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Operating Reserves and Wind Power Integration: An International Comparison

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***Abstract*—The determination of additional operating reserves in power systems with high wind penetration is attracting a significant amount of attention and research. Wind integration analysis over the past several years has shown that the level of operating reserve that is induced by wind is not a constant function of the installed capacity. Observations and analysis of actual wind plant operating data has shown that wind does not change its output fast enough to be considered as a contingency event. However, the variability that wind adds to the system does require the activation or deactivation of additional operating reserves. This paper provides a high-level international comparison of methods and key results from both operating practice and integration analysis, based on the work in International Energy Agency IEA WIND Task 25 on Large-scale Wind Integration. The paper concludes with an assessment of the common themes and important differences, along with recent emerging trends.**

***Index Terms*--operating reserves, power system operation, power system reliability, power systems, wind power generation**

I. Introduction

There has been a rapid increase in the utilization of wind power plants in the past decade. Wind energy's zero-cost fuel and emissions-free output provide great benefits to consumers and society. Utility-scale wind is a relatively new resource and is increasing at such a rapid rate that utilities and system operators are becoming concerned about the integration issues and integration costs that it brings. Wind power integration studies have been performed by numerous entities to help understand and quantify these impacts [1]-[3]. The studies typically simulate a future power system with high wind penetrations, and evaluate the impacts on the grid and the incremental operating costs that result [3]. These studies have been maturing continuously as the state of the art advances, with each study generally building on previous studies.

Grid operators already have techniques for managing the variability of demand and generation on the system through reserves. Reserves are operated for diverse purposes across multiple timescales. The impact of wind integration on reserve requirements is a current area of interest for integration studies and power system operators. This paper focuses on three major topics related to operating reserves. Section II describes the types and uses of operating reserves and proposes a consistent nomenclature to tie together the different terminology used in different regions. Section III describes the types of operating reserves currently used in North American and European systems. Section IV surveys the types of reserves considered in wind power integration studies. Finally, Section V compares and contrasts operating reserves considered in the power systems and integration studies described in the previous sections.

II. Operating Reserve Definitions

Variability and uncertainty are not unique to wind generation; similar characteristics exist in aggregate electric demand and supply resources and have always posed challenges for power system operators. Future loads cannot be perfectly predicted, loads and generator outputs can vary substantially in different time frames, and large power system equipment can fail at any given time without notice. Power system operators secure different amounts and types of operating reserves to compensate for these characteristics in order to serve load reliably and keep the system frequency stable. There are many different terms, definitions, and rules concerning what operating reserves entail. Due to the variation in definition and naming convention of reserves across different systems we attempt to construct a consistent nomenclature that categorizes the different types into a common framework.

The term operating reserves is defined in this paper as the real power capability that can be given or taken in the operating timeframe to assist in generation and load balance and frequency control. Systems also require reactive power reserve as well to provide voltage support and require certain targets for installed capacity that is often referred to as planning reserve; however, reactive power reserve and planning reserve are not discussed in this paper.

The types of operating reserves can be differentiated by the type of event they respond to, the timescale of the response and the direction (upward or downward) of the response.

The first characterization of a reserve is the type of event it is responding to. Some forms of operating reserve are kept for continuous needs (non events). Other operating reserves can be used to respond to either contingency events or longer timescale events. Contingencies are instantaneous failures such as the loss of a generator or failure of a transmission line. Longer timescale events can include net load ramps and forecast errors that occur over a longer amount of time.

In addition to the type of event, reserves can be categorized by the response time required and the physical capabilities needed of the responding participant. For instance, some reserves are required to be generating at part load to provide spinning reserve, others require automatic generation control (AGC), and still others require portions of their reserve to be directly responsive to frequency deviations. According to the North American Reliability Corporation (NERC) the difference between spinning and non-spinning reserves is that spinning reserves must be synchronized to the system while non-spinning reserves are not necessarily synchronized [4]. Spinning reserves respond more quickly as they are already synchronized to the system. AGC is a capability whereby a centralized party (system operator) sends controls directly to the resource on the desired output. Frequency responsive capabilities include governor systems that automatically adjust input when frequency deviations are sensed.

Reserves may also be categorized by whether more or less supply is needed. Upward response is required when there is less generation than load and can be attained by additional generating power or a reduction in participating loads. Downward response is required when there is more generation than load and can be attained by a reduction in generating power or an increase in participating loads.

Using the characteristics listed above, five separate types of reserves can be defined: frequency response reserve, regulating reserve, ramping reserve, load following reserve, and supplemental reserve. The characteristics of these reserve types are summarized in Table I and graphically in Fig. 1. During normal system operation, regulating reserve (seconds) and load following reserve (minutes) are used. During contingencies, frequency response reserves (seconds) and supplemental reserves (minutes) are used for longer timescale events; note that the timescales may vary by system. Supplemental reserves effectively act as a reserve for other reserve categories to replenish the faster responding reserves when operating reserves are insufficient to protect the system from the next event. As should be expected, the slower reserves (ramping, load following and supplemental) have a mix of spinning and non-spinning reserves while the faster reserves (frequency and regulating reserves) require strictly spinning reserves.

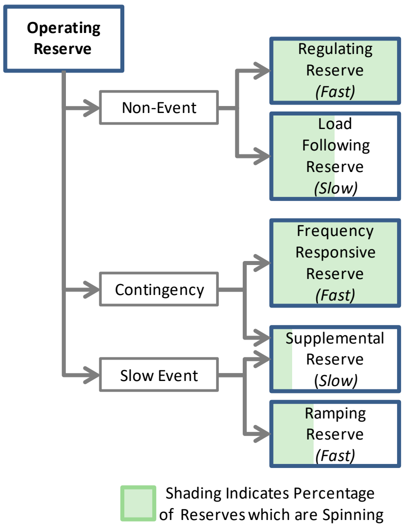


Fig. 1 Illustration of Reserve Types

TABLE I
SUMMARY OF RESERVE TYPES

	Frequency Response Reserves	**Regulating Reserve**	**Ramping Reserve**	**Load Following Reserve**	**Supplemental Reserve**
Purpose of Reserve:	*Provide initial frequency response to major disturbance.*	*Maintain area control error due to random movements in a time frame faster than energy markets clear.*	*Respond to failures and events that occur over long time frames (e.g. wind forecast errors, wind ramps)*	*Maintain area control error and frequency due to non-random movements on a slower time scale than regulating reserves.*	*Replace faster reserve to restore pre-event level reserve.*
Other Names:	*Governor response, primary control, FRR*	*Frequency control*	*Variable generation event reserve, forecast error reserve, balancing reserves*	*Load following, dispatch, tertiary reserves*	*Replacement reserve, supplemental reserve, tertiary reserve, substitute reserve*
Type of Event:					
Contingency Events	Fast (seconds)				Slower (minutes)
Non-Event (inherent randomness)		Fast (seconds)		Slower (minutes)	
Longer Timescale Events			Fast (minutes-hours)		Slow (hours)
Timescale of Response:					
Spinning Reserve:	X	X	X	X	X
Non-Spinning Reserve:			X	X	X
Type of Service					
AGC:	X				X
Upward Regulation:	X	X	X	X	X
Down Regulation:	X	X	X	X	

