foot valves in the rectification of IPS can result in 25% energy savings. Field trials of such rectification on thousands of pumps have proved this. [Patel, 1991; ORG, 1991] Moreover, with complete rectification i.e. change of pump and piping, energy savings of upto 50% can be achieved. With the metering of the IPS, the consumption is expected to further reduce by 5% [Nadel et.al., 1991: 63].[12] It is assumed that all IPS connections will be metered and 80% of all IPS will be efficient by the end of the decade. Only 25% energy savings are assumed for the rectified IPS.

<u>3.1.4. Household sector (HH)</u> : Lighting, water heating, air handling and refrigeration are the major end uses in the household sector. Table 3 shows the end use wise electricity consumption from a study of urban and semi-urban areas in Maharashtra.

Table 3 : End use-wise electricity consumption in household sector.

End use	kWh/Year/HH	Share of consumption
Lighting	459	35.5%
Water heating	245	18.9%
Fans / ACs	232	17.9%
Refrigeration	131	10.1%
Others	228	17.6%
Total	**1294**	**100%**

Source : Kulkarni et.al., 1991.

In the present analysis DSM options for lighting, water heating and refrigeration are considered.
<u>a) Lighting Improvements</u> : The incandescent bulb (IB) of average 60 Watts is still the most common source of illumination in the household sector. Use of compact fluorescent lamps can save about 45 Watts while giving same or better illumination. It is assumed that the CFLs will replace only the most frequently used IBs and will have a usage of 4 hrs/day (refer section 3.1.8 for details). It is also assumed that on the average only 1.5 light points per house will be suitable for replacement. This amounts to saving of 98.6 kWh/HH/yr and a reduction in peak demand of 27 watts per light point replaced.
<u>b) Water Heating</u> : The electrical water heaters (EWHs) used mainly by the rich urban households account for about 19% of the total household consumption. For reasons of space availability and use pattern, only half of EWHs are expected to be suitable for replacement by solar water heaters (SWHs). The SWH can save electricity on 250 non-monsoon days per year (i.e. 68% savings). For estimating electricity saving, it is assumed that present EWH efficiency is 75% and water requirement is 100 lit./day at incremental temperature of 15 'C. This implies a saving of 476 kWh/SWH/Yr and translates into reduction in average household consumption norm by 45 kWh/HH/Yr. Attempts are being made to develop low-cost solar water heaters (SWHs) of 75 litres per day (LPD) capacity [Gandhi N, Vaja D, 1991]. However, use of 100 LPD low cost unit in the market is assumed.
<u>c) Refrigerators</u> : Wide variation in the efficiency of refrigerators exists depending on the design. For a typical Indian refrigerator of 165 lit., the proven technologies of efficiency improvement can reduce consumption from 540 kWh/Yr to 205 kWh/Yr. [Nadal et.al., 1991] Here, it is assumed that all the new refrigerators bought after 1996 will be efficient. By 2001, over 1 million efficient refrigerators are expected to be sold in Maharashtra.[13] This is estimated to save 335 MU per year by 2001. Considering the expected number of electrified households by year 2001, this is equivalent of reduction in consumption norm by 19 kWh/HH/Yr.

Taken together, the above improvements in the household sector have a potential of reducing the consumption by 23.2%, with the household consumption norm dropping down to 539 kWh/HH/Yr.

It is considered that the penetration of these technologies will follow a `S` shaped curve and 80% penetration will be possible by the end of next decade. For example, in case of EWHs, only 40% of the total EWHs will be replaced by SWHs by year 2000-01.

3.1.5 Improvements in T&D network : Though not a DSM activity, this supply side efficiency improvement is very attractive investment and is considered under this section for convenience. The T&D losses in Maharashtra state were 17.6% in year 1990-91. [CEA, 1993][14] These losses can be reduced through measures such as; addition of capacitors in the LT circuit (either by consumers or at different voltage levels by the MSEB), by augmenting T&D capacity in the over-loaded sections, by using efficient transformers and other equipment. It is assumed that the savings through T&D improvements to the tune of 2.5% will be realised by year 2001. At 1991 consumption level and the system load factor of 76%, this is equivalent to a saving of about 150 MW peak demand.

3.1.6 Load Shifting in Industry : Shifting of load from peak to the off-peak period does not directly save energy. It results in reduction in peak load and increase in the base load demand. This is highly desired in thermal-heavy supply system of Maharashtra. Load shifting of 10% of the normal operating load in HT industry is considered possible [Banerjee R, Parikh J., 1993]. The connected load of HT industries is about 4,000 MW. Assuming 75% of the connected load as the normal operating load at peak time (i.e. around 3,000 MW), the potential peak savings is estimated at around 300 MW for year 1991. By year 2001 it would grow to about 550 MW. In the present exercise only 250 MW of load shifting is expected to be achieved by 2001. This is accounted by considering 250 MW reduction in peak load and corresponding increase at off peak period.

