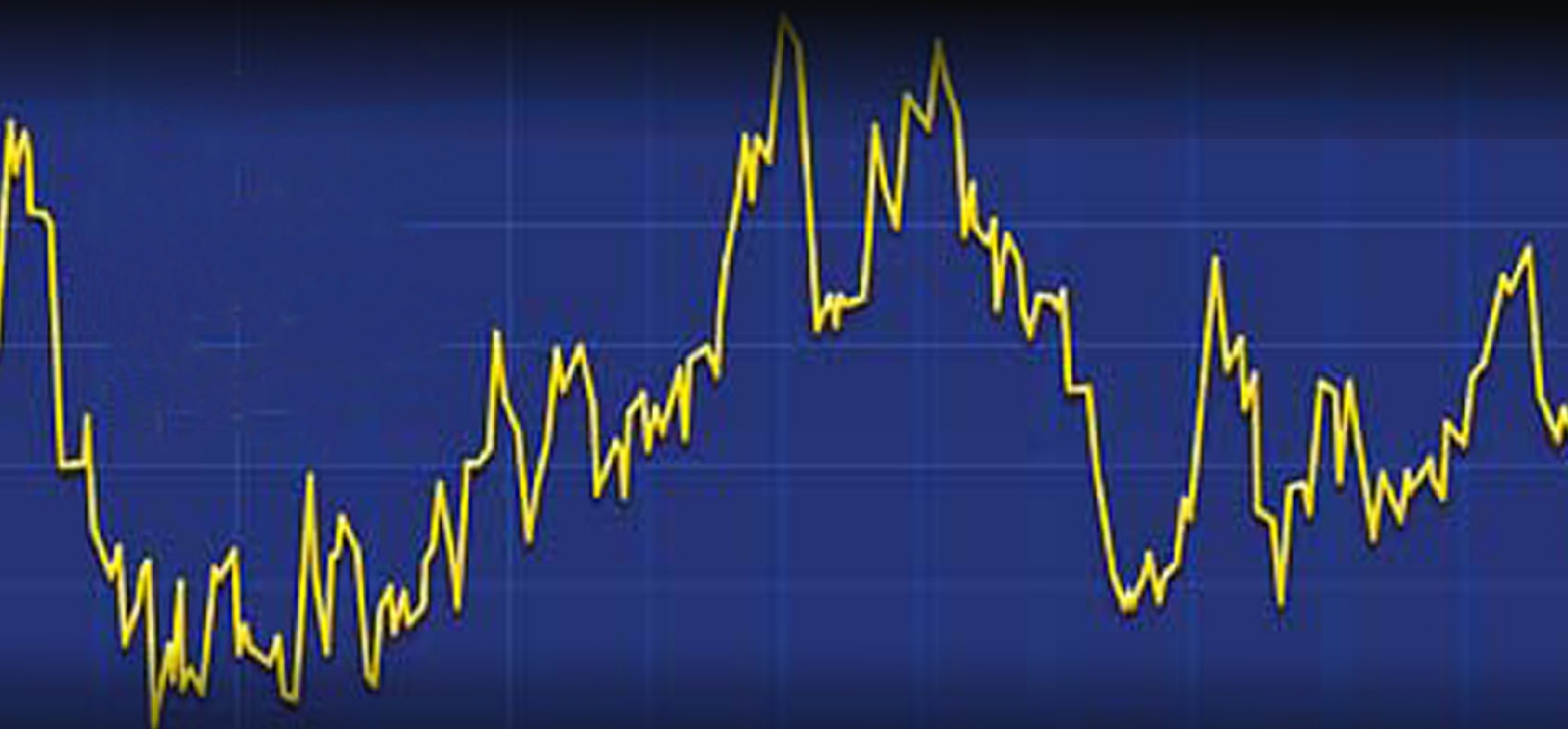


THE UI POWER POOL

THE FUTURE OF THE INDIAN ELECTRICITY MARKET



IPPAI
Independent Power Producers Association of India

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Contents

	<i>Preface</i>	1
Chapter-1	<i>Introduction</i>	2
Chapter-2	<i>The need of the hour</i>	7
Chapter-3	<i>Availability Based Tariff – Background & Structure</i>	8
Chapter-4	<i>Availability Based Tariff – How it works</i>	12
Chapter-5	<i>The UI Pool</i>	14
Chapter-6	<i>The UI Pool – Opportunities</i>	17
Chapter-7	<i>The role of Power Exchanges</i>	23
Chapter-8	<i>The UI Pool as a market mechanism</i>	25

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Preface

The aim of this document is threefold – to examine the status and structure of the Indian power market, to present a detailed perspective of the most unique and critical component of the Indian electricity system - Availability Based Tariff, and to explore viable options for development of the market and advancement of the sector.

The Indian power sector is at the crossroads. Put simply, substantial infusion of investments is required for achieving the daunting targets that has been set out for the sector. A standard market design, with options for hedging against market risks, price volatility, etc. is vital to the sustained growth of the sector. Along with independent system operators at both central and state levels, establishing an independent market operator (IMO) along with enforceable settlement mechanisms is an absolute requirement to ensure fairness and best practices. Given that all tariffs are regulated and payment security is far from satisfactory, influx of investments in adding generation and transmission capacity has been by and large limited. The new opportunities offered by the 'Availability Based Tariff' mechanism, particularly 'Frequency Linked Tariff' or 'Unscheduled Interchange (UI)' has not only exciting possibilities, but is a true reflection of the real economics of energy. This is all the more so since it is already linked to the international price of oil through the UI on the one hand and consumer demand on the other, two important indicators of the "market".

The contents of these pages are purely for discussion and debate – the result of some 'out-of-the-box' thinking. The basic purpose is to trigger a fresh approach to developing a commercially viable roadmap for the energy sector and to the possibilities of using the UI pool as a market mechanism and an investment tool.

We hope this document will kick-start many more dialogues and deliberations on the future of the Indian electricity market; and help in finding the way forward to create a truly competitive and sustainable market environment to ensure India gets the market instruments which will place it on track to meeting its energy needs in the 21st century.

We would like to thank and acknowledge a long list of eminent thinkers who have inspired us and helped shape some of the thoughts that have gone into this initiative, Dr.Manmohan Singh, the late Rajiv Gandhi, the late P V Narasimha Rao, H D Deve Gowda, Dr.R K Pachauri, R P Singh, C P Jain, the late P R Kumaramangalam, Dr.Kirit Parekh, N K Singh, Bhanu Bhushan*, S L Rao, Gajendra Haldea, R V Shahi, D V Kapur, J L Bajaj, T L Shankar, P S Bami, E A S Sarma, Firdaus Vandrewala, A K Srivastava, Cyril Shroff, S Rajgopal, Naresh Chandra, Muzafar Saifullah, Bibek Debroy, Laveesh Bhandari, R G Yadav, Alok Roy, S K Sonee, Anjan Roy, M G Raoot, V K Agarwal, Hemant Sahai, Amit Kapoor, Abheek Burman, Sanjeev Ahluwalia, Soma Banerjee etc. We would also like to acknowledge the support of Power Grid Corporation and the Regional Load Despatch Centres in our endeavour.

* the father of the UI concept

Introduction

The Indian Electricity Market

The Indian electricity market has for long been dominated by state-owned utilities which function as vertically integrated entities engaged in generation, transmission and distribution of power. Commanding over 90 per cent of the generation capacity and an even larger share in transmission and distribution networks, these state utilities have enjoyed absolute monopoly in the sector.

However, even with a total installed capacity of over 115 GW, the Indian power sector is faced with acute shortages. Typically, only three-fourths of the total capacity is available at any given time to meet the load requirements due to various reasons. Generation capacities are constantly plagued by constraints of planned as well as forced outages. Also, uneven dispersal of natural resources in the country and logistical challenges begets immense hurdles in ensuring reliable and stable sourcing of fuels. Last but not least, the geographic and demographic diversity of the country and the consequent demand variations arising at different regions and/or different seasons play an important role in triggering these shortages. On the other hand, power plants cannot be switched off and on at the flip of a switch; due to which power has to be generated constantly, irrespective of demand, causing huge wastages of power in that particular state/region.

The enactment of the Electricity Act, 2003 (EA 2003) introduced the Indian power sector to a relatively new domain – inter-state trading in electricity. By identifying electricity trade as a distinct activity, EA 2003, along with pursuant regulations from the Central Electricity Regulatory Commission (CERC), has paved the way for a paradigm shift in the power sector.

Interestingly, trade in this unique commodity not a new phenomenon in the India's power sector. For long, utilities in India have exchanged electricity by means of 'wheeling and banking arrangements'. However, the new regulations have certainly opened avenues for more active participation from the private sector as well in this vibrant market segment.

The deregulated electricity markets offer new possibilities for power suppliers. Historically, the suppliers have been bound to the power that they themselves have produced, or to long-term bilateral supply contracts. Since the dawning of deregulation, a third and very interesting possibility has developed – trading of surplus power.

Under the new trading arrangements, it is being expected that bulk electricity will be traded through a variety of bilateral and multilateral contracts. Those buying and selling electricity through bilateral contracts are likely to include not only generators and suppliers (who physically produce or consume electrical energy), but non-physical traders as well.

With inter-state trading electricity being considered as an independent and licensed activity, duly regulated by the CERC, a host of prominent power sector majors have ventured into this arena. It is also important to note that many State utilities have also taken up trading power with other States directly through bilateral as well as banking agreements.