III. Operating Reserves in Practice

Power system operators secure different amounts and types of operating reserves in order to serve load reliably and keep the system frequency stable. As discussed in Section II, operating reserves can be subdivided into five categories, but these categories are not consistent across countries. In this section, we overview the types of reserves used by system operators in mainland Europe and North America with the results summarized in Table II at the end of the section.

A. United States

In the United States, the North America Electric Reliability Corporation defines operating reserves as *"That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve"* [5]. In North America, the spinning reserve and supplemental reserves described above are often combined and referred to as contingency reserves, again as in Section II. This reserve is used only for instances of generator or other loss of supply. Regulating reserve is generally procured in both the upward and downward directions (in cases of over-generation). Fast frequency response (governor response) is not yet explicitly addressed by NERC as a distinct operating reserve but the Western Electricity Coordinating Council (WECC) has started to study the need for a 30 second frequency responsive reserve.

Both NERC and NERC subregions detail how much a balancing area will require of each type of operating reserve on its system [5]. For instance, the NERC BAL-002 standard requires that a balancing authority or reserve sharing group maintain at least enough contingency reserve to cover the most severe single contingency. For the western interconnection, this is extended by a proposal by WECC to state that the minimum amount of contingency reserve should be the greater of the most severe single contingency or the sum of 3% of the balancing area load and 3% of the balancing area generation. Detailed specifications of contingency reserve requirements, including the amount of spinning compared to supplemental reserve, are established

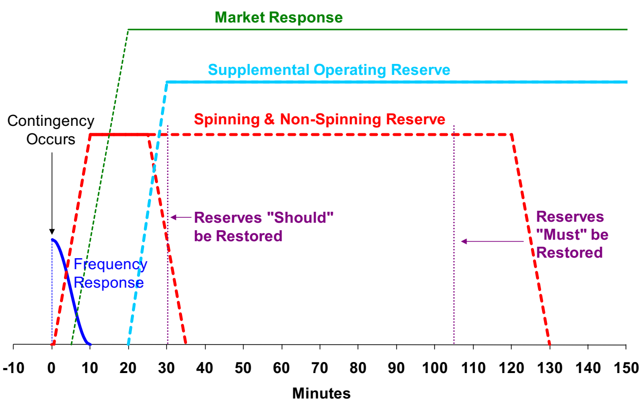


Fig. 2 Reserve deployment as defined by NERC. [7]

by each Regional Reliability Organization. Regions typically require at least half of the contingency reserve to be spinning. An example of how reserves are deployed following a contingency is shown in fig. 1. Unlike contingency reserve, regulating reserve usually does not have explicit requirements. Instead, balancing areas will maintain sufficient regulating reserves so that they meet their NERC Controlled Performance Standards (CPS1 and CPS2). In some areas that currently have high penetrations of wind power like the Electric Reliability Council of Texas (ERCOT), the forecasted wind power output is considered when making regulating and other types of operating reserve requirements [6].

B. Europe

In Europe, broad guidelines are given by the former TSO groupings such as Nordel and the Union for Coordination of Transmission of Electricity (UCTE), now part of the European Network for Transmission System Operators for Electricity (ENTSO-E). ENTSO-E defines reserve in three categories; primary, secondary and tertiary control [8].

Primary control is activated when system frequency deviates by 20 mHz from the set point value and must be fully operational within 30 seconds. The purpose of primary control is to limit the deviation of system frequency following a system event. Secondary control consists of units controlled by Automatic Generation Control (AGC) and fast starting units. These are engaged 30 seconds after a contingency event and must be fully operational within 15 minutes. This category of control attempts to restore the frequency to its nominal value and reduce the area control error. Primary control reserves are required from ENTSO-E members based on their share of network use for energy production [9]:

$$P_{pri.}^{country} = \frac{E_{prod}^{country}}{\Delta f_{\max ss} \sum_{ENTSO-E} E_{prod}^{country}} \Delta P_{cont.} \qquad (2)$$

where the quantity $\Delta f_{\max,ss}$ is a tolerable steady state maximum deviation of 0.18 Hz, and the quantity $P_{cont.}$ is a worst case continental contingency of 3000 MW determined from a system-wide analysis.

Secondary control reserves are required from members of ENTSO-E in proportion to the maximum of yearly load in their region [9]:

$$P_{\sec.}^{country} = \sqrt{a \cdot L_{\max} + b^2} - b \qquad (1)$$

where a and b have been empirical determined as 10MW and 150MW respectively. Tertiary control has a slower response and is engaged to restore primary and secondary control units back to the reserve state. The procurement of reserves and additional types of required reserves are set by the individual countries and are presented on a country-by-country basis.

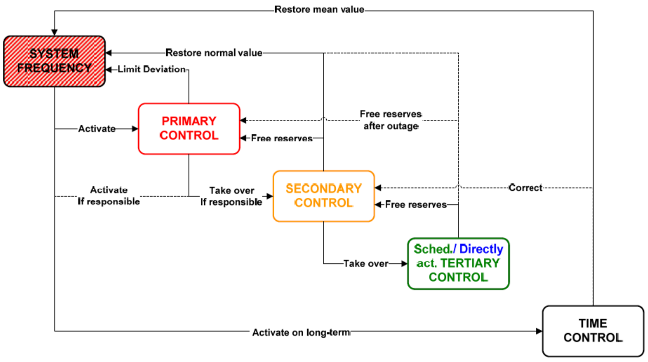


Fig. 3. ENTSO-E and UTCE control mechanisms. [8]

C. Spain

The Spanish system uses four types of reserves: primary, secondary, tertiary and deviation. Primary control reserve is mandatory in the Spanish system, being a non-paid service operated by all the generation units in the regular regime. Generators with primary regulation operate with a reserve margin of 1.5% [10].