3.1.7 Other opportunities : Better interconnection of grids can help SEBs reduce the peak deficit by more than half. This option is especially attractive for the states like Maharashtra and Karnataka [World Bank, 1991:7]. This would require small investment. Similarly, some DSM options with significant potential have not been considered. Table 4, indicates the potential of the options considered.

3.1.8 Estimation of hourly load reduction through DSM options : This section estimates the hourly and seasonal variation in load reduction due to various DSM options. The hourly load reduction is deducted from the FE forecast of hourly load (for terminal year) to arrive at load forecast with adoption of DSM (refer section 3.5). The estimate of peak load reduction are also used later for calculating the cost of DSM options (refer section 3.4 and appendix I). The estimated hourly load saving after adoption of DSM options is shown in appendix II.

The hourly demand reduction can be estimated knowing the hourly use pattern of devices and the expected savings because of efficient appliances. The information on hourly use pattern (also called duty cycle) of appliances is largely un-available in India. Hence, where ever necessary conservative estimate of peak coincidence have been used. For example, the savings in HT industry, railways and miscellaneous categories are assumed to be constant through out the day. The savings due to improvement in refrigerators would be nearly constant through out the day. These options would be similar to the base load plant. Savings in LT industry are assumed to be constant for 16 hours a day (i.e., 2 shifts between 6 a.m. and 10 p.m.). The power saving due to the T&D improvement are assumed to be proportional to the system load.

In case of IPS, information was not available about the duty cycle. The analysis of agricultural feeders indicate minimal use of pumps in monsoon period. Hence, savings on 115 days in monsoon are assumed to be nil. And predominant use of pumps is assumed in day time between 7 a.m. to 8 p.m., as shown in appendix II. The peak coincidence estimate of 16% is used [Nadal et.al.,1991]. IPS feeder data recent obtained from MSEB suggests that this is a conservative estimate and actual peak coincidence might be higher. However, this is ignored.

Duty cycle of EWH is based on survey of 250 EWH in Pune [Sant 1993]. It was found that EWH are predominantly used during morning with only a small fraction being used during evening. Maharashtra has evening peak and the peak coincidence of SWH savings is barely 4%. The average EWH was found to be of 2.25 kW. It was further assumed that SWH would not be able to function for about 110 days in monsoon.

A survey in South Bombay found that average IB in the households was used for 2.5 hours a day, with a peak coincidence of 36% [Gadgil A., et.al. 1988]. South Bombay comprises of very rich households. Since, the average household in the state has much fewer lamp points, the usage is expected to be more than what was found in South Bombay. In addition, the CFLs are expected to replace the most used IBs in the house. Hence, the average usage of CFL is assumed to be 4 hours per day, with a corresponding peak coincidence of 60%. The lighting usage in commercial sector is assumed to be 6 hours a day. The duty cycle has been worked out based on data for commercial lighting load in South Bombay study.

Table in appendix II shows the hourly reduction in power demand if the DSM options are adopted. Industrial load shifting and T&D improvements are also included in the list. Such values of hourly savings of the selected DSM options are later used to arrive at the LDC forecast of Least cost plan scenario by modify LDC forecast of FE scenario.

Table 4 shows estimate of energy and power savings expected by the terminal year, if the options are implemented. Table also shows the annual cost of implementing these options. This is calculated by knowing the annuatised cost per appliance or cost per kW saved (section 3.4) and the number of appliances planned to be installed or kW saved.

Table 4 : Cost and potential of major DSM options considered.

DSM Options	Savings		Implementation cost (Rs million)
	Peak Power (MW#)	Energy (MU#)	
Household lighting	680	1670	1,274
Solar Water Heaters	150	950	2,153
Refrigerator Efficiency	46	400	245
Commercial Sector	110	540	658
Irrigation pumpset rectification	200	2655	1,219
LT industry	164	900	458
HT industry & Misc.	400	3600	1,151
T&D Loss reduction	175	1400	637
Industrial Load Shifting	250	Nil	539
	Total Cost Rs. Million / Yr.		**8,333**

The saving refer to the bus-bar savings. The power savings values are indicative, exact values are obtained by considering the seasonal and hourly variations in the savings while constructing the LDC in section 3.5.

3.2 Estimation of potential of decentralised supply options :

This section estimates the potential of the de-centralised generation options based on the availability of resources and the ability of system to absorb this generation. Four de-centralised supply options having large potential in the state are selected for analysis.

3.2.1 Co-generation in Sugar Industry : As per MSEB's estimate the co-generation potential in 136 sugar factories is about 490 MW [Harne, 1992]. The implicit norm in this calculation is 1.7 MW per 1,000 tonne cane crushed per day (TCD). Two sugar factories in Reunion Island, for example, generate more than 4 MW/ 1000 TCD. [Sen, 1992.] Hence, at least 500 MW of sugar co-generation potential can be realised in a decade. Seasonal nature of sugar co-generation is considered problematic. Analysis of monthly energy consumption data for two years showed that energy demand in cane crushing season was 7% more than the rest of the year. Hence, seasonal co-generation capacity of at least 5% of system Installed capacity can be easily absorbed. In 1991 itself this was equal to 500 MW.

