

AVAILABILITY BASED TARIFF AND U.I. CHARGES

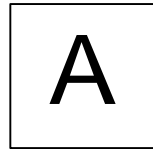
-- Dr. A K Tiwari --

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INTRODUCTION



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, i.e., 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 depends 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 gets a higher payment. In case the average availability achieved is lower, the payment is also lower. Hence the name 'Availability Tariff'. This is the first component of Availability Tariff, and is termed 'capacity charge'.

The second component of Availability Tariff is the 'energy charge', which comprises 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 specifically be noted that energy charge (at the specified plant-specific rate) is not based on actual generation and plant output, but 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 get paid for at a rate dependent 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 lower. 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 higher 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 calculated according to Gadgil formula, and 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 is dependent on the declared output capability of the plant for the day and the beneficiary's percentage share in that plant, and not on power / energy intended to be drawn or actually drawn by the beneficiary from the Central station.

The energy charge to be paid by a beneficiary to a Central station for a particular day would be the fuel cost for the energy scheduled to be supplied from the power plant to the beneficiary during the day. In addition, if a beneficiary draws more power from the regional grid than what is totally scheduled to be supplied to him from the various Central generating stations at a particular time, he has to pay for the excess drawal at a rate dependent on the system conditions, the rate being lower if the frequency is high, and being 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 Dispatch 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 Dispatch 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 duly incorporating any bilateral agreements and adjusting for transmission losses. 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, Central stations can prospectively revise the output capability declaration, beneficiaries can prospectively revise requisitions, and the schedules are correspondingly revised by RLDC.

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 generally follow 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 depending on frequency. 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, the regional grids had been operating in a very undisciplined and haphazard manner. There were large deviations in frequency from the rated frequency of 50.0 cycles per second (Hz). 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.

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 up to the specified limits 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. This payment then goes to beneficiaries who received less energy than was scheduled, and acts as an incentive/compensation for them.

How does it benefit everyone

The mechanism has dramatically streamlined the operation of regional grids in India. Firstly, through the system and procedure in place, constituents' schedules get determined as per their shares in Central stations, and they

clearly know the implications of deviating from these schedules. 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 draws, 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 pithead stations do not have to back down normally. The overall generation cost accordingly comes down. Fourthly, a mechanism is 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.

THE DAILY SCHEDULING PROCESS

B

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 the Central station are 270, 270 and 360 MW respectively, for the next day. Entitlements in the other Central stations would also be advised by RLDC to the SLDCs similarly.

Simultaneously, the SLDCs would receive availability status from their intra - State stations as well. They would then carry out a detailed exercise as to how best to meet the expected consumer demand in their respective States over the 24 hours. For this, they would 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, for the Central generating station, the total dispatch schedule 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 x 24 MWh, 270 x 24 MWh, and (200 x 24 + 160 x 16) MWh of energy respectively, at the specified energy charge rate of the generating station.

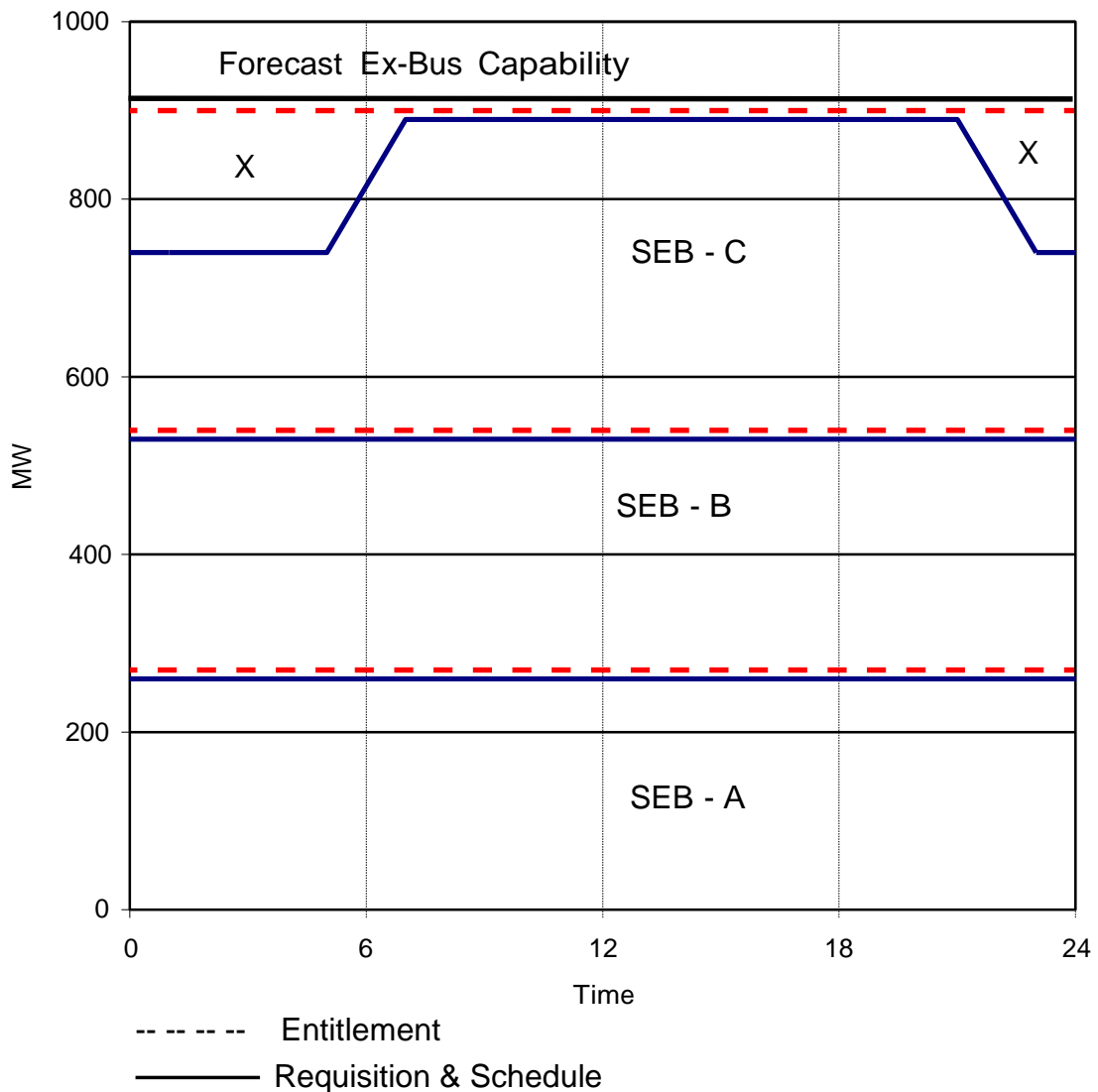
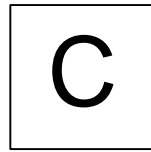