Secondary regulation is a market-driven service, which is provided by licensed units on automatic generation control (AGC) [10]. The Spanish TSO, Red Eléctrica de España (REE), procures as much as ±1,500 MW of the secondary regulation reserve to balance its system in real-time. Secondary reserve in Spain includes many fast-responsive hydro power generators, of which a total installed generation capacity of 16,657 MW exists on the system.

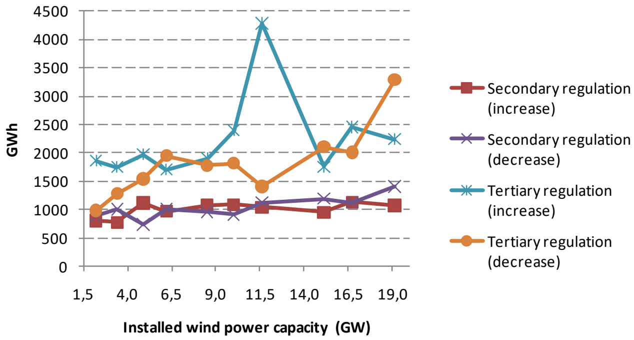


Fig. 4 plots deployments of secondary reserves in Spain from 2000 to 2009 versus the installed wind power capacity. The plot shows that secondary regulation is not significantly affected by increasing wind generation.

The tertiary reserve is a 15-minute dispatchable responsive reserve that is used for manual generation adjustments to address variations in generation and load. This service is manual and is dispatched 15 minutes before the beginning of an operating hour, or within the hour if required. When dispatched, the energy must be sustainable for two hours if required. Tertiary regulation is a complimentary optional service but with a mandatory bid, managed and remunerated by market mechanisms [10].

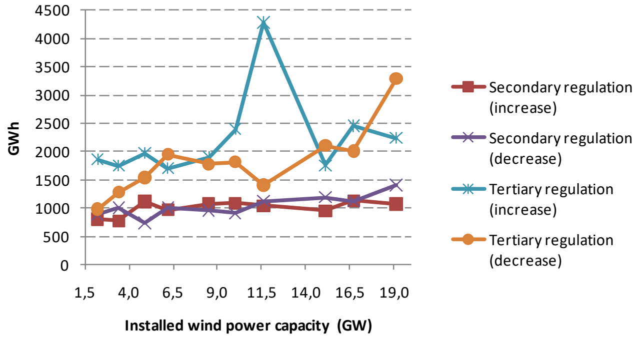


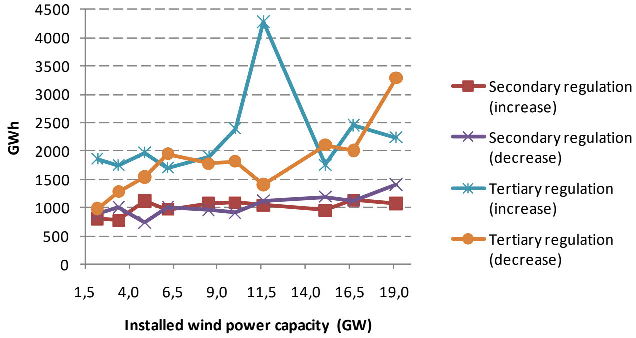
Fig. 4 plots deployments of tertiary reserves versus the installed wind power capacity and shows that tertiary regulation is affected by increasing wind generation. Therefore, in the Spanish system, tertiary reserve requirements are expected to be higher with increasing penetrations of wind power generation in the power system.

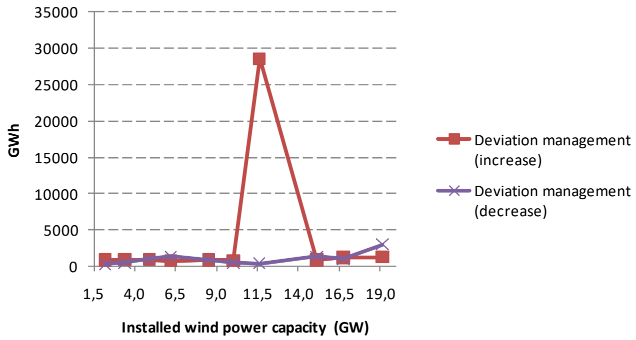
In addition to primary, secondary and tertiary regulation, an additional reserve of active power called deviation reserves can be used. Deviation reserve helps to balance large differences (> 300 MWh) between scheduled generation and forecasted demand. The foreseen deviations include unavailability or justified changes communicated from generation. This reserve is provided by generation and pumped storage power units. Deviation management also plays a role as a link between the tertiary regulation and the intraday markets, providing the TSO with a flexible mechanism to solve the imbalances between generation and demand without compromising or risking the availability of secondary and tertiary reserves. As shown in Fig. 5 wind power forecasting errors can increase the cost associated to the operation of deviation management and the tertiary reserve.

D. The Netherlands

The Netherlands are represented within ENTSO-E by the Dutch TSO TenneT. TenneT is required to maintain minimum values of primary and secondary reserve. The minimum capability is contracted, but reserves from units

Reserve Names in Operations	**Frequency Response Reserves**	**Regulating Reserve**			
ENTSO-E (Europe)	**X** *(Primary Reserves)*	**X** *(Secondary Reserves)*			
Spain	**X** *(Primary Reserve)*	**X** *(Secondary Reserve)*	**X** *(Deviation Reserve)*	**X** *(Tertiary Reserve)*	
Netherlands	**X** *(Primary Reserves)*	**X** *(Secondary Reserves)*			
Denmark	**X** *(Primary Reserves, Instantaneous Reserves)*	**X** *(Manual Regulation)*			
Ireland	**X** *(Operating Reserves, Primary, Secondary and Tertiary Reserves)*	**X** *(Regulating Reserves)*			
Quebec	**X** *(Frequency Regulation Reserves)*	**X** *(15 Minute Operations Reserve)*		**X** *(30 Minute Operations Reserves, Load Following Reserves)*	**X** *(Stability Reserves, Spinning Reserves)*





available to respond within 15 minutes are also deployed and financially compensated from a larger pool of parties via a market mechanism [11]. Entities that submit production or trade schedules are referred to as responsible parties, and can comprise both load and generation. These entities are charged an imbalance price for deviations from their schedule, but can be paid that price if it happens that their deviation contributes to reducing system imbalance. They dispatch their generation independently of and in addition to what TenneT may require.