3.2.2 Co-generation in Other Industry : Studies have indicated a large co-generation potential even in other industries [GoM, 1988]. A study by RCG/Haigler Bailley estimated the co-generation potential of 881 MW in industries other than sugar till year 1996. [as quoted in Banerjee, Parikh, 1993:1670]. For present analysis, a potential of only 500 MW is assumed by year 2001.

3.2.3 Producer Gas (Wood Gasification) Plants : Producer Gas or the wood gasification technology has been extensively tried out in India, initially with mixed results. With developments in the producer gas reactor and associated equipment it has become well suited for power generation in rural areas. With wood gasifier coupled DG set, 70 to 75% of diesel requirement is replaced by producer gas. The gasifier consumes about 1.1 Kg. wood per kWh of generator output. A 100 kW system is considered for costing. A potential of 100 MW is considered feasible by the turn of the century. These systems can be operated as per demand of the community and would usually be used in the evening peak periods for lighting and other loads. A 100 kW system running 6 hrs. per day would need 40 tons of wood per year. This wood requirement can be easily met without upsetting the land use pattern.

3.2.4 Mini and Micro Hydel Power : The small hydro potential has been rather neglected in serious planning considerations not just in Maharashtra but through-out India. The potential of small hydro electric generation schemes identified by the Department of Irrigation in Maharashtra is estimated to be 712 MW [GoM, 1991].[15] Of this, about 130 MW of small hydel schemes are under implementation and are likely to be completed by year 1995.

3.2.5 Other opportunities : Some of the important decentralised supply options are not considered in this analysis for various reasons. Wind power, now officially accepted as an important energy source, is not considered because it has relatively limited potential in the state of Maharashtra. The photovoltaic option, which is already economical for small loads in remote areas, is also ignored here. The diesel generating (DG) sets have been found to be economical for peaking power especially for PLFn values of less than 20%. High diesel oil consumption (due to low efficiency of DG sets) viewed in the light of balance of payment problem is the main reason for ruling out this option. Small power generation based on the biogas-fed duel-fuel generation sets or medium sized agro-waste fed thermal plants are similarly omitted.

Table 5 shows the potential of various decentralised options considered in the present analysis.

Table 5 : Potential of Decentralised Generation Options

Option	**Installed Capacity (MW)**
Sugar Co-generation	500
Co-generation in other industries	500
Small Hydel Plants	712
Producer Gas	100

3.3 Costing of decentralised supply options.

Costing of the decentralised supply options is done in the same manner as the centralised supply options. The decentralised supply options differ from the centralised options mainly in terms of the size, gestation period, lower requirement of T&D investment and lower T&D losses. These differences get accounted as per the calculation procedure described in appendix I. Annual cost per kW of reliable supply at bus-bar is worked out as a function of PLFn. The cost includes the investment, O&M and fuel costs. The lower gestation period and lower T&D costs reflect as lower investment cost of plant. Lower T&D losses are accounted by converting plant output to the equivalent output at the bus-bar of centralised plants. The lower availability of plants, of sugar co-generation for example get accounted in lower value of PCF and consequently higher cost of the option. For details of the methodology, assumptions and the results refer appendix I.

Some supply options have limitations in terms of the range of PLFn in which they can operate. For example, due to limitations of wood availability, producer gas based generation has been considered feasible only at lower PLFn. While, the sugar co-generation and mini-micro hydel plants have been considered only for base load operation. Figure 4 shows the costs of decentralised supply options as a function of PLFn by dotted lines.

