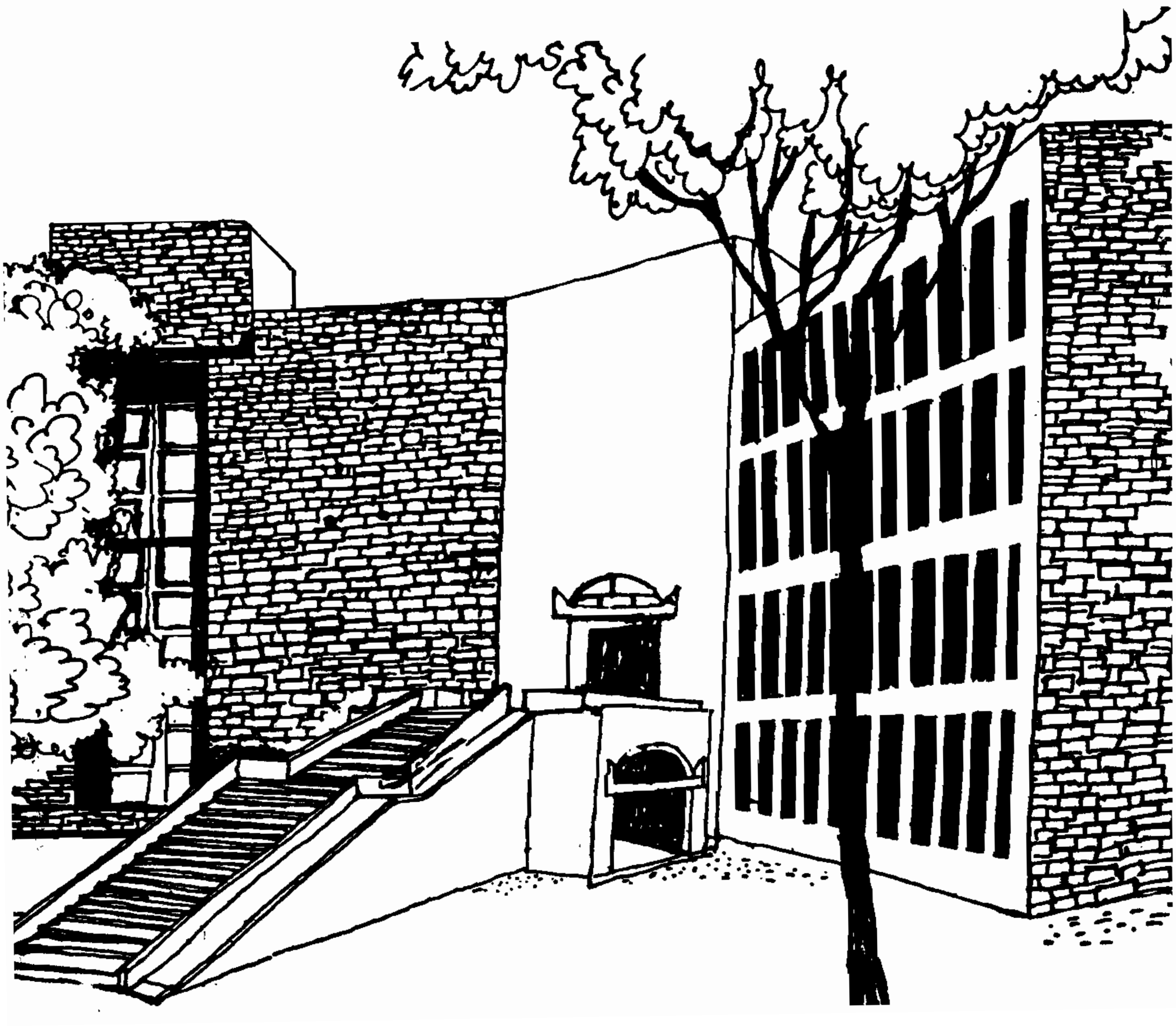
विद्या विनियोगाद्विकासः

IIM AHMEDABAD

Working Paper



GEB REFORMS: A NOTE
ON REGULATORY STRATEGY AND AN
APPROACH TO PRIVATISATION

By

Sebastian Morris

W.P.No. 99-11-04 /1560
November 1999

The main objective of the working paper series of the IIMA is to help faculty members to test our their research findings at the pre-publication stage.

INDIAN INSTITUTE OF MANAGEMENT
AHMEDABAD – 380 015
INDIA

GEB Reforms: A Note

On regulatory strategy and an approach to privatisation

Sebastian Morris

28/10/99

Executive summary

1. Briefly the proposal is for market competition in generation, through the development of a hybrid wholesale and retail (for bulk consumers alone) market.

2. It is not a market for all the electricity in the system, but largely a market that would allow distribution-cum-generation companies to purchase power from each other, and form pure generators; and would also allow bulk purchases and captive generators the choice of supply and customer.

3. A market for generation, while allowing distribution companies the comfort of having some distribution assets, would lead to quicker development of the market and allow easier privatisation.

4. The transmission assets of the GEB would need to be in a PSU with 50% shareholding by the state government and all other shares held by consumer interests including farmers' cooperatives, households and industry associations and at least 25% of the stock disbursed through the stock market.

5. The remaining assets of the GEB is most conveniently split into five distribution companies with some generating assets in-house up to about 40-50% of throughput. Thus the GEB should be split into distribution cum generating companies. Some

(surplus) generating assets of GEB, if any, could be sold as an independent generating company.

6. About 50-60% of the generating capacity in the system (GEB+IPPs+CPCs+Captive Generators) would be outside the distribution cum generating companies, i.e. with independent generating companies.

7. All manpower presently with the GEB would have to be suitably allocated to the four entities. Excess manpower handicap can be estimated and provided for in the initial assessment of the value of the business. The actual design of the VRS and the decision on whom to retrench should be left to the new management.

8. The actual sale would have to await regulatory clarification and court ruling of the validity of the regulatory decisions. Only then would excellent values for the GEB's assets be possible. Otherwise the reform may impose a severe burden on consumers, if disinvestment is pushed through when there is no regulatory clarity.

9. Distribution companies would go on a price cap regulation for their distribution business. Without 'light' price cap regulation, marketisation is out of question.

10. (With detailed regulation, the best that would be possible is to sell GEB as near vertically integrated companies. This would introduce considerable regulatory risk over medium term, and a high probability that the integrated companies would capture the regulator. The high regulatory risk in the short term would result in low values being realised for the GEB's assets. With detailed regulation, it may be better to merely corporatise GEB and offload some of the stock in the stock market, and attempt a management overhaul. The GEB or the government of behalf of the GEB would then have to carry the burden of the PPAs with IPPs that have already been signed.)

11. Good values would be realised in the privatisation of GEB when carried out in the manner described herein. The surplus so generated would have to be invested quickly

in augmenting transmission assets of the transmission company, so that a situation of no congestion, in the normal working of the system, is quickly reached. A key to ensure that pool prices are near long run marginal costs would lie in having adequate capacity in the transmission system to allow alternative sourcing for each of the segments of load.

12. Transparency especially with respect to information access, including to common citizens would be important is reducing hidden risks of change. Once the first stage of the bid process which checks out the financial and managerial capacity of the bidders is over, all short listed bidders must be allowed to have complete access to information with the GEB. Moreover, they must be allowed and encouraged to conduct independent studies and investigations with regard to the quality of assets, demand and its growth, consumer mix, and system parameters.

13. Access to transmission of bulk consumers and of captive generators above a certain size (1MW for buyers, and average sale equivalent to 1MW for generators, to start with) at standard access charges subject to price cap regulation, would be necessary. This would bring in retail competition for generation right at the start of the reform process.

14. Transmission would also have to be operated as a regulated monopoly desirably on the RPI-X type formula. Ideally, the transmission charges should be a three part tariff, each of which is subject to its price cap. The three parts would have to be connection charges (which depends on the capacity connected), line-loss or 'distance' charges (based on the current losses in transmission) and the congestion charges. The point is that there should be sufficient returns to congestion, to signal the transmission company allowing it to correctly identify the segments for investments. Yet distortion in the tariff formula that provides an incentive to maximise the returns to congestion should be avoided.

15. The initial price cap mechanism applied on distribution-cum-generating companies would be the sum of the price cap on distribution costs and cost of generation, despite the existence of a market for wholesale power. This is to ensure that final demand prices for the small consumer (households, shops etc, and farmers and small industries) do change at best once in six months. As the market develops, and the average pool prices prove to be around that anticipated in a priori simulation studies of the planned market, are realised, the cap on generation or power cost to the final consumer can go. Caps on power prices would tend to limit the scope of differential pricing for the distribution-cum-generating company. The RPI for the price-cap should be a weighted average of relevant prices, with stable weights for at least 10 years. The weights should be sufficiently broad, so that the fuel price risk is borne by the generator rather than the consumer and so allocative efficiency (as between alternate fuels) becomes an internal decision of the firm.