Figure - 1

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 were 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 what is scheduled, the generating station shall have to pay back for the energy shortfall, at the same frequency - linked rate.

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 were 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 high frequency situations, and help in containing the frequency rise.

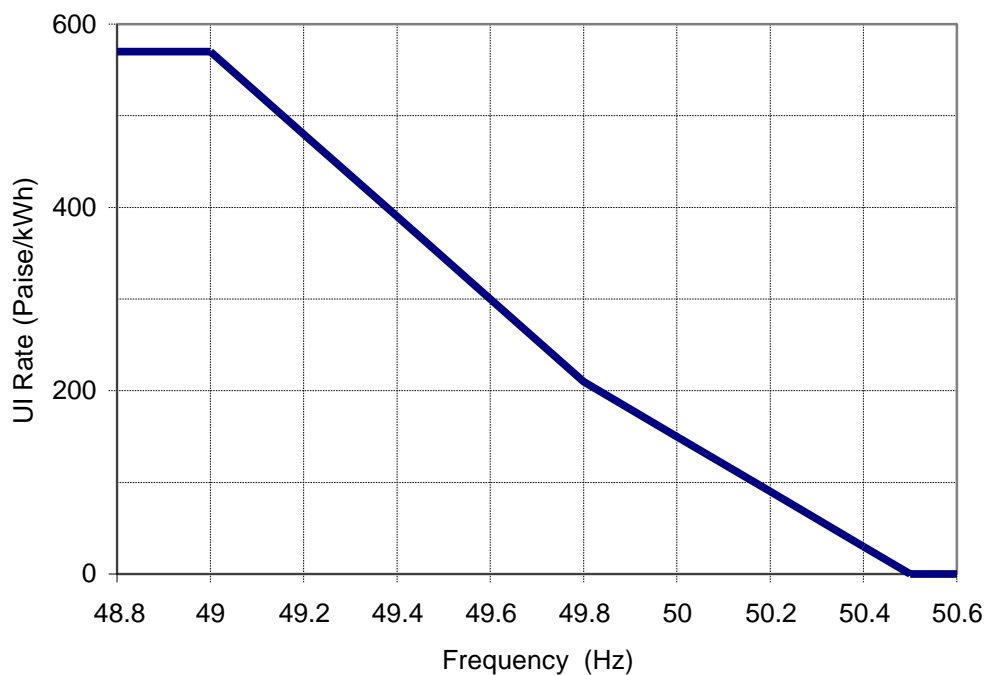


Figure – 2

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 energy not drawn

at a 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 means that the State pays for the scheduled power quantum unnecessarily. It should either reduce its schedule, or increase its drawal.

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 into account.

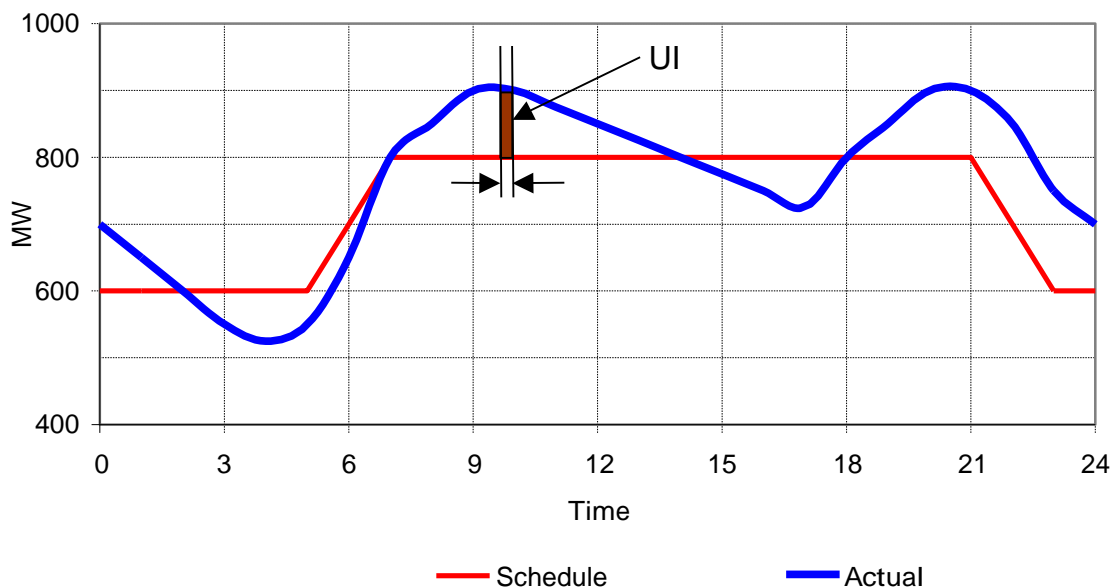


Figure - 3

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, operated by the concerned RLDC.

A SIMPLE TRADING OPPORTUNITY



Let us now 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 too particular 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 a 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 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.