3.4 Costing of DSM options.

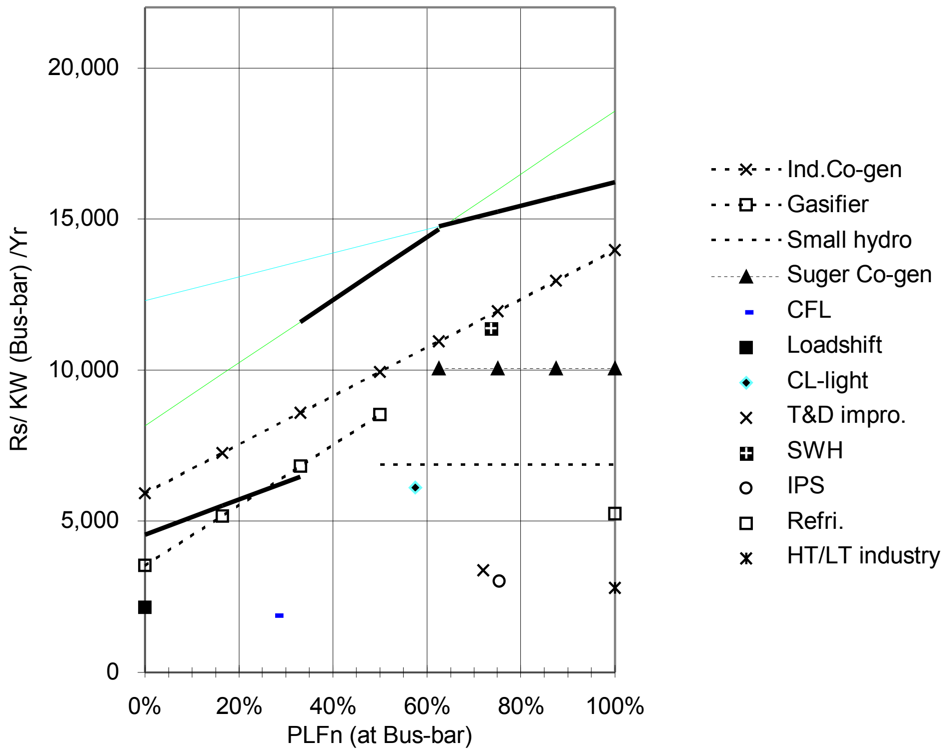
The DSM options differ from supply options in two major ways. The energy is saved at the user end, which is equivalent to the energy generated at the supply end, with a correction for the avoided T&D losses. Secondly, the savings due to DSM options occurs only when efficient appliances are in use. The use pattern of appliances is solely determined by the user. The grid controller has no control over this, unlike the supply options. But as described in section 3.1.8, the peak savings as well as the energy savings of DSM options can be estimated before hand knowing the typical use pattern of appliances. Hence, the DSM options are represented on the screening curve by a point. The methodology developed by Koomy et.al. 1990 is used for this purpose. The X-co-ordinate of the point is the Conservation Load Factor (CLF) similar to the PLFn defined for the supply options. It represents a ratio of annual average power savings to the peak power savings. Load shifting saves no energy but saves peak power, hence, its CLF is zero. While HT industry and refrigerator savings are assumed to be base load savings hence have CLF of 1. The Y-co-ordinate of the point is the annual cost of peak power saved at the bus-bar (Rs/$kW_{bus\text{-}bar}$/yr.). This cost includes (i) annuatised investment cost and (ii) change in annual O&M costs. The investment cost consists of (a) incremental cost of the efficient appliance and (b) program administration costs. This investment cost is annuatised over the life of the equipment. Detailed costing is given in appendix I.
For details of methodology, refer appendix I.

3.5 Construction of integrated screening curves and selection of options:

Costs of all supply options as well as that of the DSM options are represented on a combined screening curve in figure 4. The centralised options are represented by solid lines, decentralised options by broken lines and the DSM options by point markers. The least cost envelop of centralised options is formed by cost lines of PSS, CCGT and coal thermal plants. This is highlighted by thick lines. All option below this least cost envelop (thick line) should be included in the plan.[16] Figure shows that all DSM options considered are cost effective and fall way below the least cost supply envelop of centralised options. Hence, all these options are included in the least cost plan.

The decentralised supply options are also more economical than the centralised supply options. Hence, the decentralised options should be opted after the DSM options. The centralised options are the last resort for meeting the remaining demand supply gap.

Figure 4 : integrated Screening curves



The annual cost of a kW saved is plotted against the PLFn (for supply options) or the conservation load factor (for DSM options). The solid lines indicate the centralised supply options. The highlighted part of these lines represent the least cost envelop of centralised options. The decentralised supply options of industrial co-generation, wood gassifier, small hydro and sugar co-generation are indicated by broken lines. The DSM options of CFLs, industrial load shifting, commercial sector (CL-lighting), T&D improvements, solar water heaters, IPS efficiency improvements, refrigeration efficiency improvements (Refri.), and industrial efficiency (HT/LT industry) are indicated by point markers. The DSM options are far too less expensive than the supply options.

To follow the LCP methodology, DSM options are opted first. The DSM options can be best incorporated by modifying the energy as well as power demand forecast in a way so as to reflect the expected reduction in demand. The goal of LCP is to meet the same level of services as the FE forecast. Hence, the expected saving of DSM options should be deducted from the FE forecast. But DSM savings change hour by hour and also by season. This is accounted by following two steps : (i) hourly saving (at the bus-bar) due to DSM options are worked out for different months, (ii) to arrive at the modified demand forecast, these hourly savings are subtracted from the hourly demand forecast of FE scenario for the terminal year, (iii) Using this modified demand forecast, a load duration curve (LDC) is drawn. The new LDC assumes implementation of DSM options. Table 6 shows the growth rates of energy and peak load as per official forecast, FE scenario and the least cost plan scenario.

Table 6 : Comparison of demand growth rate forecast by different scenarios

	Growth rate of demand, 1991 to 2001 (% p.a.)	
Scenario	**Energy**	**Power**
Official forecast (14th EPS)	7.2%	7.2%
FE Scenario	6.4%	6.4%
Least cost plan scenario	4.4%	4.2%

Note : The FE scenario and the Least cost scenario plan to meet the same level of services. The Least cost scenario assumes implementation of DSM options, cost of which has been indicated in table 4.

