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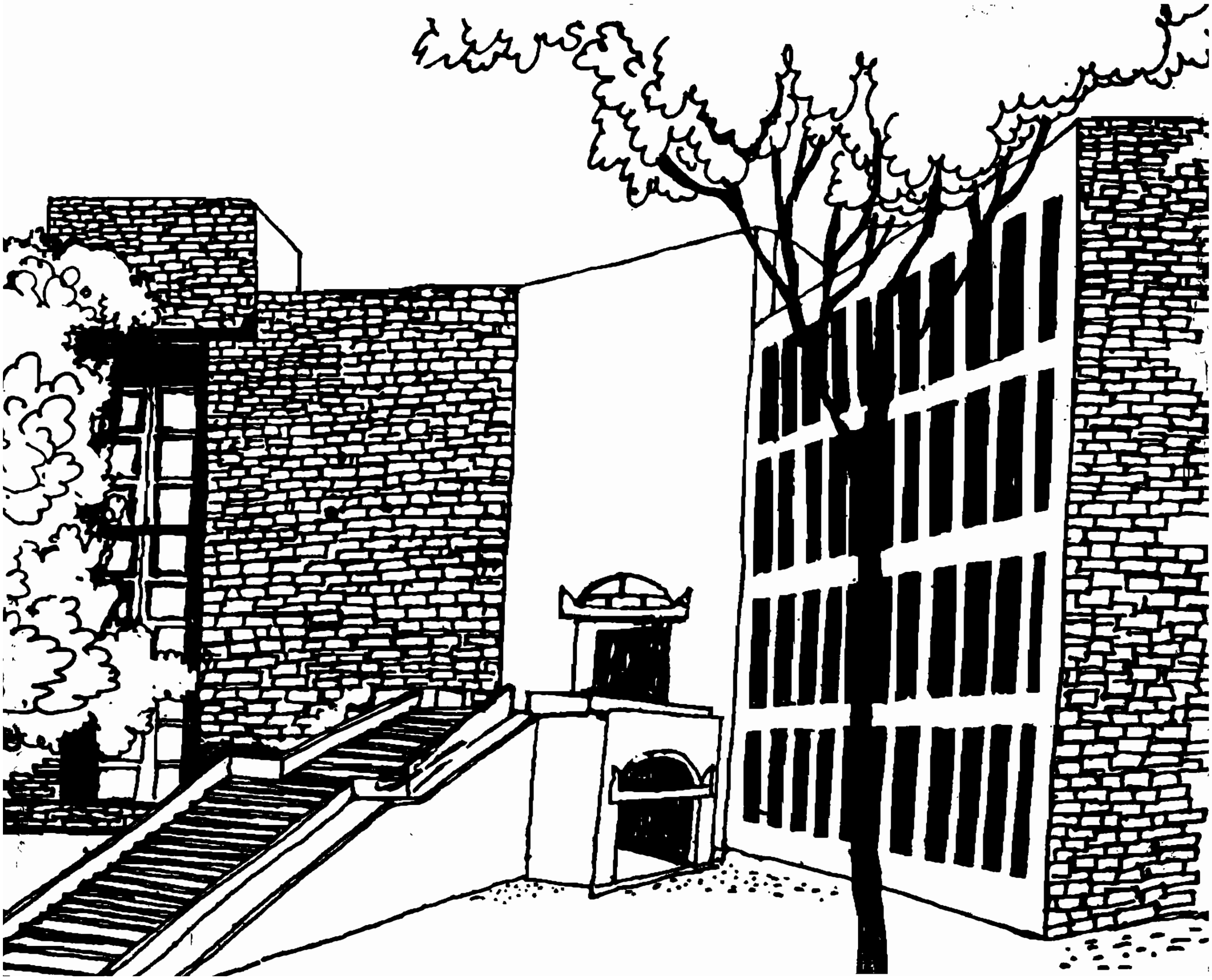

Towards a Tariff Policy for Central Power Sector Utilities (CPSUs) (Part I)

Sebastian Morris

WP No. 2001/07/01

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Indian Institute of Management
Ahmedabad
INDIA

IIMA WP-2001-07-01

Towards a Tariff Policy for Central Power Sector Utilities (CPSUs) (Part I)[1]