While inter-state trading in electricity is steadily evolving into a viable and high-potential option for stakeholders, the power sector environment is still complex and paradoxical. There is still a great deal of ambiguity in terms of the applicability of law and regulation as well as the nature and facets of the market. At the same time, the opportunities and market dynamics are progressing in leaps and bounds. The Indian electricity system has many endemic attributes which shape and influence the development of the market. It is important to understand key elements of the sector such as ABT, IEGC, regional frequency trends, demand and supply profiles, grid characteristics, market structure and commercial standards etc.

International Experiences

Globally, electricity market deregulation has been underway for more than a decade since the United Kingdom opened a Power Pool in April 1990. Some markets such as Nord Pool and New Zealand have been very successful, but others such as California and the pre-NETA UK market have failed.

The design of a competitive wholesale market is determined by two fundamental principles:

1. competitive and efficient energy trading, and
2. reliable operation of the grid

There are significant differences in the design of energy trading and in the ways to conduct security constrained economic dispatch. Some markets have a day-ahead market for spot trading and some markets just have a day-ahead or an hour-ahead scheduling process to facilitate real time operation. Most overseas markets adopt a zonal model, but a majority of U.S. markets use a nodal model.

Market deregulation started a decade ago with a central despatched pool structure with competitive bids and offers. In such a market, suppliers would submit all of their generated electricity output with associated prices and all buyers would submit bids to buy electricity. The pool would be the only place to trade electric energy and settle the energy prices based on demand-supply movement. Hence, both suppliers and buyers would be limited in their ability to hedge against potential risks.

The pool structure can suffer from various forms of market power because

- 1) electricity demand is relatively inelastic and consumers as a whole have little influence on the prices,
- 2) a large amount of energy trading provides strong incentive for suppliers to raise prices by physical and economic withholding, and

- 3) market power can be exercised in various situations that are difficult to monitor and correct in a timely manner such as happened in the United Kingdom (pre-NETA) and California.

There is a trend in recent market designs to move away from the pool structure toward using bilateral contracts to mitigate market power and hedge risks. One major example of this is the UK's replacement of the pool model with the bilateral oriented NETA. An important lesson from the California crisis is the crucial role of managing risk through market design. In most other industries, risk bearing is spread along the supply chain via long-term forward contracts or financial instruments for hedging. This is generally accepted as the optimal behaviour since a seller and a buyer have common interests in mutual insurance against the volatility of spot prices.

Some of the major international markets are, Pennsylvania-New Jersey-Maryland Interconnect (PJM), New York ISO (NYISO), ISO-New England (NE-ISO), Electric Reliability Council of Texas (ERCOT), Independent Electricity Market Operator (IMO) of Ontario, Power Pool of Alberta, New Energy Trading Arrangement (NETA) of the United Kingdom, Nordic Power Exchange (Nord Pool), National Electricity Market (NEM) of Australia, New Zealand Electricity Market (NZEM) etc.

The Indian Electricity Grid

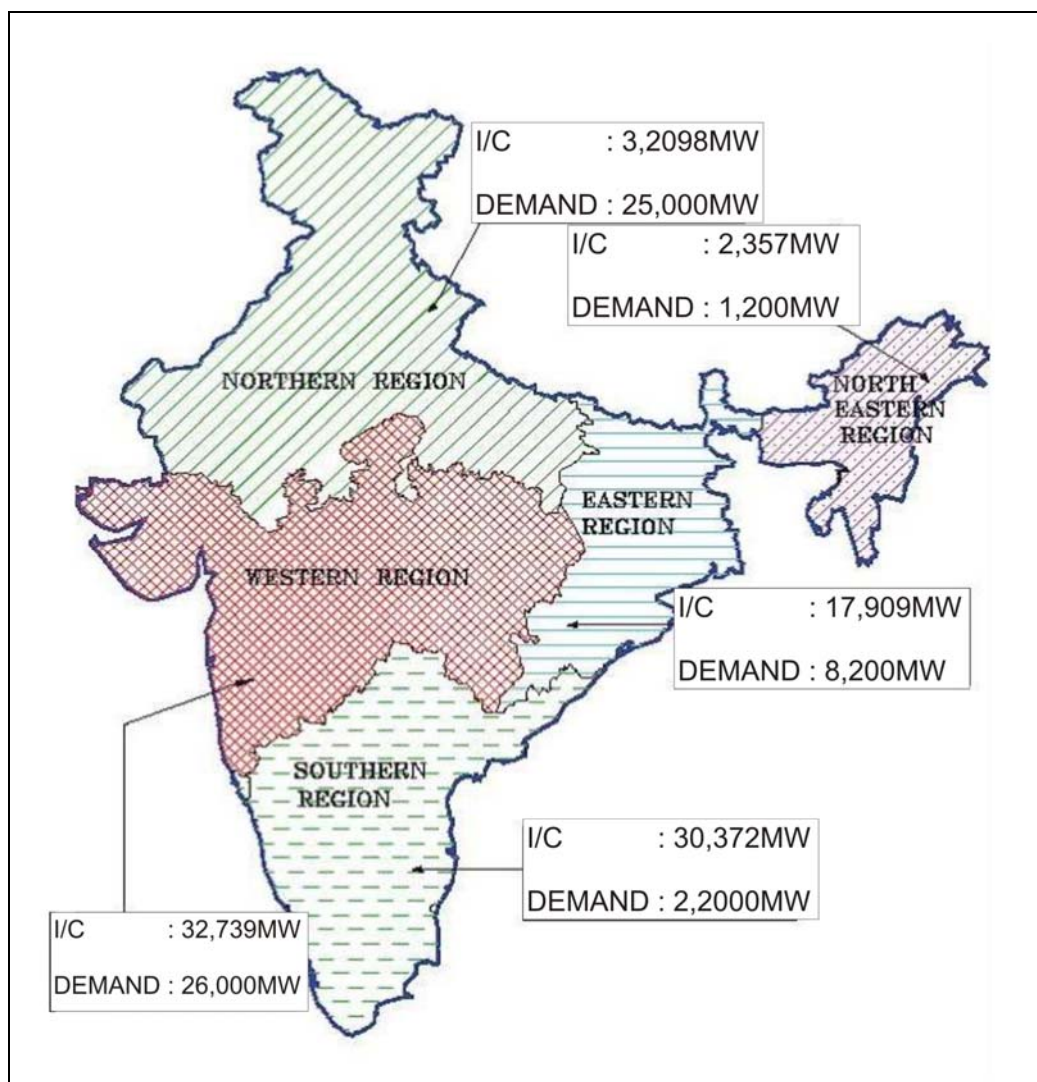
India's Transmission and Distribution (T&D) network is unique. The transmission assets and operations within states are mainly owned and managed by the respective state electricity boards (SEBs)/electricity departments/transmission companies. Interstate level transmission, however, is the sole responsibility of the central sector transmission company – Power Grid Corporation of India Limited (PGCIL). Distribution operations are entirely looked after by the SEBs/departments and in some cases by private companies.

Before independence, the electricity supply industry in India comprised generating stations supplying power to loads in their immediate vicinity. With a reorganisation of the sector and the emergence of the State Electricity Boards (post-1950) and the establishment of central sector generators (in 1975), the development of adequate power transfer network gained significance.

Consequently, PGCIL was incorporated to centralise the development of the transmission network in the country. This resulted in not only the development of regional transmission systems but also interlinking of these systems. This, in turn, led to transfer of power from surplus regions to deficit ones, facilitating better utilisation of existing resources. In order to strengthen this transfer, a strong national grid comprising a transmission system associated with the central generating projects and interregional lines was envisaged.

At present, India's power transmission and system operations are going through an extensive national restructuring program parallel with evolving state-level reforms. PGCIL, India's central transmission utility, is implementing this program.

Currently, there are five regional transmission grids for the northern, eastern, north-eastern, western and the southern regions. PGCIL has planned to interconnect its regional systems to a national power grid, which can facilitate power sharing from neighbouring states or countries with surplus power. The entire programme has been planned out in a phased manner consisting of three phases.