3.6 Capacity addition plan based on the integrated screening curves :

The difference between new LDC for terminal year (forecast of least cost plan) and the LDC for 1990-91 represent the need for the capacity addition. As per the selection of supply options, utilisable potential of the decentralised supply options is opted first followed by the centralised options. As described earlier, using the LDCs the increased energy and power demand between 1991 to 2001 is worked out. Table 7 shows the increase in energy and power demand for three periods, namely the base load, intermediate load and peak load period. Required capacity addition to meet this incremental demand is worked out. The PLFn at which the plants are expected to operate and the unit cost of the plant at that PLFn is also indicated in the table.

Table 7 : Capacity Addition Plan for 2000-01 : Least cost plan Scenario

	Base load period		Intermediate load period		Peak load period		TOTAL	
	Power (MW)	Energy (MU)	Power (MW)	Energy (MU)	Power (MW)	Energy (MU)	Power (MW)	Energy (MU)
1990-91 Actual	4,166	35,352	598	2,516	1,427	1,305	6,191	39,173
2000-01 Least cost plan scenario	6,453	55,118	820	3,530	2,071	1,648	9,344	60,297
Incremental demand	2,287	19,766	222	1,014	644	343	**3,153**	**21,124**

CAPACITY ADDITION OPTIONS

	Base load				Intermediate load		Peak load
	Small Hydro	Sugar Co-gen	Industrial Co-gen	Coal	Wood Gasifier	CCGT	PSS
Bus-bar supply (MW)	156	200	350	1581	80	142	644
Installed capacity addition (MW)	200	500	500	2,550	100	171	1,155
Expected PLFn	100	97	97	98	40	59	9
Annual cost (Rs/kW/yr.)	6,889	10,046	13,723	16,151	7,529	14,303	5,080

Total Addition of install capacity **= 5,176 MW**
Total cost of added capacity = Rs. 39.326 Billion/yr.

Note : The peaking capability factors of the plants are; Small hydro (78%), sugar co-gen (41%), industrial co-gen (70%), coal (62%), wood gasifier (80%), CCGT (83%), PSS (87%).

The LCP scenario uses a combination of DSM, decentralised and centralised supply options. As per the LCP scenario, about 40% of the incremental power demand is met by DSM options, with an average cost of Rs. 3920 /$kW_{bus\text{-}bar}$/Yr. While, 15% of the incremental demand is met by decentralised generation options, at an average cost of Rs 10,800 /$kW_{bus\text{-}bar}$/Yr. The rest, i.e. 45% demand is met by traditional centralised sources, which cost Rs. 13,030/$kW_{bus\text{-}bar}$/Yr.

4 Conclusions :

For LCP scenario, the incremental demand realised at the bus-bar is only 3,153 MW and 21,124 MU/Yr. To meet this incremental demand, the LCP scenario envisages capacity addition of 5,176 MW, with an annual cost of Rs. 39.326 billion /yr. Implementation of DSM options would cost additional Rs. 8.333 billion/Yr. Hence, the total cost of LCP scenario is Rs. 47.66 billion /yr.

On the other hand, cost of FE scenario is Rs. 71.47 billion /yr, to meet same level of services as the LCP scenario. In effect, the integrated approach in the LCP scenario is capable of financial saving of about 33% while meeting the same level of services. In addition, the LCP scenario reduces the incremental fossil fuel consumption by over 55%; equivalent to coal savings of over 12 million ton per year.

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APPENDIX I : Details of life cycle costing methodology

Costing of the Supply Options :

Different supply options have major differences in terms of expected life, gestation periods, unit cost of fuel, associated cost of the T&D network and T&D losses, etc. Hence, for comparison purposes the norms of capital cost (Rs/kW) or unit cost of electricity (Rs/kWh) are not appropriate. It is essential to work out the life cycle cost of the project while accounting for all the factors mentioned above. This is done by calculating the life cycle cost of the project and annutising it, as mentioned below.

The annual cost of a plant is calculated for the reliable plant output (in kW) at the bus-bar. It includes the fixed and the variable costs. Annual cost is a function of the net plant load factor (PLFn) and is represented by following equation :

Annual Cost = ($C_{fixed} + C_{variable}$) / T&DAF

Where :

- C_{fixed} is the annual fixed cost, representing (i) the capital recovery costs and (ii) the fixed costs of O&M. Investment for the T&D system associated with the plant is also considered.
- $C_{variable}$ is the variable cost (a function of PLFn), representing the cost of fuel to operate the plant at a particular PLFn. It is calculated based on the plant heat rate, present price of fuel and likely future escalation in fuel price.
- T&DAF is the T&D adjustment factor. To adjust for the lower T&D losses of decentralised supply options, so as to bring all costs at the bus-bar (of the centralised power plants).