Sebastian Morris
Indian Institute of Management, Ahmedabad
25/06/01

ABSTRACT

There cannot be a tariff policy for Central Power Sector Utilities (CPSUs) that is market creating without a strategy for transmission access and pricing. Similarly, the policy has to be derived from a more general policy of bulk electricity pricing. Open access, with a three-part tariff for transmission and 'right structuring' of the ownership of the transmission entity is the key to bulk electricity pricing. The important issues in bulk electricity pricing and more specifically in the pricing of CPSUs are brought out. Without a cogent policy of export and import of power, preferably via an agreed upon time schedule of tariffisation of current restrictions, and their subsequent reduction, locational risk would continue to be vary large. A strategy to replace the 'bulk purchase and sales agreement' with one that is in keeping with market development is brought out. Key to bringing about competition in generation is open access and a complete revamp of the current captive power policy. Market pricing, with half-hour slots for contract sales, stiff charges for unscheduled differences, rather than cost plus pricing is the key to efficiency and realisation of the systemic efficiencies of hydro stations.

Introduction

1. Central Power Sector Utilities today consist of a transmission company (PGCIL), several generating companies (NTPC, NHPC, DVC, and BBMB). Their numbers could possibly change with reform as multiple transmission entities may be allowed, or possibly the NTPC is split up, or NTPC takes over other utilities. Similarly other inter-state (and even inter-regional) companies are likely to emerge as some of the IPPs facing demand problems are allowed to sell in more than one state. Some states like Gujarat (located far away from

the coal fields) are actively considering setting up power plants outside the state (in MP for instance) but dedicated to sales in Gujarat. States like Karnataka and Gujarat have more than one state owned/or controlled entity in power generation.

2. These and others such entities as they are commercialised /privatised would feel the head to sell across state boundaries. The interregional and interstate sales of power which is currently restricted due to ill-defined policy, needs to grow as the regulatory and policy uncertainties are overcome. Thus, a meaningful tariff policy would have to include not merely the CPSU's as such, but also all potential participants in the interstate and interregional business. In any case, the tariff policy of CPIs in US is in jurisdiction of CERC, also having jurisdiction of players with inter-state/inter-regional operations.

3. The true benefit of 'pit head stations' can hardly be realised without systematically addressing large-scale interstate movement of power.

4. Similarly, tariff policy would have to address the issue of IPP contracts (PPAs) and how best they can be dealt with or recast in a more rational environment of interstate and interregional movement of power.

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[1] This paper was presented to the Working Group on Power of the Planning Commission for the 10th Plan, c. 26th June 2001

5. The two objectives of "affordable power" and "development of markets" for power would demand that any tariff policy would have to necessarily cover: (1) tariffs for transmission; (2) transmission access rules; (3) interregional and interstate restrictions (possibly) to protect what would otherwise become stranded assets; (4) existing IPP contracts; (5) demand conditions and capacity utilisation and hence address the option of time of day pricing.

6. The reason for a special focus on transmission rules and transmission pricing is that much of the behaviour of entities, and the options available to them in a decentralised situation (and it is already so given the separation of the PGCIL from other generating entities) would be governed a great deal by how transmission is conducted. The success of any move towards power trading would be crucially determined by how transmission occurs is defined and priced.

7. Transmission is a very tricky business and ignoring its special characteristics as both a business (potentially regulated) and as a 'regulator' and market maker has led to major set back in the commercialisation and marketising of electricity, as for instance in California.

8. It needs to be recognised that transmission is not adequately viewed as a profit maximising business. Indeed if transmission entities are left to maximise their earnings, market failure in generation and distribution are inevitable (through grid congestion, access denial, etc).

9. Thus restrictions, including on ownership, and appropriate structuring of transmission entities, besides transmission pricing and access, are the keys to commercialisation of both generation and distribution. The latter two segments being much bigger portions in the value added chain, can therefore be easily put on a market basis if the pure approach of viewing all segments (including transmission) as 'businesses' is given up.

10. The value of hydropower lies not only in the energy that a hydro station generates but also systemically in the savings that it can bring about in other (thermal) stations by allowing them to work with relatively unvarying loads near their rated capacity. Recognising this and providing for the same, in part, to accrue to the hydro station, is vital, not only for lower overall cost of power, but also to proper development of hydro power itself.