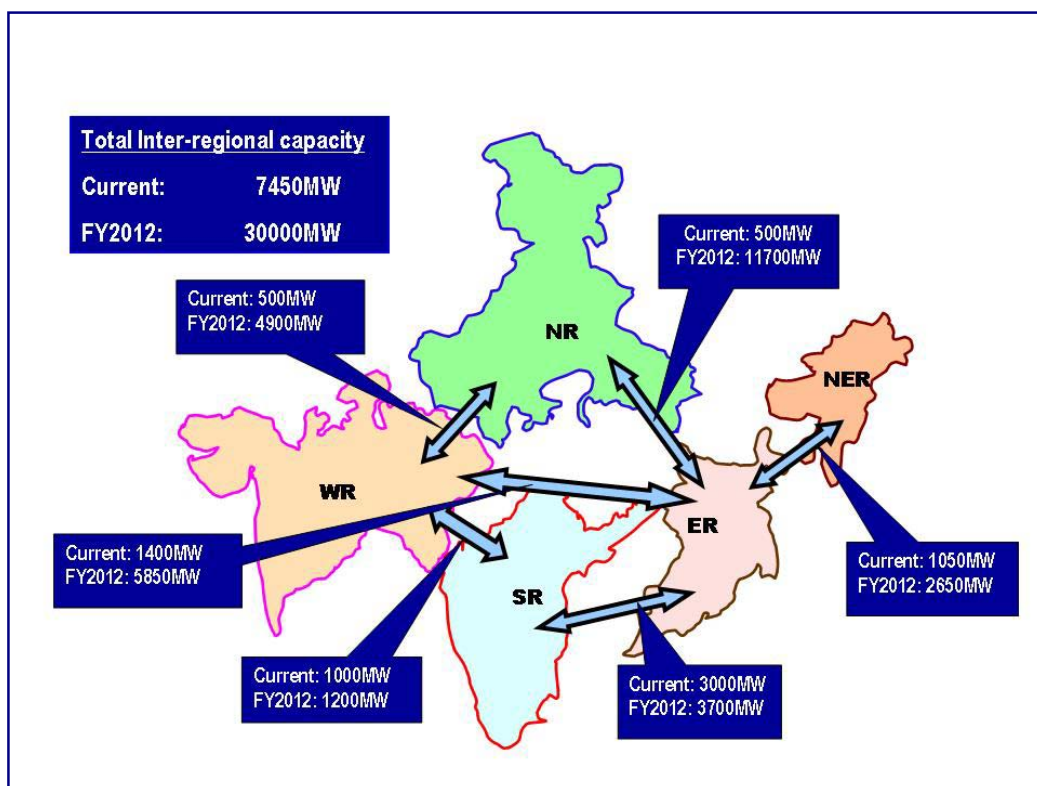


Source: PGCIL

Phase-I involving interconnection of regional grids through HVDC Back-to-Back links with a cumulative capacity of 5,000 MW has already been completed.

Phase-II is partially complete and involves a hybrid system comprising of high capacity HVDC and HVAC lines (both 765 kV and 400 kV). At the end of this phase, cumulative inter-regional capacity would be 23,000 MW. This would help transfer operational surplus and would provide flexibility in inter-regional transfer of power.

The Phase-III is scheduled to be completed by 2012. This would consist of a ring of 765 kV transmission lines inter-connecting ER, WR and NR and would be utilised for transfer of short term as well as long term surplus. The cumulative capacity at the end of this phase would be 30,000 MW.



Source: PGCIL

The Augmentation of the T&D backbone is vital to the development of the Indian electricity market, especially in view of the ambitious mission envisaged by the Government - for providing power for all by 2012. The National Electricity Policy, 2005 has endorsed this mission to fully meet demand by 2012, aiming for capacity addition exceeding 1,00,000 MW.

In order to meet these daunting targets, attracting and encouraging private investments – be it domestic or foreign, is an absolute necessity. Needless to add, this presents an immense opportunity for stakeholders to benefit from a sector that is poised for explosive growth.

The need of the hour

The most critical factor in ensuring the effective development of the market and attractive investments is the creation of an environment that bolsters investor confidence and offers fiscal security. Historically, the lack of effective use of generation to its maximum potential, poor track record of the state utilities burdened by operational inefficiencies as well as subsidies and cross subsidies have made the investor wary of the sector. Creation of a market based on standard market design and uniform market rules has to precede fresh investments and competition in the sector. Only such a market can neutralise the incumbent price and performance risk.

The need of the hour is to create market instruments that ensure payment security and manage demand risk & price risk, minimise financial uncertainties and bring greater economic performance into the electricity market. Truly independent market operators and settlement mechanisms, along with independent system operators are crucial for enabling the transition to a sustainable and equitable market environment, with a level playing field to attract private investments.

In this context, the system of Availability Based Tariff (ABT), particularly the Unscheduled Interchange (UI) pool based on frequency linked tariff (FLT) could be viewed as a potential market mechanism and investment tool that provides fiscal security and performance guarantees to the stakeholder. FLT offers a neutral and transparent mode of determining the 'true' value of electricity. FLT by its linkage to fuel prices and the frequency by its correlation to real-time supply and demand offer an excellent opportunity for automatic price discovery and sending accurate price signals to the consumer.

Availability Based Tariff – Background & Structure

What is Availability Tariff

The term Availability Tariff, particularly in the Indian context, stands for a rational tariff structure for power supply from generating stations on a contracted basis. The power plants have fixed and variable costs. The fixed cost elements are interest on loan, return on equity, depreciation, O&M expenses, insurance, taxes and interest on working capital. The variable cost comprises of the fuel cost, that is coal and oil in case of thermal plants and nuclear fuel in case of nuclear plants. In the Availability Tariff mechanism, the fixed and variable cost components are treated separately. The payment of fixed cost to the generating company is linked to availability of the plant, that is, its capability to deliver MWs on a day-by-day basis. The total amount payable to the generating company over a year towards the fixed cost would depend on the average availability (MW delivering capability) of the plant over the year. In case the average actually achieved over the year is higher than the specified norm for plant availability, the generating company would get a higher payment. In case the average availability achieved is lower, the payment would be lower. Hence the name 'Availability Tariff'. This is the first component of Availability Tariff, and is termed as 'capacity charge'.

The second component of Availability Tariff is the 'energy charge' and this would comprise of the variable cost (i.e., fuel cost) of the power plant for generating energy as per the given schedule for the day. It may particularly be noted that energy charge (at the specified plant-specific rate) is not based on actual generation and plant output, but is based on scheduled generation. In case there are deviations from the schedule (e.g., if a power plant delivers 600 MW while it was scheduled to supply only 500 MW), the energy charge payment would still be for the scheduled generation (500 MW), and the excess generation (100 MW) would be paid for at a rate which would depend on the system conditions prevailing at the time. If the grid has surplus power at the time and frequency is above 50.0 cycles, the rate would be low. If the excess generation takes place at the time of generation shortage in the system (in which condition the frequency would be below 50.0 cycles), the payment for extra generation would be at a high rate.

To recapitulate, the Indian version of Availability Tariff comprises of three components: (a) Capacity Charge, towards reimbursement of the fixed cost of the plant, linked to the plant's declared capacity to supply MWs, (b) Energy Charge, to reimburse the fuel cost for scheduled generation, and (c) a payment for deviations from schedule, at a rate dependent on system conditions. The last component would be negative (indicating a payment by the generator for the deviation) in case the power plant is delivering less power than scheduled.

How do the beneficiaries share the payments

The Central generating stations in different regions of the country have various States of the Region as their specified beneficiaries or bulk

consumers. The latter have shares in these plants according to Gadgil formula, and the shares are duly notified by the Ministry of Power. The beneficiaries have to pay the capacity charge for these plants in proportion to their share in the respective plants. This payment will be dependent on the declared output capability of the plant for the day and the beneficiary's percentage share in that plant, and not on how much power / energy the beneficiary wants to draw (and/or actually draws) from the Central station.

The energy charge to be paid by a beneficiary to a Central station for a particular day shall be the fuel cost for the energy scheduled to be supplied from the power plant to this beneficiary during the day. In addition, if a beneficiary draws more power from the regional grid than that totally scheduled to be supplied to him from the various Central generating stations at a particular time, he shall be required to pay for the excess drawal at a rate which would be dependent on the system conditions, the rate being lower if the frequency is high and higher if the frequency is low.

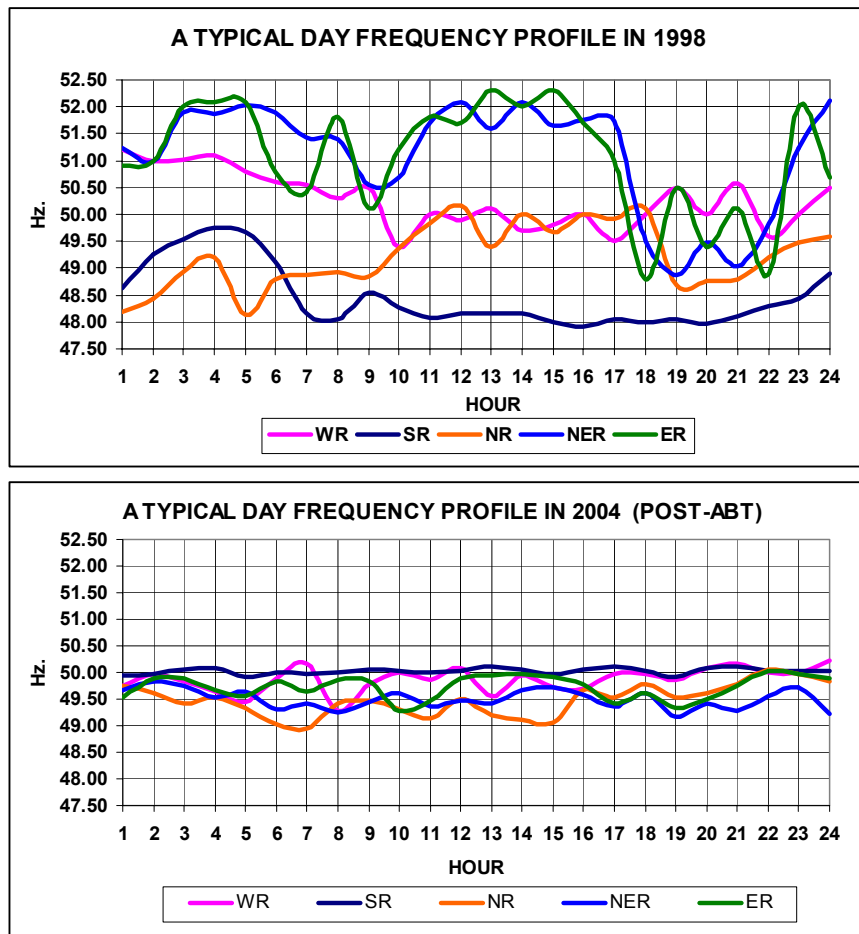
How does the mechanism work

The process starts with the Central generating stations in the region declaring their expected output capability for the next day to the Regional load despatch centre (RLDC). The RLDC breaks up and tabulates these output capability declarations as per the beneficiaries' plant-wise shares and conveys their entitlements to State load despatch centres (SLDCs). The latter then carry out an exercise to see how best they can meet the load of their consumers over the day, from their own generating stations along with their entitlement in the Central stations. They also take into account the irrigation release requirements and load curtailment etc that they propose in their respective areas. The SLDCs then convey to the RLDC their schedule of power drawal from the Central stations (limited to their entitlement for the day). The RLDC aggregates these requisitions and determines the dispatch schedules for the Central generating stations and the drawal schedules for the beneficiaries. These schedules are then issued by the RLDC to all concerned and become the operational as well as commercial datum. However, in case of contingencies, there is a provision for revising the output capability declaration by Central stations, the requisition by the beneficiaries, and accordingly the schedules.