1) C_{fixed} = (OCC * CRF) $_{plant}$ + (OCC * CRF) $_{T\&D}$ + O&M costs

Where :

- OCC $_{plant}$ and OCC $_{T\&D}$ are the 'Overnight Construction Cost' (or the net present value of investments at the time of the plant commissioning) of plant and associated T&D system respectively. A discount rate of 12% p.a. (real) is used for calculating the OCC and also in the rest of the calculations.
- CRF is the 'Capital Recovery Factor' defined as;

  CRF = d / (1 - $(1+d)^n$).

  'd' being the discount rate = 12% p.a. and 'n' being the life of equipment in years.
- O&M costs are the fixed O&M costs.

2) $C_{variable}$ = (PLFn * UFC * 8760)

Where :

- PLFn is the ratio of 'actual energy supply at bus-bar' to the 'maximum reliable bus-bar output of the plant'.

  Reliable Bus-bar output (kWh) = installed capacity (kW) * PCF * 8760 Hrs.

  where :

  - PCF is the Peaking capability factor (as defined by CEA)

    = (1- expected outages) * (1- auxiliary consumption - spinning reserves)
- UFC is the 'Unit Fuel Cost', representing the cost of fuel consumed to generate one kWh.

UFC = Heat rate * delivered price of fuel * fuel price levalisation factor.

Where:

The heat rate is the net heat rate to deliver one kWh at the bus-bar.

'Fuel price levalisation factor' is used to account for likely future escalation of fuel price in real terms.

3) T&DAF = (1- prevailing T&D losses) / (1 - expected T&D losses for the option considered)

For the centralised supply options, the expected T&D losses are same as the prevailing losses. Hence, the value of T&DAF is 1. For decentralised supply options the losses are expected to be lower and the value of T&DAF would be higher than unity.

Using the above equations, the annual cost is plotted against the PLFn. They have a linear relationship and each option is represented by a straight line. In cases, such as of PSS, the maximum PLFn permitted is limited by the very nature of the plant. Hence the line is limited by the allowed PLFn. Such a plot is called "screening curve' and is used for screening of options.

Costing of DSM Options :

A DSM option is represented on the screening curve by a point. The X-co-ordinate of the point being the Conservation Load Factor (CLF) and Y-co-ordinate being the cost of peak saved (Rs/kW/yr.). These are defined as :

1) CLF = (annual energy saving) $_{\text{bus-bar}}$ / (peak load saving $_{\text{bus-bar}}$ * 8760)

The peak power savings is worked out considering (i) the share of appliances that are expected to be operational during the peak periods (i.e. the duty cycle of the said appliance at the peak period) and (ii) the power saving while appliance is in use.

The energy saving is estimated using the expected yearly hours of operation (summation of duty cycle over the 8760 hours of the year). The energy as well as power saving is translated to the bus-bar savings by accounting for the T&D losses.

Bus-bar saving = user end saving / (1 - T&D losses).

2) The life cycle cost of the DSM option is worked out in terms of Rs per kW_{peak} saved.

Cost of power saved = ($(\text{Cost} * \text{CRF})_{\text{fixed}} + \text{Cost}_{\text{annual}}$) / peak load saving $_{\text{bus-bar}}$

The fixed costs are (i) installation cost of efficient device (the incremental cost over the inefficient device, in case of new installation) and (ii) the program cost of DSM, where the power utility is expected to take major initiative in propagation. These costs are annuatised over life of appliance using CRF defined earlier in the appendix.

The annual costs can be positive for O&M or negative in case of avoided costs due to use of efficient appliance (as in the case of avoided replacement of incandescent lamps due to longer life of fluorescent lamps).

Table I : Details of Costing of Supply options.