16. The BPSA contracts with the NTPC (and their equivalents with the NPC) are expected to be beneficial to the system after marketisation, since the implied contract prices then are likely to be lower than pool prices that would prevail. In contrast, the IPP contract are likely to be adverse to the GEB since the implied PPA prices then would most certainly be higher than the pool prices then. Both sets of contracts would have to be extinguished in ways that would release the full potential for competition in the system. The BPSAs would pose no basic problem, since doing nothing would mean that the NTPC given its low costs would gain from higher pool prices. Therefore they could be easily extinguished by sharing part of the price difference (20%) with the NTPC and keeping the rest with the GEB for subsidies and investment in the transmission company.

17. The IPP contracts would pose a significant problem, which would have to be carefully dealt with. The best strategy would be to nudge them into a willingness to exchange their current high political and regulatory risk for market risk. The presence of both groups in the generation market would be vital to its functioning, and With these players the scope for price formation significantly above costs would be quite small.

18. The most optimal way to carry out the same would be to communicate effectively and credibily, the government's firm determination to move towards a competitive market model in generation of electricity. Simultaneously the government should rule that at least 25% of the share holding of IPPs should be offloaded in the local stock market. Then the market price would reflect the true premium value (if any) of the IPPs contract with the SEB and the state. As the reform and restructuring takes place in earnest, the willingness of IPPs to trade their political and regulatory risk for market risk would improve. Any remaining premium could be compensated by special tax incentives for the IPPs, preferably linked to their future investments in the sector.

19. Initially an import tax on electricity from outside the system would have to be imposed even as the connectivity with the national grid, and the grids of contiguous states is augmented. Yet there must be up-front announcement of the intention to reduce these tariffs and eliminate them altogether over a specified time horizon. This would ensure some time for adjustment. And yet locational and fuel choices would not be made in-optimally, since in the long run the comparative advantage of pit-head location is likely to be high and generation assets would come up in these locations. Coastal locations too can have advantages and the relative merit of these can only unfold in the future. The commitment that there would be no tariffs, is a commitment on the indifference of the state and the regulator to location of generation plants and fuel choice.

20. Similarly, an export tax may be required in the first few years to have a (second) regulatory handle on pool prices. Their removal would have to be based on developments within, and in the neighbouring states. The principle governing the export tax : "that it is would be used to ensure pool prices close to long run marginal costs in a situation of surplus", would have to be known and announced.

21. Possible 'excess' profits accruing to the distribution-cum-generating companies should be allowed to be appropriated, but linked to an investment tax credit on investments in the sector and in other infrastructural areas of priority.

22. A stepping stone solution to the subsidisation of the electricity sector would be necessary, because it would be very difficult for the politician to agree to a reform proposal that quickly removes all subsidies. Yet there is strong need to cap the subsidies given the large abuse that low prices have engendered both within the organisation (SEB) that supplies power and without among the beneficiaries. The need of the hour is to not let the issue of subsidisation hold back basic reform that would in the first instance plug the leakage from the SEB, and bring about competition in generation, and correct the present 'inversion' in the tariff.

23. A scheme that subsidies the farmer through issue of electricity stamps or coupons by the agriculture /land revenue department, which the farmer uses to pay the distribution -cum - generating companies, would not only allow for capping the subsidies but also overcome the problem of moral hazard in the identification of the consumer. It would also make possible simple price cap regulation for distribution, and for power cost in the early stages before the market for wholesale and retail bulk power has developed. Prices differences if any would then be related to cost of supply, time of use and other aspects such as whether it is interruptible or otherwise. As the reform succeeds and credibility of the system to deliver good quality power is established, the willingness of the farmer to pay would allow a gradual scale back of subsidies. Stamps would also allow better targetting of the subsidies.

Restructuring of GEB: A Possible Option

Introduction

The reform of the electricity sector, especially the decision to unbundle and privatise, has been based on the premise that the state (government) does not have adequate financial resources, given it's a need to control the fiscal deficit. Thus it is argued that the investable resources would require the active and large participation of the private sector. Privatisation has its own logic, in terms of overcoming the 'principal-agency' problem, and ushering in incentives for efficiency especially allocative efficiency. The resources gap argument is not only misleading but is inconsistent, and take privatisation in the wrong direction.

Moreover, we would contend that this premise is entirely inadequate as a basis for a privatisation programme, since it ignores the underlying reasons for the financial incapacity of the state, in general and electricity sector in particular. It takes as given, the current inefficiencies, and leakage of resources from the SEBs, and does not factor in improvements, that can contribute a great deal to the investable resources. Similarly, the hastily crafted IPP programme (especially the so-called fast track projects) have added considerable burden on the SEBs, especially on the 'well' performing SEBs of Maharashtra, Gujarat and Karnataka. This has happened, because in a situation, where basic reform was not pursued, private parties have successfully shifted nearly all risks on to the state sector. The contingent liabilities of the state governments have as a result swelled. While it is privatisation of a sort, it can hardly be sustained, and the vast potential benefits of privatisation would go unrealised.

These and other problems had been anticipated, when the first of the `reform' initiatives were announced, but governments chose to ignore these issues, or have only belatedly recognised a few of them.

The present paradigm of reform has many inadequacies, the more important of which may be listed as under:

Privatisation is not possible without reform

The assumption that large scale privatisation is possible without a reform, or a delayed reform of tariff is questionable. Thus in most PPAs, private generating companies have (expectedly) insisted upon guarantees and counter-guarantees, and escrow accounts. The cash flow position of the SEBs is, therefore, worsened, since the purchase price per unit of power by SEBs is much higher than the long-run marginal cost of generating the same internally. Profitability too is affected when this purchase price does not leave enough room to recover distribution costs.

Equal importantly, the guarantees only mean that the contingent liability ceiling is either breached or under pressure. The limits of escrowability have already been reached in some SEBs.

The question: "Where are resources for 6000 MW + capacity addition equal to approximately Rs 18000 crore to come from?" is often rhetorically posed with the 'answer' being from outside the sector, and the country. This is an obvious fallacy, which even the Infrastructure Report is not free off. If a growing sector cannot generate sufficient portion of the resources that it invests, then prima facie it is unviable for private capital. And most certainly foreign resources are out, unless they can be allowed to ride upon increasing the contingent liability of the state, and on the meager surplus of the SEB sector, driving them faster to bankruptcy. The correct approach to the question would involve recognizing the present constraints that prevent the SEB sector from generating adequate resources, and in relaxing these, rather than attempting the impossible – of privatisation of the sector, with these constraints.

IPPs with risk free contracts are not the answer

In privatising generation alone or first, and in the framework of legally enforceable PPAs, as at present, and based on near cost plus tariffs, there is no incentive on the part of the generating company to worry about demand. The Pakistan story despite being all too familiar, and repeatedly pointed out, has nevertheless been systematically ignored. Competitive bidding for generation projects, while they have the potential to reduce project cost and tariffs, do not correct this problem: Over investments or incorrect investments can take place – as when high cost fuels are used for base power, or when plants are inappropriately located.

The embedding of demand in the risk analysis of private generators has been weak when the state is the intermediary. Considerable demand risk has been shifted on to the state.

Private generators, when operating on return on capital basis (cost plus essentially) have little incentive for correct technology choice. If bids are based on lowest total cost of power and not also on the composition between variable and fixed costs, in situations where merit order is not strictly enforced (or when PPAs subvert the same), the socially desired usage of plants across all owners is vitiated. This has several effects. It makes the task of a future regulator very difficult, since he would be burdened with prior socially inoptimal contracts. It would also considerably delay the process of forming a market for wholesale electricity, leave aside the issue of formation of retail markets. Equally importantly, the potential for prices to be related to the load on the system (as it must be for a demand side participation in improving the system stability and fuller utilisation of capital) in the near future would be ruled out, or made difficult. This is because generators being separate from distributors and buyers would not be too concerned about fuller utilisation given the two part tariff.[1]

Policy makers, and especially the bureaucracy have failed when they have sought and pushed forward "options" that at best only shift forward the day of reckoning. In the process, they have not only delayed reform, but have made sustainable reform and basic reform even more problematic. Thus, it is quite feasible that private parties with IPPs and PPA contracts in their pockets would be averse to attempts to reform SEBs, that seek to lower the SEBs own marginal cost of generation. They would, for instance, insist on being protected against price cap regulation.

Foreign funding adds no value in the electricity sector

The earlier insistence, that domestic institutional funds should not exceed 20% of project cost, has deepened the interlocking[2] of markets for foreign capital resources and technology and equipment. Thus most clearly IPPs based on tied finance have ended up choosing high cost equipment. As the policy was amended more local resources could flow into IPPs.

Risk mitigation is the crucial issue

Risk mitigation (not its shifting) which in the real solution to large scale privatisation, is hardly possible without basic reform on tariffs, collections, and appropriate incentives for all involved parties. It has hardly been addressed. Risks, which were high even before the reform process began, have increased considerably. Indeed today "policy risk", and regulatory risk may be too high to permit socially beneficial privatisation.

---

[1] The two part tariff is a good mechanism for a robust, well-diversified utility to contract with a few generators for peaking power (at the margin). It assumes that the utility retains the 'advantage' and sets the terms, and gains from shielding the generator from demand, and variability risks.