While the schedules so finalized become the operational datum, and the regional constituents are expected to regulate their generation and consumer load in a way that the actual generation and drawals are generally according to these schedules, deviations are allowed as long as they do not endanger the system security. The schedules are also used for determination of the amounts payable as energy charges, as described earlier. Deviations from schedules are determined in 15-minute time blocks through special metering, and these deviations are priced as described above. As long as the actual generation/drawal is equal to the given schedule, payment on account of the third component of Availability Tariff is zero. In case of under-drawal, a beneficiary is paid back to that extent according to the frequency dependent rate specified for deviations from schedule.

Why was Availability Tariff necessary

Prior to the introduction of Availability Tariff, our regional grids had been operating in a very dissatisfactory manner. There were large deviations in frequency from the rated frequency of 50.0 cycles. Low frequency situations result when the total generation available in the grid is less than the total consumer load. These can be curtailed by enhancing generation and/or curtailing consumer load. High frequency is a result of insufficient backing down of generation when the total consumer load has fallen during off-peak hours. The earlier tariff mechanisms did not provide any incentive for either backing down generation during off-peak hours or for reducing consumer load / enhancing generation during peak-load hours. In fact, it was profitable to go on generating at a high level even when the consumer demand had come down. In other words, the earlier tariff mechanisms encouraged grid indiscipline.



Source: PGCIL

The Availability Tariff directly addresses these issues. Firstly, by giving incentives for enhancing output capability of power plants, it enables more consumer load to be met during peak load hours. Secondly, backing down during off-peak hours no longer results in financial loss to generating stations, and the earlier incentive for not backing down is neutralized. Thirdly, the

shares of beneficiaries in the Central generating stations acquire a meaning which was previously missing. The beneficiaries now have well defined entitlements, and are able to draw power upto these entitlements at normal rates of the respective power plants. In case of over-drawal, they have to pay at a higher rate during peak load hours, which discourages them from over-drawing further and thereby pulling down the frequency. This payment then goes to beneficiaries who received less energy than was scheduled, and acts as an incentive/compensation for them.

How everybody has benefited

The mechanism has greatly streamlined the operation of regional grids in India. Firstly through a defined scheduling procedure, the constituents are encouraged to follow the given schedules for generation and drawal during the normal course. Any constituent which helps others by under-drawal from the regional grid in a deficit situation, gets compensated at a good price for the quantum of energy under-drawn. Secondly, the grid parameters, i.e. frequency and voltage, have improved, and equipment damage correspondingly reduced.

During peak load hours, the frequency can be improved only by reducing drawals, and necessary incentives are provided in the mechanism for the same. High frequency situation on the other hand is being checked by encouraging reduction in generation during off-peak hours. Thirdly, because of clear separation between fixed and variable charges, generation according to merit-order is encouraged and pit-head stations do not have to back down normally.

The overall generation cost has accordingly come down. Fourthly, a mechanism has been established for harnessing captive and co-generation and for bilateral trading between the constituents. Lastly, Availability Tariff, by rewarding plant availability, enables more consumer load to be catered at any point of time.

Availability Based Tariff – How it works

The daily scheduling process

Suppose a 1000 MW Central coal-fired power station has three beneficiaries (States – A, B and C) with allocated shares of 30%, 30% and 40% respectively. Suppose the station foresees a capability to deliver 900 MW (ex-bus) on the next day, and advises the same to the RLDC by 9 AM. The RLDC would break it up, and advise the three SLDCs by 10 AM that their entitlements in that Central station are 270 MW, 270 MW and 360 MW respectively, for the next day. Entitlements in the other Central stations would also be advised by RLDC to the SLDCs similarly.

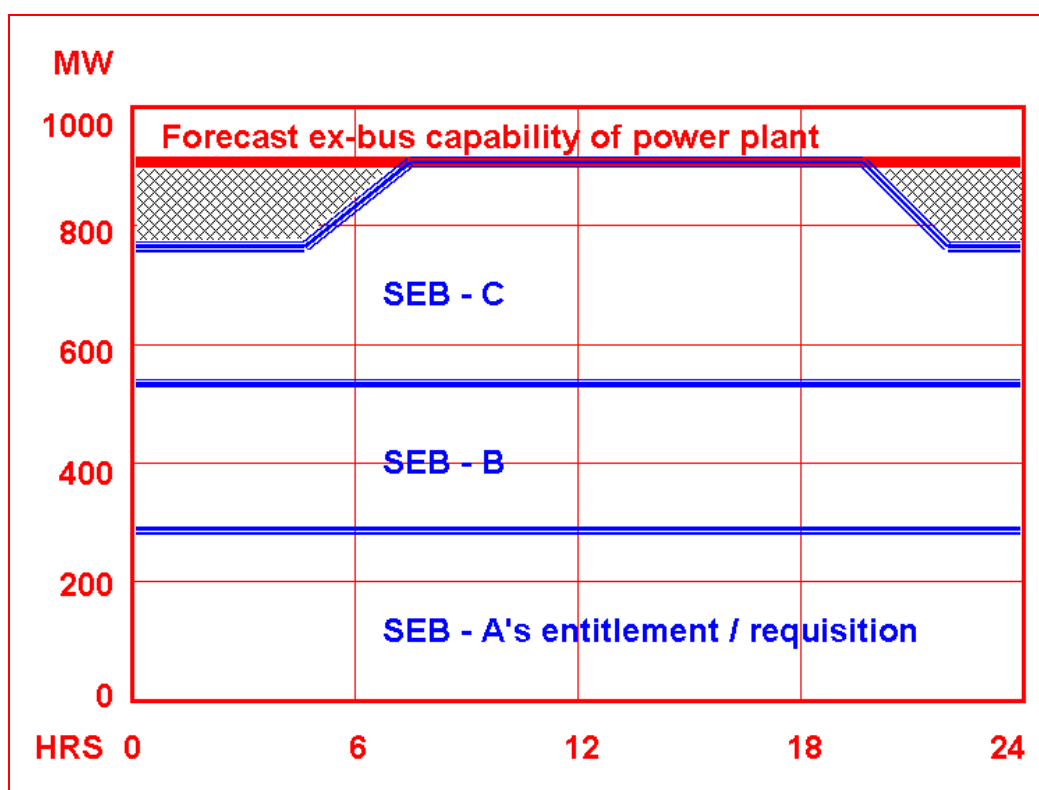


Figure - 1

Simultaneously, the SLDCs would receive availability status from the intra-State stations as well. They would carry out a detailed exercise as to how best to meet the expected consumer demand in their respective States over the 24 hours. They will have to compare the variable costs of various intra-State power stations inter-se, and with energy charge rates of the Central stations, and also consider the irrigation release requirements vs. energy availability of the hydro-electric stations. After this exercise, the SLDCs will issue the dispatch schedules for the intra-State stations, and their requisition from the Central stations (restricted to the States' respective entitlements). Suppose States – A and B fully requisition their shares from the Central station under

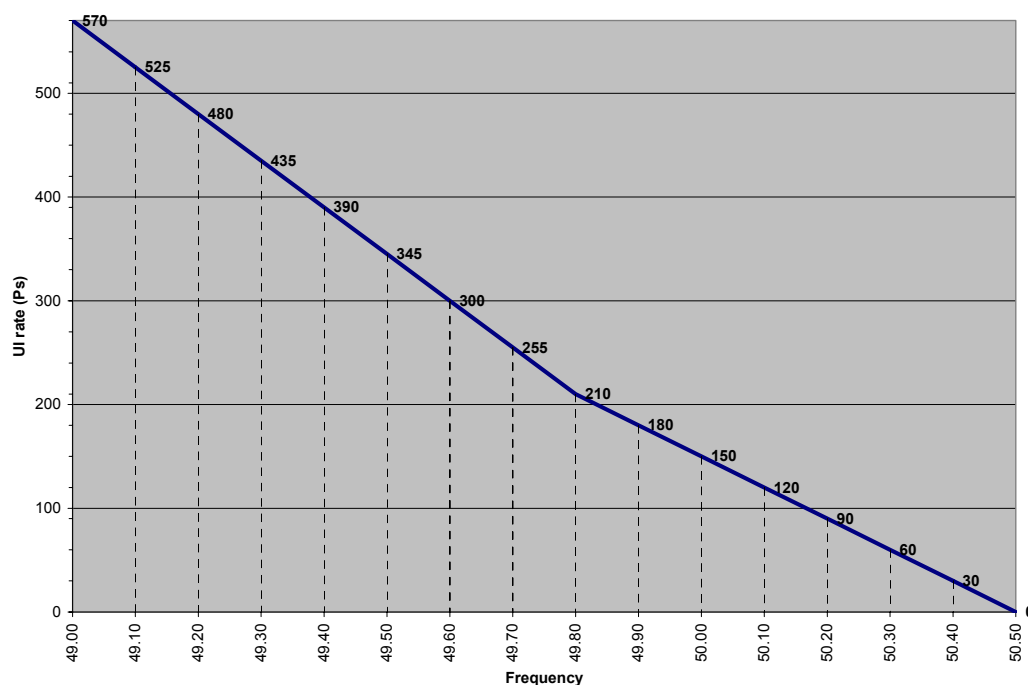
consideration (270 MW each, throughout the 24-hour period), while State–C requisitions 360 MW during the day time, but only 200 MW during the night hours.