11. Hydropower in India has a certain peculiarity in India that is not often recognised today. Given the fact that in most regions of the country the rainfall months are few, the storage to throughput ratio from any reservoir is far higher than in temperate countries with more even distribution of rainfall through the year. It is higher in areas with only a single monsoon as compared to dual monsoon (China, the North East and the extreme South of India). Thus, when the reservoirs are overflowing the social price of hydropower is very small being only the small O&M cost, and in such situations hydropower becomes base power. At other times, when no more

flow into the reservoirs can be expected, the marginal social cost of stored water (hydropower) is very high. And when the reservoir has a dual use in irrigation this could be prohibitive enough to not allow net use of water for power, and as such hydropower is then ideally used as peaking power, and as pumped storage if such assets exist.

12. (When the electricity sector was managed as a fully integrated system the working rules of the various hydro-reservoirs did take into account this aspect). Social optimality in hydropower use has to recognise its alternative use for irrigation. Incorrect (very low) pricing of irrigation water has distorted not only the use of stored water but also the planning and investment in hydro resources, to result in vast deadweight losses to the economy.

13. Today thermal power prices are distorted by the absurd coal transport pricing resorted to by the railways, and a virtual mafia at the coal mines. This has made the economics of Indian coal in relation to either imported coal or other fuels difficult to assess.

14. Similarly, the economics of pumped storage (when conjunctive with irrigation) and coal vis-à-vis gas is not even recognised as an issue, leave alone any attempt to remove the vast distortions therein.

15. Experience elsewhere and a priori analyses tell us that the success of a decentralised system would depend upon the choices available to price

elastic participants whether suppliers or buyers. Thus crucial to the emergence and successful working of a market is the existence of sufficient price elastic demand, i.e. bulk consumers.

16. Today many of these have been repelled from the utility system by the absurd tariff structure of the SEBs, that has made the stand alone cost of power for large buyers lower than the price at which the utility (SEB) supplies!

17. Similarly, the need to bring in as much of the elastic supply as possible would mean that the access (including access prices) to the grid would have to be easy and never above the true marginal social cost of access. Cost of access we define as the additional cost of installing meters data loggers and monitoring rather than of grid capacity. Today in the rare instance when access is allowed, it is charged at very high rates. In the case of captive generators the current policy has effectively barred their access. It is necessary that such suppliers are brought on the state/regional/central grid, and interstate transmission would have to worry about such players. In other words, open access is crucial to overall efficiency and optimality of the system.

18. Much has been said about time of the day pricing, and its potential for flattening the load curve. Indeed the potential in this regard is very high. Today the met demand tends to get flatted because of unmet demand being

high during peak hours. With correct pricing and pricing systems it is possible to flatten the load curve considerably, since a significant part of the final demand today is quite price elastic (especially industrial and agricultural)[2].

19. Equally importantly and what is not generally known is that the effective peak capacity (or the available capacity at the peak) can go up considerably by "effectively" bringing in 'captive' stations during peak and by creating the right incentives to value availability during peak more than during off peak.

20. As important as the tariffs or prices themselves, the system of tariff determination is crucial to the development of the sector. With the changes since 1993-94, the CERC and even the SERCs have moved towards a cost plus regulatory mechanism that is not only outdated but would create (and had created) perverse incentives for putting up high cost stations on the system. Not only that, nearly all the privatisation has been of a perverse kind. Such IPPs have shifted major business risks on to the state and ultimately on to the consumer[3].

21. Modern regulated systems attempt to use markets wherever possible, and 'incentive' regulation elsewhere. In re-designing the tariffs and their determination it is important to worry about 'incentive compatibility' i.e., to

[2] Even though difficult for all, at least for bulk consumers it should be possible, even today to offer rates that are 'availability based', since any way was the CERC is pushing for `availability based' tariffs.
[3] The policy rather than any `special behavioural trait' of IPPs have to take the blame. We have argued this elsewhere. Morris, Sebastian (2000).

be sure that all participants have appropriate incentives both negative and positive to do what the designer expects them to do. Additionally with well designed incentive regulatory system it may even be possible to further lower the required return since regulation can reduce volatility.

