Market for Tertiary Response in the Indian Market

Highlighting the dynamics of Short Term Market for Tertiary Reserve

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***Abstract*— The need of renewable sources of energy is highly sought by all the Electrical industries with the aim to curb down the Co2 emission and to remove the ill effects of Green House gasses which has been accepted by experts in all fields across the world. India, in her developing phase in terms of electrical equipment, market and design is evolving to achieve perfection in terms of seamless integration of this green source of power. While at present the rotating machines do perform in synchronism to restore a country wise uniform frequency, the unpredictability and no-spin form of energy is posing a challenge to get integrated in its full form, where it can meet the demand of this large grid. This unpredictability needs the Indian system to be fully prepared with enough reserves ready to be dispatched when required. Today the tertiary response is dispatched in the name of Reserve Regulation Ancillary Service dispatching the un-requisitioned power of the Central Generating Stations. However, many times when tertiary response needs to be dispatched, this power is not available or available in fewer quanta due to their requisitions by the Discoms itself. This paper proposes a market mechanism to increase the participation of the generators in making available a portion of the generation for tertiary response in the form of a separate market for tertiary along with the existing practice of the participation of the Central Generating Plants.**

Keywords—control area, Frequency Variation Index, Load Generation Balance, Ancillary Service, ACP, MCP.

I. Introduction

The Indian Power Sector has majorly the Interstate and state sector generating stations to cater the long-term needs of a state demand portfolio management in terms of Long-Term Access (LTA) or Medium-Term access (MTOA). This helps the power system operator to plan the load generation balance as a one to one correspondence in the form of scheduling of power from the generator to the distribution companies (Discoms). However, Power system observes grid events on regular basis such as a tripping of a large generating unit or any other contingency which impacts the load- generation balance in the grid. This impacts the frequency of the power system which needs to be brought back to nominal frequency i.e. 50 Hz. Even though through pen and paper, a curtailment of the load schedule that the plant was supplying to, may mean a balance of load and generation Pan India, the frequency has now been mapped to a new setting point. This is firstly done through governor action as a primary response, then through secondary control action as has been tested at Dadri successfully [1], though not implemented fully. This is followed by tertiary control through available tertiary reserve, where the new set point of the frequency is either moved up or down as per the events to bring it back closer to the nominal frequency or reference frequency by dispatch of power from remaining generating plants by the system operator. The tertiary response is then withdrawn sequentially keeping frequency constant by scheduling of other generators which helps in maintaining the tertiary reserve margin for the next event.

Today in the Indian Power Scenario, the Dispatch of tertiary reserve is primarily done through the Un-Requisitioned Surplus (URS : Quantum of LTA/MTOA not scheduled by beneficiaries at any time block in the plant) available to the system operator from the Central Sector Generating Stations by means of economic dispatch considering their merit order [2]. The present framework of ancillary services has introduced the Reserve Regulation Ancillary services (RRAS). In this framework All the Generating Stations that are regional entities and whose tariff is determined or adopted by the Central Commission (CERC) for their full capacity can only participate [2]. The generators majorly under this category are Inter-state generating stations. These generators can provide RRAS UP services where they will increase their generation as per merit order and requirement by System operator and RRAS DOWN services where they will reduce their generation.

However, one of the key issues faced in this framework of tertiary dispatch is that it is dependent on the requirement of any beneficiaries and thus during high demand period the amount available for tertiary reserve may deplete. While the second key issue is that if the original beneficiaries if withdraws their URS then in many a case the sole purpose of the tertiary control is not met [3]. The third key issue is non-utilization of spare capacity available in various independent Power producers in the system due to the existing framework for tertiary reserve thus depriving system operator of the spare spinning reserve lying idle in the system.

The above issues can be best described by the following example:

On a typical day the URS available in a region is shown in figure 1. The URS available after the dispatch of RRAS is also shown where it can be observed that when the frequency is low the tertiary reserves available from participating generators are also low. This indicates that if other generators like Independent Power producers if have surplus available in form of spinning reserve may be allowed to participate by honoring the merit order and economic dispatch keeping the competitive market in place.

