Provision of Control Reserves for facilitating large-scale RE integration in Southern Region Grid States

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***Abstract*—This paper analyses the potential impact of integrating large volumes of variable renewables (RE) on frequency control reserves and presents options for mitigating the associated challenges and costs by enhanced cooperation between the state and regional level. The Southern region is key for the Government of India's target of installing 175 GW of RE by 2022. With an expected 70 GW of wind and solar power, or about 40% of the national target, up to 38% of local consumption may be supplied by variable RE in the Southern region.**

In the first part of the paper, we apply a proven probabilistic method, also used by several European system operators, to quantify the impact of these developments on the future need for secondary and tertiary reserves in the Southern region. By looking at different scenarios and assumptions, we highlight key drivers and risks.

In the second part of the paper, we investigate possible approaches for cost-effectively managing control reserves and real-time system balancing by means of enhanced cooperation between the regional and state load despatch centres. We assess several options for and potentials benefits of improved vertical and horizontal cooperation, including enhanced methods of reserve sharing. We present examples of international best practice and discuss their applicability to the Indian context. We conclude by identifying the most promising options, which appear worth being further discussing by relevant stakeholders in the Southern region.

Keywords- Ancillary services; reserve dimensioning; reserve sharing)

I. INTRODUCTION

The Government of India has set itself an ambitious goal of installing 175 GW of renewable energies (RE) by 2022. As the Indian electricity sector is still dominated by electricity generation from fossil fuels, in particular coal, the efficient integration of variable RE (VRE), such as wind and solar power, may create substantial challenges for system planners and operators. These challenges will become particularly relevant for the Southern region (Andhra Pradesh, Karnataka, Kerala, Telangana and Tamil Nadu). This Southern region alone is expected to account for up to 70 GW of wind and solar power, which is equivalent to about 40% of the national target and more than the Southern region's peak load expected by 2022 [2].

One of the key challenges for successful integration of VRE will be short-term system balancing, i.e. the continuous balancing of supply and demand in real time. In India, system operators use a range of so-called Frequency Control Ancillary Services, or FCAS, for this purpose, namely primary, secondary and tertiary frequency control. Primary frequency control is provided by generators from all over India and the corresponding needs are unlikely to be materially influenced by VRE in the short to medium term. Conversely, both secondary and tertiary reserves must be held by each region separately, and future reserve needs may be strongly influenced by an increasing penetration of VRE. Furthermore, secondary control is still operated on a pilot basis and will only be gradually rolled out throughout India in the next few years. For these reasons, the responsible load dispatch centres still have limited experience with this new service, and there is still scope for optimizing the cooperation between the national, regional and state level in this respect.

Against this background, the remainder of this paper is structured as follows:

- First, we investigate the impact of VRE on the future need for secondary and tertiary reserves in the Southern region, using a proven probabilistic method that is widely used in Europe,
- Secondly, we look at different options for cost-effectively managing and coordinating the provision of control reserves between the regional and state load despatch centres.
- We conclude by highlighting key drivers and issues for future reserves needs and identifying promising approaches for ensuring an efficient provision of frequency control reserves in the Southern region.

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II. Impact of VRE on future needs for Secondary and Tertiary Reserves in the Southern Region

A. *Rationale for Probabilistic Reserve Dimensioning*

To maintain system frequency within defined limits, system operators typically use a well-defined set of different services. In India, primary frequency control is used to arrest any frequency deviations immediately after an incident. Conversely, secondary and tertiary reserves both serve to restore system frequency to its nominal value (50 Hz). However, whilst secondary reserves are automatically activated almost instantaneously (i.e. after less than a minute), tertiary reserves are subject to manual activation with a lead time of 15 or even 30 minutes.

In line with traditional practices in many other countries, the volumes of secondary and tertiary reserves to be held available are currently based on a very simple (deterministic) measure. For instance for the Southern region, CERC has set a target of 1,000 MW for secondary reserves, whilst each state must maintain tertiary reserves equal to 50% of the size of the largest generating units operating in the state's control area. These simple measures clearly do not reflect the stochastic impact of wind and solar power and will thus become inadequate in a future system with a high share of VRE.