22. Besides, the costs of regulation (which have been going up rapidly) even more important is the aspect of regulatory risk -different systems carry with them different degrees of risk. Suitable `incentive-regulatory' systems can be designed with very little regulatory risk.

Towards a Tariff Policy

1. If indeed a market in wholesale power is accepted as a means for ensuring the lowest possible cost of power for consumers, then there is little reason to arrive at the tariff for bulk power. Instead, the focus would have to be on how best to create competition in generation.

2. Nevertheless, such a change is likely to take time, and different state systems are likely to move towards that object of marketisation taking differing times. In order to remove the current distortions it is imperative that a tariff framework for interstate and interregional movement of power is announced quickly that is in keeping with the long term objective, but is not suboptimal today.

3. The setting up of state level regulators (SERCs) rather than Regional regulators, implies that one starts with a certain friction in the interstate trade (movement) of power. The object of the policy should be to declare a time frame and a maximum barrier to interstate sale of power. This means that an import duty (and an export duty) should be the basis of restricting interstate transfer of power- not grid capacity per se.

   Such a policy may involve legal issues since electricity is on the concurrent list. Even then, many state governments are likely to accept the delimitation implicit in such a policy taking away the right to ban export and import of power, since the gain in terms of regularity and policy clarity are likely to be large. In any case state governments can be coaxed into the right reform through incentives for the same.

4. The base for the duty both import and export can be as follows: When the power is supplied (contracted and deemed to have been supplied) from a state system with a market in bulk power then the import duty is on the price prevailing at that time. Obviously, measurement of power by the hour at the relevant point on the grid would be necessary. Where the market is not developed then the contract price for power between the two parties across the state would be basis for levy of import duty.

5. Import duty would have to be in addition to other duties on power. All duties need to be made vattable, because otherwise the distortionary effects on the

economy would be severe and the competitive potential of Indian industry would be adversely affected.

6. For the Centre (central regulator) it is necessary to announce a maximum duty that is permissible today as also a time frame for the gradual abolition of this duty. Thus as an example the maximum import duty today should not be more than 30% and the same should be brought down to 15% in five years and to nil in ten years. The point is to quickly announce such rates and then to make the same credible, by carrying out other changes and taking policy measures that lead to the creation of easy interstate movement of power.

7. Ideally the net import duty so collected (import duty - vat credit) that accrues to each state, should be used by the state to finance restructuring, and as commercial loans (credit enhancement) for power related infrastructure that is not fully commercially viable or where the market failures are severe. Good examples would be R&D for coal using technologies, CFBCs, funding to improve safety, for advanced turbines etc. Given the status of power as a regulate industry, and as largely an input, corporate taxes are not justified. Neither are non-vattable excise duties.

8. As stated in the introduction it is only generation and trading in power that is amenable to a market solution. Distribution (at least the wires business) and transmission are best organised as regulated regional and natural

monopolies[4] respectively. This much is clear. Differences though arise when the issue is the mode of regulation. The options here may be broadly classified into actual costs (plus) regulation, and incentive regulation.

9. Cost plus has typically lead to regulatory capture and generally higher prices and inefficiencies unless accompanied by rather special conditions.[5] Cost plus (rate of return) assumes that some central body (the regulator, the CERC/SERC and the CEA earlier in India) knows best and its behaviour is predictable and such as to result in all possible economies including those in the manner of capacity addition can be realised.

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[4] Some have argued and experimented with auctionable /marketable /tradable property rights over segments of the transmission network. These are inherently doomed to failure since the sin quo non of a transmission network is its holistic character. (This is true also of pipeline networks). The value of a segment of a network is a function of what the other segments carry. Thus, a new demand /supply entirely coming up distant from a segment can upset its value by changing the flow through that portion of the segment. Thus, only two options are possible. The regulated common carrier model or the integrated one where transmission is combined with generation and in part (but not necessarily) distribution. This is the usual integrated system - EdF, the Indian systems before changes were introduced in the early nineties being examples.

[5] The Wisconsin system even under the older cost plus traditional regulation worked well resulting in very low prices for electricity. But this was rare and was due to the special condition that the distribution entity was controlled by final consumers, The main distribution entity was a cooperative having strong incentives to question generators and actively examine their tariff applications and bring all relevant information that could result in lower tariff awards to the regulator's court.