U.I. 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 the help of any 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 were 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 under-drawal, 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. For a pit-head generating station having an ex - power plant variable cost of 90 paise/kWh, the threshold frequency, with the present UI rate – frequency relationship, shall be 50.2 Hz. For a load-centre thermal plant with a variable cost (ex - power plant) of 180 paise/kWh, the threshold frequency would be 49.9 Hz, as illustrated, and so on.

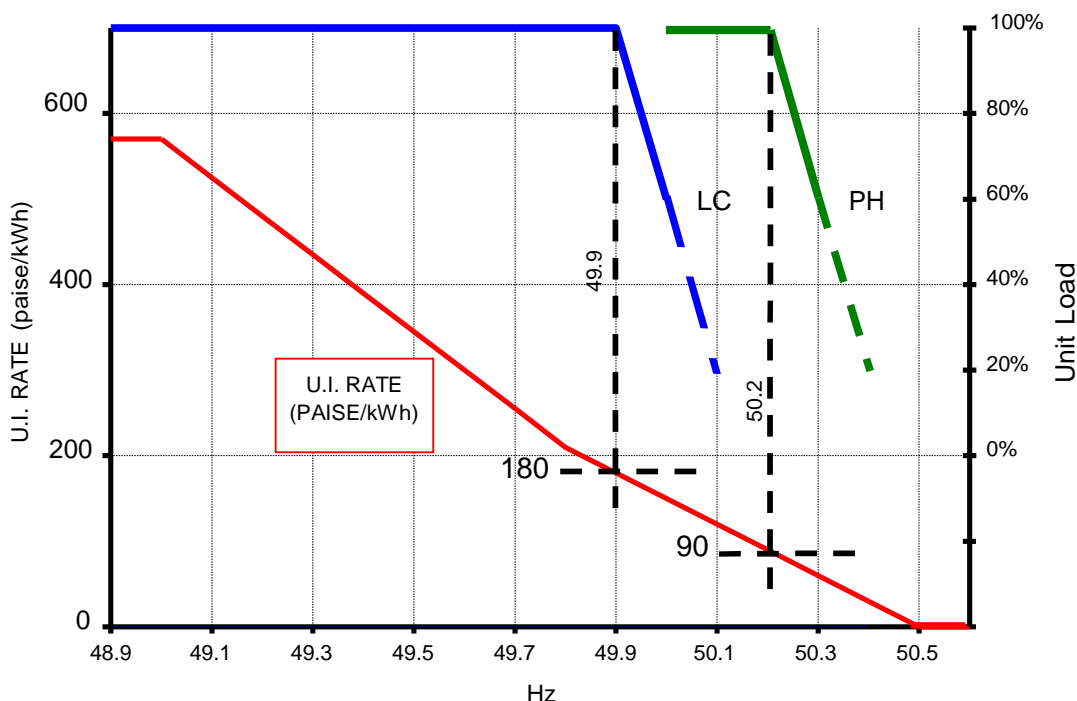


Figure - 4

As a consequence of this, the grid frequency would modulate over the 24-hour period. It would be 50.0 Hz when the system load can be met by the available generating units having a variable cost of up to 150 paise/kWh (generally the case in late night hours). It would be only 49.5 Hz when all generating units of variable cost up to 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 (after effective implementation of free - governor mode of operation) are shown in figure - 5.

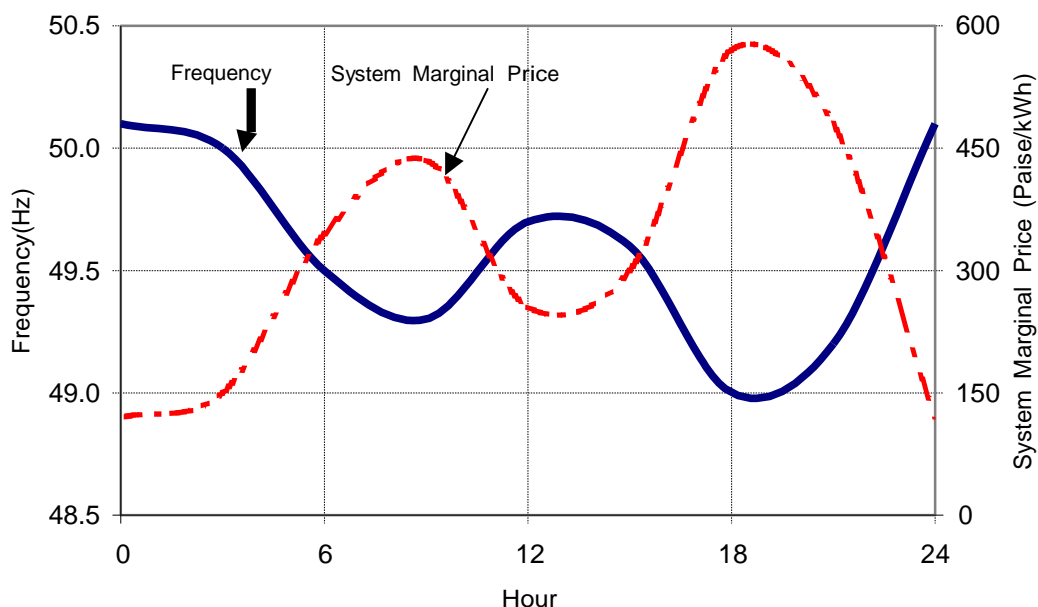


Figure – 5

As far as the hydro-electric units are concerned, their actual variable cost is zero, but their 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.

This would lead to a frequency - based dispatch of generating stations (typically as shown in figure - 6), which can be given out by the SLDCs as the dispatch guideline or instructions for their generating stations. The underlying approach is that the frequency would be allowed to float, and there would be no attempt to operate the grid at a frequency very close to 50.0 Hz. Also, while the schedules would serve as the commercial datum, the entities would be free to deviate from the schedules, to achieve real region - wide merit - order in generation, in an autonomous, decentralized and very cost - effective manner, without depending on any communication and EMS / SCADA system.