For reserve dimensioning, it is helpful to consider the type and nature of the underlying drivers. The need for frequency control reserves is essentially driven by up to four different types of system imbalances:

- Sudden disturbances, such as a loss of generation, load or HVDC links with other interconnections,
- Continuous, stochastic variations of load and/or generation, such as load noise or the minute-by-minute variability of wind or solar power,
- Forecast errors of load or generation (e.g. wind, solar or run-off-river hydro power),
- Any deterministic deviations caused by market imperfections[1].

As indicated by Table I, not all factors are equally important for all types of reserves. For instance, continuous variations and deterministic imbalances are of a temporary nature and are thus mainly relevant for primary and secondary control. Conversely, forecast errors are of a more persistent nature and must be addressed by secondary and tertiary control. Similarly, one has to account for different timeframes. For instance, the use of secondary control will often be limited in time, i.e. until is replaced by tertiary reserves. In contrast, tertiary reserves may have to deal with forecast errors one or several hours ahead of real time. Likewise, the probability of several 'simultaneous' outages increases with the applicable time horizon and will generally be larger for tertiary than for secondary (or primary reserves).

TABLE I. Drivers of frequency control reserves

Frequency Control Reserve Type	**Driver**			
	Distur-bances	***Continuous variations***	***Forecast errors***	***Deter-ministic imbalances***
Primary	✓	✓		✓
Secondary	✓	✓	✓	✓
Tertiary	✓		✓	

1 A well-known example of such deterministic deviations is the use of step-wise generation schedules in many European power markets, resulting in temporary deviations during the transition from one scheduling interval to the next one.

To account for the impact of the different drivers, e.g. European system operators are increasingly relying on probabilistic methods for reserve dimensioning. As illustrated below, such methods are based on empirical data, which is used to estimate a probability functions of relevant drivers. In contrast to simple regression analysis, these individual probability functions are then converted into an aggregate probability function, which then allows determining the necessary level of reserve for a defined security level.

B. *Approach and Assumptions used for Probabilistic Reserve Dimensioning*

For our analysis, we have used a proven probabilistic model, which is similar to the methods applied by the German and other Central European TSOs ([4],[5],[8]). This method was originally developed in Germany in the early 2000s and has been constantly improved over time. In line with Table 1 above, it allows for consideration of outages (generators or HVDC links), stochastic forecast errors and the short-term variability of load and variable RE, whilst we have neglected any deterministic deviations for our analysis. For the purpose of our analysis, each of these stochastic processes has been represented by a separate probability distribution.

Where possible, this information has been based on data received from the Southern Regional Power Committee (SRPC) or publicly available sources from India. Alternatively, we have used relevant information and statistics from other geographies, trying to adjust those to local conditions as far as reasonably possible. For instance for unplanned outages, we have had to rely on statistics from Europe as the corresponding details were not readily available for India. However, information from CEA reports ([1],[3]) has been used to calibrate those values. Similarly, we have used European statistics for wind and solar forecast errors but have been able to check those against detailed statistics from one Indian state.

Next, the individual probability functions have been into an aggregated probabilistic distribution by means of a convolution algorithm as illustrated in Fig. 1. Due to the impact of generator outages, which may only lead to a loss of generation, the resulting distribution is skewed to the left, i.e. there is (substantially) higher risk of system deficits than surpluses. Similarly, whilst the illustrative example in Fig. 1 assumes Gaussian distributions for all forecast errors, the method is compatible with other forms distribution of functions (such as Weibull functions) as well.