As described above, primary control reserves are required from ENTSO-E members based on their share of network use for energy production; the share due from the Netherlands, based on 2008 load data, amounts to 670 MW/Hz [12]. Based on 2008 load data, the Netherlands is also responsible for 300 MW secondary reserves [12].

E. Denmark

The Danish Power System is part of both the Organization for the Nordic Transmission System Operators (Nordel) and the Union for the Co-ordination of Transmission and Electricity (UCTE). Primary reserves are required by both Nordel and UCTE to stabilize the system frequency following an instantaneous imbalance. Primary reserves activate in seconds to minutes and are used for 15 minutes at most. Secondary reserves are automatically dispatched to restore frequency according to UCTE requirements. These reserves typically stay active for 15 minutes. Tertiary reserves are required both by UCTE and Nordel and are used to manually restore primary and secondary reserves. Tertiary reserves consist of start-ups and shutdowns of generators as well as redistribution between generators and change of exchange levels. [13]

F. Ireland

The Irish system is a relatively small and isolated power system, and has a more granular approach to its definition of reserve [14]. There are five main types of reserves including: regulating, operating, replacement, substitute, and contingency reserves. Regulating reserve is a subset of operating reserves and acts within 30 seconds of a frequency deviation to restore the frequency to within 0.1 Hz of the set point value and controls inter-system transfers on the North-South interconnector which joins the two systems on the island. Operating reserve, as defined in the Irish system, is divided into three parts: primary, secondary, and tertiary operating reserve. Primary reserve acts for the first 15 seconds to avoid transient nadirs below 49 Hz. Secondary reserve then acts to avoid continuous system operation below 49.5 Hz, and it is fully available from 15 seconds after an event for a further 75 seconds. Tertiary operating reserve is used to replace the primary and secondary reserve. It is split into Tertiary1, which restores primary and secondary operating reserve for the first 5 minutes and Tertiary2 reserve which is available after 5 minutes for an additional 15 minutes.

Replacement reserve acts as a longer term resource to restore secondary and tertiary operating reserve from operation. This is fully available within 20 minutes for a four hour period. Substitute reserve is utilized to restore replacement reserve after 4 hours for a duration of 24 hours and is available for the replacement of emissions-restricted plants. Contingency reserve is available to restore all reserves 24 hours after the event.

G. Quebec

Hydro Quebec requires six broad categories of reserves: stability reserves, 10-minute operations reserve, 30 minute operations reserve, energy balancing reserves, frequency regulation reserves and load following reserves. Stability or spinning reserve, typically 1000MW, represents 60% of the largest single loss of generation. The 10-minute reserves also typically operate at 1000 MW and consist of non-firm sales, interruptible load and a large portion of stability reserves. 30-minute reserves, typically about 500 MW, represent 50% of the second most severe single loss of generation. Energy balancing reserves vary from 1500 MW in the day-ahead time frame (1200 MW in the summer) to 500 MW in real-time two-hours ahead. They consist of available generating capacity and interruptible load that could be deployed when needed to offset discrepancies in supply caused by errors on current forecasts. Frequency regulation reserves operate using AGC and a 500 MW (minimum) modulation range. Finally load following reserves do not have a strictly defined standard due to the large hydro-generation base (43,000 MW in 2009) which allows for load-following without any practical constraint.

IV. Operating Reserves in Wind Integration Studies

Over the past several years, various organizations have participated and/or initiated wind power integration studies. The studies evaluate a power system in the future with high wind power penetrations and simulate the impacts that occur. A general process for wind power integration studies can be found in [15] and recommendations so far in [3].

A major component of each study is to evaluate the incremental need for additional operating reserves for the future system that result from high wind penetration. The study teams usually consider traditional definitions and requirement determinations and propose needed changes to maintain reliability while accommodating the variability and uncertainty present in the wind power. The uncertainty and variability are compared before and after the addition of wind because in most cases there are no set rules for the load following reserves. This value is generally calculated via statistical methods analyzing wind power time series that are modeled for the study. The methodologies used to compute these values have evolved as each study learns from past studies. The most recent studies evaluating very high penetrations are using sophisticated methodologies that are diverging further from the traditional methods used today in actual operations. The types of reserves considered by the different studies discussed below are summarized in Table V. Note that studies completed in the United States also considered contingency reserves; however, the introduction of wind generators did not change the required quantity of contingency reserves.

A. Minnesota and New York Integration Studies

In the United States, some of the first major wind power integration studies were performed in the states of New York and Minnesota [1] [2]. In New York, the study evaluated 3,300 MW of wind power on the 33,000 MW peak load NYISO system. The study concluded that no incremental contingency reserves would be needed since the largest single severe contingency would not change. The study concluded that an additional 36 MW of regulating reserve was required on top of the current 175 - 250 MW procured today. This is a result of analyzing the standard deviation of 6-second changes in load net of wind compared with that of load alone. The standard deviation with wind increased from 71 MW to 83 MW, presenting a 12 MW increase. As was the current guideline in New York, the total standard deviation is multiplied by three to ensure that the total regulation requirement is sufficient to cover 99.7% of all instances, thus giving the 36 MW increase.

In Minnesota, the study evaluated 15, 20, and 25% wind energy as a percentage of total annual demand (3441 MW, 4582 MW, and 5688 MW on a system with a peak demand of roughly 20,000 MW). Similar to New York, it was concluded that there would be no impact on the contingency reserve requirement with the added wind penetrations. The regulating reserve requirement similarly evaluated the added variability of wind but calculated it to be a 2 MW standard deviation for every 100 MW wind plant installed. This calculation was based on operational data from existing wind plants. The ratio was used to calculate the regulating reserve requirement as seen in equation (1).

$$Reg\ Req = k\sqrt{\sigma_{load}^2 + N(\sigma_{W100}^2)} \qquad (1)$$

where k is a factor relating regulation capacity requirement to the standard deviation of the regulation variations (assumed to be 5 in this study reflecting current practices); σ_{load} is the standard deviation of regulation variations from load; σ_{W100} is the standard deviation of regulation variations from a 100 MW wind plant; and N is the wind generation capacity in the scenario divided by 100. The results showed increases of 12, 16, and 20 MW for the 16, 20, and 25% cases, respectively.