Further, it can be observed that during the time blocks of 28 to 34 when the RRAS up schedule is given, it is deficit in the availability as the available URS becomes zero. This is due to the facts that under low frequency period the URS reserve is being withdrawn by the constituents as the demand is high by recalling their surrendered share.

The above three challenges describe the need of full-fledged ancillary services market which can overcome these challenges and honors the economic dispatch. This will help the system operation considering the ongoing large-scale integration of renewables and the target of 175 GW of renewable by the year 2022.

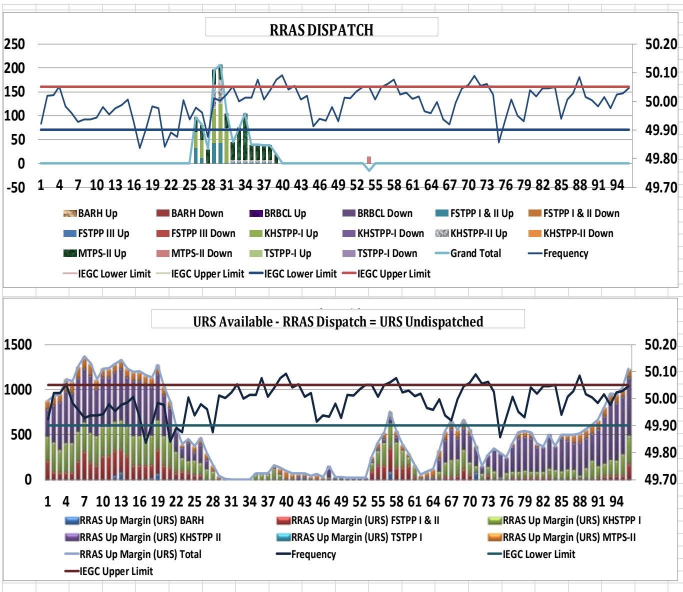


Fig 1: RRAS Dispatch and Margin URS for 6/02/2019 of Eastern Region.

The frequency is the indicator of the load generation balance across all the generators and all the loads connected to a synchronous power system. Frequency Variation Index is a performance index representing the degree of frequency variation, from the nominal value of 50.00 Hz, over a specified period of time. For the purpose of calculation, the following formulae has been adopted to calculate the frequency variation index as a measurement of performance of the power system.

$$FVI = 10 * \frac{\sum_{i=1}^{N}(f_i - 50) * (f_i - 50)}{N}$$

Where fi is the actual frequency in Hz averaged over the time period i. And N is the number of such observations made. Thus, the FVI defined for the period N is arrived through the above formulae [4].

Clearly higher the value of the FVI, more will be the deviation from the standard value of 50 Hz and will mean that the load-generation mismatches are occurring more frequently and adversely affecting the power quality of the inter-connected power system. Indian power system has seen FVI to be as low as 0.02 and to be very high but limited to only 0.07 over the past year. The excursion in the frequency is anticipated to increase with the integration of renewables, and thus a dedicated resource for the purpose of tertiary is needed.

As a system operator, it was also felt that lack of optimal resources available to be dispatched under tertiary has resulted in the increased FVI over the past month and thus has inspired for the articulation of this paper.

II. Market for Tertiary

A. *Abbreviations and Acronyms*

ERLDC is defined as Eastern Region Load Dispatch Centre. RRAS is termed as Reserve Regulation Ancillary Service. PX is defined as Power Exchange. STOA implies Short Term Open Access. NLDC is defined as National Load Dispatch Centre. RLDC is defined as Regional Load Dispatch Centre. Discom is defined as Distribution Company. RTC means Round the Clock.