Using the resulting probability function, the required reserve levels are then determined from the cumulative probability function, i.e. by calculating the system deviation for a given confidence interval. Using the aggregate probability function, it is thus easily possible to investigate the relationship between different security levels and the resulting reserve requirements. Similarly, the overall analysis can be applied across different products, i.e. by

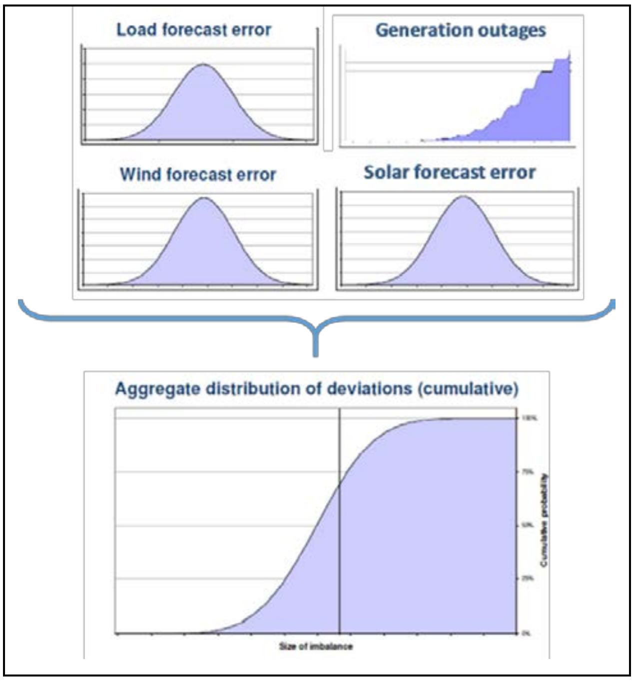


Figure 1. Convolution of individual probability distribution (illustrative example)

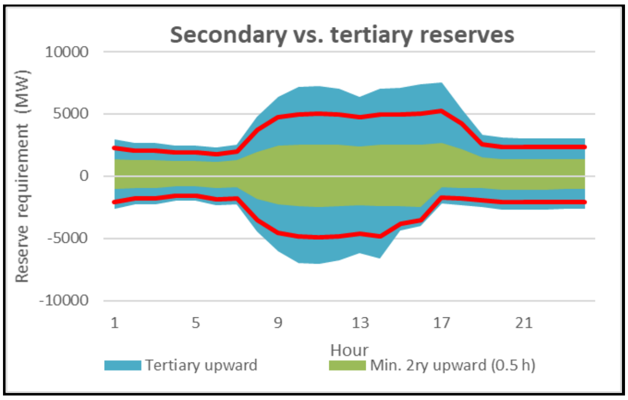
tailoring the underlying assumptions to the relevant time horizons, ranging from several minutes to many hours into the future.

In line with common practices in continental Europe, we have applied the same method for secondary and tertiary reserves. Due to the partial overlap of these two services, the effective need for tertiary reserves was finally calculated as the difference between the overall reserve needs over the time horizon for tertiary reserves and the amount of secondary reserves.

C. Reserve needs for the Southern Grid Region

Fig. 2 shows sample results for 2022 with a total of 70 GW of VRE in the Southern region, including 42 GW of solar power and 28 GW of wind power. Whilst overall reserve needs remain in a range of up to ±2,500 MW during night hours, they increase more than two-fold during the day. The latter reflects the fact that this day is characterized by up to 50 GW of VRE generation during the middle of the day, including 30 GW of solar power. The increase of reserve needs thus mainly reflects the risk of solar forecast errors. Similarly, the marked reduction of the need for downward regulation in the afternoon hours can be explained by the fact that solar power is generating close to its maximum during the corresponding hours, such that there is a very limited risk of unexpected additional generation. Finally, we note that the difference between secondary and tertiary reserves is mainly caused by the growing forecast risk over an increasing time horizon.