Summation of the three requisitions would thus produce the total dispatch schedule for the Central generating station, of 900 MW during the day time and 740 MW during the night hours, as illustrated in figure - 1. This would be issued by the RLDC by 5 PM, and would be effective from the following midnight (unless modified in the intervening hours). States – A, B and C shall pay capacity charge for the whole day corresponding to plant availability of 270, 270 and 360 MW, and the generating station would get capacity charge corresponding to 900 MW. Energy charge payments by the three States would be for 270×24 MWh, 270×24 MWh, and $(200 \times 8 + 360 \times 16)$ MWh of energy respectively, at the specified energy charge rate of the generating station.

Deviations from schedule

As mentioned earlier, the energy charge, at the specified energy charge rate of a generating station, is payable for the scheduled energy quantum. The energy actually supplied by the generating station may differ from what was scheduled. If actual energy supplied is higher than scheduled, the generating station would be entitled to receive a payment for the excess energy (the deviation from schedule, technically termed as Unscheduled Interchange (UI) in Availability Tariff terminology) at a rate dependent on frequency at that time. If the energy actually supplied is less than that scheduled, the generating station shall have to pay back for the energy shortfall, at the same frequency-linked rate.

UI Tariff Chart w.e.f 1st October 2004

**Figure - 2**

The relationship between the above UI rate and grid frequency, for the inter-State system, is specified by CERC. The present relationship, applicable from 1.10.2004, is shown in figure - 2. When the frequency is 50.5 Hz or higher, the UI rate is zero, which means that the generating station would not get any payment for the extra energy supplied. It would burn fuel for producing this extra energy, but would not get reimbursed for it at all. Conversely, if the actual energy supplied is less than scheduled energy, the generating station would still be paid for the scheduled energy (at its energy charge rate) without having to pay back anything for the energy shortfall. It would thus be able to save on fuel cost (for the energy not generated) and retain the energy charge as net saving. There is thus a strong commercial incentive to back down

generation during the high frequency situation, and help in containing the frequency rise.

On the other hand, when frequency goes down, the UI rate (for both over-supply and under-supply) ramps up, reaching a ceiling level of Rs. 5.70 per kWh at a frequency of 49.0 Hz. At a frequency of 49.5 Hz, the UI rate is Rs. 3.45 per kWh presently. Under this condition, any extra energy sent into the grid would get the generating station a UI payment at the rate of Rs. 3.45 per kWh. For any shortfall, the generating station shall have to pay back at the same rate. It would thus have a strong commercial incentive to maximize its generation during periods of such low frequency.

A similar scheme operates for the States (beneficiaries) as well. Any State drawing power in excess of its schedule has to pay for the excess energy at the same frequency-dependant rate. The high UI rate during low-frequency conditions would induce all States to reduce their drawal from the grid, by maximizing their own generation and/or by curtailing their consumer load. If a State draws less power than scheduled, it pays for scheduled energy quantum at the normal rate and gets paid back for the energy not drawn at the much higher UI rate. On the other hand, during high-frequency conditions, a State can draw extra power at a low rate, and is thus encouraged to back down its own costlier generating stations. An under-drawal during high-frequency conditions would mean that the State would pay for the scheduled power quantum unnecessarily. It should then either reduce its schedule, or increase its drawal.

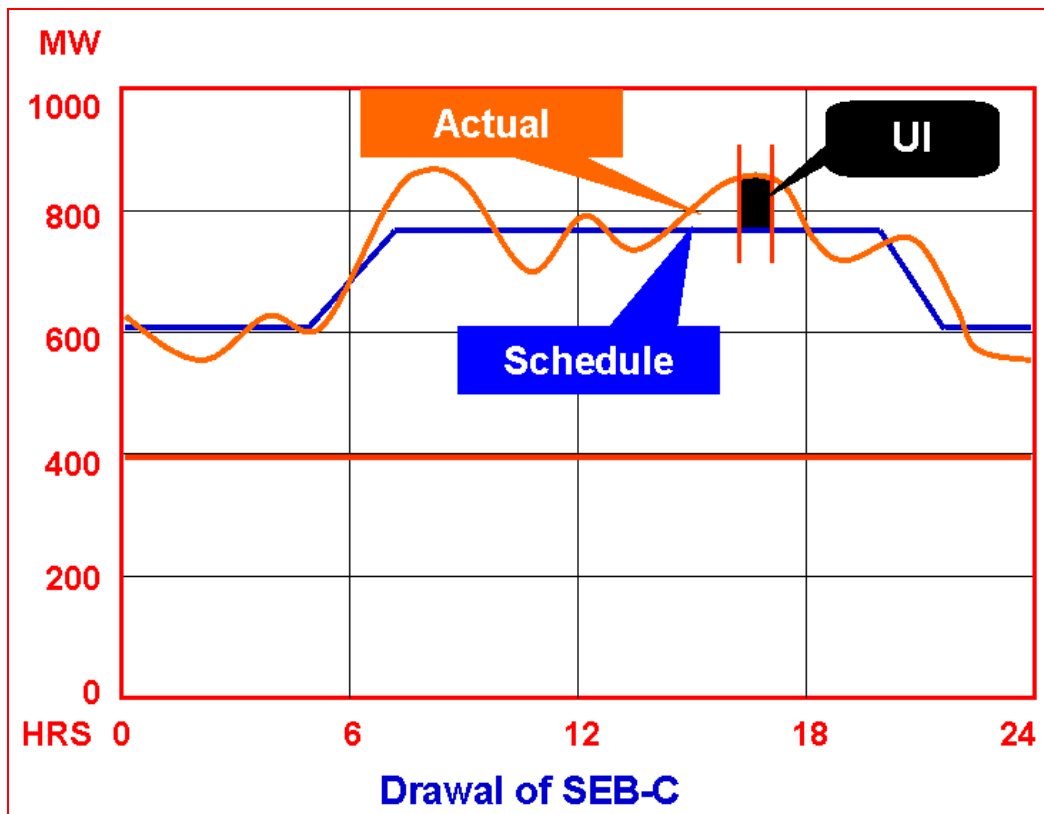


Figure - 3

For the above purpose, the energy is metered in 15-minute time blocks, since frequency keeps changing (and the UI rate with it). The metered energy is then compared with the scheduled energy for that 15-minute time block, and the difference (+ or -) becomes the UI energy, as illustrated in figure - 3. The corresponding UI rate is determined by taking the average frequency for the same 15-minute time block.

Also, for each Central generating station and State, the actual energy has to be metered on a net basis, i.e. algebraic sum of energy metered on all its peripheral interconnection points, for every 15-minute time block. All UI payments are made into and from a regional UI pool account.

The UI Pool - Opportunities

A simple trading opportunity

Let us return to figure - 1. The two areas marked X represent the off-peak hour capability of the Central generating station which State-C has not requisitioned, although within its entitlement. This capability (160 MW) is now available with the Central station, and it has three options before it, as follows:

- i) Back down the station during off-peak hours, i.e. generate power only according to the schedule given by RLDC by aggregating the requisition of the three States. In this case, the station gets capacity charge for the day corresponding to its availability declaration (900 MW), and energy charge to fully recover its fuel cost for generating the scheduled quantum of energy during the day.
- ii) Find a buyer (other than State-C) for the above off-peak surplus, and generate power adding the MW agreed to be taken by this buyer to the aggregate schedule for States-A, B and C. As the station is already being paid capacity charge for 900 MW, it may not be fussy about further fixed cost recovery. As long as the energy sale rate agreed upon is higher than the fuel cost per kWh of the station, it would be financially beneficial for the station to enter into such a deal. It would also reduce the technical problems associated with backing down of the station and improve the station's efficiency. If time permits, the Central generating station may look around to find the party which would pay the highest rate, and maximize its profit. (There is a mistaken belief that the generating station has to share the accruing profit with State-C. There is no such stipulation by CERC. The station is free to retain the whole profit accruing on this account).
- iii) Instead of selling the off-peak surplus power through a bilateral agreement as described above, the station may accept the schedule given by the RLDC, but generate power to its full capability of 900 MW even during off-peak hours. The result would be an over-supply of 160 MW (as a deviation from schedule), for which the station would get paid from the regional UI pool account at the prevailing UI rate. In effect, it would be a sale to the regional pool, and would make financial sense as long as the prevailing UI rate is higher than the fuel cost per kWh of the station.