The Minnesota study quantified two other defined categories that the New York study did not. In the study these are defined as load following and operating reserve margin (Load following reserve and ramping reserve in Table I. Load following was calculated as twice the standard deviation of the five minute changes in the net load, and increases ranged from 10 to 24 MW for the three cases. The operating reserve margin was allocated specifically for hourly forecast errors in the net load. This analysis assumed a dynamic requirement, one that was not constant for all hours but in fact was a function of the amount of expected wind capacity during the operating period. The data analysis showed that the variability of wind is highest when the wind capacity is in the middle range (i.e. 40-60% of installed capacity) because the wind turbines are on the steepest parts of their wind speed to wind power conversion curves. Therefore, more reserve was needed for the middle range compared to times of very low wind generation or times of very high wind generation.

TABLE II
Summary of Reserve Types Used in Operations Today

These studies paved the way for the development of dynamic operating reserves for wind energy. More recent studies have evolved and developed methods from those preceding studies with increasing sizes, penetrations, and scopes. The traditional definitions and methods used in current operations were simply not feasible with penetrations of 20% wind energy and more.

B. Eastern Wind Integration and Transmission Study

The Eastern Wind Integration and Transmission Study (EWITS) evaluated the operational impacts of various wind penetrations, locations, and transmission build-out options for most of the United States eastern interconnection. The study included three scenarios of 20% wind energy with each representing different primary locations of the wind, and one 30% wind energy scenario [16]. The majority of this region is currently operated by Independent System Operators (ISO) and Regional Transmission Organizations (RTO) who administer the wholesale electricity markets. These markets have evolved since their inception in the late 1990s. The further evolution of the rules and procedures that the markets will follow is a key assumption on how operating reserve requirements are determined in the study. The boundary between operating reserves and what is extracted from sub-hourly energy markets also has an impact on the method used.

The first procedure of the study was to determine the contingency reserves required. As many previous US studies have done, these assumed the current rule and determined that the largest contingency was not affected by the large amounts of wind generation. One and a half times the single largest hazard in each operating region determined the amount of contingency reserves for that region.

Many prior studies in the US concluded a slight, but not insignificant, increase in the amount of required regulating reserve due to the increased variability of wind added to that of the load. In EWITS, a similar methodology to the prior studies was performed. The minute to minute variability separated from a 20 minute rolling average of a 100 MW wind plant was used for the analysis and the standard deviation was determined to be 1 MW. It was assumed that there is no correlation between wind plants for power output deltas in this time frame, and therefore the total standard deviation for a balancing area was calculated by geometrically adding the 1-MW standard deviation for all 100-MW wind plants on the system. For load-only, the regulating reserve requirement was assumed to be 1% of the total load, and assumed to be equal to three times the standard deviation of the load variability. Since load and all wind variability on this timeframe were also considered to be independent of one another, the standard deviations of all wind and all load were then geometrically added together by calculating the square root of the sum of their squares. The total standard deviation was increased by less than 1 MW when the wind was added to the load, and therefore the variability of wind was not considered as part of the regulating reserve for the study.[1]

In contrast to from most studies, however, it was determined that the uncertainty in the wind forecasts used for economic dispatch would impact the regulating reserve much more than what was shown for the variability. Economic dispatch programs that run every five minutes would use information from at least ten minutes before the operating interval. Since it is too late to adjust the economic dispatch for any deviations, these deviations would all be met by units providing regulating reserve. Assuming a 10-min ahead persistence forecast, the additional regulating reserve was determined by looking at the standard deviation of ten-minute changes in wind output (load forecast for 10-min ahead was assumed to be quite good and load forecast error was ignored). Fig. 6shows the standard deviation of the 10-min ahead wind forecast errors as a function of the average hourly production of the total wind. The highest variability is near 50% production where the anticipated 10-min change can be up or down and also relates to wind turbines being at the steepest part of the power conversion curve. The function was used for the standard deviation of the hourly wind-related standard deviation of the regulating reserve requirement and was geometrically added to the load regulating reserve requirement discussed above. The equation (3) is shown below, where σ_{st} is the standard deviation of wind forecast errors described in Fig. 6.

$$\begin{aligned} &Regulation\ Requirement \\ &= 3 * \sqrt{\left(\frac{1\%Hourly\ Load}{3}\right)^2 + \sigma_{ST}(HourlyWind)^2} \end{aligned} \quad (3)$$

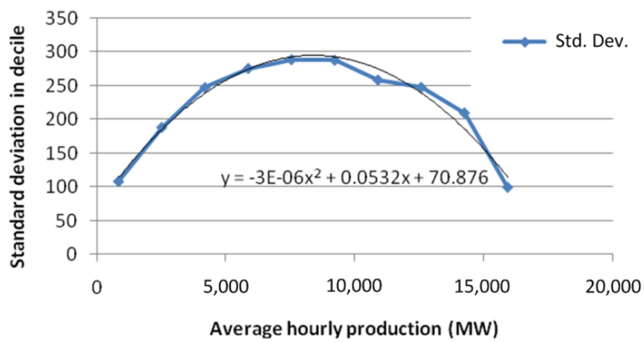


Fig. 6. 10 Minute ahead wind generation forecast errors as a function of production.

A similar approach was used for the hour-ahead wind forecast error. However, in this case it was assumed that the errors did not occur often could be compensated for with off-line non-spinning reserve. Therefore, one standard deviation of the hour-ahead forecast error was required to be spinning, and two standard deviations could be non-spinning. Also, because the reserves were used in the production cost simulations for the study, if the reserves had to be used for the hour-ahead forecast error of the hour in question, those reserves did not have to be kept in real-time. In other words, if reserves were needed because less wind was available than forecast, the model would release that amount of reserves in real-time since the reserves were used for the forecast error and not needed further. The total amounts of all reserves used in the study are shown in Fig.

[1] Calculations based on a balancing area with 100 GW load and 60 GW wind, which was about the average for the largest ISO balancing areas that were a part of the study.

7. The reserve requirement was an hourly value that was a function of both wind and load levels.

Reserve Component	Spinning (MW)	Nonspinning (MW)
Regulation (variability and short-term wind forecast error)	$3 \cdot \sqrt{\left(\frac{1\% \cdot HourlyLoad}{3}\right)^2 + \sigma_{ST}(HourlyWind)^2}$	0
Regulation (next-hour wind forecast error)	$1 \cdot \sigma_{NextHourError}\ (PreviousHourWind)$	0
Additional Reserve		2 × (Regulation for next hour wind forecast error)
Contingency	50% of 1.5 × SLH (or designated fraction)	50% of 1.5 × SLH (or designated fraction)
Total (used in production simulations)	Sum of above	Sum of above

Fig. 7. Summary of reserve methodologies for EWITS.