The results clearly show the importance of accounting for the impact of VRE. According to current regulation (see above), the southern region would have to hold about 1,000 MW of secondary reserves and approx. 1,500 MW of tertiary reserves, which is broadly equivalent to the values calculated for the night hours. Conversely, current reserve volumes would clearly be insufficient during day hours, due to the impact of solar power. The wide range of required reserves during the day furthermore highlight the benefits of



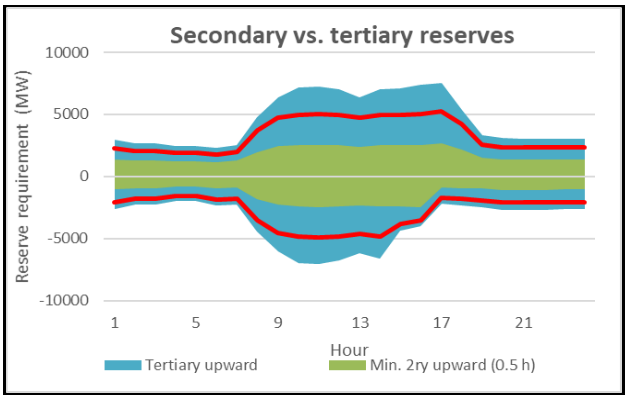
Red line indicates reserve needs for a forecast horizon of one hour

Figure 2. Reserve needs for 2022 (42 GW solar, 28 GW wind)

dynamic reserve dimensioning, i.e. of accounting for changing conditions and best available predictions. In contrast, using static requirements throughout the day would either lead to risk of insufficient reserves during the day or result in excessive reserve requirements during the night.

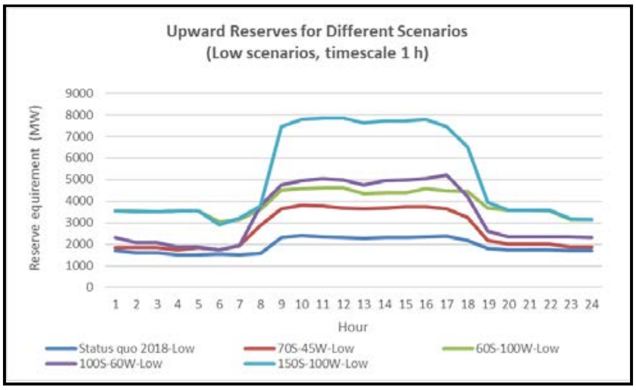
For comparison, Fig. 3 shows a similar graph, in this case for the year 2018, again for a day with substantial electricity generation from VRE. Whilst the pattern is broadly similar the chart in Fig. 2, the resulting reserve requirements are substantially lower than for 2022. This firstly reflects the lower penetration of variable RE and, secondly, significant load growth between 2018 and 2022. Nevertheless, as solar PV generates up to 10 GW during the day, the impact of solar forecasts has a significant impact on reserve requirements during the day already.

The differences between Fig. 2 and Fig 3. indicate that reserve requirements may be significantly impacted by the rapid growth of VRE in the Southern region. To assess the corresponding impacts, we have simulated a range of scenarios with different shares of wind and solar power; see Fig. 4. Besides the status quo (2018), this chart shows the resulting reserve requirements for four future scenarios, with between 50 GW and more than 100 GW of VRE in the Southern region. Compared to today, this may lead to up a four-fold increase of future reserve needs. Furthermore, one can observe major differences between the future scenarios. This mainly reflects the overall penetration of VRE, although the variation between the 100S-60W and 60S-100W scenarios indicates that the relative shares of solar vs. wind power are relevant as well.



Red line indicates reserve needs for a forecast horizon of one hour

Figure 3. Reserve needs for 2018 (15 GW solar, 17 GW wind)



"S" and "W" specify installed capacity at national level of solar and wind power, respectively.

