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A MARKET DESIGN FOR DEVELOPING COUNTRIES

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SUMMARY

Power system operation in India was in disarray till the year 2002, in spite of the country having a generating capacity of over 100,000 MW. Some of the underlying problems were peculiar to India while some were common with other developing countries. The scenario has changed dramatically thereafter, thanks largely to introduction of an innovative concept of frequency-linked pricing of unscheduled exchanges between utilities as an integral part of the so-called Availability-Based Tariff (ABT). Many things have happened in the process, one being establishment of a framework in which utilities can freely buy from and sell to the "pool" (the large power system) at a pool price (as per the regulator - specified relationship between frequency and per kWh rate) known on-line, without entering into a contract with any party.

Many may find it hard to believe that although the frequency in Indian grids varied by as much as 3 Hz daily, the power system still operated uninterruptedly most of the time. The concept of frequency - linked pricing was developed primarily to restrict these frequency deviations, through incentives for generation increase and load curtailment when frequency was low and incentives for backing down of generation when frequency was high. However, this concept can work only in a system wherein frequency is allowed to vary by, say, +/- 0.5 Hz. As such, it can be deployed in developing countries which suffer from problems similar to those existing in India and where frequency already varies. They could reconcile to formalisation of such frequency variations. The scheme cannot be applied in developed countries where frequency remains substantially constant, say, within +/- 0.05 Hz for most of the time, but it could be of academic interest to them.

In the overall scheme (somewhat similar to NETA of UK), all scheduled interchanges between utilities take place at specified or pre-agreed rates, independent of frequency. Scheduled supplies from generating stations to their long-term customers are based on Availability Tariff, with clearly specified capacity charge (linked to plant availability) and energy charge (for scheduled energy). Only the deviations from schedules (over/under-supply, over/under-drawal) are priced at the frequency-linked rate, which is zero when frequency is 50.5 Hz or above, and ramps to a ceiling (higher than diesel generation cost) at a frequency of 49.0 Hz. Special metering measures the actual net interchange of each party every 15 minutes, which is compared to the scheduled energy for the same 15-minute block to determine the algebraic deviation. The rate charged / paid for this deviation depends on average frequency during the given time block.

The paper describes the pre-2002 situation in India, the improvements brought about since then, details of the Indian version of Availability Tariff, and the various facets of frequency - linked pricing of deviations. Special emphasis is laid on the market mechanism already operating in India, wherein participants have unrestricted choice between long-term contracts, short-term bilaterals, trading

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through an exchange and trading to the "pool", and all this through decentralized scheduling, self-dispatch, minimal communication and at negligible cost. How the concept facilitates, with minimal regulatory oversight, true merit - order in generation, harnessing of captive and co-generation, optimal utilization of hydro, pumped-hydro and non-conventional resources, merchant plants, cross-border trade with neighbouring countries etc., is also explained.

KEYWORDS

Availability Tariff – Deviation – Frequency – India – Market – Pricing – System Operation

1.0 THE BACKGROUND

India is a large federal democracy, with a population of over 1000 million, and a generating capacity of over 100,000 MW. It was demarcated into five (5) electrical regions in early Sixties, for planned development of the power system. Each region comprises of 5 to 8 States (provinces), each having a State Government - owned State Electricity Board (SEB) – a vertically integrated monopoly utility responsible for power supply to all consumers within the respective State. (This position is now changing). The SEB - owned generation is supplemented by large pit-head, hydro, nuclear and gas - based generating stations owned by Central Government - owned companies. These generating stations have been established on regional basis, and regional 400 kV a.c. super grids have been developed by another Central Government company to transmit power from the remotely located Central generating stations to the receiving points of SEBs.