[2] Interlocking of markets for credit or funds and equipment is too well known. Earlier, tied 'aid' especially bilateral credits were important. Today private global institutions like GE Capital have emerged to push GE equipment in global markets particularly in the LDCs. It is inappropriate macroeconomic policies that have

Governments have an advantage when policy and political risk is too high

In the era of near-exclusive state provision of electricity the risks were high, but the state having had a comparative advantage to bear risk[3], as well as the weaknesses of the administration, protracted approval procedures and modes, of tariff whetting, and other dysfunctionalties emanating from political and legal processes. These risks continue without much change. Basic risks emanating from environmental movements, wherein even the Supreme Court's verdict is not final, the softness of the state, and the dysfunctional and contradictory rulings of environment bureaucracy, have considerably increased.

Regulation, yes, but detailed regulation no

The central government's initiative to set up a central level regulator, and urge state governments to set up state level regulators while undoubtedly a step in the right direction, may have unwittingly introduced considerable `regulatory risk', rather than resulting in risk mitigation and bringing about transparency. Thus the recommendations of the "Committee on Distribution Privatisation" against price cap regulation is a case in point. Price cap regulation, besides the well-known advantages, has the added merit that its costs are one time, and low, in comparison to cost plus regulation. It brings about significant clarity to potential participants in distribution (and generation), can easily accommodate the long-run `marginal' cost principle, and shields regulators from undue influence[4]. Besides this, it has sufficient incentives for cost reduction. In a country like India, given its

---

raised the cost of domestic resources for Indian firms. And the large fischer-open' differential between India and international capital markets would mean that neither do they have access to foreign funds.

[3] Inappropriate contracts that shift risks asymmetrically or inappropriately among parastatals or state owned enterprises (SOEs), are still internal to the state. Similarly, in the disagreements between government departments and SOEs no litigation is involved. As such delays in settlements do not immediately feed back into decision making to enhance the risk perception.

[4] It is almost certain that in most states the regulator would be captured by a privatised electricity sector, if detailed or cost plus mode were going to be the practice. Fertilser, steel. paper, sugar are all industries that in the control period and fertilisers even today. generate vast rents out of regulatory prices. In states like West Bengal, the political processes could drive the regulator to unviable prices for industry. Buses, trams, CESC electricity business are examples.

large diversity there is a need is for a `core price cap formula', with certain parametric values being different for different locations. In the long run, as a national market for wholesale power is possible with (more than) adequate capacity in long distance transmission, the need for varying the regional formulae would no longer be there. This is as it should be, since power is best produced where long term costs are low (at pit-heads, and near the coast for e.g.), subject to transmission costs. Price cap regulation, would leave technology choice to the producer-distributor in the medium term, and to the producer, given redundant grid capacity in the long run. Scale, choice of fuel, location, peaking capacity would then be internal decisions driven by cost factors, demand, and willingness to pay as they should be.

Regulation an economic rather than a legal or engineering task

Unfortunately, there are no guidelines for the involvement of experts in regulation. It is not sufficient to involve legal persons, and engineers. Regulation is typically an analytical exercise that understands not only electricity economics, but also the cost of information, and policy, the value of time, transparency, and simplicity, and most importantly the `incentive' implications of regulations. In other words, regulators would have to worry about, how best they can take the electricity system to the planner's optimality through prices (rather than administrative measures or fiat-though these are not entirely avoidable). If the regulator was to become an authority that examines all aspects in their specific details and has to worry about `correct' costs and prices of every project, and has to be able to justify its rulings in courts, then the task is Herculean, and beyond the capacity of any reasonable sized public organisation. More importantly the firm and producer side costs that such a regulator would impose would be very large.

The particular 'philosophy' of regulation needs definition

Thus, there is a need for a `strategy of regulation' for the sector as a whole that addresses how transparency can be built into the process, reduces regulatory risk, and keeps regulation costs low, exploits the full potential of competition in generation, and improvements that privatisation can bring. Otherwise, we may be taking a step backward.[5]

Restructuring of SEBs would have to be derived from the regulation strategy

The restructuring of the SEBs can hardly be addressed without clarity on the role of the regulator, and the strategy of regulation. Unfortunately, this has not been acutely realised by the central government. Thus, the role of the SERCs is hardly as yet clear, for state governments to go ahead with particular schemes including privatisation for restructuring.

The problem of the SEBs

Specific to the Indian situation is the rather unique managerial situation with regard to the SEBs, especially with regard to the managerial incentives. While generation performance, and production of electricity and its distribution is carried out reasonably well, at least in the well performing SEBs, SEBs have increasingly become corrupt organisations, with significant theft of electricity, and materials with the connivance of managerial and field staff. Thus even as PLFs have generally improved, the `T&D' losses (substantial portion of which is really theft) and the now `standard' practice of passing on industrial load as agricultural load have only increased. The significance of T&D losses to the financial performance of GEB for example is considerable. If these thefts could have been avoided, then the profits of GEB could have swelled up the profits of the GEB by as much as Rs 2500 crore annually without any adjustment of tariff ! [6] The reported 'commercial' losses for 1994-95 and 1995-96 were Rs 551 and 1026 crore.

[5] The US had to go through a major deregulation effort away from ROI/RONW type of detailed regulation. At one time, more than 50,000 `experts' and their staff were involved in the task of regulation, and utilities had effectively captured the regulator, as the steep fall in retail prices on de-regulation would indicate.

[6] This is an estimate of the upper bound of the leakages from the GEB. To arrive at this figure about 40% of the reported agricultural consumption is assumed to be theft and avoidable losses. About half of T&D losses and a quarter of auxiliary consumption could have been easily avoided. The electricity so available is valued at average industrial tariffs, and the gross agricultural collections today are subtracted.

Restructuring proposals cannot side step the main problem

Any attempt at marketisation, privatisation or regulatory reform, and especially restructuring that does not squarely address this problem would not be meaningful. Thus the problem of the SEBs is far more basic than the typical `inefficiencies of the public sector noted worldwide. Indian bureaucracies are eminently capable of crafting institutions and rules that in form resemble success stories elsewhere, but in content and behaviour continue to remain dysfunctional.[7]

Subsidy issue has been largely sidestepped

The subsidisation of agriculture (even after recognising that substantial portions of the reported consumption by the agricultural sector is fictitious), is considerable. Central government committees and enquiry reports, as well as policy statements have for sometime been urging that this subsidisation should be considerably reduced or even eliminated. Variously it has been stated that tariff should be raised so as to achieve a minimum return of 3% on equity, that agriculture should be charged at 50 p. per unit, Re 1 per unit etc. Yet, no meaningful measures to reduce and contain the subsidies have been made. The only meaningful recommendation thus far is that the subsidy cost must be made good by the state governments to the SEBs, so that SEBs are able to retain at least accounting independence from state governments. Yet this recommendation in itself if implemented could create a problem of moral hazard. It could result in an incentive for the SEBs to over report its subsidisation cost.[8] This bind of the agricultural sector has coloured the recommendations of the central government on distribution and privatisation. It has been generally assumed that distribution areas with larger agricultural load would be less amenable to privatisation, or that differential costs would have to be recognised. The Report on Distribution Privatisation has hardly appreciated the point that differential tariff

[7] Thus the oversight of the public sector in India has witnessed all the modalities found successful elsewhere. The contract form of the French in the MoUs, the holding company form of the Italians in our own holding companies. True success as we have observed elsewhere (Morris, 1987) has always eluded us because these modalities or institutions were replicated merely in form, but not in the true spirit and content.

[8] We shall see that this has already begun to happen in the case of the GEB.

in principle would be very difficult if not impossible to administer by privatised licensed monopolies without vast independently verifiable information on customers' identity. Such measures open the door to faster growth in subsidies, or to a parallel growth of the regulator's back office to ensure the validity of subsidy claims.

Stepping stone solution to subsidisation necessary

That removal or considerable scaling down of agricultural subsidies would be very difficult:

- Electricity using farmers comparing themselves with canal water using farmers would still find themselves relatively discriminated;

- There is no way non-agricultural rural use can be separated from agricultural use by the utility; and as the non-agricultural use increases, subsidies would in fact become rural rather than agricultural.

While it is true that "farmers would chose priced power available regularly rather than free power available just four hours", as many enlightened politicians have said, farmers would generally disbelieve that the SEBs could in fact deliver quality power. Political entrepreneurship would also be necessary to translate this preference to acceptance. There is a catch 22 situation here, since without tariff and basic reform the system would hardly be able to add capacity to ensure quality and reliable power. And farmers know this. Thus a `stepping stone' solution of continued but capped subsidisation, which makes tariff reform politically acceptable is necessary.

A Proposal for Restructuring/Reform of GEB

GEB could be restructured in several ways. What is feasible and meaningful would of course depend on the regulatory arrangements. Thus a regime of detailed regulation, with the power to license being in the hands of the regulator, would largely preclude, competition in generation, which would otherwise be possible.

Similarly, recognition of the constraints in transition would mean that proposals would have to consider not only the envisaged end-result of reform and restructuring but also lay out a transition path.

Rather than discuss all possible proposals, we put forward a proposal (that is really a joint one for restructuring of GEB, and a regulation strategy) whose merits would be brought out vis-a-vis alternatives.