B. *Practices Across the Globe*

In Germany, Control reserve is tendered on the internet platform www.regelleistung.net that is commonly operated by the German TSOs. Each bidder has its individually secured bidder's domain at the disposal on the internet platform for the submission of offers and access to the allocation results. The German regulator Bundesnetzagentur determines market rules and access conditions for each control-reserve quality after consulting the TSOs and bidders. While provision of positive and negative FRR (Frequency Restauration Reserve) is tendered separately, FCR (Frequency Containment Reserve) is procured as a symmetrical product. Suppliers must provide an upward resp. downward regulation related to the power offered.

mFRR separates each day into six time-slices consisting of 4 hours. Due to a larger scale of products and shorter tendering periods, mFRR is as attractive as controllable for smaller operators and controllable consumers, evident in the structure of the prequalified providers of the products. With FRR, provision of control reserve capacity and deployed control energy are separately paid. Therefore, the bid of each supplier must specify a capacity price bid for provided reserves (paying the provision) as well as an energy price bid for deployed reserves (paying a possible activation). However, with FCR only provision is paid, the deployed energy will not be paid separately. In general, selected bidders are selected for provided control reserve only in accordance with the merit order of capacity prices. Bids for the deployment (energy price bids) are only considered in case marginal bids have identical capacity prices. All selected bidders are paid according to their individual capacity-price bid (pay-as-bid).

C. Market Design for India

The present practice of RRAS dispatch from the CGS will not be changed. However, the participation of the merchant plant/capacity to be included is proposed in this paper and a design for the same is subsequently suggested. Availability of cheaper generation is the major reason for any Discom to switch its portfolio between available resources in Day-Ahead and Same Day Scheduling. The surrendered power from CGS by the Discom had led to the availability of URS to a sufficient quantum over the years and has been utilized as tertiary reserve in the form of RRAS. However, the linking of the reserve which is a fundamental requirement and the URS has led to under-utilization of the RRAS ancillary service. This is either due to the beneficiaries recalling the URS, or the system operator allocating the URS suo-motu to the over-drawing entity. However, this does not help in maintaining the frequency at 50 Hz, since the entire load-generation imbalance would be required to be off-set by an equal active power of opposite polarity. If the same had been segregated, would have been put to its fullest use. The proposed mechanism thus gives a solution to this.

Quite recently, generator has been given the option to sell the URS power at the day-ahead market after getting due consent from the tied beneficiaries assuring non recalling the power on the day of operation. The power is sold and scheduled specially by the generators whose variable cost is high. However, for the tertiary market the power will not be in use until instructed by the operator, thus this will be a type of capacity market suited to the Indian Scenario. The following steps are as proposed:

Step 1: The willing CGS generator will take the consent of the beneficiary for the latter's consent to sell the URS power on D-1 basis. The merchant power plants however will have full autonomy to participate in the Ancillary market.

Step 2: The total capacity required to be reserved for dispatch in tertiary is to be mentioned by the system operator on day-ahead basis.

Step 3: It may so happen that the quantum of actual regulation up dispatched in real time is less than the reserve that is made available in the day ahead. However, the fixed price corresponding to the entire capacity is to be paid to the generator getting its reserve sold. The rationale behind the same is that, the need of tertiary to be under operation is assumed to increase in the upcoming era of renewables' integration, thus the need of such guaranteed capacity of generation.

If the total volume bid by the generator participating in the AS market is less than the required tertiary reserve as determined by the system operator, the total bid volume will be accepted and even though the value is less the requirement it is a guaranteed reserve ready to be dispatched.

Step 4: If more than the quantum required by the system operator is bid and cleared in the tertiary market then the generators having the lower variable cost as bid will be cleared first, and so on, until the last bid is cleared. However, all the generators once cleared will be paid at the average price at exchange which will be the fixed cost of the tertiary dispatch.

Step 5: This payment will account for the fixed cost of the generator. The variable cost of the generator will be frequency linked at the time of the dispatch and paid according to the actual dispatch in real time, post-dispatch.