Up to the year 2002, each region operated as a separate a.c. system, with a few inter-regional links of back-to-back HVDC for controlled exchange of power between the different regions. Due to backlog in generating capacity addition over the years, all regions face large peak-hour shortages, and extensive load-shedding is a daily routine. The SEBs have specified shares in the Central generating stations, but tended to overdraw (in their anxiety to meet consumer demand in the respective State). In the process, grid frequency often fell to dangerous levels (~ 48 Hz), leading to grid collapses almost every year. The prevailing commercial arrangements were simplistic – a single-part tariff for supplies from Central generating stations, in which the per kWh rate remained constant irrespective of the quantum or hour of drawal. There was, therefore, no incentive for SEBs to keep their power drawal restricted to their respective Central station share. In fact, the SEBs' drawals were measured only in monthly energy, and an SEB could neutralize its peak-hour over-drawal by off-peak under-drawal.

On the other hand, the prevailing single-part tariff encouraged both the Central companies and the SEBs not to back down their generating stations during off-peak hours (when system load came down, below the available generating capacity), and grid frequency rose to levels as high as 52 Hz, causing tripping of gas turbines and long-term damage to steam turbines. SEBs compared the variable cost of their own generating stations with the total (fixed + variable) cost of Central generating stations, and wanted the latter (mostly pit-head) to back down, leading to non-optimised operation of the whole system.

2.0 AVAILABILITY TARIFF – THE INDIAN VERSION

A World Bank / ADB - sponsored study was carried out by M/s ECC of USA in 1993-94 in the above scenario, and adoption of a 3 - part Availability Tariff for supplies from Central generating stations was recommended. Its implementation took time, and finally started in 2002, region-by-region. The three parts of this Indian version of Availability Tariff are: (1) capacity charge, for payment of fixed cost of a generating station, (2) energy charge, for payment of variable cost for scheduled generation, and (3) a plus/minus charge for deviations from schedule.

The capacity charge payment is linked to plant availability declared the previous day in terms of capability to deliver MW. Its amount over a year would equal the normative annual fixed cost if average plant availability over the year is 80% of rated capacity, and it is paid by the SEBs in proportion to their shares in the plant capacity. The energy charge corresponds to the fuel cost of the generating station for the given scheduled energy for the day. The SEBs have to pay it for their respective scheduled energy to be received from the station. Any deviation from the schedule is accounted for as Unscheduled Interchange (UI), the rate for which depends on frequency at that time. The UI rate is zero when the frequency is high (50.5 Hz or above, signifying a surplus situation), and ramps to a ceiling level (higher than the diesel - generation cost) when frequency is low (49.0 Hz or lower, signifying a serious shortage), as shown in figure - 1. The net energy interchange of each party is metered for every 15-minute time-block and compared with the scheduled energy for the same time-block to determine the UI energy, as shown in figure - 2. The UI rate depends on the average frequency for the given 15-minute time-block. A generating station gets paid for any over-supply, and has to pay for under-supply. An SEB pays for over-drawal and gets paid for any under-drawal. All UI payments are routed through a regional UI pool account, on a weekly cycle. There is no frequency bias in interchange schedules.