10. By bringing in the existence of asymmetric information, need for incentive compatibility[6], incompleteness of any contract and the need for some price variability at least to price elastic large final consumers, it is easy to show that traditional return on investment (cost plus) is entirely dysfunctional. Indeed the entire deregulation movement in the US and UK arose out of the failure of this kind of regulation. We have argued elsewhere (Morris, 1999) why incentive regulation is particularly suitable to India today.

11. Essentially it can be very light, reduce regulatory risk considerably, and be very inexpensive and quickly be put in place. And (with safeguards) it brings about large incentives on the part of the regulated to reduce costs. The RPI-X is only one form of incentive regulation, others being sliding scale[7] and a more special indexed regulation (where the price of the regulated service or

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[6] The notion of incentive compatibility inter alia leads to solutions in terms of ownership restrictions. It is a broader concept than the notion of the public sector in situations of market failure. The idea that the public sector is a solution in the case of a public good was dominant among economists of many varieties including neoclassicals. This idea may be seen as special application of the notion of incentive compatibility given the a priori that the state knows better and is necessarily (and always) keen on achieving the greater common good. Today with the understanding that the state can 'fail' even in the best of situations, the separation of generation from distribution, bans on investments by both in transmission companies are to be seen as other applications of the general notion of incentive compatibility.

[7] These were pretty much in existence in the UK and the US at the turn and early part of this century and were crucial to the private provisioning of many municipal services especially bus and trams, and gas lights, with very little regulatory effort.

commodity is indexed to a suitable index of relevant costs rather than the retail price index) (Morris, 1999).

12. The allowed rate of return as it exists has a major difficulty in that makes it completely unsuitable to a situation wherein the bulk of the external funds have to be raised in markets rather than from government or multilateral and parastatal financial institutions. The return today is on the equity base. This gives rise to perverse incentives to not look for the cheapest sources of debt and capital in general, to designate more of the funds as equity than is necessary since the equity rate (for IPPs) is far higher than the market cost of debt plus the risk premium. This is because equity, given the risk character of electricity generation as a business, is being allowed a higher rate. (Debt cost, as also foreign exchange service cost is entirely a pass thru). If nothing else the base for the regulated return to NTPC and CPSUs as also to the IPPs should have been on the total capital cost. This would have ensured at least an optimal capital structuring and generally lower financial service costs.

13. Today's return of 16% at 68.5% PLF on the 'equity base' for IPPs works out to a much larger return (at 68.5%) since the equity is assumed to continue even after the plant is fully depreciated in 10 to 12 years. (This is apart from the higher return due to higher PLFs being achieved). Such obfuscating base has helped to understate the true returns possible in the power generation sector under the IPP policy. The net effect of higher PLF, and equity

definition is to give `surreptitiously' a return as high as 25-32%. See (Pandey Ajay , 2001, and Paul Pallavi, 2001).

14. In contrast many of the earlier BPSA contracts with much residual life of the NTPC allow a return on equity of 12%. Even on some of the contracts signed after 1993-94, NTPC's return is significantly lower than typical than IPP's returns.

15. The question of what return is to be given to central power utilities is very important. Prices (whether determined through the market, or through incentive price regulation) would have to be such as to give an expected return on total capital employed that would allow CPSUs (and others) to go the market for both debt and equity.

16. Lower return on equity, just because the CPSUs are government owned, is entirely untenable today. This is because, unlike in the past, there is no credible commitment on the part of the government to provide budgetary support for expansion and replacement of assets, at levels commensurate with the capacity of these organisations to invest and grow. And the power sector is in any case expected to grow at the very least 5% p.a.

17. Moreover, there is little doubt that costing has to be on replacement costs basis at the margin, rather than on historical cost as is the case today.