Step 6: The transmission charge of the short-term open access customers has a reliability support charges of a fixed value of 3 to 4 Paisa per kWH. If this charge is increased to the tune of 1 Paisa per kWH, it will produce enough revenue to cater to the energy charges of the generators for tertiary response.

Step 7: The Bids at the Ancillary market by the generators will be used both in calculating the RRAS dispatch efficiency as well as the dispatch order in the real time dispatch. That is the generator having bid at a lower price will be dispatched first and then the next generator with the higher bid will be considered.

III. Average Price at Exchange and Tertiary

The market dynamics of the tertiary is divided into two components. First there is the allocation of the fixed charge to the participating generators in the tertiary response. This will be provided to all the generators who will be cleared in the exchange after selection of their bids. Secondly, there will be the payment of the variable charge of the ancillary to the generators who will be dispatched in real time. In the last section there is a mechanism shown to identify the performance of the ancillary dispatch in terms of actual energy released to the grid.

A. Allocation of Fixed Cost

The fixed cost of ancillary is linked to the average price at exchange. The logic is elucidated here. In a perfectly competitive market in the long run equilibrium the fixed charge is also recovered in the energy market run by exchange. Thus, for the amount bid in the ancillary market, the fixed cost may be recovered and result in extra profit to the merchant plant that is the profit corresponding to the capacity bid in the ancillary market. The average price at the energy exchange varies from over 7 Rs/KWh in the peak months of September, October and in the summer seasons and goes down to below 3 Rs/KWh during the months of December, January etc. when the demand of power is low. On an average over the year, the average price at exchange is around 5 to 5.5 Rs/KWh. Considering an IPP in the eastern region X, the mu sold at exchange during a day of average price of 6.92 Rs/KWh is 1.78 mu that is roughly 80 MW Round the Clock on 23rd October 2018. While considering 11th March 2019 having average price at exchange to be 3.31 Rs/KWh the mu sold at exchange is 0.87 mu which is 80 MW RTC expect during the non-peak hours. X has a profile of having 92 MW untied capacity. Since the property of exchange is such that the generator gets selected once the bid is lower than the clearing price, the generator bid price averaged throughout the day after calculating its' profit is less than or equal to the MCP. The generators having more untied merchant capacity, the participation increases and over the long run, the generator receives Fixed and Variable cost of production through the energy exchange itself.

The quantum of energy traded in the Short-term market to 5000 mu in a month. Thus, a reliability support charge of Rs 0.01/kWH alone will recover the fixed charge of the tertiary. This will help in quantifying the Reliability support charges that are collected from the Short-term customers and will encourage more participants to participate in the tertiary market.

Date	Average Price	Date	Average Price	Monthly price to dispatch 1000 MW RTC
01-Nov	3.00	16-Nov	3.53	2,65,89,110
02-Nov	3.04	17-Nov	3.32	
03-Nov	3.21	18-Nov	3.74	
04-Nov	3.36	19-Nov	3.17	
05-Nov	3.00	20-Nov	3.79	
06-Nov	3.59	21-Nov	3.30	
07-Nov	3.97	22-Nov	3.37	
08-Nov	4.29	23-Nov	3.38	
09-Nov	4.33	24-Nov	3.22	
10-Nov	4.25	25-Nov	3.30	
11-Nov	4.04	26-Nov	2.90	
12-Nov	3.59	27-Nov	3.07	
13-Nov	4.25	28-Nov	3.25	
14-Nov	4.09	29-Nov	3.47	
15-Nov	3.91	30-Nov	3.60	

Table:1 Monthly price of RTC dispatch of Tertiary

The 1000 MW capacity availability will mean a monthly mu of 7,20,000. The total mu considering that of the bilateral STOA and the All India participants of PX amounts to 49,31,934 MWH and at a reliability support charge to 0.01 Rs/kWH, will amount to Rs 10,00,00,000 approximately, since 1 MWH traded has both buyer and seller paying the reliability support charge netting to 0.02 Rs/kWH in this example. There is thus a necessity to maintain a pool for the commercial settlement of the quantum under tertiary response. Firstly, the pool balance will increase for each STOA transaction, and will get depleted for each generation dedicated to tertiary. The rationale behind involving only the STOA consumers in the tertiary response is that, the margin of available generation is assumed to be depleted lastly by them, so the burden of the cost of tertiary response should also be fully borne by them.