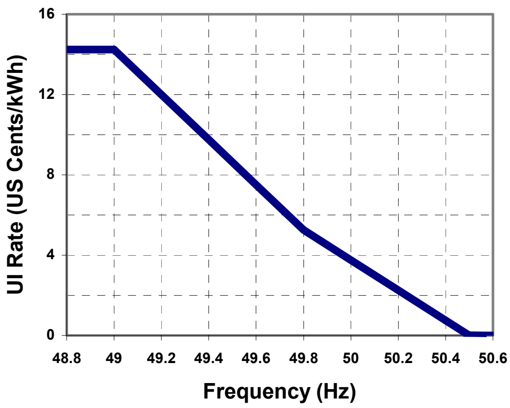

Figure - 1

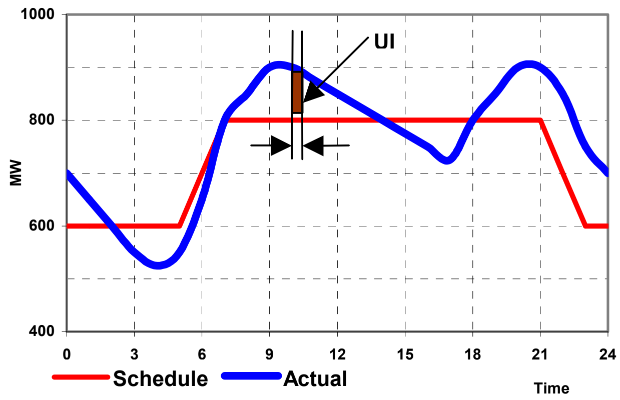

Figure - 2

The generation of Central stations is scheduled on day-ahead basis. The stations declare their MW capability for the next day by 9 a.m. daily. The Regional load dispatch centres (RLDCs) break up these as per States' standing shares and convey them to State load dispatch centres (SLDCs) by 10 a.m. The SLDCs examine how best to meet the consumer demand, from State's own stations and out of the State's share in Central stations' available capacity. SLDCs then advise the RLDCs by 3 p.m. their requisition from Central stations. RLDCs aggregate these and issue by 5 p.m. the generation schedules for Central generating stations and drawal schedules for the SEBs.

The above schedules serve as the operational and commercial datum, but it is not mandatory to maintain the net interchange as per these schedules. The SEBs and Central stations can deviate from these schedules, as long as the deviation does not cause a transmission constraint or a grid contingency. The UI mechanism, however, ensures that the parties are perpetually encouraged to deviate in the direction beneficial for the interconnection, i.e. towards enhancing overall optimization and / or improving the frequency.

3.0 IMPROVEMENTS BROUGHT ABOUT

The operating pattern of regional grids in India has dramatically changed since the year 2003. The frequency now remains between 49.0 and 50.5 Hz (the range permissible for sustained operation for steam turbines as per IEC:45) for most of the time. The generating stations, irrespective of ownership, are backed down according to merit - order. The scheduling and energy accounting processes are fully streamlined, as a result of which there are no operational or commercial disputes any more. Grid collapses have stopped and grid disturbance have become rare. As described above, the scheduling has been delegated (decentralized) to the SLDCs, and RLDCs basically coordinate the scheduling of Central stations. Dispatch decisions are decentralized even further, to the power station operator level.

There are many other advantages as well, as would be seen from the discussion which follows. The process is still 'on' in India. Unbundling (separation of generation, transmission and distribution) of SEBs has started, and it is necessary to replicate the above-described regional scheme within each State. Free - governor operation has been another contentious issue. Most generating units presently do not respond to frequency changes, causing unacceptable frequency fluctuations. A major drive has started to put all generating units on free - governor mode of operation and thereby stabilize the frequency, to enhance grid security as well as to enable sustained frequency signal for self-dispatch of generation and decentralised load management.

In the process of implementation of Availability Tariff, a complete infrastructure has been established wherein utilities can enter into long-term contracts for supply from identified generating stations, can enter into short-term bilateral arrangements (directly, through a trader, or through an exchange), or can trade power with the pool, i.e. the large electricity grid, at the frequency - linked UI rate, which is synonymous with pool price.

4.0 A PRE - REQUISITE FOR ELECTRICITY TRADING

Electricity is a unique commodity. It cannot be seen, or measured in kilograms and metres. Since it cannot be stored, its production has to match the consumption from minute-to-minute. In a power system, all supplies get mixed up and ownership cannot be tagged. Still, it is sold and bought (notionally) between multiple players operating in an interconnected system, and at different prices. Even the price structures may differ from transaction to transaction.