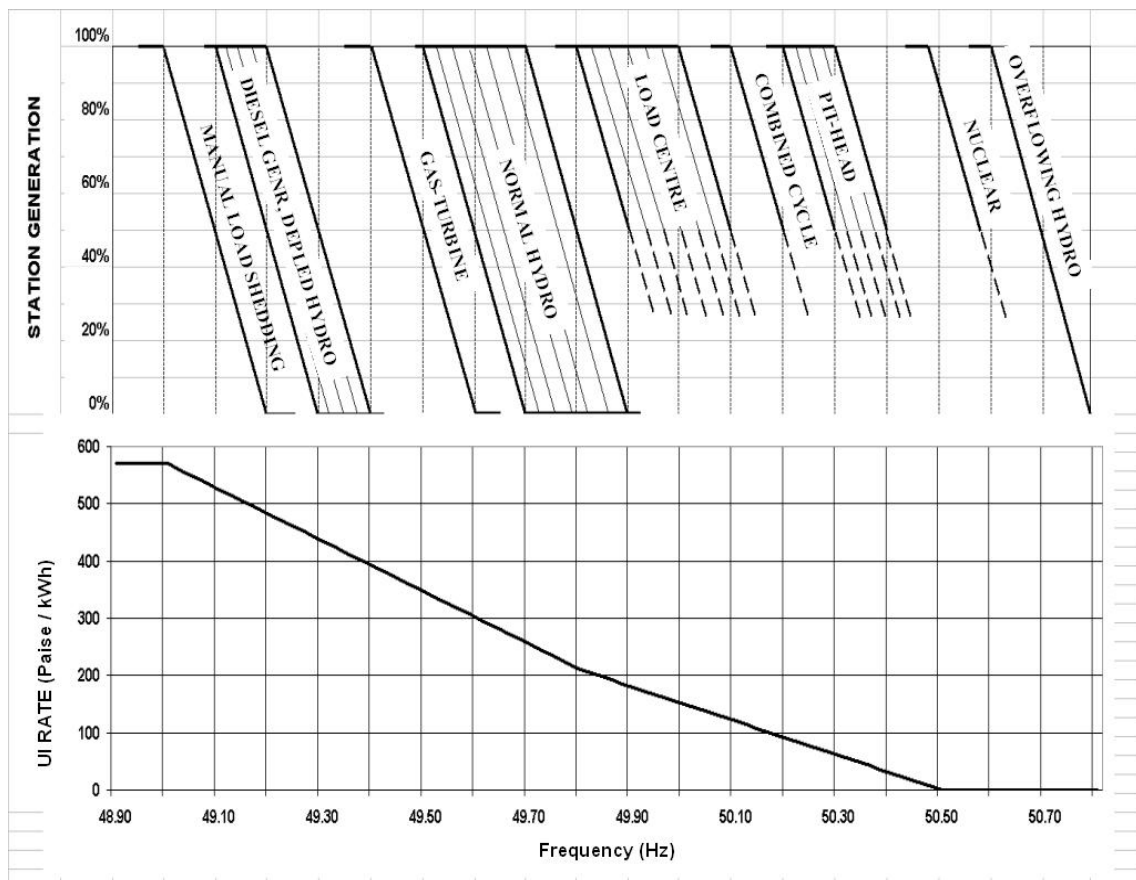


Figure - 6

TRADING OF STATES' SURPLUS GENERATION



A simple trading opportunity has been described in chapter - D, 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 determined as surplus would occur only when the off-peak hour consumer demand in the State can be and is 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 more commonly 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 surplus 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 this off-peak energy, 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 chapter - D would arise, and options as explained therein shall have to be exercised.

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. Instead, it will 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 (iv) 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 arises 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 off-peak hours, and no other State is willing to enter into 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 suitably passed on to the concerned generating station. This would happen automatically when Availability Tariff is implemented for the intra - State stations as well.

EXPECTATIONS FROM CENTRAL STATIONS



In the day-to-day operation under Availability Tariff framework, a Central generating station has to declare by 9 AM every morning its foreseen MW output capability for the next day. This must be done judiciously and faithfully. Unless it is planned to bring in or take out a generating unit or a major plant auxiliary, a thermal station should have only one figure of MW availability for the whole of the next day, i.e., for 24 hours midnight to midnight.

The above availability forecast should be the best assessment by the plant operators of the average MW output capability. Based on the operational feedback during the day, the availability forecast can be trimmed by 10 PM. No margins / cushions need be kept. As long as the actual average availability during a day is close to the declared availability for that day, there would be no commercial implications. In case the foreseen plant availability changes due to a unit / equipment outage during the day, the same should also be advised by the Central generating station to the RLDC, latest by 10 PM.

In case a unit or auxiliary is required to be taken out of service during the next day, it would be expected that it is planned to be done after the morning / evening peak. Similarly, if a unit or auxiliary is to be brought back in operation, it should be so planned that plant availability increases before the onset of morning / evening peak. It is expected that these plant availability changes are declared faithfully, and plant operation is attempted accordingly. There could however be problems during a unit restart, resulting in deviations from schedule. As long as these are not deliberate, such deviations should only be accounted as UI, and should not be viewed as “gaming”.

By 5 PM of the scheduling day, the dispatch schedule for Central stations (for the next day) would be available from the concerned RLDC. Normally, all beneficiaries would requisition their respective entitlements fully for all 24

hours, and the Central stations (other than liquid fired) would not have any residual capability available for trading. However, in case a beneficiary requisitions less than its full entitlement, the Central station may at its sole option, trade the resulting residual capacity, as described in chapter - D. If it is done on a bilateral basis (as per second alternative), it has to be included in the final schedule for the next day, for which the RLDC has to be advised by the Central station by 10 PM.