Figure 4. Impact of VRE capacity on future reserve needs

Overall, these results indicate that the expected growth of VRE may indeed lead to considerable challenges for the Southern grid region. Nevertheless, it should be noted that the results above depend on a range of assumptions, such that the real values may be different:

- As stated above, our calculations have been based on the use of European statistics on (regional) wind and solar forecast errors. Although these assumptions have been checked against analysis from an Indian state, climatic conditions in India are different and the development of future forecast accuracies remains uncertain. As sensitivity analysis has shown, the volumes presented above may easily change by ±20%.
- The use of European outage statistics induces further uncertainty. Our analysis shows, however, that the potential error remains limited, especially during the critical periods with high shares of VRE.
- As illustrated above, reserve needs are strongly impacted by the applicable time horizon. Consequently, the future definition and interaction of different frequency control reserves as well as short-term re-scheduling of generators in the intra-day wholesale market may have a major impact on the requirements for individual services.
- For the results presented above, we have assumed an allowed error margin of 0.1%, i.e. a security level of 99.9%. Since system security and frequency control are effectively shared throughout the national system, one could argue that a slightly confidence level would be justified, which would result in reduced reserve requirements at a regional and/or level.

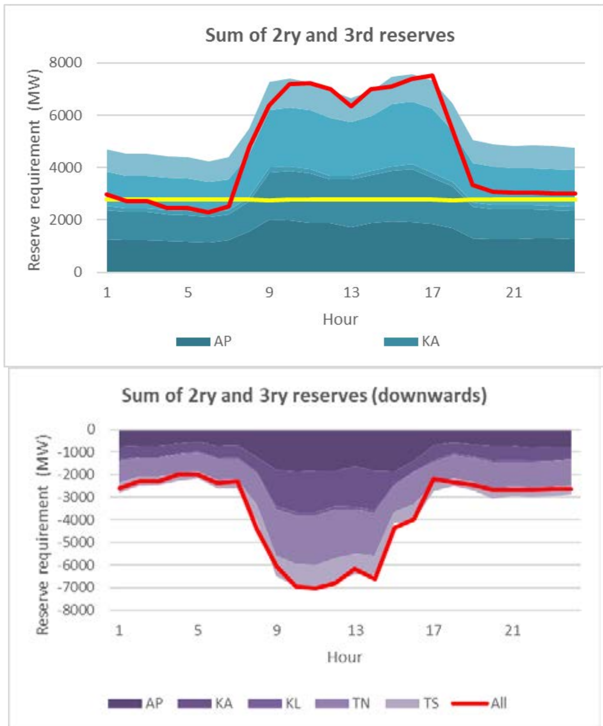
D. Benefits of Regional Reserve Sharing

At present, secondary reserve needs are set at the regional level, whilst each state has to maintain its own share of tertiary reserves. In contrast, all results presented above have been calculated for the entire Southern region as a whole. As a separate step, we have, therefore, also investigated the impact of dimensioning reserve needs separately for each state. Fig. 5 shows the corresponding results, using the same scenario as considered by Fig. 2 above. Whilst the shaded areas represent the reserve requirements for each state [2], the red curve shows the outcome when dimensioning reserves at the regional level. The yellow line finally indicates the volumes, which would result from application of current regulations.

The two charts in Fig. 5 reveal two interesting observations:

- First, the sum of the state-wise reserve requirements is substantially larger than under regional dimensioning for upward regulation during night hours. In contrast, it is broadly equivalent during day hours and for downward regulation.
- Secondly, regional needs for upward regulation are comparable to the volumes to be maintained under current rules during night hours, whereas the latter fail to account for the additional risks during day hours. For downward regulation, the volumes calculated by us are consistently larger than current requirements, which are limited to 1,000 MW of secondary reserves.

Both effects can be explained by similar factors, i.e. by the relative importance of generator outages, on the one hand, as opposed to load and VRE forecast errors, on the other hand. As we have assumed a very similar relative forecast error for the state and regional level[3], the impact of load and VRE forecast errors is largely equivalent, irrespective of whether reserves are determined by state or for the entire region. In turn, this implies that requirements during day hours as well as for downward regulation in general are primarily driven by forecast errors. The same



Acronyms represents individual states (e.g. AP – Antra Pradesh).

Figure 5. Comparison of state-wise vs. regional reserve dimensioning (2022 - 42 GW solar, 28 GW wind)

[2] Please that the results for Kerala are hardly visible due to their small size.
[3] In practice, the regional forecast error can be assumed to be slightly lower. Due to the lack of robust information from India, we have refrained from corresponding assumptions, however.

seems to hold true for the regional approach even during night hours, as the decline during the early morning hours corresponds to a decrease of load and wind power.