Yet another peculiarity of power system operation is that any interconnected entity can change its supply or drawal quantum on its own, without any other entity being able to control it. The supply / drawal by an entity may also differ from its contractual position. For example, entity A may enter into a contract to supply 10 MW to entity B through the electricity grid, but in actual operation, the supply by A into the grid at a certain time may reduce to 9 MW, while B may be drawing 11 MW from the grid. A question may arise as to who would be responsible to whom for these deviations. And how would the situation be handled commercially?

At another time, entity A may be delivering 10.5 MW into the grid while entity B may be drawing only 8 MW from the grid, although the contract and schedules are for 10 MW. Should B pay to A for 8 MW or 10 MW? Who has received the differential (2.5 MW)? Who should pay for it to whom and at what rate? These situations and questions did not rise earlier when there was only one vertically bundled utility, operating as the monopoly supplier. However, with the advent of "reforms", vertical unbundling of utilities and moves towards establishment of "electricity markets" (in which there would be many suppliers, and distribution utilities / consumers would have a choice to select their suppliers), these issues would become paramount. Intractable disputes could arise unless an infrastructure is in position to tackle the situation.

The transition to "market" could be specially painful in the developing countries where the new entities neither have the technical means to maintain their actual interchange with the grid as per their respective schedules, nor have the culture of operational discipline in which the actual interchanges have to be equal to the respective schedules all the time.

A pragmatic approach to handle this situation, particularly in the developing countries, would be to accept (and formalize) such deviations, and to have a regular pricing scheme for all deviations from schedule. The matter then becomes fairly simple. To illustrate, in the first example, entity B would pay to entity A for 10 MW (irrespective of actual deliveries) at the contracted rate, A would pay for one MW of under-supply into a pool account at a certain rate, and B would pay into the pool account for one MW of over-drawal at the same rate. The deviations from schedules may be viewed as energy exchanges with the grid (a power pool). Entity B can be viewed as having bought 10 MW from A and one MW from the pool. Entity A can be viewed as having taken one MW from the pool to meet its commitment to supply 10 MW to B. The drawals from the pool obviously have to be at the "pool price", the short-term system marginal price.

In the second example, entity B has still to pay to entity A for 10 MW at the contracted rate, but gets paid for 2 MW under-drawn at the pool price, from the pool account. Entity A also gets a payment from the pool account for 0.5 MW of over-supply, at the same pool price. A and B need not bother as to who has received the 2.5 MW differential, as they get paid for it from the pool account. The contract between them also continues to be fully honoured by all concerned.

5.0 THE INDIAN SOLUTION

The "pool price" in the two examples above may not be equal, being the system marginal price at two different times. It is important that the pool price is determined in an unambiguous manner, and is not disputed. Since the deviations from schedule discussed in the above examples are same as the unscheduled interchange (UI) of Availability Tariff, and the "pool price" is nothing but the UI rate, India had no problem at all in this regard. The total mechanism for commercial handling of deviations was already in place when electricity trading started in India in 2003. Put differently, the "pool price" has been linked to grid frequency. The scheme has been in operation for over two years and is now fully proven. It cannot be applied in developed countries where the grid frequency is substantially constant, but it can bring immense benefits to developing countries which suffer from problems similar to India's, or which can let their grid frequency vary by +/- 0.5 Hz or so.

The tight linkage between frequency and pool price, which has been duly approved by the Central Electricity Regulatory Commission, induces frequency - linked dispatch of generating stations, as shown in figure - 3. In turn, it induces real merit - order in generation, and links the system marginal cost also to frequency. This is briefly explained below.