C. *Western Wind and Solar Integration Study*

The Western Wind and Solar Integration Study (WWSIS) investigated the operational impact of up to 35% energy penetration of wind, PV, and concentrating solar power on the power system operated by the WestConnect group of utilities in the southwest and mountain states for the year 2017 [17]. In this study, the entire Western Interconnection is modeled with up to 23% wind and solar penetration in the rest of the Western Electricity Coordinating Council (WECC). Three geographic scenarios are modeled in which 1) each state meets its own wind and solar target, 2) wind and solar sites are concentrated in the best quality resource areas, and 3) some resources come from within each state and some resources are concentrated in high resource areas. Additionally, three penetration levels were used in WestConnect: 10% wind/1% solar energy penetration, 20% wind/3% solar and 30% wind/5% solar, with correspondingly increasing levels of wind and solar in the rest of WECC. The high renewables case consists of 30% wind and 5% solar energy in WestConnect and 20% wind/3% solar in the rest of WECC, for an overall average penetration of 27% wind/solar energy in the western U.S.

The study employed hourly production simulation analysis, statistical analysis down to the 10 minute level, and quasi-steady-state power simulations on a 1 minute level to examine difficult events. WECC's Regional Reliability Standard dictates that contingency reserves should be 6% of load or the largest single contingency, whichever is greater. At least half of these contingency reserves must be spinning reserves. Since the worst contingency in this region tends to be smaller than 6% of load, WWSIS production simulations held spinning reserves equivalent to 3% of load.

Hourly production simulation analysis showed that in the high renewables case, there were contingency reserve shortfalls for 89 hours of the year. This was driven by the extremes of the day-ahead wind/solar forecast errors. There were no contingency reserve shortfalls in the perfect forecast case. Additional sensitivities showed that increasing spinning reserves by 5, 10, 15, 20 or 25% of the day-ahead wind forecast would increase costs by up to $2.75 per MWh of *total* wind generation. However, even increasing spinning reserves by 25% of the day-ahead wind forecast did not completely eliminate the contingency reserve shortfalls. Additionally, the *incremental* cost per MWh of increasing spinning reserve from 20 to 25% of the forecast was over $100,000/MWh. The study concluded that it was more cost-effective to have demand response address the 90 hours of contingency reserve shortfalls rather than increase spinning reserves for 8760 hours of the year.

In addition to examining contingency reserves, WWSIS evaluated the impact of increased variability and the need for additional regulating and load following reserves. Unlike contingency reserves, WECC does not have a specific formulaic rule for regulating and load following reserves, but requires sufficient reserves be held to meet NERC's Control Performance Criteria. WECC guidelines ask that expected load variability be met 95% of the time.

Statistical analysis on 10 minute variability was conducted to determine that the average requirement to cover 10 minute variability reserves doubles from ~425MW to ~850 MW at the WestConnect level in the high renewables case. However, the production simulation analyses showed that high penetrations of wind and solar displaced other resources, in some cases decommitting units, and in some cases backing down units. Production simulation results showed that there were more up-reserves available in the high renewables case than in the no renewables case (see Fig. 8). So while the variability reserve requirement approximately doubles, economic operation of the power system *naturally* provides this increased reserve requirement so that there is no need to commit additional reserves.

To help utilities develop simple rules for determining variability reserve requirements, extensive analysis was undertaken on a WestConnect and individual state basis. In the high renewables case, the variability reserve requirement for the WestConnect footprint could be distilled down to 1.1% of load plus 5% of wind online (not capacity) up to 47% of nameplate wind. Similar rules for developed for each state within WestConnect.

Regulating reserves are a subset of the fast variability requirement but are held separately from the 10-minute variability reserves. While WWSIS did not evaluate which units were on AGC, the minute-to-minute analysis showed that sufficient regulating reserve capability was available.

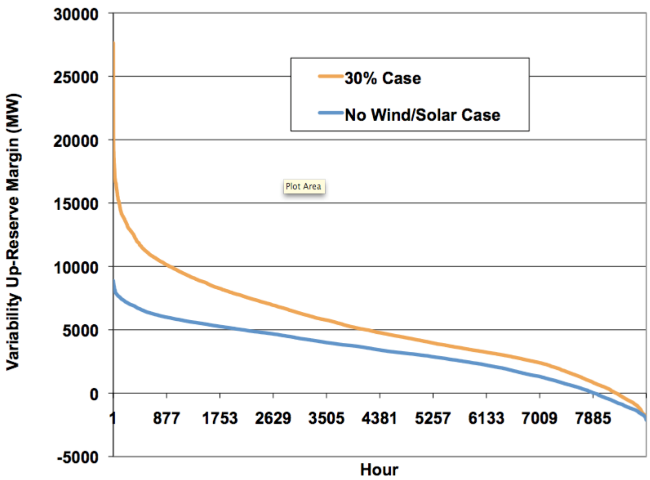


Fig. 8 There are more up-reserves available in the high renewables case than in the no wind/solar case because the additional renewable energy generation causes many conventional units to be backed down. [17]

D. *All Island Grid Study (Ireland)*

The All Island Grid Study in Ireland was published in 2007 and examined, among other things, the Irish system's ability to integrate various penetrations of wind generation [18]. Six plant portfolios were examined to meet the load forecasted for 2020. Portfolio 1 contains 2 GW of wind; 2, 3 and 4 contain 4 GW of wind; portfolio 5 contained 6 GW; and portfolio 6 contained 8 GW of wind generation. This is in the context of a projected peak load of 9,618 MW and a load factor of 63.9%. The study involved hourly scheduling of the system with the WILMAR system planning tool [19].

The study incorporated a refined implementation for reserve provision with only two categories specified in the model: spinning and replacement reserve. The definition of a unit capable of meeting the replacement reserve standard was an off-line unit with a start up time of less than 60 minutes and online units whose capacity was not allocated to the spinning reserve requirement. This is a highly simplified model given the existing structure of reserve provision in the Irish system. The requirements for spinning and replacement reserve were based on a mixture of existing and proven requirements and newer techniques for the provision of reserve for wind generators.

Spinning reserve demand is calculated as being the size of the largest online unit plus an additional demand for wind generation. This is calculated based on the work in [20], which links the amount of reserve carried on the system in any hour with the reliability of the system over a year. Reserve is allocated in such a way as to keep the average risk of having a load shedding incident in each hour the same for all hours of a year and includes the effect of generator outages and load and wind forecast errors.