Conversely, the state-wise need for upward regulation is determined by the risk of generator outages during night hours. In other words, the size of the largest unit is greater than the combined forecast risk of load and VRE in this period. But as the risk of four simultaneous outages, i.e. one in each of the four larger stages, is extremely small, the probabilistic method results in a much smaller outage risk and hence reserve need than the sum of the results per state. Accidentally, this impact seems to be comparable to the current principle of require only 50% of the largest incident to be maintained as tertiary reserves by each state.

As mentioned, Fig. 5 refers to a future scenario with a high penetration of VRE. When looking at 2018 instead, our analysis consistently shows substantial savings in case of a regional approach. Moreover, Fig. 5 represents an example with considerable electricity generation by wind and solar power. On other days, the impact of VRE on the need for upward regulation will remain more limited. These considerations imply that the benefits of regional dimensioning will likely remain significant.

III. Options for Enhanced Cooperation and Management of Reserves and Real-Time Balancing

A. Benefits and challenges of coordination

Our analysis has shown that a regional rather than state-wise approach for reserve dimensioning and provision may offer major benefits, i.e. in terms of reducing the aggregate volume of reserves to be maintained. Furthermore, the general increase of reserve requirements can be expected to create major challenges for regional and state load despatch centres as growing reserve volumes will put increasing restrictions on the dispatch of conventional generation. Both aspects indicate that increasing coordination may offer significant benefits to the Southern region.

But the analysis above also indicates that the benefits of regional dimensioning may become less relevant as the penetration of VRE grows. Moreover, current arrangements are implicitly based on a shared approach already today, as each state has to cater for 50% of the largest incident only. In the following, we therefore focus on different approaches for coordinated procurement and use of secondary and tertiary control.

B. Discussion of potential options

In line with relevant experiences from Europe, we subsequently differentiate between four different approaches for coordinated procurement and use of secondary and tertiary control, i.e.:

- System Operator – Actor model
- Imbalance Netting
- Mutual exchange of balancing services
- Joint merit order

1) System Operator – Actor model

Under the first model, which also used to be known as 'TSO-Actor' model in Europe, service providers, i.e. individual generators, are allowed to provide operating reserves to a system operator (load dispatch centre) outside their local control area. In an Indian context, this might for instance involve a state generator offering its services to either the regional load dispatch centre (RLDC) or one of the state load dispatch centres (SLDC) of another state. This concept was for instance used in Germany, France or Switzerland, including the cross-border exchange of secondary and tertiary control between different countries.

On first sight, this concept appears straightforward and similar to current contractual arrangements for wholesale energy in the Indian market. However, as the corresponding services are typically activated during real-time operations, i.e. past the scheduling stage, it is no longer possible to account for the impact of the corresponding transactions by means of normal generator and/or exchange schedules. For instance in Germany, this issue was resolved by virtually moving such generating units into the external control area. More specifically, measured generation was excluded from the real-time area balance of the local control area but added to the area balance of the 'receiving control area' for the purpose of calculating the Area Control Error (ACE). Clearly, this process becomes increasingly demanding as the number and frequency of such changes increases. Moreover, this approach basically provides for a 'swap' of resources only but does not contribute to an efficient use all available resources in the region.

2) Mutual exchange of balancing services

Rather than allowing individual generators to provide frequency control to external control areas, an alternative is the direct exchange between different system operators, or load dispatch centres. Under this approach, which is also known as 'TSO-TSO model' in Europe, each generator may provide frequency control to the local system operator only, known as 'Reserve Connecting TSO' in Europe. In turn, the Reserve Connecting TSO may utilise these either itself or provide them to the system operators of other control areas.

This approach has the advantage that it may give all participating control areas access to all available resources. As such, it is conceptually clearly superior to the previous model. Moreover, it relies on a well-defined and constant relation between individual generators and load despatch centres, allowing for a stable and much simplified framework of operational communications, measurements and settlement.