The principles and experiences that have informed this proposal are the following:

- The experience of reform and regulation world over, but especially of California, the UK (England and Wales), the Nord Pool System, the Victoria Power Pool (Australia), the New Zealand Electricity System (NZM), and other electricity reform efforts in the US. Similarly, the experience of well performing vertically integrated monopoly like the EdF, and the Wisconsin system where detailed regulation has actually worked.

- The present situation with the GEB, wherein quick reduction in T&D losses (both technical and theft) would have to be brought about; and rationalisation of tariff is presumed.

- The need for political feasibility, especially of tariff reform, and acceptance by workers of the proposals.

- The reform, including the regulatory proposals, should have adequate incentives for various stakeholders to favourably dispose them to the same.

- Limitations arising out the system, especially transmission, IT system, lack of skills to work in the changed environment, would all have to be accommodated during the initial years of restructuring and reform. Such limitations would nevertheless have to be quickly overcome in the working of the system.

- Regulation that works needs to be 'light', low cost, simple and transparent, and greatly lower if not completely eliminate regulatory risk. Competition and competitive structure wherever possible would have to be taken advantage of.

- Existing systems and institutions of considerable strength—like the capital market, existing organisation and engineering skills available within the organisation, and the country would have to be taken advantage of.

- In comparison to other states and regions but especially Maharashtra and Madhya Pradesh with ample coal and water resources, Gujarat would, in the immediate future, be on an average, a high cost producer. There is, therefore, a need to minimise stranded costs and assets especially of older coal based stations, allowing them a period of adjustment to shift to more rational fuel sources or shut down, in a system of intra and inter regional competition in generation, that is envisaged for the future.

The regulatory proposals.

Independence of regulator is absolutely necessary

The office of the regulator needs to be independent especially of government and industry; and ought to have the option to choose the mode of regulation, and tariffs. It should also lead developments in the sector. His office must adequately represent consumer interest.

Transmission as a regulated monopoly

Transmission would continue to be operated as a regulated monopoly with price cap regulation. It would be desirable that transmission is a public sector undertaking with majority but not full ownership by the state government. Adequate representation of consumers and disbursal through the stock market would be desirable. Transmission should be confined to system integrity, investments, operations on behalf of buyers and sellers of power, for the benefit of the consumers. The transmission company should not buy and sell power on its own account, but should facilitate the selling and buying of power, in other words, be a market maker,[9] rather than a participant.

Own account trading by the transmission company should be in-admissible

In principle too if the transmission company buys and sells power on its own account, then the generating company is to that extent shielded from demand risk, and from variability in demand. The transmission company then would have to bear these risks, which would be an intrusion into its principle business of transmitting power, which tends to be a natural monopoly.

Instead, the intermediation should take place contracts and markets (spot and futures). Transparent rules for access to the transmission network, and standard changes based on price cap regulation, would be crucial to the market making process. Additional requirements would entail definition of differences between contracts to buy/sell and realised purchases/supply, and the modalities for their settlement and pricing. Then transmission becomes analogous to transport services in the trade of goods.

Transmission, we have mentioned, should be a public sector monopoly but not with 100% state ownership. It would be desirable to have significant ownership of the transmission utility with consumers, because consumers have a natural interest in expanding the transmission system in such a manner that the cost of delivered power at their meters is least and reliable. Generators, and distribution entities with significant generation assets would be more concerned about protecting the returns to their assets, and would strive to

[9] The NTPC for instance has resisted enormous government pressure that it become a power trader on behalf of the IPPs, rightly knowing that under the present circumstances, its cash flow would greatly deteriorate with such operations, since the receivables from the SEBs would mount even faster them.

protect their returns to congestion. In the Indian context it is very important that returns to congestion are almost completely eliminated except in abnormal situation of system failure. Ideally, the transmission company should lay down grid rules covering engineering standards, and economic aspects separately. Charges should be a three part, one covering connection charges (based on maximum connected load or load capacity), distance or line loss charges, and most importantly congestion charges, which often tends to be ignored. While connection charges can be subject to standard RPI-X regulation, and so can line loss charges to a large extent, though the X factor here would have to have a system improvement component. The congestion charges would have to be based on periodic system simulation studies, and allocation of contribution to congestion by users. Congestion charges could create a long-term incentive to delay or not remove congestion, so they need to be appropriately structured so that the gains from connection charges and line losses at standard rates are always greater than the gains from congestion. These, along with the difference in prices of wholesale prices at each segment or subregion, have the important role of signaling the transmission company to direct its investments to overcome congestion.

It is important to realise that large generators would attempt to enhance their returns by creating congestion situations, when connection rights are traded in a market. This has happed in systems where connection rights exclude other competitors. Such artificial congestion could also take place when grid restrictions are significant, even when connection rights are periodically assigned, as would be the case of a regulated transmission monopoly. To avoid or minimise such situations, the ownership structure of the transmission company is crucial. Also, the returns to the transmission company in relaxing congestion in the form of line loss charges and connection charges, should be significantly large. In other words, the transmission company should have appropriate incentives to maintain optimal overcapacity.

Competition in generation ought to be a major concern

The potential for competition in generation can only be realised when there is no cost plus or detailed regulation of generation. It is on this aspect that the proposals of the central government are inadequate. Competitive bidding at the time of setting up an IPP, can at best, ensure low plant costs and optimally at that point in time with respect to fuel choice. Since PPAs are cost plus and fix the fuel, the generators have little interest in terms of either reducing operational cost including O&M, or in changing the fuel when relative prices change significantly. Moreover the cost of regulation of every expansion, substantial capital addition, retrofitting etc would be stupendous, in the case by case mode that is implied in detailed ROI regulation. As such as IPPs with PPAs are the antithesis of a structure that can engender competition.

Costs of immediate and complete separation of distribution and generation may be too high

To realise the total potential of competition in generation, it would be desirable to separate generation completely from distribution, and ensure that the Herfindahl Index (H-index) of concentration in generation is not too large.[10] Yet, the true costs of learning to separate generation entirely from distribution, and then put them together through a `market' would have to be reckoned with. In the initial stages, rather than the entire generation going through the market, it may be more appropriate to start only with market for surpluses and deficits;[11] i.e. in other words to allow some generation assets to distribution companies.

The possible abuse of vertical integration economies by distribution cum generation companies no doubt exists. This can be addressed in part via a price cap on retail electricity prices, and in stages by moving towards a retail market for electricity, as we will argue below.

---

[10] Thus, collusive behaviour that raised pool prices in the E&W System by National Power and Power Gas the two largest players in the UK market in the first few years when the pool trading system was introduced did take place. This had to be corrected by specific regulatory measures including the sale of generation assets to smaller companies, and closer oversight of the market by the regulator. There is no merit in having a very large number of small generators. The point is to ensure that the market power of no generator is particularly large.

[11] The Nord Pool of Norway and Sweden, is essentially such a market.

Structural determinants of competition potential

The potential for realised competition in generation would depend upon the following: The industrial structure of independent generators – specifically the H-index, the distribution of variable costs, and break even (cost recovery) outputs of each of the plants; the potential for trade, which depends upon the capacity of unattached generators including exporters to the system, the deficits and surpluses of utilities with their own generation capacities; and the variability in final demanded load. High unanticipated variability across the seasons and intra-day would reduce the potential of pool prices to be close to the long run marginal costs. Another important factor in the potential for competition is the excess capacity in the system since transmission is in part a substitution for generation, `excess' transmission capacity and 'excess' generation capacity would tend to keep pool prices low. It would most importantly depend upon bulk consumers to choose their supplier, including taking up self-generation when they find it most suitable.

Variability in pool prices would depend upon the variability of demand, the response capacity of the system, especially of the extent of hydropower available, the two acting in opposite directions.

Prima facie, the proposal to keep much of the generation assets of the GEB as part of the privatised distribution companies, would, despite some reduction in the competitive potential, ensure their quick privatisation. This is because the overall proposals are linked together holistically, and the credibility that they would be implemented as planned is likely to be low, given the fact that governments in India have not only dramatically modified policy and proposals, but have also announced contradictory guidelines and intentions. The willingness of governments to seriously pursue reform is also at present questionable. Conviction need to be communicated and the credibility would only gradually build up as the implementation process is seen to be well on its way. Therefore to bundle some generation assets with the distribution companies would partly insulate the proposed distribution-cum-generation companies from perceived demand and supply risk, and from the incomplete or slow implementation of the proposals.

This would allow for quicker privatisation of distribution which is the immediate requirement , because that alone can plug the leakages from the system. Moreover there is a period of learning, when the price cap formulae and the rules are fine tuned, and participants learn, and the IT system is set up to allow for quick contracting and settlement, and monitoring of power generators and consumers at each of the connection points on the grid. The bundling would allow for a smoother transition than otherwise.

In privatising GEB by separating its geographical (distribution) zones with linked generation assets into distinct companies, the capital market assessment of such entities would be very favourable. They would be seen as having little demand risk. Moreover, the market is familiar with such companies (given that licensees like the BSES, SEC, AEC, etc. have been in operation for long.). Their investment arrangements to expand capacity need not necessarily go through the SPV route. They could take advantage of balance sheet financing for instance to considerably lower their cost of capital. Such companies would have a strong incentive to expand demand at any given price, and so service quality would not be under as much pressure, as in a pure distribution company subject to price cap regulation.