		COAL Thermal	GT Gas/Oil	CCGT Gas/Oil	Pumped Storage	Industrial Co-gen.	Seasonal Sugar Co-gen	Small DG Sets	Small-Hydro 1.05 MW	Wood Gasifier
	FIXED COSTS									
1	Economic Life (Yr.)	25	20	20	35	15	15	15	35	10
2	Capital Repayment Factor (CRF)	0.127	0.134	0.134	0.122	0.147	0.147	0.147	0.122	0.177
3	Plant Capital cost, OCC (Rs/kW)									
	(NPV at Commissioning)	35,453	21,698	29,591	13,226	20,347	20,347	5,400	36,547	9,981
4	Annualised Plant capital cost									
	(Rs/kW/Yr)	4,520	2,905	3,962	1,618	2,987	2,987	793	4,470	1,766
5	Annualised T&D capital costs									
	(NPV at commissioning, Rs/kW)	2,220	2,220	2,220	2,220	1,110	1,110	1,110	1,110	832
6	Sum of Annulised capital Costs									
	(Rs/kW/Yr) [4+5]	6,740	5,125	6,182	3,838	4,097	4,097	1,903	5,580	2,599
7	O&M costs (Rs/kW/Yr)	886	434	592	132	509	509	600.0	365	679
8	Total Annual Fixed Cost (Rs/kW)	7,627	5,559	6,773	3,970	4,606	4,606	2,503	5,946	3,278
9	Aux. Consumption (%)	8.0%	2.0%	3.0%	1.0%	8.0%	24.6%	1.0%	1.0%	1.0%
10	Peaking Capability Ratio, PCF									
	(=1/Reserve Margin Ratio)	0.62	0.84	0.83	0.8695	0.70	0.41	0.84	77.8%	80.0%
11	Adjustment factor for T&D Loss	1	1	1	1	1.11	1.11	1.16	1.11	1.16
12	Adjusted Fixed Cost (Y intercept)									
	(Rs/kW$_{bus\text{-}bar}$/Yr)	**12,301**	**6,634**	**8,167**	**4,566**	**5,929**	**10,046**	**2,567**	**6,889**	**3,537**
	VARIABLE COSTS									
13	Delivered Fuel Price (Rs/ MCal)	0.138	0.301	0.301	0.138	0.526	-NA-	0.862	-NA-	
14	Increase in Fuel Price (% p.a.)	2.5%	8.7%	8.7%	2.5%	2.5%	-NA-	2.6%	-NA-	2.6%
15	Levalisation Factor	1.191	1.824	1.824	1.191	1.137	-NA-	1.144	-NA-	1.100
16	Levalised Fuel Price (Rs/MCal)	0.165	0.548	0.548	0.165	0.598	-NA-	0.986	-NA-	
17	Heat Rate - bus-bar (kCal/kWh)	2,724	3,112	2,165	4,012	1,533	-NA-	1,540	-NA-	
18	Unit Fuel Cost - bus-bar (Rs/kWh)	0.45	1.71	1.19	0.66	0.92	0.00	1.52	0	1.14
	AT 100% PLFn									
19	Annual cost (Rs./kW$_{bus\text{-}bar}$/Yr.)	**16,229**	**21,584**	**18,567**	**10,351**	**13,964**	**10,046**	**15,867**	**6,889**	**13,518**

1. All costs in constant 1992 Rs.; Costing at Bus-bar,
2. T&D capital costs for centralised plants is Rs.11,298/kW (I.C.), & assumed to be Rs. 5,649/kW for decentralised plants.
3. Discount rate used - 12% (real)
4. For GT and CCGT present gas price is used with assumption that in near future gas price will escalate to the level of international oil price.

Table II : Details of Costing of DSM options.

Technology	< - - - Households - - - >			Commercial	Irrigation	T&D	Load	HT,Misc.
	Compact	Solar water	Refri-	Sector	pump set	savings	Shifting	savings
	Fluorescent	Heater	gerator	(lighting)	(IPS)	(1 kW)	(1 kW)	(1 kW)
1 Usage (Hours/Yr)	1,460	-NA-	-NA-	2,190	-NA-	-NA-	-NA-	-NA-
2 Life (Hours)	7,000	-NA-	-NA-	14,000	-NA-	-NA-	-NA-	-NA-
3 Life (Years)	4.8	10	15	6.4	10	15	15	10.0
4 Incremental capital cost (Rs.)	192	6,139	1,516	150	2,500	31,860	2,219	17,496
5 Program administration costs								
(% of incremental capital cost)	30%	15%	10%	30%	30%	0%	10%	10%
6 Total Investment (Rs.)	250	7,060	1,668	195	3,250	31,860	2,441	19,246
7 Capital Recovery Factor (CRF)	0.286	0.177	0.147	0.233	0.177	0.147	0.147	0.177
8 Annulised capital Cost (Rs./Yr)	71.5	1,249	245	45.4	575.2	4,678	358	3,406
9 Other added/avoided costs (Rs./yr)	-10.2	0	0	0	0	0	2,270	0
10 Total annulised Cost (Rs./Yr)	61.2	1,249	245	45.4	575.2	4,678	2,629	3,406
11 Load Saving while in operation								
at user-end (Watts)	45	2,250	38.2	14	933	-NA 1-	1,000	1,000
--- Figures below refer to Bus-bar values ----								
12 Annual Energy Savings (kWh/Yr)	80.1	708.2	408.5	37.4	1,254	8,760	-NA-	10,683
13 Average load saving (Watts)	9.1	80.8	46.6	4.3	143	1,000	-NA-	1,220
14 Peak load saving (Watts)	32.8	109.8	46.6	7.4	190	1,389	1,220	1,220
15 Cost of Conserved Energy (CCE)								
(Rs./kWh)	0.76	1.76	0.60	1.21	0.46	0.53	0	0.32
16 Conservation Load Factor (CLF)	**0.28**	**0.74**	**1.00**	**0.57**	**0.75**	**0.72**	**0**	**1.00**
17 Annual cost per peak kW saved								
(Rs./$kW_{bus-bar}$)	**1,866**	**11,384**	**5,251**	**6,114**	**3,029**	**3,368**	**2,156**	**2,793**

The Real discount rate used = 12%, Avg. Inflation rate assumed = 8%, Avg. T&D losses assumed = 18%
- NA - = Not applicable.

APPENDIX II : Hourly bus-bar saving due to DSM options..