B. Allocation of Variable Cost

The variable charge of the ancillary will be linked to the actual average frequency of the block in real time of the dispatch. This is shown in the next paragraph.

The mathematics is highlighted in the table below: Let's consider the date of dispatch as 5th March 2019. The frequency data for 4th March and the trading details at the IEX for the delivery on 5th March will be considered for the calculation of fixed and variable charge.

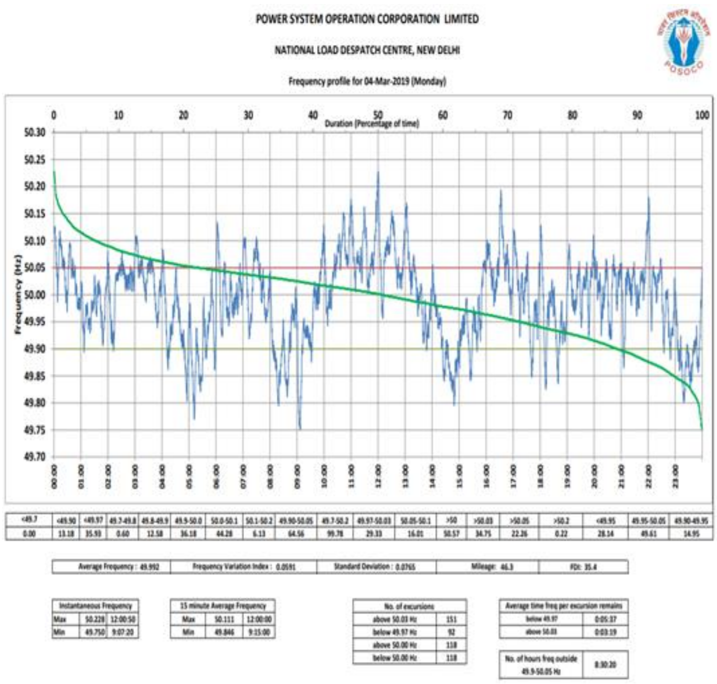


Fig 2: Frequency curve for 04/03/2019.

The 15-minute average minimum frequency is: 49.85 Hz on 4/3/2019.
The 15-minute average maximum frequency is: 50.11 Hz on 4/3/2019.

The ACP is defined as the area clearing price in case of market constraint. The ACP of the split region shown in the blue color is higher than the rest of India. Thus, separate look-up table will be needed to be calculated for the purpose of discovering the variable charge of the ancillary. The average ACP will be that at 50 Hz and an empirical formula will be made to have a look-up values for other values of frequency.

Fig 3: Price at exchange for delivery date 5/03/2019

The average ACP of the split region is 3575.03 Rs/MWh and The average ACP of the rest of India is 3011.50 Rs/MWh [5].