18. The generating CPSUs have long term contracts with SEBs for supply of power called BPSAs signed before 1994. The residual life of these contracts could extend up to seven (?) years. It goes without saying that with the expiry of these contracts the allowed rate of return (on capital employed rather an equity) should be raised to market rates. For all fresh agreements, shorter duration negotiated contracts should apply (as for any seller of power). It is necessary to ask the SEBs who are the beneficiaries of these BPSAs to give these up, allowing NTPC and others to compete in the market. The larger part of the difference between the traded value of power and the contract value of power can then be given to the SEBs to support reform, and a smaller part be retained by the NTPC. Such revenues from residual BPSAs are quite considerable, and needs to the internalised by the SEBs.

Towards a Framework or Transmission Tariffs

1. Transmission charges ought to be viewed as consisting of three components. Connection charges, line loss charges and congestion charges. The first is an access charge to the network and the second is a charge for actually using the network. The third is not really a use charge but a `rent' that reflects the scarcity value of portions of the network. These should be made nearly symmetric between purchases and sellers of power.

2. In addition adjustment charges would arise as when contracted supplies and demands are not realised exactly. These are best considered as not part of transmission charge but as system management charges.

3. Connection charges are charges levied for connection to the grid. Ideally, even in the interstate context all generators and purchasers including potential small distributors and of course the SEBs and their inheritor organisations must have the right to connect to the central grid[8]. The minimum connected load for which interstate and interregional grid should allow connection should be no more than 10MW. At the state level this could be as low as 1-5 MW[9].

4. The charges are proportional (or based on a known relationship) to the connected load for which the connection is sought. The price should be the actual cost of connection linked to an appropriately constructed price index. These are annual charges. The grid utility has the responsibility of ensuring connections whenever sought within a stipulated period.

5. Line loss charges are essentially to recover the cost of operations and need to be proportional to the use of the grid. It would have to proportional to the energy drawn or fed to the grid times the notional distance that the current

[8] Ideally this presupposes that they have the right to connect to the state level grids. Otherwise inoptimal connection points would arise.

[9] Technical limitation may limit these to somewhat higher values.

travels. Notional distances can be worked out given the grid geometry and simulations of the current flow patterns. To start with they need to be simple and be based on the energy times the geographical distance between the point of connection for upload and drawal as specified in matched contracts. This could be made even simpler by declaring upfront a few standard distances into which potential matched contracts fall.

6. Participants - buyers and sellers of power draw and supply power to the grid only when they have matched contracts and which are checked for system feasibility through load flow analyses. Such analyses should also lead to congestion values for each segment of the grid. There would be convergence to congestion values such that few contracts would have to be rejected. Contract rejection to meet feasibility can be based on least deviation from lowest cost optimal for each say half-hour slot).

7. For both connection and line loss charges the prices arising out of the indexed formula should be seen as ceiling prices with the transmission utility being free to offer lower prices.

8. Congestion charges cannot be treated as earnings of the regulated transmission entity. Thus with connection and line loss charges the utility would have to earn the stipulated return if it performs as anticipated. Congestion charges would have to be levied only on those suppliers and buyers who come out as being the cause of the congestion given their

contracted schedule of power supplies and purchases. Such charges should be kept in a suspense account and be made available as funds for expansion of the network with a view to relax congestion.

9. Other more sophisticated schemes to link appropriation to reduction in the growth rate of congestion charges could be thought off. Similarly, part appropriation (return) of the congestion charges to other entities 'helping to relax congestion' can also be thought off in a more sophisticated mechanism.
10. The investment performance (allocative efficiency in a transmission entity's investment decision) can be judged by the gradual reduction in the deflated congestion charges over time.

11. Transmission entities should strictly avoid any actual exposure to the trade. Such exposure would create a conflict of interest, a problem well recognised generally. Additionally, in the Indian given the problem of receivables collection, the transmission entity would be pushed to the wall with own account trading.

12. It is difficult to bring about `incentive' compatibility in a transmission company without ownership restrictions. But incentive compatibility, to keep the cost of transmission down and to vitally improve the choices to suppliers and buyers has to be ensured. The only foolproof way this can be done is to allow the voice of the final consumer (large power using industry, municipal corporations, tram and railway companies, consumer groups and farmers'

associations). in the management of transmission. Therefore, not only debarring generation and distribution companies from ownership of transmission companies, but also ensuring right ownership is important. Even if transmission costs (typically 2 to 5% in most rationally managed systems) are double through `rational over provisioning to increase the choices available to generators, distributors and bulk consumers', the gains elsewhere - in generation and distribution - would more than compensate this underutilisation of assets in transmission. All this means that transmission is best owned partly by the state (up to 49%) and the bulk of rest by final consumers. Small shares by distributors, `captive generators', and generators would also be desirable, to bring possible `technical' issues to the board. Less than majority shareholding by government is desirable, since otherwise the transmission company would be constrained by the status of being a PSUs - dysfunctional interference by the government, vigilance, audit, and being considered as `state' by courts.