The major drawbacks of this approach are that it requires an increasing level of coordination between all participating system operators. Furthermore, in order to reap the full benefits of common use all available resources, standardised products and well-defined rules for pricing and settlement are required. For illustration, we subsequently present two possible options, i.e. of imbalance netting for secondary control and the use of a joint merit order for tertiary control.

a) Imbalance netting (secondary control)

Imbalance netting refers to the real-time netting of opposite system deviations in two or more control areas, i.e. before activation of secondary control. For this purpose, the area imbalances of all participating control areas are corrected (reduced) in real time such that only the net imbalance of the total area is corrected by secondary control. As illustrated by Fig. 6 this is achieved sending the (unprocessed) ACE to a centralized controller ('aFRR Optimization System') where it is netted with the ACE of all other participating control areas. Thereafter, a correction factor is sent back to the local control loop and subtracted from the measured area balance.

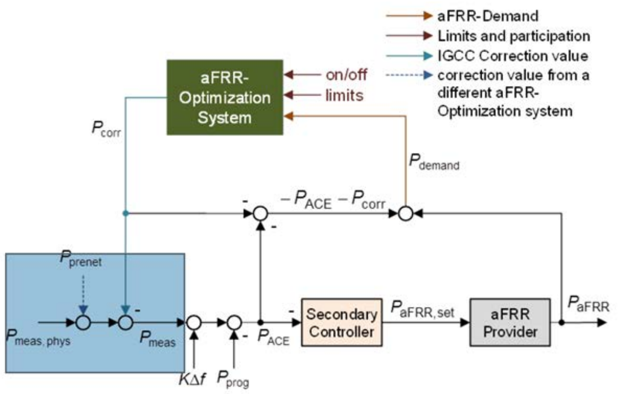
Imbalance netting was first introduced in Germany in 2010 but has now been extended to thirteen system operators from ten countries [4]. Each month, imbalance netting allows for netting of about 300 – 400 GWh of imbalances [7], thereby reducing the need for activation of secondary control by about 30% - 40%. The resulting exchanges are financially settled, using a mechanism that leads to cost savings for all participating system operators. This allows for monthly savings of about EUR 4 – 8 million, or more than € 400m since the start of imbalance netting.

As these experiences show, imbalance netting represents an effective tool for avoiding unnecessary activation of secondary frequency control. However, it requires a well-functioning scheme for automatic generation control (AGC). Given that this service is still under implementation in India, it would seem useful to consider the corresponding European experience during further implementation. Nevertheless, as we expect that a substantial share of future system deviations will have to be compensated by tertiary control, imbalance netting alone is unlikely to be sufficient.

b) Joint merit order (tertiary control)

The establishment of a merit order represents the most intense form of cooperation in the area of real-time balancing. This approach has been successfully used for more than 15 years in the Nordic electricity market and for almost a decade within Germany. In both regions, system operators combine all available bids and offers for a given product category into a single merit order. Each of them has the right to select the most economic option from the common merit order list, unless the resulting transfer of electricity was constrained by network congestion.

By definition, this concept requires some form of standardised product definition, which can be easily compared based on price and defined technical properties. It is thus comparable to the current use of Reserve Regulation Ancillary Services (RRAS) by POSOCO. A similar well-defined production would be required for other tertiary reserves, which are currently procured and managed at the state level. Experiences from Europe have furthermore shown that application of this concept may be difficult under



aFRR – automatic Frequency Restoration Reserves (= secondary frequency control)

Figure 6. Integration of imbalacne netting in control loop for secondary frequency control [6]

[4] Germany, Denmark, the Netherlands, Switzerland, Czech Republic, Belgium, Austria, France, Croatia and Slovenia

marginal pricing. But as we understand that generators in India are currently remunerate at the offered price (i.e. their tariff), this would not seem to be an issue.