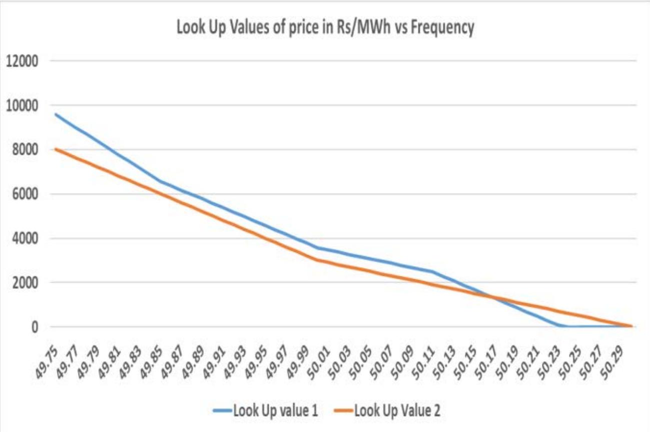


Fig 4: Look up table for split and non-split regions

With each decrement of frequency by 0.01 Hz from 50 Hz the variable price is increased by 200 Rs/MWh, and for every increase in frequency by 0.01 Hz from 50 Hz the variable price is decreased by 100 Rs/MWh. For frequencies above the 15-min average maximum frequency reached on 4/3/2019 the variable cost will be reduced by 200 Rs/MWh for each 0.01 Hz up to nil cost and for frequency below the 15-min average minimum frequency as seen in the previous day, the variable cost will increase by 300 Rs/MWh for each 0.01 Hz.

The variable cost of the RRAS dispatch will be zero if not dispatched, for ancillary up service will be given to the RRAS provider at the average frequency of each time block of dispatch and for RRAS down service the amount will be recovered from the RRAS provider. The Deviation pool as maintained by RLDCs will be used for the purpose of variable charge as is done now and is an existing practice. This look up table is dynamic in nature and will be dependent on the data available from the previous day. The minimum and maximum frequency will be calculated from the performance of the grid the previous day and the exchange price will be derived from the exchange market carried out the previous day for the delivery date as today. This will change on daily basis. This is done with the logic that if the grid performance improves the need for ancillary will reduce and so will the price.

For the purpose of RRAS down service, the payment is to be by the generators participating in the tertiary to the Tertiary pool, while they continue to receive the energy charge receivable by the generator from the beneficiary against the original schedule of the beneficiary. If the difference to the amount received by the generator from the beneficiary to the amount payable for RRAS down is positive, then the net amount will be receivable by the generator and vice-versa. The rationale behind the same is that schedule of the beneficiary is not getting changed due to RRAS down and that the liability to pay the energy charges for the beneficiary to the generator is still present, but since the generator has to generate less, the difference of price between the Charge receivable from the beneficiary to the average price linked to the frequency as per the look-up table, will be paid back to the tertiary pool or refunded to the generator as the case may be.

C. *RRAS Dispatch efficiency*

The main idea is that since the RRAS is a separate commercial agreement between the system operator and the ISGS to provide tertiary, the response in actual needs to be catered and settled. The measure of the AS is through the deviation measurement, which will determine the compliance of the generator to the ancillary command. This is done at the bid price of the generator getting selected in the AS market and at the variable cost of the CGS whose tariff is determined by the Commission. Deviation by its very nature is to balance the energy price in real time.

Consider the block where there is a selling schedule and ancillary. The deviation of the total schedule is considered for balancing purpose to the up to the actual generation. However, ancillary has no contribution to the energy market although it is priced at the same energy price. Thus, the deviation for this block cannot be put in energy terms only since it has a component who is one sided only.

The block where there is no ancillary, the total deviation of the sellers is equal to the total deviation of the buyers since the total schedule of the seller is equal to that of the buyer ignoring the losses, and the total actual generation of the sellers is equal to the total actual demand of the buyers in real time. This makes the deviation settlement a net zero pool (ignoring the additional deviation charge) and hence the name balancing. However, in the block where there is ancillary dispatch, the net deviation of the sellers is not equal to the net deviation of the buyers since the Actual generation in real time is equal to the drawl in real time, but there is more schedule of generation. This violates the basic principle of balancing of the deviation. As per the present practice, the deviation in an ancillary block is solely balanced as per energy balancing principle which does not identify the dual characteristic of the deviation. As we cannot identify and divide the total deviation into two parts for the contribution from ancillary and contribution from energy sold term, we can however use the deviation both as energy mechanism and to evaluate the performance of the ancillary. This parsing of deviation is thus necessary and correct.