13. In the intervening period leading financial institutions with commitment to reform and to the development of a market in power, (but with no exposure to IPPs) could hold part of the equity especially of consumer groups, till these appropriate institutions are developed or identified.

14. The PGCIL with the concurrence of the CERC has put forward an 'availability based and frequency linked tariff' (ABT) for entities supplying power to the grid. This has major dysfunctionalities hidden, which are likely to be revealed

as it·put into practice. It attempts to solve the problem of 'lack of adherence to rules', by incentivising deviant behaviour. This is a fatal error. (Chitkara et al, 2000). All situations cannot be affected as desired by financial incentives, particularly when the disincentives are not being passed on. Pandey, Ajay (2001). In certain situations (and adherence to grid rules is a primary example) only credible denial (disconnection) can ensure grid discipline. The ABT presumes that the frequency would vary significantly from the norm of 50 hertz. As the grid frequency reaches 50 hertz its potential to regulate would decline. There is only one way to overcome grid indiscipline - disconnect overdrawing (and oversupplying entities)[10].

15. For bulk power time of the day pricing that goes beyond a few blocks to which the 24 hours of the day are divided, to at least every half hour slot is necessary. Technically this would mean that for each connector to the grid (buyer or seller), the transmission entity would have to install continuous data loggers that record voltage, current, frequency, power factor, time etc., and whose readings have legal validity.

16. In a developed market for wholesale power there is no need for the regulator to actually determine the prices. The final prices to the small retail consumer would then consist of average of traded prices (market determined)+ allocated transmission charges (regulated) + distribution charge (regulated

[10] There are other measures through that would help. Foremost would be removal of the PLF based incentives for SEB staff, which makes the SEBs reluctant to backdown when the load goes

by SERCs) + stranded contracts /costs recovery (for example to allow IPPs to continue with their sweet contracts if that is so desired). For others depending, on the contracts, variable prices could carry through.

17. In the course of the development of the market though, the regulator would have to specify **maximum** prices for bulk electricity contracted. Here it would be good to do so for say four slots - high peak, peak, off peak and low load hours. Unfortunately these timeslots have to be hard determined to start with at least a few months in advance. Detailed historical data of load, and frequency at each important segment of the grid would prove very useful.

18. Studies of typical Indian systems show that peak load pricing would give rise to optimal prices at the peak that are six to eight times higher than at the base. Ultimately it depends upon the amounts of elastic supplies and demands. Thus the regulator could work on a rather simple model. Start with an optimal capacity addition model with possible constraints being the hydro capacity addition and foreign exchange[11]. The model would give an optimal capacity addition path over time with a break up of fuel mix and size. Using the revealed fuel mix it is possible to construct a hypothetical average plant whose costs and cost parameters are then worked out in great detail. These lead to the base price for each type of demand block. Future prices are announced as a formula the REPI-X (relevant price index formula). These

down (off peak), to result in high frequency during such hours.

[11] Such a capacity addition model has already been put in place at IIMA. See Paul Pallavi (2001).

apply as ceiling prices to all bulk sales of electricity on the grid. Producers are free to charge lower prices. Such a scheme could hold for the next several (say five years till the market comes into existence).

19. Relevant referral prices for major components would have to be carefully specified. Thus the price of coal should be the international coal price (given a standard) + import duties + countervailing duties + sales taxes + average transport cost index of coal by truck and rail from say four coal unloading ports to point x say Nagpur in the interior. Similarly the price of gas could refer to weighted average price of gas in say two or three markets, and in long term contracts with appropriate weights. O&M would have to refer to cost of living index for urban manual and non-manual workers for example.

20. Once the formula is announced it should not change for five years. If legal (or other measures) can bind the system to the announced formula, then they become credible and private investment would flow in.