Bulk consumers can provide 'retail' competition

Table 1 reports the average size of various classes of consumers, based on officially reported data of the GEB. We have modified the data and reworked the average size of various classes of consumers. The principal changes that we have assumed are: Forty percent of reported agricultural consumption is assumed to be potentially industrial HT. Similarly, possible savings on account of recognising that about 12% of T&D losses are really theft and about a fourth of auxiliary consumption could be avoided. This leads one to the total supply (or potential supply) to HT to be 14067.6 m KwH rather than the reported 6325 mKwH. See Table 2. This means that there are potentially about 9539 HT consumers rather than 4208, with an average capacity requirement of 0.26 MW. Assuming a long-normal distribution of consumption with a standard deviation of 2μ , it is most likely that there would be 476 or so HT consumers with a capacity requirement of 1MW or more. Nearly all railway consumers are bulk. Similarly, all public lighting in towns and cities. Only in tiny towns and villages would the load be small. This would give at least 30-50 public consumers whose capacity demand would be in excess of 1MW. Thus approximately 500 bulk consumers would be able to buy power in the retail market, and their total off take is likely to be at around 1200 MW of capacity. Their presence in the market would constitute a major force to competitive determination of prices. On the supply side, the present captive and co-generators with a total generation of 4132 mKwH at 50% average PLF today, would up be able to raise their PLF[12] to 70% and even more. Assuming a third would give up operations under a regime of reliable power, they could still contribute up to about 1653 m KwH of net sales. The retiring units would anyway become bulk consumers, and hence contribute to demand that is price sensitive. The net effect would be to add about 1653m KwH ~ 270 MW at 70% PLF of capacity implied in the current captive generators' realisable surplus.

Table 1: Average Sizes of Various Classes of Consumers of GEB, circa 1995-96

Type of consumer	Electricity consumed in mKwH	No of consumers	Average consumption per year per customer (KWH)	Average implied generation capacity serving each consumer (MW) at 65% PLF
		Assuming correctness of reported data		
Domestic	2176	4.951m	439.5	0.0000769
Commercial	601	0.700m	858.6	0.0001507
LT	2283	0.160m	14268.8	0.00251
HT	6325	4208	1.5031m	0.26
Railways	331	10	33.1m	5.82
Agriculture	10132	0.527m	19225.8	0.00337
Public lighting	94	0.017m	5433.5	0.000955
Public water works and sewerage	239	0.020m	11962	0.00211
Licensees	2675	2	1337.5m	234.92

[12] Those with marginal cost below pool prices would be able to price the power at marginal cost, other would probably have to wind-up/retire their operations, since they would find it cheaper to purchase power.

		Adjusting reported data suitably		
HT	14037.6	9539	1.5031m	0.26
Agriculture	6079.2	0.527m	11535.5	0.00202

NB: The adjustments are: About 40% of agricultural demand is assumed to be fictitious and could have been /is being sold to HT users. Half of T&D losses and similarly a fourth of auxiliary consumption could either be saved or is could be /is being sold to HT users. This gives the number of HT users to be in excess of 9500. Assuming a log normal distribution of consumption, with a standard deviation of 2mu, the number of HT consumers above 1MW demand would be 476!

Thus we can estimate the amount of power that would be marketed, under the proposed scheme of bundling all generation assets within the distribution companies. All 'imported' electricity from NTPC, NPC, etc. is 10,055 m KwH. Other purchases from captive generators could be ~ 1653 m KwH. Similarly, sales by GEB to bulk consumers and other utilities would be 8000 m KwH approximately (HT consumers above 0.5 m KwH), and 2675 sales to AEC, SEC etc. Thus, the traded electricity would be as much as *(Purchase + Sales)/(2* throughput)*; which would be in the range of 35.40%.

Some asymmetry in (zonal) distribution-cum-generating companies is desirable

Recognising that the zonal distribution companies could be so structured as to leave all of them with asymmetry between demand supply, and the planned investments by the IPPS and the NTPC, the trading potential would be in the region of 50%. This estimate is no doubt crude and could easily be refined with more accurate and reliable information. Thus a market-based reform is consistent and feasible with bundled distribution and generation companies.

In table 2 we work out the H-index for all generation c.2002; and for the traded power that is likely of GEBs current generation assets are split into six portions. Five of which are bundled along with five (zonal) distribution areas to form the distribution-cum-generating companies (DCGs), and the sixth is sold off as an independent generating company (MCG). The H-index for traded power alone is moderate , and would permit adequate competition under the right rules.

Table: H-index in the Generation Subsector in Gujarat in the Immediate Future, c.2002

Producer /Supplier	Capacity	Traded capacity	Market share (%)	Market share (%)
DCG1	800	0	7.7	0.0
DCG2	800	0	7.7	0.0
DCG3	800	0	7.7	0.0
DCG4	800	0	7.7	0.0
DCG5	800	0	7.7	0.0
MGC	800	800	7.7	16.5
GIPCL	305	305	2.9	6.3
NPC	125	125	1.2	2.6
NTPC	1008	1008	9.6	20.7
IOC	1000	1000	9.6	20.6
Gujarat Torrent	1200	1300	11.5	26.7
AEC (Torrent)	900		8.6	0.0
Essar Hazira	515	200	4.9	4.1
Jagadia Chem	41	10	0.4	0.2
Koraya	60	15	0.6	0.3
Reliance Jamnagar	500	100	4.8	2.1
ALL	10454	4863	100.0	100.0
H-index			0.1	0.2
Share of traded to total capacity				46.5

*AEC and Gujarat Torrent are assumed to be merged; or coordinate operations

Distribution-cum-generation companies on a price cap

Distribution companies with some generation assets would need to be subject to price cap regulation. The maximum price changeable to any customer would have to be fixed by the regulator in the form of a formula RPI-X-R. The price at starting year reflects the average present costs of the SEB duly adjusted for avoidable T&D losses,[13] the leakage that canbe quickly plugged, and a desirable return of 14% on all capital assets.[14] The RPI formula could be a weighted average of various prices (fuel, salaries and wages, interest rate, etc.) with the weights being derived from standards and GEB's present proportions of various costs. R can be based on a desired adjustment period. Thus if the system as a whole can be expected to improve its efficiency at a rate of R% per year to reach international standards,

[13] Thus (SEB's total cost of power generation + purchase)/(Units sold + A. (T&D loss of units)).

[14] It is desirable to base the return on total capital assets rather than on equity capital. This would allow firms the option of innovatively and efficiently structuring their capital.

say in five years and if international standards are presently 30% below GEB's, then R could be as high as 6% for each year. In other words, the regulator expects real prices of electricity to fall with the reform. X may be zero over the period of adjustment and then at a rate that is based on expected improvements in efficiency that follow from technology. Ceterius paribus, in a system growing rapidly, X can be expected to be large as compared to that in the advanced countries where expected growth is much low.

Exact value of 'X' not important; 'X' should be stable and should not be backward looking

There has been much discussion in the role of `X' in price cap regulation. Given that technological change is less unpredictable in power as compared to telecom, which is technology driven, price cap regulation is for more suitable in power then in telecom.[15] Some have suggested that a sliding scale regulation is better, others have argued that price cap regulation is no different from detailed regulation. The point is to not go back on an X that is agreed upon to be valid for a certain number of years. If X is adjusted, ex-post after firms make larger than expected profits, then the value of price cap regulation to provide incentives for efficiency and improvements is attenuated. Moreover, with a backward looking X, regulatory risk enters into the picture, to raise the a priori expected returns. In the Indian situation, the need of the hour is efficiency, and even if X is in the past known to have been smaller than desirable, there are other ways to overcome the problem, than to make X backward looking.

Investment tax credit and 'X'

It would be for better to allow regulated distribution cum generating firms their high profits, provided these are invested in infrastructure, with a sliding scale of investment tax

[15] In telecom, detailed regulation would be even worse than price cap regulation. Here, beyond a price cap, the regular has to worry about new technology and its diffusion, so that the benefits of technological change (the major source of efficiency gain) lead to expansion of the market, new products, and low prices to the consumer. As such ensuring an industrial structure with low barriers to entry would be of primary importance in telecom. In telecom, it is possible to argue that regulation should be concerned less with tariffs and returns,and more with ensuring that the technological drivers are allowed full play, and that diffusion of cost reducing technology takes place.

credit, linked to an increasing tax scale. Such an arrangement would have the merit of directing investments into infrastructure and especially power distribution itself[16] to relax present constraints. Moreover, it is not difficult to predict reasonable values for X in the power sector, since much of the power industry in India in the post reform period would be in a catching up phase vis-à-vis other more efficiently organised countries. As the reform restores managerial incentives for efficiency through both competitive measures and regulation, it would be not too difficult to base X on a comparative study of happenings elsewhere. That would give the regulator enough time to build the necessary skills to arrive at X periodically.