There is no restriction of any kind in this respect, and the Central generating stations are free to exercise any of these options from time to time, or even a combination. The only precaution the station needs to take, in the second option, is to ensure that its agreement with the off-peak surplus buyer has a provision for termination / reduction of supply at a very short notice. This may be required in case State-C, on the day of operation, suddenly reverts and asks for scheduling of its full entitlement, and the surplus capacity available

with the Central station for such sale is no longer available. In other words, the agreement has to be non-firm or interruptible. Consequently, the price of this supply would be much lower than that for power supplied on firm basis.

However, the above options for the generating station arise only in case a State has not requisitioned its full entitlement in the first place. In fact, the same three options as described above are available to State-C, before they get passed on to the Central station, and are as follows:

i) Requisition power from the Central station only as per its own requirement, and draw power as per the resulting schedule.

ii) Requisition full entitlement of 360 MW from the Central station for the entire 24-hour period, find a buyer for the off-peak surplus and schedule a bilateral sale. This would make sense as long as the sale rate per kWh is more than the energy charge rate of the Central station.

iii) Requisition the full entitlement for the entire 24-hour period, but draw power only according to its actual requirement (i.e. as per its requisition in figure-1). In effect, this would be a pre-planned deviation from schedule, for which State-C would get UI payment. All that State-C has to watch for and be vigilant about is that the UI rate during the off-peak hours remains above the energy charge rate of the Central station. In case the frequency rises and UI rate falls below the energy charge rate of the concerned Central station, State-C should reduce its requisition and thereby stop under-drawing.

Availability of various and similar options, both for the beneficiaries and for the generating companies, means that the mechanism is sound and equitable.

UI rate vs. System Marginal Cost

UI rate is tightly linked to grid frequency. As the frequency is same all over an A.C. system, and can be readily seen through a simple frequency meter, it is easily possible to know the prevailing UI rate anywhere in the system, without needing any separate communication system. With this on-line knowledge of the current UI rate, a State would know what it would have to pay for an extra MW that it may draw from the regional grid. It can readily compare this with the fuel cost it would save if generation is reduced by one MW at its own station having the highest variable cost. If the UI rate is lower than the latter, it would be beneficial for the State to reduce its own generation and draw the replacement energy from the regional grid, till it has backed down all generation having a variable cost higher than the current UI rate. In the process, the State's marginal generation cost would move down, towards the prevailing UI rate.

Meanwhile, other States too would take a similar action in the same time frame, and total generation in the system would come down, resulting in a downward movement of frequency and an upward movement of UI rate, till the attainment of a state of equilibrium wherein the marginal generation cost of every State would equal the UI rate.

On the other hand, if a State finds the UI rate to be higher than the variable cost of any of its partly loaded generating units at any time, it would be financially beneficial for the State to maximize the output of all such generating units and thereby reduce its drawal from the regional grid. The State would have an underdrawal, for which it would get paid a UI rate higher than its marginal generation cost.

With similar action being taken by other States as well, the frequency would tend to rise, and UI rate would decline correspondingly, till equilibrium is reached wherein the marginal generation cost of every State would equal the UI rate. In other words, there would be perpetual movement of UI rate and the system marginal cost towards each other, leading to ultimate optimization in generation, on a region-wide basis.

There would be another fallout of the above. Depending on its variable cost, each generating unit would have a threshold frequency, i.e., the frequency at which the UI rate equals the variable cost of the generating unit. The output of the generating unit should be maximized as long as the grid frequency is below the threshold frequency, irrespective of the schedule given out by the RLDC/SLDC for the unit. And the unit should be backed down when grid frequency climbs up and exceeds the above threshold frequency, as shown in figure-4.

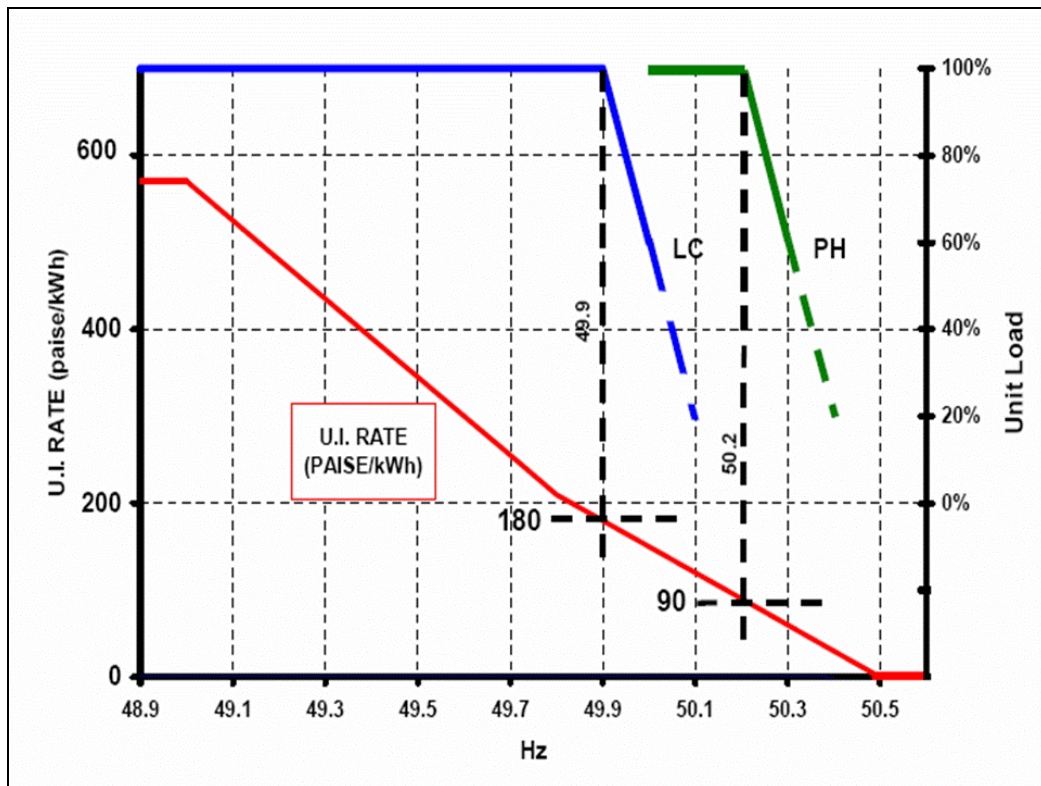


Figure - 4

For a pit-head generating station having an ex-plant variable cost of 90 paise/kWh, the threshold frequency shall be 50.2Hz. For a load-centre

thermal plant with a variable cost (ex-power plant) of 180 paise/kWh, the threshold frequency, with the present UI rates, would be 49.9 Hz, and so on.

A consequence of the above would be that grid frequency would modulate over the 24-hour cycle. It would be 50.0 Hz when the system load can be met by the available generating units having a variable cost of 150 paise/kWh or less (generally the case in late night hours). It would be only 49.5 Hz when all generating units of variable cost upto about 350 paise/kWh have to be harnessed for meeting the system demand (during peak load hours). In due course, a frequency pattern would emerge depending on the daily profile of total system load, and the generation mix. The corresponding UI rate profile shall reflect the daily pattern of system marginal cost. Typical patterns that may emerge are shown in figure - 5.

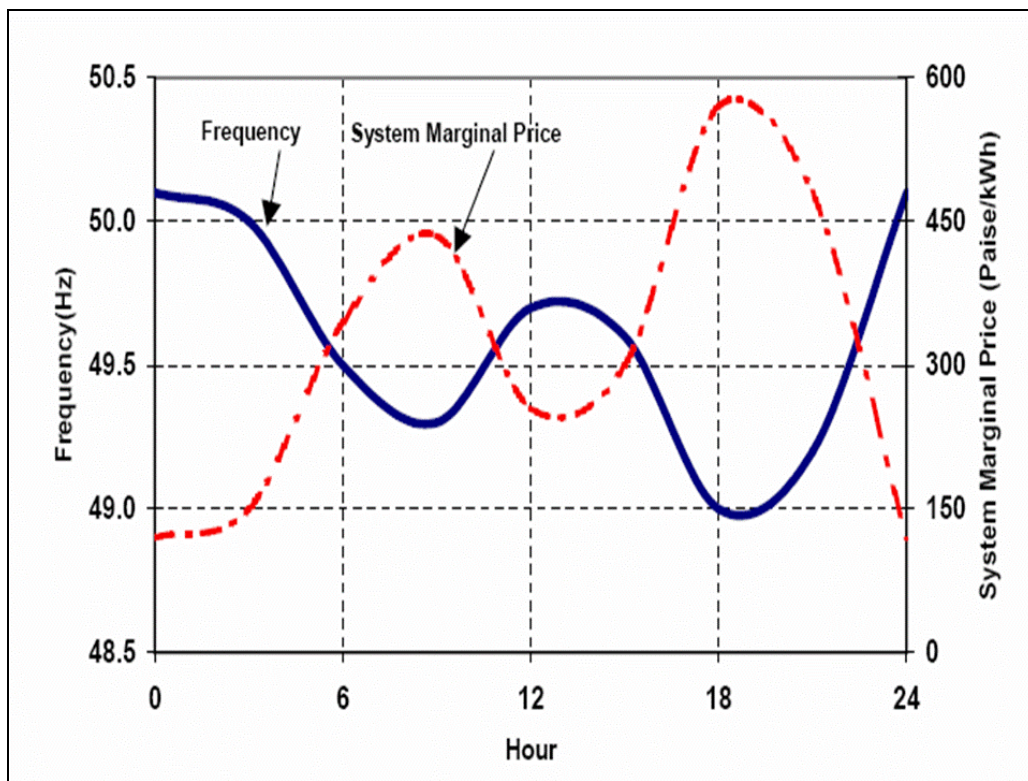


Figure - 5

As far as the hydro-electric units are concerned, their actual variable cost is zero, but the generation may be restricted depending on availability of water. As such, each hydro station would have an energy value in terms of the cost of energy (from other sources) it can replace. Hydro stations with a storage capacity should be run only during the peak-load hours, when their output can replace or supplement the costlier energy. Again, depending on the frequency pattern and availability of water, each hydro station can be assigned a threshold frequency. While the depleted hydro plants may have a threshold frequency in 49.0 – 49.2 Hz range, the over-flowing hydro stations may be assigned a threshold frequency of 50.5 Hz.