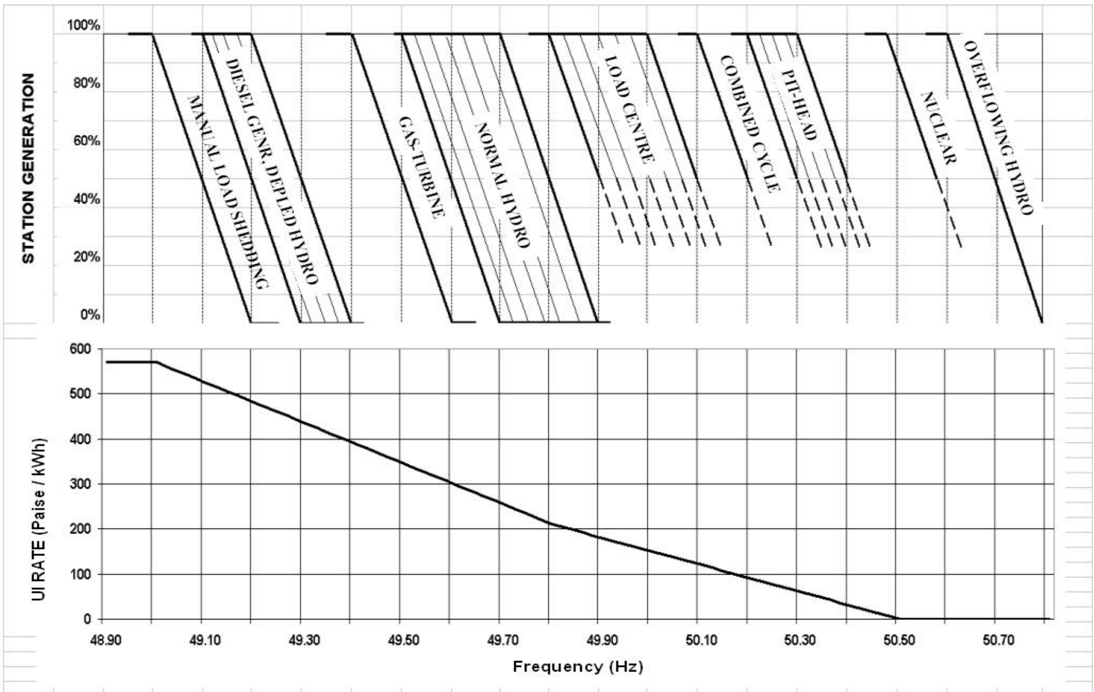

Figure - 3

Suppose a generating station has a variable cost of 180 paise (about 4 US cents) per kWh. The pool price is at this level when the frequency is 49.9 Hz. If the actual frequency is below 49.9 Hz, the pool price is higher than 180 paise / kWh, and any over-generation by the station above its schedule would fetch the station (from the pool account) a UI amount higher than its fuel cost for the extra generation. The station is thus encouraged to maximize its generation (irrespective of the schedule given to it) whenever the frequency falls below 49.9 Hz. On the other hand, when frequency rises above 49.9 Hz, the station is induced to back down. It would save fuel cost @ 180 paise / kWh, and pay to the pool account at a lower rate for its under-generation, thus saving money. Cheaper energy would be replacing costlier energy in the process.

For a generating station having a variable cost of 90 paise per kWh, the corresponding threshold frequency would be 50.2 Hz, and it would start backing down only when frequency goes above 50.2 Hz. It is thus possible to allow the utilities and generating stations to self-dispatch (deviating from schedules given a day ahead, in the process), and still achieve the ultimate merit-order operation on interconnection - wide basis.

Once this scheme is adopted, reliability of communication would no longer be an issue, because all generating stations can self-dispatch, based on the reading of the local frequency meters. There would be no centralized computations at all, with the dispatch function totally decentralized to the station level. The station operator has only to compare his own actual variable cost and the current pool price, to decide whether the generation should be changed, and in which direction. Data integrity and confidentiality, as also cyber safety, would become non-issues, at least as far as dispatch decisions are concerned.

6.0 THE FRAMEWORK

In the overall scheme successfully operating in India since 2003, all contracted supplies are translated into day-ahead net interchange schedules, and the contracted capacity charge and energy charge rates apply for scheduled quantum of power / energy. Special static energy meters installed on the periphery of each entity record the actual energy interchanges for each 15-minute time block. These meters are locally read electronically once a week, and all readings are transmitted to a centralized processor through PC to PC communication. The actual net interchange, 15-minute wise, for each entity is then computed, week - by - week.