The main challenges for India would thus likely be the establishment of well-defined market mechanisms not only at the regional but also at the state level. In addition, it would be necessary to design and implement robust systems facilitating real-time access to and activation of available bids and offers as well as orderly settlement.

c) Joint merit order (secondary control)

In principle, the concept of a common merit order can be equally applied to secondary control. Yet, the potential scope and constraints for implementation critically depends on the approach for procurement, activation and remuneration. For instance if all available resources were activated on a pro-rata basis, this might simply take the form of an extended version of imbalance netting as explained above, i.e. distributing the residual net imbalance to all participating control areas based on a defined distribution key. Alternatively, if a full market-based system was used, the principle of a common merit order can be equally applied to secondary control, as is already the case within Germany or between Germany and Austria.

C. Specific issues with for coordination between the regional and state level

So far, we have generally referred to the coordinated use of frequency control reserves between different control area. But in the Southern region, as well as more generally in India, one furthermore has to consider the split of responsibilities between the regional level (RLDC) and the SLDCs. In this context, it is useful to consider the distribution of the key drivers and the main resources for frequency control reserves. As shown in Table II, states will generally be exposed to all relevant drivers of imbalance risks, i.e. load and VRE forecast errors and variability as well as generator outages, whereas deviations at the regional level will be largely limited to generator outages. In contrast, flexible generation is distributed across the region and individual states, but not necessarily in the same proportion as the underlying needs.

These observations emphasise that our previous considerations on the benefits of coordination to not apply to the interaction between different states, but at least equally to cooperation between the RLDC and the SLDCs. Whilst this seems straightforward for the case of tertiary reserves, the situation appears more complex in case of secondary control. In particular, the relevant stakeholders and authorities will have to decide whether:

- AGC should be controlled from the regional level only, in which case all relevant resources would need to be directly controlled by the RLDC for real-time operations, which would lead to issues similar to those pointed out for the System Operator – Actor

TABLE II. DRIVERS AND SOURCES OF OF FREQUENCY CONTROL

Level	**Driver**			**Source**
	Load	***VRE***	***Generation***	
State	✓	✓	✓	✓
Region		(✓)	✓	✓

model above,

- AGC should be controlled by the RLDC and the SLDCs, i.e. each of them being responsible for all generators under their authority, in which case a strong form of coordination (like imbalance netting) would appear highly desirable if not essential,
- AGC should be based on a hierarchical concept, similar to the traditional approaches in European load-frequency control blocks, which would effectively resemble some form of hybrid between the concepts of imbalance netting and a common merit order presented above.

IV. Summary and Conclusions

This paper has investigated the impact of the expected growth of wind and solar power on the requirements for secondary and tertiary control reserves in the Southern region. Based on the application of a probabilistic methodology for reserve dimensioning and consideration of several future scenarios, our analysis has shown the following:

- The expected growth of VRE can be expected to lead to a (major) increase of current reserve requirements, especially during day times.
- As forecast accuracy will become a major driver of future reserve needs, load despatch centres at the national, regional and state level will need to robust statistics on the variability and forecast inaccuracy of wind and solar power, which requires access to reliable measurement data from relevant plants.
- As reserve need vary greatly for different conditions, a dynamic approach for reserve dimensioning will become essential to help limiting reserve needs.
- Probabilistic approaches allow for explicit consideration of defined risk level. Given the hierarchical structure of system operation in India and the principle of distributed action, Indian authorities should carefully consider the scope for sharing risks between different regions as well as the interactions between different reserve products and the intra-day wholesale market when deciding on the applicable safety margins.
- Our calculations show clear benefits for joint dimensioning and sharing of reserves at a regional level. Relevant stakeholders and authorities should thus carefully consider relevant experiences from other geographies, such as Europe, in order to facilitate the coordinated and cost-efficient determination, procurement and use of frequency control. In particular, we recommend further studying concepts like imbalance netting or a clear hierarchical philosophy for secondary reserves and loves towards an integrated market arrangement with a common merit order for tertiary reserves.

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