During the day of operation, the Central generating station would be expected to operate in a safe and efficient manner, keeping in view its dispatch schedule and grid conditions. As long as the grid frequency is below a generating unit's threshold frequency (described in chapter - E and illustrated in figure - 4), the unit should deliver its full continuous output capability. When the grid frequency rises above the unit's threshold frequency and is likely to remain high, the unit should be backed down in a graded manner, irrespective of its dispatch schedule.

Please note that the "unit load" shown in figure - 4 is the load to which a generating unit is to be brought back after primary response to frequency fluctuation in the grid. All generating units have to be on free - governor mode of operation (FGMO), and have to participate in primary frequency control. For example, if frequency rises by 0.1 Hz, the unit load should automatically and immediately come down by 4 - 5%. Over the next 4 -5 minutes, the unit load should gradually be brought back to the previous level by supplementary control, as long as grid frequency remains below the unit's threshold frequency. When grid frequency goes above the threshold frequency, the unit load should be reduced to the level as plotted in figure - 4. The desired FGMO and supplementary control are illustrated in figure - 7. The recommended rate of supplementary control is one percent per minute, e.g. 2 MW per minute for a 200 MW unit.

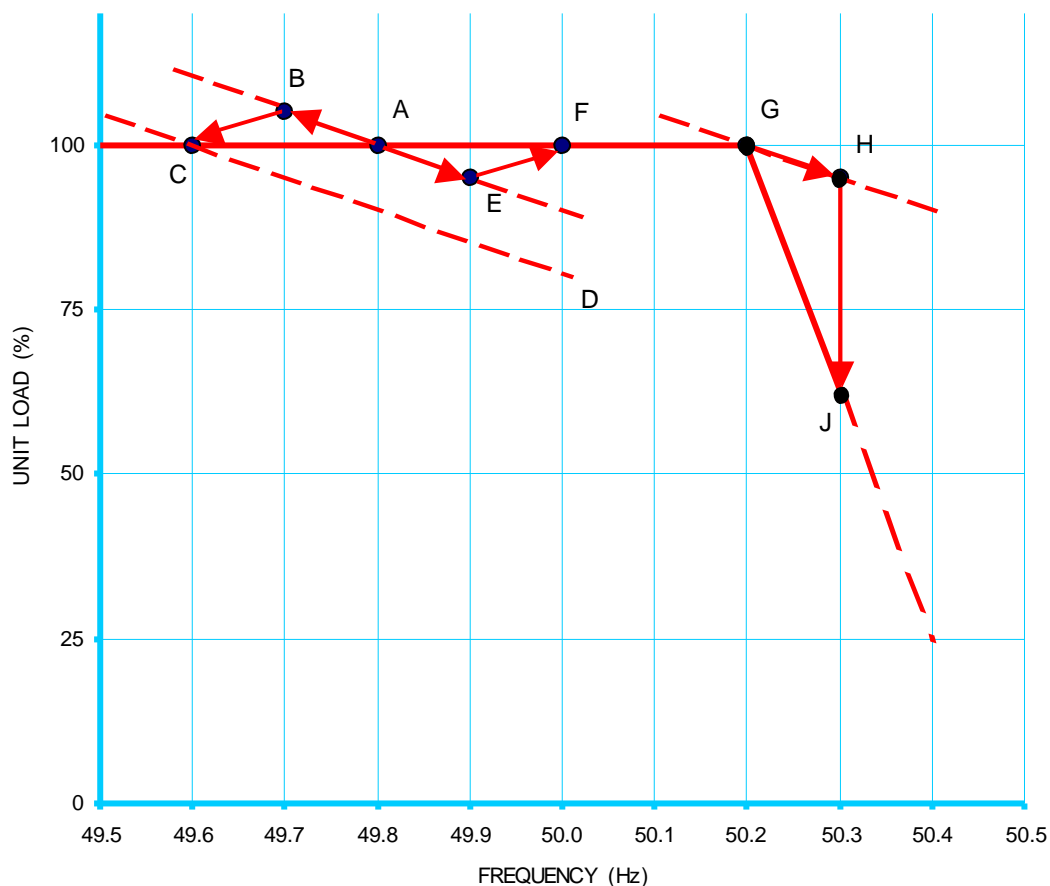


Figure -7

In the event of unforeseen tripping of a generating unit or of a major auxiliary (forced outage), which brings down the availability of the station suddenly, the operator should quickly assess the possibility of bringing back the unit / auxiliary and resuming generation as per the given schedule. In case this is possible within an hour or two, the operator should inform the RLDC that the station's availability declaration (for commercial purpose) and schedule should not be revised. On the other hand, in case the station availability is foreseen to remain curtailed for a longer duration, the RLDC should be formally informed about the change in station availability, along with the curtailment duration, to the extent determined. The RLDC would give effect to the availability change, and corresponding revision of schedules, after one hour. During the intervening period, the deviation from schedule would be recorded as UI, and the station would have to pay back for the shortfall at the prevailing UI rate, while getting paid the capacity charge and energy charge respectively

as per pre-revised availability declaration and dispatch schedule. This is illustrated in figure - 8. The plant operator should therefore not delay his availability change advice to RLDC.