The above would lead to a frequency-based dispatch of generating stations, (typified in figure - 6), which can be given out by the SLDCs as the dispatch guideline for their generating stations.

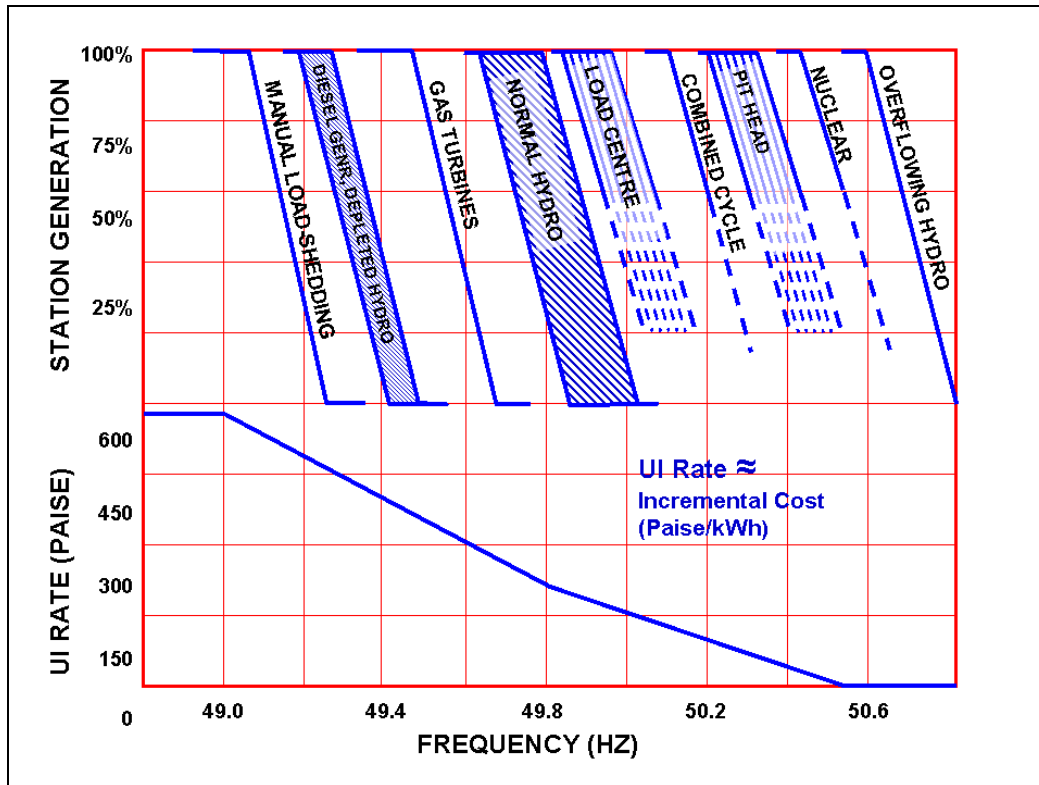


Figure - 6

Trading of states' surplus generation

A simple trading opportunity has been described at the beginning of this Chapter, for the purpose of explaining the working of the available mechanism. A surplus availability of Central station entitlement for State-C has been assumed therein. Most of the large Central stations are however pit-head or nuclear plants, with comparatively low variable costs/energy charge rates. The instances of such low variable cost power being categorised as surplus would arise only when the off-peak hour consumer demand in the State can be met from other sources having a comparable or still lower variable cost. State-C would generally have its own load-centre plants, with a variable cost higher than that of the Central station under consideration. These load-centre plants would naturally be scheduled to back down during off-peak hours, before the possibility or requirement of backing down the Central station arises.

In other words, the more common situation would be that the States' own generating stations are backed down during off-peak hours. It would therefore be the energy from off-peak surplus of such stations that would be available

daily for being offered to another State, either for catering to consumer demand which the latter cannot meet on its own, or to replace costlier energy. The State-C (which has such off-peak surplus) should first try to find out if there are any buyers available for its own generation. Obviously, such buyers would have to pay a price higher than the variable cost of load-centre stations concerned. If nobody is ready to pay such a price for the off-peak energy available, the concerned load-centre stations will have to be backed down. If State-C has a surplus even after the permissible backing down / shutting down of all such stations, the circumstances described in this Chapter would arise, and options shall have to be exercised as explained therein.

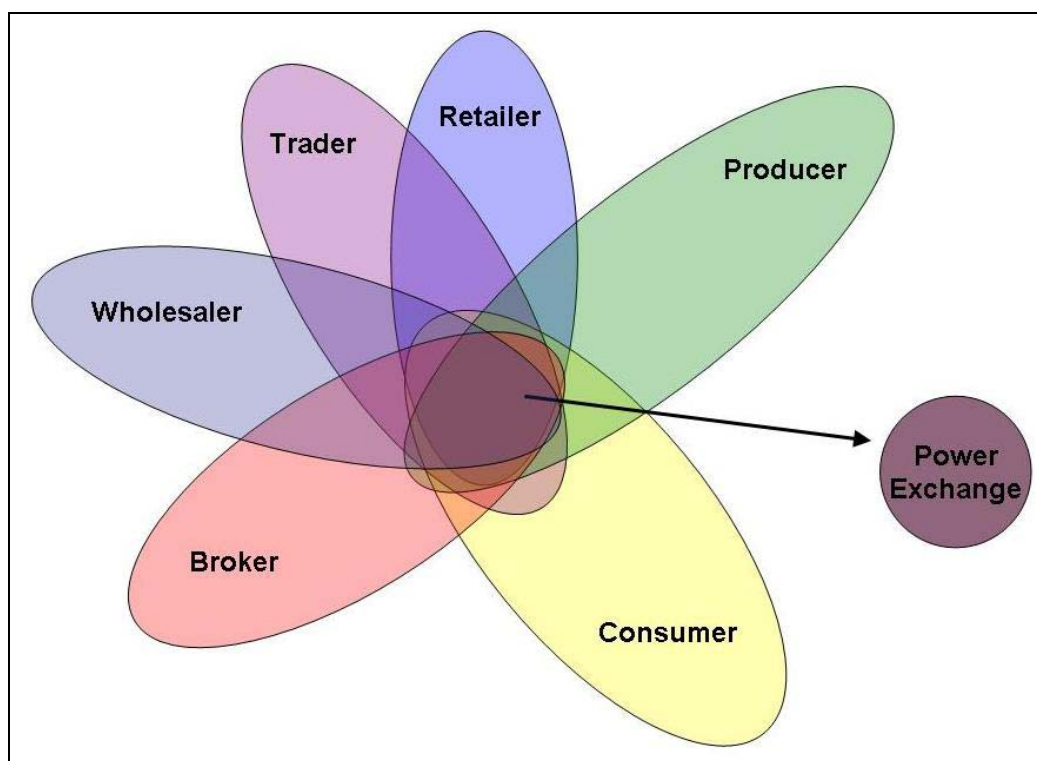
The price at which State-C considers selling its own surplus generation would have no relationship with the rate(s) at which State-C gets its entitlement from Central generating stations. It shall have to be higher than the variable cost of State-C's own stations which would have to be backed down if this power is not purchased by another State. The price that the latter may agree to pay shall however depend on (i) the price at which off peak power may be available to the needy State on comparable terms from some other source, (ii) the likely UI rate during those hours, and (iii) the criticality of the need for additional power and the price the needy State is ready to pay. Obviously, these aspects cannot be covered in a formula, and the price will have to be negotiated between State-C and the purchaser(s).

Now, suppose a situation arise wherein State-C does not require energy from a certain station of its own, having a variable cost of say 200 paise/kWh, during certain hours (off-peak), and no other State is willing to sign a bilateral contract for taking this energy on a scheduled (committed) basis at 200 paise plus. In such a situation, the State load dispatch centre (SLDC) shall have to schedule this station to back down during such off-peak hours. However, if the actual frequency during those hours on a particular day is below 49.8 Hz, this station should not back down. The resulting surplus energy should go into the regional grid as State's UI. The State would get paid for it at the prevailing UI rate, and the amount should be passed on to the concerned generating station.

The role of power exchanges

As the power market is liberalized, power will become a common commodity at par with, for instance, wheat or petrol. This will result – as in all other markets – a wholesale market and a retail market with three usual participants: the producers, the retailers, and the end users. As far as power is concerned, more advanced commercial patterns can quickly develop in a free market environment. New participants will appear on the scene: the traders and the brokers.