Marketability of units proposed to be privatised is necessary

Since retaining generation along with distribution in zonal companies would make such companies marketable, privatisation could be very quickly carried out (even with present levels of over manning). Privatisation[17] would be necessary to eliminate theft, and restore managerial incentives, which would have to the immediate concern of any reform.

Privatisation proceeds should go to augmenting transmission assets

Moreover, the considerable proceeds from such privatisation (assuming that regulatory clarity has emerged by then) and a price cap regulatory formula, that is entirely transparent and valid over the next five to eight years is in place, would release resources for the state government to put into transmission assets. Investment to create adequate capacity to allow wholesale markets, and later partial retail markets to function, would be vital to ensuing

[16] Indeed the investment tax credit could be linked to investments in the rural and sparse component of the distribution system, and in investments in equipment like electric meters, that allow ToU pricing etc., if there are envisaged right at the beginning of the reform process.

[17] We know that many PSUs in Sweden, Norway, US, Korea and China to name first a few countries, and even in India (NTPC for example), but especially in utilities perform very efficiently. It is always true that if the SEBs could be corporatised, and truly distanced from government, and dealt with through an annual contract alone, leaving its managers operational and administrative functions, then they would perform efficiently. But this has remained a futile hope, in India; since governments in India would never really 'give' this autonomy. In India today, only disinvestment can restore managerial autonomy and bring about ownership of responsibility in PSUs that have veered far from task orientation.

competition among generating stations including those which are part of distribution companies.

Fairly quickly substantial investments would be required in transmission. This is because `excess capacity' in transmission is vital to the creation of a power market that imposes competition on generation. Analyses of deviation of traded or pool prices from generation costs across existing market systems reveal that the `degree of monopoly' exhibited by generators is a function, not only of concentration, but also of grid restrictions, and the proportion of `near zero variable cost power' typically hydro power in the system.

Besides price cap regulation for transmission operations in the public sector, the transmission companies would have to provide access to all potential users of the transmission: Generating companies, distribution companies including those with generators assets, outside suppliers of power (NTPC from stations outside Gujarat for example, or the adjoining SEBs), and large captive generators. There is considerable potential of large captive generators to offer competition to utility generators, especially in Gujarat given fairly large installed capacity in captive generation, and lower PLFs presently at such stations[18], under appropriate regulation.

Bulk buyers can usher in 'retail markets'

Very early in the market forming process, bulk buyers of power should be allowed to purchase their power directly from any supplier-generating company, another distribution company not in its area, a party outside the state, a captive generator, or any combination of these, subject only to grid restrictions, and system integrity requirements. The market for power would be a market for wholesale power to trade surpluses and deficits of distribution companies[19] with generating assets, with generating companies and among

[18] Emanating largely out of the present captive generation policy, which places severe restrictions on captive generators attempting to sell `surplus' power.
[19] At off peak periods when wholesale prices are below variable costs of expensive generating stations of distribution-cum-generating stations, they would enter the market to buy power (cheaply) from the pool suppliers.

themselves, plus a market for bulk retail power.[20] This would mean that access rules to distribution company assets would have to be defined for bulk users, for whom the distribution company's wires business is separate from power purchase.

Export and import tariff

Gujarat has a comparative disadvantage vis-à-vis states like Andhra Pradesh, Madhya Pradesh, Maharashtra, Bihar and Orissa in generation of power, since it has few hydro assets, and hardly any reserves of coal. Lignite remains problematic, and a gas-based strategy is contingent on low gas prices, and quick development of coastal infrastructure. Moreover, imported fuels would introduce significant foreign exchange risk on Gujarat based generators.

This means that as the national market develops, or even before, when it becomes possible to transmit power in larger amounts across regions,[21] there would be a period when generators in Gujarat would face competition from outside the state.[22]

There is, therefore, a need to recognise this competitive pressure from outside the state, at the outset of the reform process, and plan for the same. To cap the risk emanating from this future possibility, the regulator would have to impose a tariff on imports of power from outside the state, with a pre-announced schedule to lower the same gradually and ultimately eliminate it altogether. It would be necessary to `control' imports through such a price-based mechanism rather than through grid restrictions or quantitative restrictions. Besides the well-known advantages of tariffisation, this measure would have the added advantage of signaling the generators on location choice. If, for example, the imports grow faster than the Gujarat market for retail sales, then it would be clear that generating companies would have to increasingly locate elsewhere to retain competitive potential or

[20] It is bulk retail power that has created a market for retail power in the UK, which first attempted markets in retail power. Even there over 95% of the retail consumers despite choice, buy power from their own regional distribution companies. It is only the bulk users who can actually take advantage of competitive structures.
[21] As the planned investments by the PGCIL materialise the national grid would take shape.

use better technology.[23] It would also give the right signals to the transmission company on investment choice.

Variations in value of distribution assets and territory is not a major problem in privatisation

To allow even the wholesale market for deficits and surpluses, and a 'bulk retail' market for captive procedures (as both consumers and sellers), the composition of the distribution-cum-generating companies is important. Distribution being a natural-geographical monopoly, it is desirable that the current distribution zones should constitute the core of the distribution companies. Differences in terms of consumer mix, ratio of low voltage lines to high voltage lines, of distribution transformers to substations, should be of secondary importance. This is because, if subsidisation is taken care of externally and not through the distribution companies, then the issue is only one of differences. Thus a distribution zone with a larger proportion of rural customers and sparse networks and lower consumption per meter[24] would show a higher distribution cost per unit of power distributed or sold. Basic asymmetry in the form of large (bulk) power consumers could be eliminated by defining such entities as 'bulk consumers' who are able to take part in the power market, using the distribution company's wires for a fee. To start with all consumers with a connected load of one MW and above could be so declared. Despite this measure, it would no doubt be true that the average distribution cost would vary across the zones, so that the offer price for purchase of bulk power by a distribution company with high cost of distribution would be lower given, uniform price caps on all consumers.

If the price-cap were such as to allow all distribution companies, including the one with (structural) high cost, the desirable return, then those with lower costs would make high

---

[22] Thus even today a large pit head based coal station in Madhya Pradesh/Maharashtra or even distant Orissa, can deliver base power at less than Rs 2.30 per unit (wholesale), with full recovery of cost.

[23] We presume that simultaneously reforms that bring about competition in generation would be pursued in nearby states, and grid capacities develop to allow long distance transport of power in large quantities. The present grid rules would actually allow even a state level transmission company to contribute to the national grid in partnership with the PGCIL.

[24] Official data though show a very high consumption in agriculture per meter.

profits. This would be so unless the price elasticity of demand (assuming existence of supply) is such as to lower the final effective price to consumers of the favourably disposed distribution company. This is unlikely in the immediate post-reform period, when overall supply restrictions would be there. The way out would be to bundle the generation plants with the lowest marginal costs to the distribution company with high costs, in general to bundle generation assets and distribution in such a way as to ensure that total costs of generation do not vary by more than 10%. Variation within this range would not be a problem since the market valuation would most certainly adjust to take care of such asymmetry.[25]

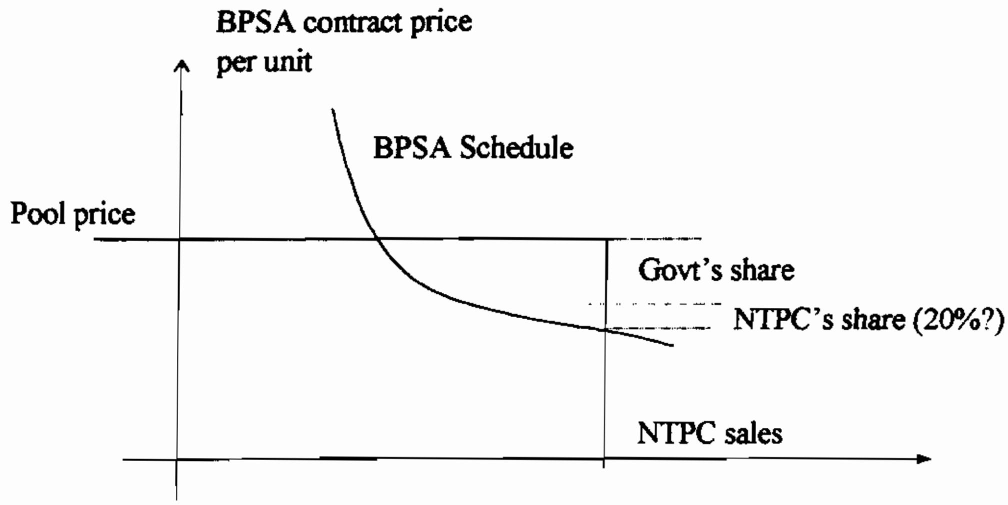
Returns to scarcity may have to be capped through demand backdown rules

The broader issue really is between generators and distributors, who would be able to mop up the returns to scarcity as they arise. The reform in advanced capitalist countries started from a situation of overall low PLFs (the range of 35% to 50%), so that generation companies have not been able to mop up the entire value of scarcity. Overriding rules for supply and availability of generators, and appropriate rules for market pricing and rules for demand backdown would be called for. In situations of overall shortage, because some generation assets are bundled with distribution, there is less likelihood of steep market clearing prices emerging, if the incentive for demand to back down is sufficiently large.