First, the response for 25/02/2019 is shown in the figure below:

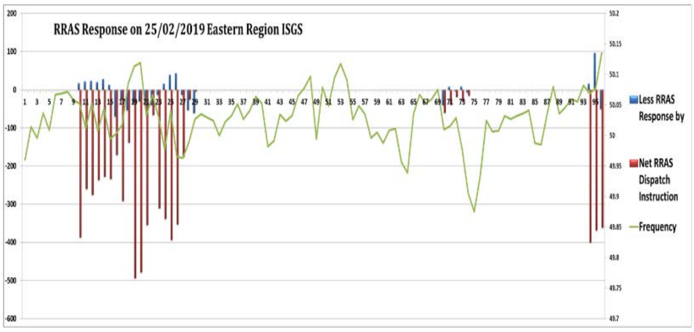
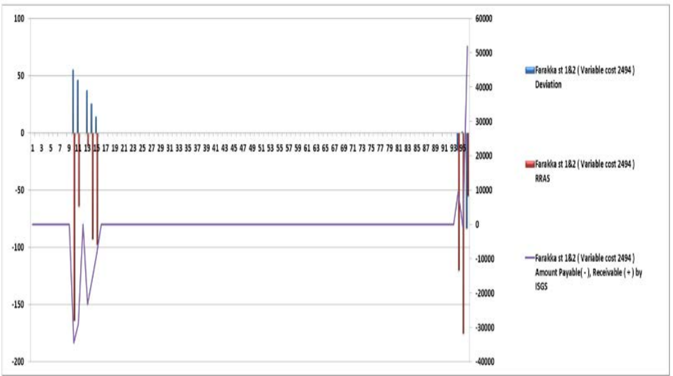
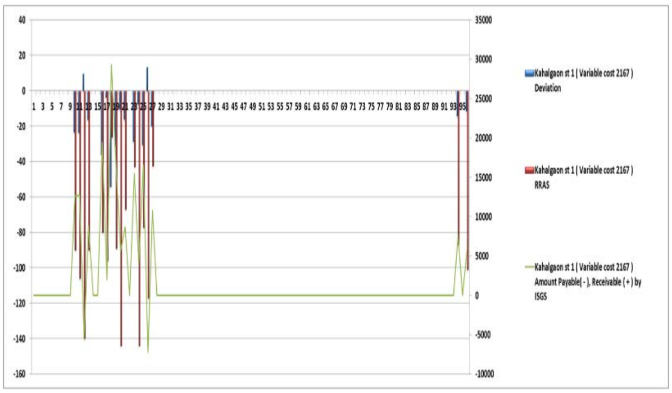


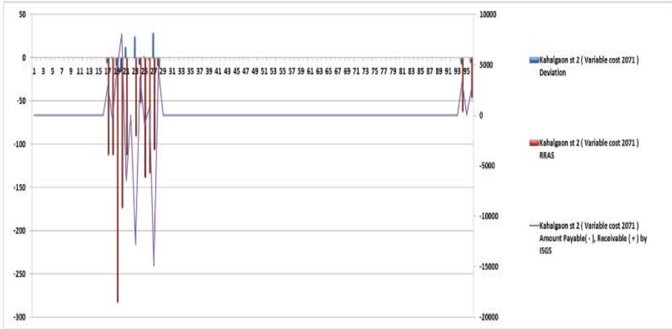
Fig 5: RRAS response for 25/02/2019

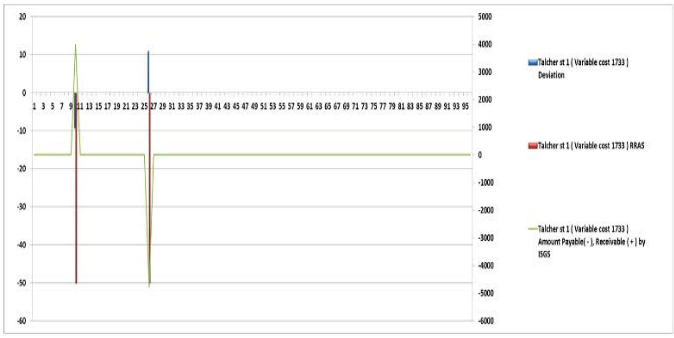
As per the proposed mechanism:

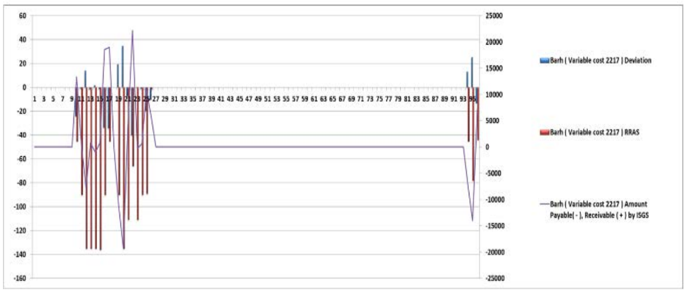
1. For Deviation in the direction of RRAS: Amount is to be paid to the ISGS which is the value obtained by multiplying the variable charge/bid price to the deviation quantum.
2. For Deviation in the opposite direction to RRAS: Amount is to be paid by the ISGS to the pool which is the value obtained by multiplying the variable charge/bid price to the deviation quantum.

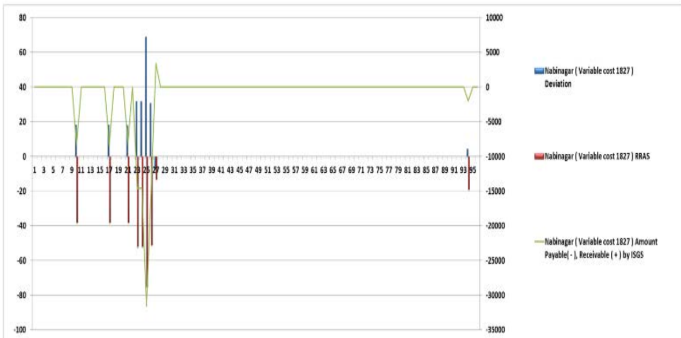












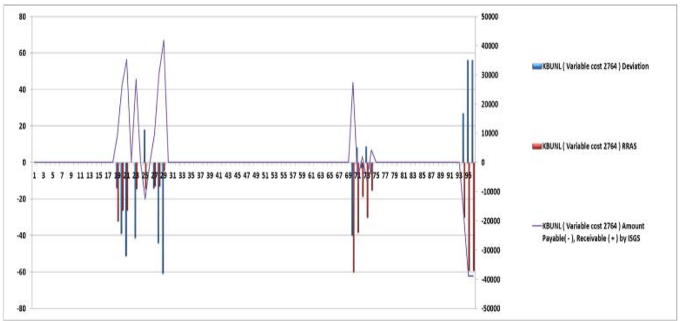


Fig 6: Settlement based on RRAS dispatch efficiency of ER CGS on 25/02/2019.

The total amount payable to ISGS in the Eastern Region is Rs 1,27,991 from the deviation pool. The basis of payment for bilateral LTA/MTOA/STOA is though the schedule between the beneficiary and the generator. This is irrespective of the actual dispatch. Deviation settlement (Balance mechanism) tries to find the cost of the deviation volume and settles the quantum up to the actual dispatch of the generator and the actual dispatch of the beneficiary. This settles bilaterally the actual dispatch.

IV. Conclusion and Future Scope

The RRAS in the present scenario is under the ambit of URS, therefore the result achieved is not optimum for which the RRAS is applied in the scheduling of power. Having a separate, non-overlapping market for RRAS service will ensure better results both in terms of system operation and division of calculation of the charges acquired for RRAS service. The market design proposed is simple in terms of quantifying the reliability support charges that are socialized among all the STOA consumers. As a future scope, once this market has gained some experience Pay-As-Bid option to pay-in and pay-out the cost of ancillary service may be adopted in the Indian market as is practiced in other countries after making few regulatory changes as required.

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