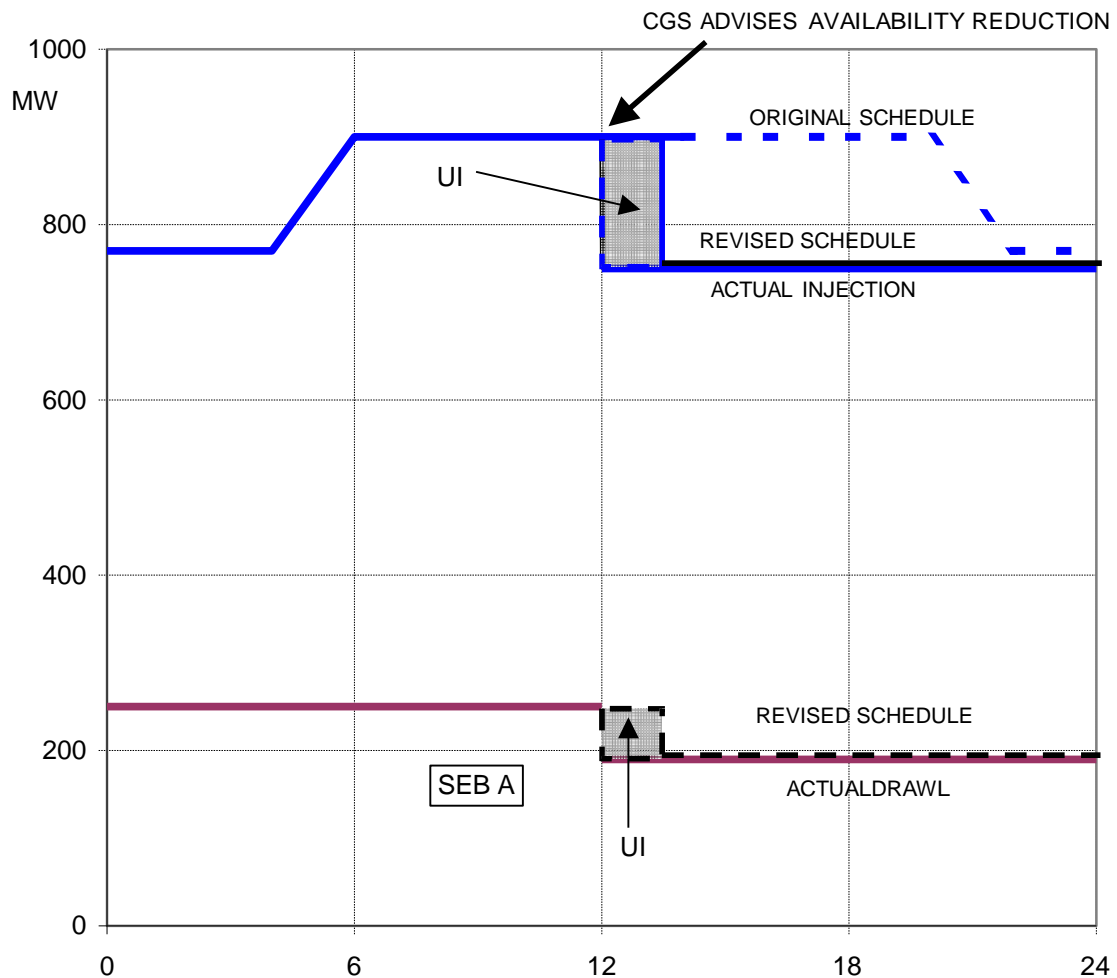


Figure - 8

It would be noted from the foregoing that the Central generating stations, at their discretion, can deviate from the schedule given out by RLDC, and take advantage of the UI mechanism. The schedule too is based on availability declaration by the station. The stations thus have the desired autonomy. The only mandatory requirement is that of operating within the overall framework of Availability Tariff and Indian Electricity Grid Code (IEGC). FGMO is mandatory for all generating units connected to grid. Another requirement under IEGC is that reactive power (MVAR) generation at the Central stations

shall be as per instructions of the concerned RLDC, but within the generating units' reactive capability.

On a long-term basis, the Central generating companies are expected to operate and maintain their stations diligently, and ensure high plant availability in a sustained manner. They should also coordinate sincerely with the concerned Regional Power Committee (RPC) and RLDC in respect of scheduling of planned unit outages.

One of the primary objectives of Availability Tariff is to encourage maximisation of generation, particularly during periods of power shortage. It is evident that the country would continue to suffer from daily peak-hour shortage for many years to come. No body need grudge the Central generating companies earning extra money through achievement of a plant availability level higher than the norms; it only enables more consumer demand to be met, and load-shedding to be correspondingly reduced. The only thing to be guarded against is that the plant availability is not deliberately under-declared, with the objective of earning high amounts as UI. Once the plant availability, i.e. the MW output capability, has been declared judiciously and faithfully, the generating station should be freely allowed to deviate from the given schedule without any restrictions, as long as there is no transmission constraint. Any deviation which gives extra income to a generating station through the UI mechanism also ensures extra power for consumers and/or enhanced optimisation / conservation of resources, and is therefore acceptable.

GUIDANCE FOR STATE LOAD DISPATCH CENTRES (SLDCs)



The SLDCs shall have to carry out their functions in compliance with provisions in the respective State Electricity Grid Code. This chapter is intended only for general guidance of SLDCs from the perspective of Availability Tariff for Central stations and Indian Electricity Grid Code (IEGC).

The daily scheduling process for Central stations has been described in chapter - B. How the States can take advantage of the commercial mechanism now available, to trade surplus generation in off-peak hours is described in chapters - D and F. These mainly deal with actions on the previous day, up to issuance of final schedules by RLDC. As a general rule, the SLDCs should requisition their entire entitlement in the available Central generating station capacity (other than liquid fired) for the whole day, unless their consumer load profile and intra-State generation mix is such that the total State load during certain hours of the day is expected to be less than the Central entitlement plus intra-State generation of a variable cost lower than the highest energy charge rate of Central generation. In such a case, the requisition from Central stations having high energy charge rates could be suitably curtailed during the concerned hours, provided the frequency is expected to rise during those hours to a level that causes the UI rate to fall below the energy charge rate of the concerned station. In case frequency is not expected to rise to such a level during those hours, Central station requisition should not be curtailed, and the surplus should be traded bilaterally or as UI, as explained in chapter - D.