The average frequency for each 15-minute time-block is also recorded by the above meters. The corresponding pool price for each time-block is multiplied by the energy deviation (actual energy interchange minus the scheduled energy) for the same 15-minute time-block, to arrive at the UI payments to be made or received by the entities from the pool account. These accounts are also issued weekly, for payment within ten days. The capacity charge and energy charge payments are made by the purchasers directly to the suppliers, as per the terms of their contracts. Only the payments for deviations from schedules are routed through the pool account, which is operated by the respective load dispatch centre.

7.0 FURTHER OPPORTUNITIES

Other opportunities which open up, once the above described scheme is in place, are as follows:-

7.1 Merchant Plants: It would be possible to set-up and operate power plants without signing power purchase agreements. For such plants, since there is no contract, the schedule would be zero and there would be no capacity charge or energy charge. The entire energy supplied by them would be treated as a deviation from schedule, and paid for at the pool price. One need not be apprehensive about destabilization of the system by any over-supply: it would only raise the frequency and cause a decline in the pool price. Further, new power plants could be set-up with only a part of their capacity covered by PPAs. The remaining capacity could be supplied into the grid as a deviation, at the pool price.

7.2 Default coverage for PPAs: In case a distribution utility which has signed a power purchase agreement (which in turn has enabled an IPP to set up a power plant) defaults in making payments, the IPP would have to sell the power to some other entity. In case the IPP fails to find another buyer on reasonable terms, he can at least sell the power into the grid as UI and get pool price for it from the pool account.

7.3 Captive and Co-generation plants: The captive and co-generation plants set up by industries often have surplus idling capacities, which should be harnessed for meeting the system load during periods of shortage. Since the availability of such capacity is uncertain, it may be difficult to have contracted arrangements and schedules for the same. What is readily possible is to absorb such supplies into the grid as deviations from schedule (the schedule being zero), and pay the pool price for energy actually supplied. The plant operator would know the pool price on-line through a local frequency meter, and would decide when to supply power into the grid. It would automatically ensure that such power is supplied only when the grid has a shortage (and frequency is tending to be low), without any intervention or advice from the concerned dispatcher.

7.4 Hydro-electric generation: For optimal utilization of the available hydro-thermal mix, the hydro stations should be operated only for peaking. This can be achieved in a decentralized manner by stipulating that a hydro station would be paid only the pool price for its output (the schedule being zero). Applying this approach to small and mini-hydel would be particularly useful, as it would reduce the burden on load dispatchers. Pumped-storage schemes would become viable, and would operate optimally by drawing pumping energy when pool price is low and generating peak-hour power when pool price is high.

7.5 Non-conventional / Renewable sources of energy: Wind and solar plants generate power depending upon wind and solar power availability, and not according to grid requirement. Devising equitable contractual arrangements for them is problematic. An alternative would be to dispense with any contractual arrangement, and treat their entire supply (as-and-when-available) as a deviation from schedule, and pay the pool price for it.

7.6 Cross-border trading of electricity: This is another complex area where matters can be considerably simplified through use of UI mechanism. There could be two types of cross-border exchanges. One would be for contracted sale, where the exchange would have to be scheduled on day-ahead basis, and paid for at contracted tariff. The other would be for as-and-when-available energy without any prior commitment. For the latter, instead of a pre-fixed price, the UI rate could be applied. For example, Nepal could supply its hydro power surplus to India at the UI rate on Indian side, in localized manner. On the basis of UI rate and its trend (seen through a local frequency meter), the Nepalese hydro station could decide when to generate how much, to send maximum possible energy to India during low-frequency periods, benefiting both countries.