Ireland is an island system with one 400MW interconnector in operation and a 500MW interconnector under construction. System modeling for the year 2020 assumed that 100MW of spinning reserve can be obtained through interconnection. Another 50MW of reserve is assumed to be provided from interruptible contract loads. Of the remainder, a constraint of a maximum of 50% of reserve demand can be provided by pumped storage. Wind generators are allowed to provide spinning reserve through curtailment.

The demand for spinning reserve is illustrated in Fig. 9 on a weekly averaged basis. Spinning reserve is required more frequently as the amount of wind increases in the portfolio, significantly so in portfolio 6. The scheduled outage of the largest unit on the system (480MW CCGT unit) is seen to reduce the spinning reserve demand significantly during weeks 31 to 34. While the variable generation requires extra spinning reserve, the largest contributing factor remains the loss of the largest conventional unit.

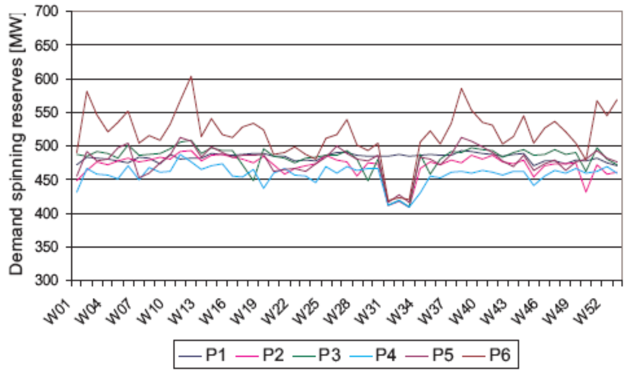


Fig. 9. Weekly demand for spinning reserve for each generation portfolio.

Replacement reserve is calculated as a function of the possible forced outages of units and an additional margin which is a function of the 90th percentile of the net load (load- wind) forecast for each particular scenario. The 90th percentile was chosen as it most closely matches experience with proven reserve standards. WILMAR implements rolling unit commitment and has stochastic optimization functionality. This requires the forecast data to be an input to the scenario tree tool and thus, replacement reserve is activated accordingly by the scheduling tool. Demand for replacement reserve is a function of the installed wind power and the forecast error over longer timelines. This is shown in Fig. 10 and Fig. 11. Fig. 10 shows how the replacement reserve requirement is a function of how far ahead the optimization is evaluating. In other words, generally, errors will be larger further out and therefore more replacement reserve are required than more immediate horizons. In Fig. 11, where portfolio 5 contains 6GW of wind generation, the demand for replacement reserve is seen to exceed 3GW in one instance. This is due to a 1GW load rise at the same time as a 1GW decrease in wind, combined with a forecast error.

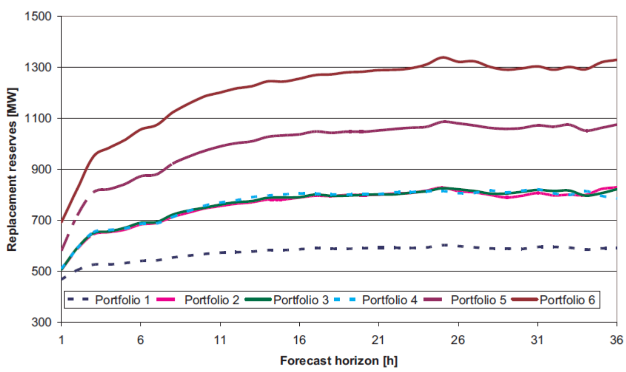


Fig. 10. Average demand for replacement reserve by time horizon.

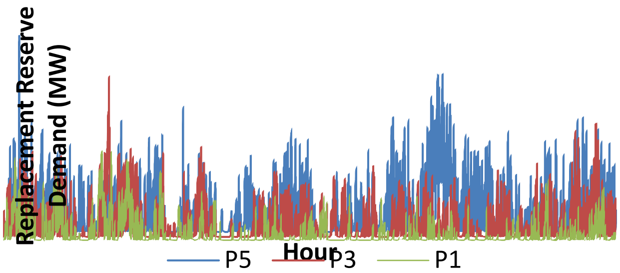


Fig. 11. Hourly Demand for replacement reserve.

E. Spain

The European Council set a target of 20% share of renewable energies in EU energy consumption by 2020. In terms of electricity in Spain, 40% should be generated by renewable power stations The Spanish target by 2020 is 40 GW in onshore wind power, together with 5 GW in offshore wind farms [21]. The Spanish and Portuguese (REN) TSOs are studying the operation of their future power systems facing important implications of this penetration to address changes resulting from the fluctuations and uncertainty of wind power generation and the assessment of the adequacy of the available operational reserve. REE and REN have concluded that deterministic methods and classical probability methodologies are insufficient for demand coverage; instead, a time-stepping Monte-Carlo simulation as a method is being studied for capturing demand coverage and operational reserve strategies in Spain and Portugal [22].

Different scenarios were studied, each with different expected electrical system configurations, hourly electrical demand and electrical generation in power stations. Wind power generation is estimated based on hourly predictions, whereas in fast-responsive hydro power generators, historical monthly series are used. Scheduled maintenance periods for power stations are also considered, together with failure periods and repair times according to specific statistical distributions and parameters.

In power systems with large amounts of wind power, power fluctuations impact the security of supply or the system operation. Unit commitment has to be redefined to face rapid changes in wind power generation, especially when opposing the movement of load.

Therefore, reserve regulation (to rise or to fall), and its value are topics to be studied in power systems with high wind power's penetration. Operational reserve, defined as the one mobilized in less than 1 hour, should be sufficient to absorb changes in generation/demand that could occur in less than 1 hour (power station failures, changes in demand or unexpected variation wind power generation). Different power plants to be added (400 MW in 2015) to the future power system were characterized from technical and economic points of view: pumped storage power stations, CCGT and OCGT units.

F. The Netherlands

To explore the effects of aggregation and geographic smoothing, several scenarios of up to 12 GW wind were statistically evaluated (see Table III); however, the need for reserves changes over time, and the response time of reserves for one aggregation of load and supply may be different from that of another. Flexible and targeted reserve requirements increase the efficacy and flexibility of power systems. The research program ``Regelduurzaam" examines technical and market concepts for reserves in the context of large amounts of decentralized and renewable generation. It is a joint effort of several Dutch universities, TenneT, the Energy Research Centre of The Netherlands, and the spot market operator APX. As part of this program, methods have been explored to quantify the reserve needs in the frequency domain based on a digitally sampled signal of historical imbalance. For the more immediate future a comprehensive range of issues related to various wind power integration scenarios in the Netherlands were assessed in a study funded by the We@Sea program. The study did not assess reserve estimations directly. However, detailed simulations were used to assess the adequacy of a particular choice of reserves for short-term power systems operation.