Retention of gains of marketisation within the system is desirable

[25] The important issue here is to make available reliable and detailed information on the status of networks, distribution loss (technical), and such other information vital to the estimation of costs, well before the financial bids take place.

Presently, the GEB holds contracts with the NTPC for power supply from NTPC's stations at Korba and Vindhyachal which use coal, from Kawas and Jhanor (gas), and with the Nuclear Power Corporation. The current average cost of power purchase is less than Rs 1.70. Thus the bulk purchase agreement with these central PSUs is an asset of great value to the SEB. The 'market clearing' prices in the post-reform period, with the arrangements and strategy as outlined in this paper, would most certainly be significantly above these prices. Roughly, energy purchases amounted to 49% of generation. Therefore, it is vital



Box 1: Extinguishing BPSA like Contracts

that the value of these BPSAs with the NTPC and NPC, till they come up for renewal in the cycle after the reform is internalised by the state to a great extent.[26] The NTPC would naturally welcome a change since then it would not have to wait for the expiry of the currently valid BPSAs, if part of the difference between the pool prices and NTPC's expected BPSA prices, at current load factors, in the future, can go to the NTPC. This would mean that NTPC could be used as a major source of competition in the generation sector. The correct way would be to first arrive at the schedule of NTPC's sales and the prices it realises over the range from 10% of its current maximum supply to the full supply. The schedule would obviously be such as to decline with supply. Then NTPC can be offered a schedule as given in Box 1 for any particular pool price.

[26] We know that in E&W (England and Wales) there were large benefits of privatisation and reform. About a third of these benefits accrued to the EdF, which was able to supply at pool at prices higher than its original contract prices.

This is one way, and probably the best way to deal with favourable contracts that the SEB has with other power producers. The cash flows so generated could be used to enhance transmission infrastructure, finance the on-going expenses of the office of the regulator, or even to finance in part the subsidies to farmers, through the latter is less desirable.

An alternative, though this would only be a distant second best option, would be to assign the BPSA like contracts to the distribution entities in such a manner, that companies with high likely distribution costs receive the same. This arrangement while quick would considerably reduce the potential for competition in the generation sector, and need to be avoided.

IPP contracts are a problem to competition in generation

The contracts with IPPs, would be a problem to the SEBs and an a priori strategy of reform, which allows IPP shareholders to exit would be necessary. Much would depend upon pool prices. If pool prices are higher than the IPP's implicit prices at that time then there is no problem. This is highly unlikely since competition would most certainly reduce the average prices of wholesale power.[27]

But the problem can be overcome

The contract with the IPPs can be approached in several ways. One would be to threaten to renege the contracts, raising the point there were `unfair'.[28] Then a negotiated deal which allows the IPPs to quench their contracts and be full fledged market participants and earn somewhat lower rates of return then their currently projected returns at 20 to 30% equity capital would be possible. This is an option that would necessitate a political commitment

[27] Only if demand were to grow at rates much higher than those currently envisaged, or those, which have obtained in the initiate part, is this situation likely. About a third of all power fed into the GIB system is purchased from the NTPC at low cost as mentioned earlier. This would keep pool prices pretty low, almost certainly lower than IPPs contract prices.

to replace IPPs, and would have the `negative' consequences of a state going back on its earlier agreements.[29] But, if the commitment to a fair market based reform and restructuring of the electricity sector is strong and very credibly pursued, and seen as such, then constituents for change would be strong enough to overcome the difficulties in re-negotiating these contracts on the lines above. A second approach would be to estimate the `premium' value of these contracts to the IPP, the value of the project that is over the value of being a generator in the competitive market that is being engendered. This can be approached as follows. In terms of a PPA a schedule of price as a function of quantities sold given terms and conditions can be worked out (IP). This would also be a downward sloping curve. The likely pool prices at these outputs let us say follows the schedule (P). IP is likely to be above (P) at likely range of outputs. Then a price in between P and IP could be negotiated as a price payable to the IPP, and the difference between P and IP could be made good by the state. This arrangement has the merit of ensuring that the capacities of the IPP would result in competition; but has the significant disadvantage that the state, over the life of the PPA as envisaged originally, would pay out to the IPP. In other words, the more the reform succeeds in lowering the generation prices, the greater is the out flow from the state.

Cajoling IPPs to trade political and regulatory risks for market risk

An alternative would be as follows: As part of the regulatory strategy the state announces that its policy would go on to a competitive market based solution for generation, and simultaneously imposes upon IPPs the condition that 20% of their stock would have to be

[28] Unlike Maharashtra or Karnataka, Gujarat is not going to be too severely burdened by patently `unfair' contracts.

[29] On this again many economists have with much logic argued that the IPP in coming to a deal with the state took a bet that these favourable contracts would continue, and that the regulatory policy regime would continue. Then the high return is only a rent to this speculation. That the market with absolute certainly does not expect such returns, has no doubt been proved empirically in similar situations of regulation created rents. If events do not turn out as expected, so be it. There is also the point of whom to compensate if the ownership of these contracts can potentially change, as it happens in the case of widely held corporations. Thus it would be wise on the part of the state planning for true reform and marketisation, to begin by insisting upon wide dispersal of shares. Moreover, this would have the benefit that market price of the stock of IPPs would change to reflect increasing probability of nonrealisation of rents. Naturally, attempt to fight back the change that removes rents would be blunted to that extent.

traded in the domestic market. The stock price then would reflect the emerging uncertainties with regard to IPPs, and would correctly value of the IPP/PPA contracts. The difference of the market capitalisation of the IPP and then the cost of setting up a similar capacity plant as a competitive generator, would be the premium value, if any, of the IPP/PPA contract. The IPP would then be willing to give up its contract and become a player in the market, if a value close to this premium can be transferred to it. This can be done in several ways. One would be to provide this as directly from the budget, once the bids for privatisation and marketisation are known. Most interesting would be to offer a bid amount handicap for GEB's assets-distribution cum generation companies, and other unattached generating companies, equal to the premium value. Care would have to be taken communicate to the market, the governments firm intention to go ahead with a market based competitive solutions to generation, and to privatisation. In that case, the bid process would have to include the clause that the IPP would be bundled with a distribution company. So a bid from a third party would have to be one that is a joint bid for the IPP (without its contract premium), and the other bids for the two assets separately. Yet, this approach would reduce the potential for competition. The option to extinguish the contracts in the manner outlined below would be the best.

The problem may not be as difficult as it appears. A strong and credible commitment to marketisation of generation and privatisation that is communicated well, would be necessary and vital to the success of any approach that is finally adopted. Indeed the distinct possibility arises that IPPs with a little nudging from the state may be quite willing to trade political and administration risk for market risk. That the political risks never really disappear in concession based projects in a competitive democracy like India is obvious. Even as the Enron project after its cancellation and re-examination by the Maharashtra government seemed to be on a firm ground, with the new government in Maharashtra has announced its decision to reexamine the project (the second time!), which introduces fundamental uncertainty again into the project. Most companies and promoters would not be able to bear this kind of risk even if the rewards are large. The state and government in Gujarat too has witnessed uncertainty with regards to terms and conditions. It is almost certain that, if the government were to change, at least some of the IPPs would be reexamined. In these circumstances, a credible option to trade such uncertainties with market risk (which tends to be bounded, at least in the case of electricity) would be welcome. Prior ruling to dilute the shareholding of IPPs in the local market would be essential. To sweeten exchange of political and policy risk for market risk, tax incentives linked to expansion of capacity could also be made available to the IPP.

Agricultural subsidies need not stand in the way of full-fledged reform

Agricultural subsidies need not stand in the way of privatisation and marketisation. As mentioned in the review of the current thinking and recommendations of the central government on privatisation of distribution, retention of agricultural subsidies well into a programme of reform and restructuring would be vital to the political acceptability of reform. This is so because any effort, at reform, even one that promises ample supply at competitive prices and good quality, would lack credibility given the history of governments and states to flounder in the pursuit of reform.[30] Similarly, reform that improves productivity, and allocative efficiency, through privatisation or otherwise, need not in general be halted by subsidies. There is a need to conceptually separate the two, and provide a transition path[31] to reform the system, while subsidies continue, but are capped and finally reduced considerably.

Stepping stone solution would be continuation and capping of agricultural subsidies

Thus it is important for the state government to ensure that agriculture subsidies, it in some manner would continue, so that a veto over reform is neutralised, and reform as such can be pursued.

[30] Fertiliser subsidy in case is a point. Similarly, the singular inability of the state to control the growth rate of revenue expenditures. The clear viability of electricity reform, and the service being highly excludable and capable of generating surpluses, and having immediate multiplier effects on the rest of the economy, means that policy makers must see electricity reform as a vehicle for overall reform. In other words, a successful electricity reform would be the key to success elsewhere in irrigation water, in urban and road infrastructure, and privatisation and reform.