8.0 BENEFITS FOR DEVELOPING COUNTRIES

Many developing countries suffer from peak-hour shortages, and this situation is likely to persist due to continuing load growth and resource constraints. The system described above would benefit them in the following ways, almost overnight:

i) Maximization of peak-hour supply from existing power plants of different types, due to built-in incentives.
ii) Harnessing of surplus generation from captive and co-generation plants through a simple commercial mechanism.
iii) Optimum utilization of hydro stations, including pumped - storage.
iv) Encouragement for setting up IPP plants and even Merchant plants, through reduction of commercial risk.
v) Merit - order operation of all generating stations in the real sense, leading to optimal utilization of resources and reduction of cost of supply.

A number of other advantages that would accrue are:

i) Much simpler and cost - effective infrastructure for load dispatch, communication, metering, energy accounting, etc.

ii) Improvement in frequency regime, in case it has been a problem earlier, and consequent enhancement of grid security. Also, reduced damage for generating units and consumers' equipment, at least in the years to come.
iii) Decentralization of controls and total autonomy / flexibility for participants in scheduling and dispatch.
iv) Collective control of pool price through load - generation balance in the grid.
v) Incentive to distribution utilities to manage consumer load, particularly during shortages, and to shift it to off-peak hours.
vi) No subjectivity in computation of pool price, and no risk of spiking, miscalculation, etc.
vii) Uniform incentives/disincentives to all players through on-line indication of pool price.
viii) A complete framework for scheduling of power supplies according to contracted arrangements, both long-term PPAs and short-term bilaterals.
ix) A true electricity market for on-line trading at the prevailing pool price, without entering into any contract / agreement at all.
x) A stable mechanism with a strong feedback loop: too much supply increases frequency, lowers the pool price and induces curtailment of supply; supply shortage decreases frequency, raises the pool price and induces enhancement of supply.
xi) No need for tight control of net interchange and, therefore, no requirement of close on-line monitoring, AGC, etc.
xii) Utilities can be allowed to lean on others during contingencies, since they pay for support actually received, and the mechanism is reciprocal.

9.0 CONCLUDING REMARKS

A pre-requisite for trouble-free operation of the mechanism described above is that the entire a.c. interconnection is free-flowing, i.e. free of transmission constraints in the normal course. The regional grids have been developed in India over the years through coordinated planning. 400 kV lines running across the regions have been built as per foreseen requirements of generation addition. Stated differently, transmission augmentations were / are scheduled and implemented along with the proposed generation addition, and in coordination. The 400 kV supergrids so developed already have the capability to transmit the entire output of remotely located pit-head and hydro stations, with a degree of redundancy. Such a system, when all lines are in service, has built-in margins to accommodate power flow changes on account of deviations from schedule by players. It is only rarely that the RLDCs have to intervene and ask a utility to restrict its deviation from schedule, on account of transmission constraint. (India has only a few transmission constraints of consequence, and these are associated with inter-regional exchanges of power, which were not planned for and accordingly can not be fully accommodated). To reiterate, before adopting the described mechanism, a developing country has to check that its transmission system is robust enough to accommodate a reasonable degree of deviations from schedule. These can be assessed: no utility would deviate to replace cheaper energy by costlier energy.

One must also reconcile to frequency being allowed to float in a range of about +/- 0.5 Hz, with no attempt to bring it back to (or keep it close to) 50.0 Hz. Consequently, there is no time error correction in this scheme, and frequency clocks cannot be used. The control areas are notional, with no requirement to maintain the actual interchange close to the net schedule, or to reduce the area control error to zero every ten minutes, etc. Deviations from schedules need not be returned in kind, and there is no frequency bias or tie-line bias in the simple mechanism.

The UI mechanism in India can be looked at in many ways. Though seemingly radically different, it serves the same purpose as the balancing market component of UK's NETA. The UI rate is also like the pool price of the earlier UK mechanism, except that the UI rate is linked to frequency and is known on-line, whereas UK's pool price was computed, retrospectively.

BIBLIOGRAPHY