DSM Option / Hour of the day

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
I.B.-> CFL	5	5	5	5	54	120	103	69	82	101	112	165	162	159	160	153	185	407	679	644	471	429	219	49
Refrigerator	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
SWH	0	0	0	0	0	273	626	937	872	569	300	38	0	0	0	0	0	152	152	114	0	0	0	0
Load shifting	(250)	(250)	(250)	(250)	(125)	0	0	0	125	125	0	0	0	0	0	0	0	125	250	250	250	125	0	(125)
IPS	198	198	198	198	330	462	660	660	660	660	660	660	660	660	660	660	660	462	330	198	198	198	198	198
LT Industry	0	0	0	0	0	55	110	164	164	164	164	164	164	164	164	164	164	164	164	164	110	55	0	0
HT+Rly+Misc	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412
Commercial	1	1	1	1	10	20	18	13	37	75	96	103	103	102	101	104	109	170	128	104	73	64	32	7
T&D Saving	144	141	139	137	141	153	168	176	182	183	180	174	169	167	167	169	173	177	186	193	188	179	165	152
Total Savings (bus-bar)																								
Monsoon	358	355	353	351	537	805	857	880	1049	1107	1010	1064	1056	1050	1050	1048	1089	1502	1866	1814	1550	1310	873	541
Rest of the Yr.	556	552	551	549	867	1540	2142	2477	2581	2335	1970	1761	1715	1710	1710	1708	1749	2116	2348	2125	1748	1508	1071	739
Yearly average	493	490	489	487	763	1308	1737	1974	2098	1948	1667	1542	1508	1502	1502	1500	1541	1922	2196	2027	1686	1446	1009	677

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End-notes

[1] Over 85% of state's power needs are met by MSEB and the central government owned power utilities, such as National Thermal Power Corporation (NTPC).

[2] National level demand forecast are also carried out by the planning commission using econometric models. These are used for fund allocation. But the actual power planning is based on the CEA forecasts. The CEA finalises the forecasts after discussions with the SEBs. The projects for capacity addition are suggested by SEBs. CEA studies the 'least cost generation expansion' options and approves the projects based on the power deficit in the state. In effect, EDFs are the basis of future planning.

[3] One argument for this is that power deficit results in reduced demand. But Maharashtra has experienced very small power deficit and still the EDFs have predicted higher growth rates.

[4] For the Maharashtra system February to April are the months of maximum demand. The hydel resources are dwindling in the summer period (April and May). Both these periods are included in the sample of the load shedding data. Hence, the load shedding in 1991 can be expected to be at most equal to the load shedding experienced in the sample period.

[5] For about 2 hours a day, the average load suppression was more than 3% due to low frequency, the maximum suppression in 1991-92 was 5.4%.

[6] The estimate by Dhokrikar (Director GSDA) was highly criticised for being an overestimate. [Dhawan B D, 1991] Some IPS are expected to be on surface water, hence this estimate has been used.

[7] This assumes that consumption of the new rural households will be as much as the present norm for rural households.

[8] The load data for 101 days was not fully representative, as it also included some energy exports to the neighbouring state. A small correction is made to account for this.

[9] The net plant load factor (PLFn) is a ratio of actual bus-bar energy generation to the maximum reliable bus-bar generation feasible from the plant. Hence, (1-PLFn) represent the forgone generation due to backing down of plant. PLFn is different than the usual concept of Plat Load Factor (PLF) as PLFn accounts for the expected outages and spinning reserves. For details refer appendix I.

[10] US $ = 32 Indian Rs.(as per 1994 exchange rate).

[11] The intention of the exercise is to show the benefits of the least cost plan over the conventional plan. Hence, the capacity planning of FE as well as the LCP scenario, evolved later, focus only on new capacity addition; without considering change of pattern in which the existing capacity is used. If the existing capacity was also considered the possible addition of PSS would have been substantially higher.

[12] The world Bank estimates that achievable saving through metering of pumps is 15%. [World Bank, 1991:164]. In other section of the same report over 12% reduction in the capacity addition is predicted if the retail tariffs are increased to 50% of Long range marginal cost. [World Bank, 1991:152] Large share of this saving (but unspecified in the report) is expected from reduced IPS demand.

[13] Separate estimates of sales of refrigerators in the state are not available. Hence, a figure of 10% of national sales is used as a rough estimate. Stock of refrigerators in year 1992 in the country was 7 million and the annual production was 1.25 million, increasing over 10% p.a.

[14] The T&D loss estimates seem highly variable. The losses reported in 1991-92 were 18.61%. And it is well known that actual T&D losses are likely to be substantially more than what is declared by the power sector.

[15] The micro hydel schemes of less than 100 kW have a potential of 4 MW. The schemes identified in mini hydel category (100 kW to 2 MW) have a potential of 119 MW. While the small hydel schemes (2 MW to 15 MW) have the largest potential of 589 MW.

[16] This is because the DSM and decentralised options cannot meet all the incremental demand. And the centralised options also have to be included in the plan.