21. Should the formula allow for foreign exchange pass thru? The question does not explicitly arise. Being a price index that applies to all plants irrespective of fuel used and ownership, or the currency of designation of liabilities, the question dies not arise. Implicitly though, via inputs (and their expected relationship with international prices) the price would adjust in part. More importantly it would not favour plants with foreign currency designated liabilities (equity and debt). It would create the right incentive to use

domestic resources. That in itself has the potential to break the interlocking of international finance and equipment markets, which is the root cause of high priced equipment.

Towards Rules and Prices for Grid Operations

1. Gas stations would come up to serve high peak and peaking demands, since the higher tariffs at these times would help them to recover their fixed costs. Similarly, hydro stations despite their high initial cost would come up to serve the high peak and peak, and base load (during reservoir overflow). There is no need to give a higher regulated return for hydro stations.

2. Hydro stations can raise and lower their power output much more easily than other stations. Typically, coal stations when they run far below their continuous rating capacity become unstable and need oil support. Similarly, above their continuous rating they can deteriorate very rapidly, and suffer efficiency penalty.

3. Effectively therefore coal stations have only a small window over which their output can fall or rise. Gas is in between hydro and coal in this respect, though improvements in gas technology now allow a wider range over which the output from gas turbines can be varied.

4. For minute to minute management of the grid, load dispatch centres (the Regional Load Dispatch Centres -RLDCs - in India) have the crucial responsibility of maintaining frequency and voltage, and keeping the grid together. Principally this is done by continuous monitoring of various parameters and by calling upon stations to respond to rising demand, and, in case of inadequate availability, by asking distribution entities/ segments to backdown.

5. In an integrated system, this task can be performed optimally with much efficiency by adhering to "merit order"; given the set of available plants. Merit order dispatch is also socially optimal. In the decentralised and fragmented situation, where the grid entity is separate from the generation and distribution entities, and obviously so in the market model, 'defacto-merit order' has to emerge out of the rules and prices. The operational efficiency of any decentralised /market system can be judged by how close it is to merit order in operations. Even if it is not very close, the decentralised /market system can when designed correctly, result in better investment efficiency, i.e. capital assets are created in a such a pattern and manner as to result in higher capacity utilisation. Thus some small gaps (as long as they do not widen) between the theoretical marginal cost of power and the traded prices are not worrisome.

6. In a fully developed market, the difference between contracts and realisations would have to appropriately priced. But even before such

differences are priced so as to create a market for the same, the transmission company needs to have the resources to be able to manage the grid, i.e. either to make up the difference, or the authority to eliminate the same through rules.

7. It could tie up capacity (typically hydro and gas) which are then available on tap. Thus another relatively small market for capacities rather than power can emerge. In such a situation where the contracted supply is not forthcoming the contracted demand could backdown if such is the contract (interruptible). Otherwise the grid company could still supply it at a higher price (say some percentage above its contract price or the price of the highest priced contract in the system) by calling upon the standby capacity to deliver. Standardised punitive collections can be imposed upon the original contracted supplier that failed to deliver. Similarly, in a situation where a contracted demand did not fully materialise, if the supplier correspondingly reduced output in a demand constrained situation (excess availability), and when there was no congestion based prior rejection of contracts, then nothing more needs to be done. In all other situations punitive charges would have to be imposed on both parties. When the supplier would like to supply, he could do so at a price x% lower than the original contract price or at the price of the lowest contract through the system.

8. Thus in system operations the grid company would make revenue out of 'failures' or 'differences', and contracting parties would lose when their

contracts are not fully realised. Therefore, the contracts would tend to be risk efficient. Thus a supplier may well choose to contract at a lower price with a distributor /consumer whose demands are predictable, and vice versa.

9. The grid company would lose money when it has to hold capacity contracts and when there are system failures. The probability of cascading system failures can be reduced considerably when the grid company retains the right to automatically cut off any segment of connected load /source or portion of the grid.

10. Some generators with high variable cost but low fixed cost may choose to operate in the second market for capacity (with the grid company). If capacity contracts were permissible between other players, the grid company would be forced to be efficient in its capacity contracts.

(I am thankful to Ajay Pandey, my colleague for his very useful comments).

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