Besides subsidies, leakages have drained the GEB

Reported agricultural demand for power grew much more rapidly than every other category of demand to become the largest component of demand and nearly equal to 40% of total demand. There is obviously mis-reporting on a large scale going on within the GEB, to the private benefit of GEB engineers and industrial (especially small industry) consumers who are the principal beneficiaries of the mis-repórting.[32] Real agricultural demand for irrigation is likely to be much less than what is reported; perhaps not more than half the present level reported. This means that the need for subsidy is to that extent significantly reduced. Using the agricultural demand to be 60% of current reported demand, and the average agricultural realisation per unit to be 55 p. per unit, and an assessed Rs 2.75 for the true standard cost of delivered power today, we would arrive at a subsidy requirement of Rs 1350 crore. This is in fact less than the subsidy actually received by the GEB from the state government! In table 2 we have the upper bound of the leakage from the GEB for the year 1995-96. The estimate of course depends upon the two assumptions made: That 40% of agricultural demand is mis-reported, and about half of T&D losses are recoverable. These are the estimates we obtained from certain knowledgeable sources within the GEB. Others have disputed the figure of 40% to claim that it is likely to be closed to 25%. It is imported to note that at reported agricultural consumption, the average energy drawn per pumpset in Gujarat would be between two and three times higher than in comparable states: Maharastra, AP, TN, Karnataka and MP. See table 3.

Even ignoring some recovery that is possible from auxiliary consumption, the estimated leakage was double the magnitude of the reported losses in the same year. In that year GEB reported a loss of 20.3% on capital employed. With the leakage plugged it would have in fact made a profit (including additional duty realisation) of 20% on capital

[31] Especially so since a net insignificant part of the subsidies would be producer subsidies that cover their inefficiencies.

[32] We had argued this case by comparing Gujarat with Maharashtra, Tamilnadu and Andhra Prades, and by showing that the official data would mean, more than 3 to 5 times energy per pump set in Gujarat as

employed! With the estimate of 20% of agricultural demand being misreported the return would have been as high as 9%.

Vested interests the real barrier to reform

Thus the real barrier to reform is not so much the politician, as the vested interests within the GEB. GEB has estimated the "effective subsidy to agriculture" to be Rs 2713 crore in 1997-98. The same year it claimed that 10,089 million KwH of electricity was sold to the agricultural sector. (The latter figure is wrong as argued before). Even assuming for a moment that it is true figure of the actual sales to agriculture, then the subsidy per unit of sales is implicit in the GEB's reckoning is Rs 2.689 per KwH, which is untenable. At a more likely 6000 million units of sale to the agricultural sector for irrigation this would be Rs 4.52 per unit! Thus the GEB has been attributing all its inefficiencies, and T&D losses including theft on to the agricultural sector to claim a whopping Rs 2713 crore from the government. It actually received Rs 1666 crore, the rest being covered by net cross subsidy from the industrial and domestic sectors.

Table 3: What would be the position of GEB if leakages had been plugged? (1995-96)

1	Gross generation (mKWH)	25979
2	Net generation (mKWH)	20547
3	Purchase gross (mKWH)	7200
4	Purchase net (mKWH)	7128
5	T & D losses (mKWH)	5549
6	Sales (mKWH)	22198
of which	domestic	1927
	commercial	581
	agricultural	9383
	industry	7940
	railway	345
	outside	72
	others	1950
7	Tariff average	1.415
	domestic	1.22
	commercial	2.91

compared these states. It would also mean that a pump set is used for more that a third of the time all the year round, which is a patent absurdity.

	agricultural	0.27
	industry	2.57
	railway	2.4
	outside	1.65
	others	1.79
8	Leakage (T & D) assuming half of it can be recovered at industrial tariffs (Rs crs)	713
9	Leakage in mis-reporting industrial supply as agricultural (Rs crs) assume 40 (20) % of agricultural sales	863 (432)
10	Total leakages excl recovery of some auxiliary consmption (8)+(9)	1576 (1145)
11	Reported losses of GEB (Rs crs)	778
12	Profits with leakges plugged (Rs crs) (10)-(11)	798 (367)
13	Sales revenue (Rs crs)	3141
14	Costs (Rs crs)	4045
16	Reported return(-) on capital % (without subsidy)	20.3
18	Implied capital (Rs. crs)	3932
19	Implied 'return'(+) on capital with leakages plugged (%)	20.3 (9.3)

Large moral hazard in GEB

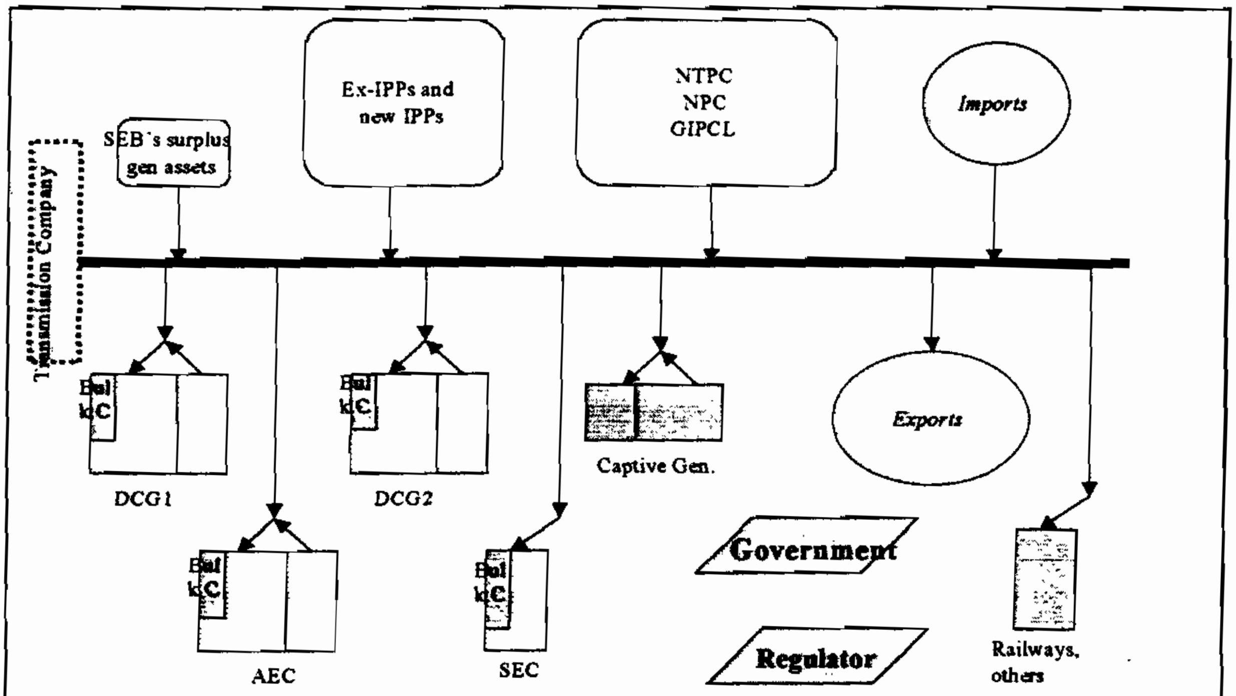
What we have in effect is the extreme exhibition of moral hazard in a situation where `subsidy administration' was not separated from the GEB, allowing GEB the scope to use the excuse of low prices to the agricultural sector to cover up its inefficiencies and more importantly to cover graft.

Privatisation is necessary

Therefore, no reform is really possible unless there is surgical change in the organisation and its relationship with government. Privatisation could be the quickest solution, since the problem with GEB goes beyond the usual problem of displacement of the primary task, rule bound rigidity, etc typical of SOEs to systematic corruption. Simple restructuring of finances and capital restructuring, formal corporatisation, and making good the subsidies via explicit budgetary contributions, would, today, not do at all. The present organisations need to be completely reoriented around task orientation, and under an altogether different variety of management. Hence privatisation would be necessary, and all other considerations, even regulatory issues arising out of the natural monopoly character of electricity distribution and transmission would only be secondary importance to the objective of privatisation.

Stamps based agricultural subsidy

Agricultural subsidies should take the form of an electricity stamps or coupons scheme, which is administered by the Agriculture Department. The scheme would necessitate the use of land records, records related to operational holdings and to the identification of farmers who need subsidy. The government would have to decide to what extent it needs to subsidise rich farmers; although the electricity subsidy has thus far been a production subsidy and not poor oriented. Even if it continues to be treated as such, farmers would have be identified, and matched to their present commercial load, and issued stamps. The annual issuance of stamps through the BDO can be made a very simple activity through appropriate design to guard against malpractices.



THE PROPOSED COMPETITIVE STRUCTURE OF THE ELECTRIC POWER

Should the stamps be made tradable? As long the subsidy is not poor oriented, tradability would not be desirable. When the subsidy is for poor farmers, in their status as poor people, tradability would allow such of them who want to exchange electricity for food or other consumption items to do so. In effect then it would become an income subsidy.

Stamps collected by the distribution companies would entitle them to subsidy revenue from government. The need for stamps or coupons in the manner described above arises because of the need to target the subsidy better, to cap the same, and to prevent subsidised electricity being used for non-farm activities. Perhaps most importantly the need for stamps arises because that is one way the subsidisation can be entirely separated from the business of electricity distribution. Thereby the problem of hazard – that the company over reports the consumption by the subsidised category of consumers - is entirely avoided. This would be absolutely necessary to the success, and credibility of a privatisation programme.