Quite simply, the power exchange is a market where all the participants meet to trade. A power exchange can act as a neutral and confidential platform for all trading entities, offering each participant the choice of customer and price. E.g. Nord Pool is an exchange of primary produce for the wholesale trades. The primary produce is power. Nord Pool's customers are the producers, retailers, and traders who choose to trade via the power exchange. In addition, few large end users also trade via Nord Pool, though usually, end users do not deal via Nord Pool.



One distinguishing feature of an exchange is that it allows trade on real time basis. The buyers and sellers of power are able to take real-time decisions, trading at real-time prices factoring in various aspects like weather, outages, load crashes, demand and supply mismatches etc. The exchange's ability to

facilitate power trade on a real time basis in a vast market will translate into financial gains for the participants. For instance, in a grid which is already facing demand crashes, any additional supply would fetch a low UI price. On the other hand, the exchange can enable diversion of power to states/regions facing shortages. The exchange can, therefore, also address uncertainties caused by variances of Frequency Linked Tariff.

An online trading platform offering ease of use, transparency and fiscal security has immense potential in the present context. Also, a power exchange with lower transaction margins than bilateral transactions will draw more players as participants. Innovative financial engineering will drive deal making and buyers & sellers always remain open to the possibility to restructuring their commitments in order to become more profitable. By ensuring a transparent bidding and allotment process, conducted anonymously, the exchanges leave no scope for identification of counterparties. In effect, the probability of manipulation in transactions is virtually nil.

Power exchanges can create the marketing instruments to assure payment security, demand risk, price risk, reduce the financial uncertainty, and bring greater economic performance into the electricity market. The creation of a competitive marketplace will spawn a multitude of opportunities to entice investments and active participation of private players.

Exchanges can provide options for aggregation of captive stranded power, a vital factor in establishing a cost-efficient power market for captives/traders. As a result, the generators/traders can benefit from enhanced productivity and profitability and minimize inherent risks. In the case of hydro-producers and traders of hydropower, exchanges afford the capability to source default/alternate buyers on a real-time basis. Hydro-power producers can benefit by accessing day-ahead markets to reduce off-take risks and trade power which would otherwise be lost in run of the river projects. Embedded suppliers, hydro-generators etc. can access wider markets spread across the country through power exchanges.

In the Indian context, there are some issues concerning power exchanges that need to be addressed and clarified. The Supreme Court of India has defined electricity as a commodity. At least in the initial phase, trading on power exchanges is expected to be limited to spot transactions. Uncertainty of regulatory superintendence needs attention. It is not clear if power exchanges will be governed by the Commodities Market regulator or by the Central/State Electricity Regulatory Commissions. Practical difficulties for power exchanges facilitating the scheduling of traded power in the face of transmission congestion have to be ironed out to ensure the delivery of electrons pursuant to the exchange based trade. Options for credible payment security mechanisms for power traded on exchanges have to be put into place. Access to available transmission capacity is still more or less on a first come-first serve basis, with little recourse to competitive bidding for procurement of transmission corridors on a real time basis. Regulations which permit the transfer/sale through competitive mode of not only electricity, but generation and transmission capacity are required to enable market development at the desired levels. These regulations must be sensitive to intra day and real time demand supply issues.

Based on physical trading on the exchange, a natural progression is to move on to the realm of the forward market, with futures and derivative trading. Enabling an efficient spot and futures market can create hedging tools and derivatives like options, swaps, spark contracts, etc. Thus market instruments to assure fiscal security, demand risk, price risk, reduce the financial uncertainty can be generated through power exchanges, bringing greater economic performance into the electricity market. Ample evidence shows that financial markets with the multiplier effect have far outsized the physical markets in any commodity and electricity trading will be no exception. In the developed international power markets, it is estimated that paper trading will be 50 to 100 times the size of the physical trading. Even assuming a conservative 20 times for India, the volume of paper trading in electricity could exceed Rs.1,00,000 Crores per annum.

The UI Pool as a market mechanism

The UI (FLT Frequency Linked Tariff) pool in India is quite unique in structure and performance. Since its inception over three years back, the UI pool has collectively transacted around Rs.15000 Crores (\$4 billion). Interestingly, these are just fringe numbers, comprising of only 5% of the total power market since these are the deviations from the constituent schedules. These schedules, in turn, are products of the allocation of the constituents in the central power generating stations, which are approximately 20% of the installed capacity nationwide. It is also pertinent to note that, in spite of the lack of any enforceable payment security mechanism, the level of default in the UI pool has remained marginal. Over the past couple of years, short term bilateral trading between state utilities through trading entities have increased manifold. As the short-term bilateral market grew, a very interesting situation developed in the market – the prevailing UI rates in each region become the ‘unofficial’ benchmark for determining the bilateral trade prices. State utilities have been able to use UI trends to decide whether it is commercially viable to do bilateral contracts, or to simply ‘underdraw’ from the grid for substantial gains on the UI pool. Safe to say, the UI has emerged as a serious competitor for bilateral trading as it happens in our country today. However, this presents an immense opportunity for developing a competitive and sustainable market environment. The biggest problem in attracting investments in the Indian power sector has been the lack of fiscal security, besides performance risks and sanctity of contracts. Further, creation of a level playing field is necessary to attract fresh investments in the sector. The UI pool can offer a departure from the long prevailing single buyer model and allow access to a multitude of customers. This will be effective in dispersing the incumbent risks and enabling an enforceable settlement mechanism. The UI pool could be extended across the entire electricity market, either on a regional basis or on a national basis to allow all stakeholders access to the unified pool market which would **reflect** the demand supply mismatch through the real-time frequency linked tariff.

One important step required for successful functioning of the expanded UI pool is the establishment of a credible payment security mechanism. Incumbent utility balance sheets are not sound enough to support the entire UI pool. As of now, commercial exchanges by SEBs are being backstopped by escrows and other banking instruments, which put a heavy strain on their financial resources. A collective process of spreading the risk to various entities participating in the UI pool through mandatory payment security mechanisms and transaction rules may be the way forward in strengthening the UI pool. Options like collective insurance on UI transactions, wherein the premium is spread across all participants proportionately, **and** setting financial and transaction limits for participation may be considered to achieve adequate security for the pool.

The proposed Road map:

Currently the UI Pool and frequency linked tariff is limited to deviations from schedules of the region constituents. Extending the UI pool to all stakeholders and all power flowing on the grid will open up the Rs.100,000 Crores electricity market. Combined inflows into the system, of merchant power, distress / stranded power and the existing generation will create a neutral yet dynamic market which will meet investor concerns as it will give them more comfort by allowing them to make investments based on market risks. The level playing field and potential for sustained returns will instil confidence in stakeholders and attract private investments.

No tariff regulation on any generating companies, whether central sector or state should be permanent. Their tariff can be regulated till the term of the existing PPA / contract. Thereafter, the generator should be free to sell bilaterally, through an exchange or in the UI pool. Independent / Merchant / Captive Power plants should be treated on the same basis.

Apply frequency linked tariff to the complete electricity supply chain, from generator to consumer. It is interesting to note that power @ Rs.11 per KWh is being pumped into the state system to avoid peak cuts in Pune and power @ Rs.7.60 per KWh from liquid power stations of NTPC is also being scheduled to state utilities, despite being far above the present UI peak of Rs 5.70. Linking the UI ceiling rate to an index of the international fuel basket could be considered as an option to accurately represent real-time cost of energy. Alternately, anchoring the UI (FLT) to a level higher than the cost of diesel based power, say Rs. 15 per KWh @ 48.70 MHz would give the signal to kick in all reserve and stand by generation when the frequency drops as a result of increased demand. This will allow the market to absorb price shocks due to upstream volatility. The consumer in turn can control and redistribute load to optimise the cost of electricity consumed.

The generation tariff may be determined automatically by linking it to the ABT tariff at the time of injection. The same principle may be applied to consumers, linking consumer tariff to the prevailing UI rate both inter or intrastate basis.

Postage stamps can be imposed at appropriate levels to factor in the cost of delivery of electricity to the end consumer including transmission and distribution.

Inter-State ABT is effectively implemented and fully functional. Extending this to the intra-state level is a natural progression, already under planning. Induction of intra-state generators and consumers into the UI pool will increase the overall volume of the market by at least 30%. Once Intra-state ABT is implemented, a composite UI pool could replace the existing market structure. The national grid, when established will further enhance the strength of the UI Pool and enable an equitable market environment across the country. The NLDC can be designated the role of the taskmaster for operating the UI Pool.

Advantages of the UI as an investment tool

Irrespective of whether the power flow includes allocations or not, the frequency linked tariff and the UI pool are a reflection of the real-time demand supply position and indicates the true 'spot' price of electricity at that point in time. This will serve as a benchmark when the market transcends to the domain of futures and derivatives.

'Smart' generators can optimize generation to maximize returns and 'smart' consumers can redistribute loads to minimize costs. The UI financial settlement mechanism, which is proven and operative, can guarantee payment security for stakeholders. The Pool automatically fulfils the role of a truly independent IMO, with enforceable settlement mechanisms. This will in turn trigger a market based investment environment sans electricity board/buyer credibility issues which are presently frustrating developers of power projects. This may well be the way forward to galvanize the Indian power sector for the daunting task of sustaining our burgeoning global economy.