On the day of operation, the SLDCs have to primarily monitor the intra-State system. They have to keep a general watch on the actual net drawal of the State from the regional grid vis-à-vis the State's net drawal schedule, but it is not necessary to endeavor to equalize the two. In fact, in the system in place, it is beneficial as well as desirable to deviate from the net drawal schedule depending on the circumstances. For example, an overdrawal may result from

increase in consumer load or reduction of intra - State generation. If there is no transmission constraint and grid frequency is good, it causes no problem for the larger grid, and the extra energy comes to the State at a low UI rate. There can be no objection to extra consumer demand being met through such over-drawal. There can also be no objection to the over-drawn energy replacing the intra - State generation of a higher variable cost. The SLDC should in fact try to increase its overdrawal further, as long as frequency is good, by (i) reducing own generation which has a variable cost higher than prevailing UI rate, and (ii) restoring consumer load that had been shed.

Even if a State overdraws in a low-frequency situation, it would mean meeting consumer demand which would not have been met otherwise, and is beneficial from this angle. However, it has following adverse implications:

- i) The regional grid may be endangered if frequency falls below 49.0 Hz, or if some transmission element gets excessively overloaded. RLDC may then ask the SLDC to curtail its overdrawal, and SLDC must take necessary action immediately.
- ii) Another State (which is under-drawing) may be perceived to be getting deprived of its rightful share. However, this would be the case only if that State has resorted to load shedding, AND frequency is below 49.0 Hz. If a State carries out load shedding and thereby causes inconvenience to its consumers while frequency is above 49.0 Hz, it would be doing so either because of a misconception or for commercial reasons, i.e., to get UI payment, and therefore would not have a valid ground for feeling aggrieved.
- iii) The over-drawing State shall have to pay UI charges at a high rate. The SLDC would have to be sure that it is in the State's overall interest.

The SLDC should therefore take the following corrective action in the event of overdrawal during low frequency situation:

- i) Increase Central station requisition to full entitlement (in case not fully requisitioned earlier).
- ii) Maximize generation at intra - State stations having variable costs lower than prevailing UI rate. (This can be in the form of standing instructions, i.e., frequency - linked dispatch guidelines).
- iii) Harness captive and co-generation, to the extent available at a price lower than the prevailing UI rate.
- iv) Explore the possibility of purchasing power through a bilateral agreement.
- v) Curtail consumer load.

A situation of under-drawal can arise in case consumer load in the State comes down in an unpredictable manner. If this happens at a time of general shortage in the regional grid (wherein frequency would be low), the under-drawal is beneficial for all, and SLDC should let it continue. For enhanced optimization, the SLDC may even resort to:

- i) maximizing generation at all intra-State stations whose variable cost is below the prevailing UI rate.
- ii) increasing Central station requisition to full entitlement (in case not fully requisitioned earlier).
- iii) harnessing captive and co-generation, to the extent available at a price lower than the prevailing UI rate.
- iv) curtailing consumer load, by shedding low - priority consumers (provided UI earning for the utility justifies such load shedding). This is totally optional, and helps the regional grid. Overall interest of

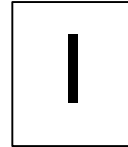
consumers in the State is however to be safeguarded by the concerned State Electricity Regulatory Commission (by specifying limits for such load shedding).

In case under-drawal takes place when grid frequency is good, the SLDC should take action to reduce the under-drawal, through one or more of the following measures:

- i) Restore consumer load which may have been shed.
- ii) Back down intra-State generation having variable costs higher than prevailing UI rate, preferably through standing frequency - linked dispatch guidelines.
- iii) Reduce drawal schedules for Central generating stations whose energy charge rate is higher than the prevailing UI rate, and/or arrange a bilateral sale.

It would be seen from the above that the action to be taken by the SLDC depends on the grid frequency, rather than on whether the State is in under-drawal or over-drawal mode. The need for action on the above lines would generally arise when there is a change in system status, e.g., tripping of an intra-State generating unit, a load crash within the State, or a frequency change due to load-generation imbalance elsewhere. Hence, the SLDC operators need to be perpetually vigilant to promptly initiate the desired action, for grid security as well as commercial optimization.

OPTIMUM UTILIZATION OF INTRA - STATE RESOURCES



Although Availability Tariff has so far been implemented only for Central generating stations, and is perceived to be operating at regional (inter-State) level, it has an immediate, though indirect, impact on intra-State operation, as explained below. In the mechanism now in place, each State has a specified allocation in the identified Central stations, in terms of a percentage share in the generating capacity. This determines the MW entitlement of each State day-by-day, depending on ex-power plant capability declared for the day by the respective generating stations on the previous day, as described in chapter - B. Since the above entitlement can meet only a part (around 30%) of the total consumer demand in a State, it is necessary for each State to optimally deploy the other (intra-State) resources, particularly because the total demand far exceeds the total power availability presently.

In an interconnected power system, the net drawal of a State is always equal to the total consumer load within the State minus the total of intra-State generation. In case the actual net drawal exceeds the net drawal schedule (based on State's entitlement in Central stations and its requisition), the State has to pay UI charges. This liability can be reduced by restricting the overdrawal, particularly when frequency is below normal. This in turn requires (if load shedding has to be restricted) maximization of output from all intra-State stations, which means that there is a pressure on each State as well for perpetually enhancing the availability of all intra-State stations. It is another matter that in the absence of Availability Tariff for intra-State stations, these stations have no direct incentive acting on them for maximizing their availability.

On the other hand, during off-peak hours, when total consumer load can be met from only a part of the generating capacity available, the stations of higher variable cost should be backed down. The intra-State stations are

mostly located at load-centres and have a higher variable cost as compared to Central stations, which are mostly pit-head. In the earlier regime (pre-ABT), in case an SEB reduced its drawal from Central stations, its payment liability came down at the composite rate (fixed + variable cost) of those stations. The SEBs, therefore, made an uneven comparison: variable cost of their own stations versus composite cost of Central stations, and did not back down their own stations if former was lower, even if it was higher than the variable cost of Central stations. In effect, the merit order was being distorted and generation was not being optimized. The position has now radically changed. The SEBs compare only the variable costs, and ask intra-State stations to back down during off-peak hours. These stations, however, are reluctant to back down (due to continuation of single-part tariff for them, which discourages such backing down) and SLDCs face problems. The remedy lies in implementation of Availability Tariff for all intra-State stations as well, and only then would the States be able to achieve maximum optimization in their own operation.

Further, extension of the UI mechanism to the intra-State stations would get them to respond to grid conditions on their own in the most desirable way. The States would be directly benefiting: higher power availability during peak-load hours, reduced load shedding, and a possibility of earning UI.

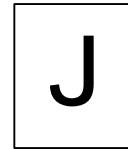
All hydro-electric stations, to the extent possible with storage / pondage volume available, should be scheduled to generate during hours of peak system demand and to shut off / back down during off-peak hours. During actual operation, they should back down any time the grid frequency tends to rise and remain above a threshold even if it means deviating from the schedule advised by SLDC. Similarly, when frequency tends to be below the threshold, the generation should be increased (even if not scheduled during those hours of the day). Further, bringing in of hydro generation should be held up/deferred if frequency is rising, and backing down should be held up/deferred if frequency is falling.

Pumped-storage plants should be operated with grid frequency as the primary signal. They should be pumping during those hours of the day when frequency is at the highest level, even if it causes the State to over-draw from the regional grid. They should be generating as per capability during the hours when the frequency is at the lowest level. Such optimal operation, however, requires the grid frequency to have a daily pattern, which should emerge when a majority of the generating units are brought on effective free governor mode of operation.

The demand - supply gap in the country can be bridged substantially by harnessing the existing captive and co-generation into the grid. This can be done fairly quickly by stipulating that any injection from such plants into the grid (to the extent not covered under a contract with the SEB / local utility) would be paid for as per the frequency-linked UI rate. The logic for this is simple: such injection, with other things within the State remaining unchanged, would either reduce the State's over-drawal from the regional grid or increase its under-drawal, MW for MW. For each unit injected by captive/co-generation, the State would financially gain with respect to regional grid at the prevailing UI rate. This can be passed on to the supplier of that energy.

UI is a very versatile mechanism. It can even be applied for non-conventional generation (solar, bio-mass, wind, mini-hydel) to gainfully harness the capacity, which may not come into the grid otherwise.

“OPEN ACCESS”, “WHEELING” AND “ENERGY BANKING”



Availability Tariff is primarily meant for long-term supply from generating stations on a contractual basis and is not directly applicable for transactions under “open access” and “wheeling” provisions in the Electricity Act, 2003. However, its third component (UI) has a great relevance. “Open access” and “wheeling” generally involve two parties, one supplying a certain quantum of power to the other through the regional / State grid. Any such transaction involves a number of parties, and disputes could arise in scheduling, energy accounting and commercial settlement, unless an appropriate framework is in place.

Suppose party - A has contracted to supply 10 MW round the clock to party - B (in the same State) at a certain price (which need not be disclosed to others), through the State grid. Suppose the transmission loss apportioned to this transaction has been determined as 0.5 MW. Party - B would then be entitled to receive 9.5 MW, provided party - A is actually injecting 10.0 MW into the State grid at its end. In actual operation, both injection by A and drawal by B may fluctuate over the day and the differential may vary from 0.5 MW. Who would pick up the commercial liability arising on account of these deviations? Since A and B are physically apart and operationally independent, a pragmatic solution for commercial treatment in such a case would be to meter the actual injection of A and actual drawal of B in 15-minute time blocks, and separately compute their deviations from their respective schedules (10.0 MW / 2.5 MWh for A and 9.5 MW / 2.375 MWh for B). The frequency-dependent UI rate can then be applied for the deviations, A getting paid from (paying into) the State UI pool account for over (under) - injection, and B getting paid from (paying into) the State UI pool account for under (over) - drawal. The above would supplement the contractual payment by party - B to party - A for 10.0 MW of power supply, and applicable wheeling charges to the State grid owner, to complete the settlement. Installation of this mechanism is absolutely a must for dispute - free and judicious

operationalisation of “open access” and “wheeling” provisions. Besides, UI has another application.

It would have been realized from chapter - D that UI provides an alternative to bilateral trading of power. An entity with a surplus can sell it either by entering into a contract with another entity, or can supply (sell) it to the pool (the regional grid) as UI. Similarly, an entity with a deficit, or an entity wishing to replace its own costly generation with cheaper energy, can buy its requirement either by entering into a contract with another entity, or simply draw (buy) it from the pool (the regional grid) as UI.

A contracted sale or purchase necessarily involves (i) identifying a counterpart, (ii) agreeing on power quantum, duration, price and other terms & conditions, (iii) ascertaining the adequacy of transmission system, (iv) payment of applicable transmission / wheeling charges and absorption of wheeling losses, (v) day-ahead scheduling through SLDC / RLDC concerned, (vii) payment security for transaction, etc. An agreement also means a commitment by both the parties, to sell / buy as per agreed terms. In case the seller fails to schedule the supply of the agreed quantum of power (due to a short-fall in its own power availability, etc), or the buyer fails to schedule the drawal of the agreed quantum of power (due to fall in its requirement, etc), it would mean a contractual default. The agreement between the two parties must specify how such defaults are to be handled. Another issue would be as to how a party (in case it is a regulated utility) selected its counterpart and agreed on the price, and whether these have been done judiciously. Required checks and balances may even delay the finalization of agreement, and trading opportunities may be missed.

All of the above-listed complications get avoided if one goes through the UI route, but it has the following implications: (i) there is no certainty about price (ii) RLDC/SLDC may ask the supply/drawal to be curtailed in case of a transmission constraint. The major advantage, however, is the flexibility: there is no commitment about the quantum. Also, no question can be raised on the price from audit angle, since it is the prevailing pool price or system marginal

cost. The point being made here is that UI route provides an alternative to “open access” and ‘wheeling”, and can be taken when one prefers flexibility over certainty. Even the “energy banking” arrangements hitherto operated can all be beneficially replaced by the UI mechanism.