TABLE III
STATISTICS OF THE DEVIATION |P(N)-P(N-1)| FOR 15-MINUTE VALUES FOR DIFFERENT AGGREGATIONS OF TURBINES

Source	Rated Capacity	Area (km^2)	Full (100%)	3σ (99.7%)	2σ (95%)
			Per Unit Deviations		
Meas., 1 site	25 MW	2	0.7	0.37	0.15
Met. Data [24], 1 site	550 MW	39	0.63	0.27	0.09
Met. Data [24], 6 sites	1600 MW	9000	0.29	0.15	0.07
Met. Data [24], 36 sites	12000 MW	35900	0.32	0.13	0.05

1) Reserve Estimation in Frequency Domain

Study of the frequency components of a signal allows a natural de-trending of its content. The range of variations that occur faster than a certain frequency ω_n and including variations up to another frequency ω_m can be approximated by assuming the components Y_k of a signal's discrete Fourier transform (DFT) are uncorrelated, and adding them in quadrature to obtain an equivalent amplitude

$$P_{\omega_n \omega_m} = \sqrt{\sum_{k=n}^{m} \left| Y_K(\omega_k) \right|^2} \qquad (3)$$

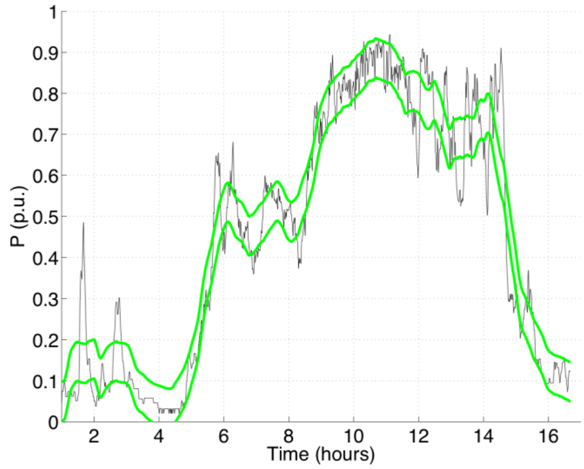


Fig. 12. Output of 25 MW wind farm, with secondary reserves band specified by frequency domain method superimposed on an hourly moving average.

where $n = \omega_n \dfrac{(N-1)T_s}{2\pi}$, m is defined similarly to n, T_s is the sample time, and N is the number of samples. The

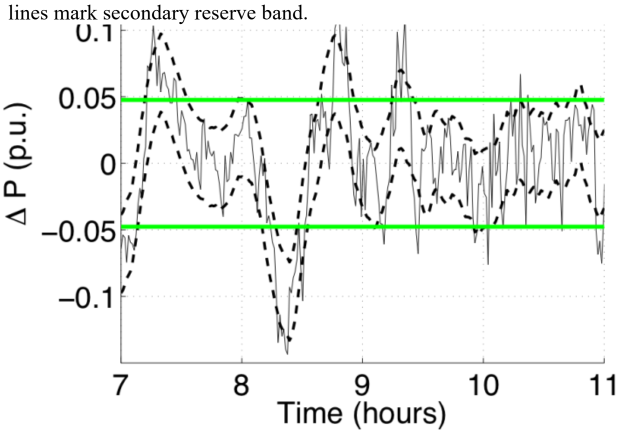
peak to peak value associated with the amplitude (3) can be used to analyze reserve requirements [23].

To demonstrate the method, power data from a single farm are examined here, using a frequency range based on how imbalance is handled in the Netherlands. The Netherlands energy and imbalance markets are based on 15 minute program time units (PTUs). Primary reserves react within 30 s to all disturbances and are replaced by other reserves after 15 min [23]. Secondary reserves act within an hourly window to eliminate larger imbalances between PTUs and to help achieve new set points when new units are committed. The amplitude (3) was computed for the DFT of a wind farm power waveform sampled for 30 days at one minute intervals. Ideally the method should be based on data with a resolution of 1 second, in order to better assess primary reserves. In this case, primary and secondary reserve values were computed using the frequency bands listed in Table IV, which correspond to periods of one hour to 15 minutes, and periods shorter than 15 minutes. In this paper the peak to peak value is interpreted as the total amount of reserves in a class, representing the sum of up and down reserves. The third column of Table IV gives the outcome of this calculation, and in Fig. 12 and Fig. 13, the resulting bands of regulation requirement are plotted on detrended versions of the farm output to show how they relate to actual power variations. From Fig. 12 two types of events not represented by the method are apparent: passing fronts (hours 1-3) and long wind ramps (hours 14-15). This is acceptable for an estimation of primary and secondary reserves, as the former type of event cannot occur at multiple farms simultaneously, and the latter type of event could be forecast and dealt with via unit commitment. Fig. 13 shows that variations around a 15 min moving average are well described by the primary reserves band given by the method. Inspection of the centre of the band confirms that the secondary reserves band reasonably accounts for variations in the frequency range expected from Table IV. The method could also be applied to data aggregated at the country level, but is only meaningful for data with at least 1-min (preferably 1 sec) resolution.

2) Assessing Adequacy through Scenario Simulation

In the Dutch wind integration study [25], the unit-commitment and economic dispatch (UC-ED) optimization software PowrSym was used to determine a realistic mix of on-line generators for every 15 minute interval in a year. Both dispatch to AGC units via the imbalance bidding ladder and self-regulation by market parties were modeled using Simulink, for worst cases identified from the UC-ED. The scenarios studied ranged from 2-12 GW, which corresponded to a percentage of 5-33% of annual energy. For the purposes of the study, a secondary reserve of 1600 MW (equal to twice the size of the largest generator, and 0.13 p.u. in the 12 GW case) was selected for enforcement by the optimization algorithm. System frequency was found to be properly maintained (with respect to area control area) even in worst case configurations of high wind and low

Fig. 13. Detrended output of 25 MW wind farm, using hourly moving average. Dashed curves mark primary reserves band specified by frequency domain method superimposed on 15 min moving average, while horizontal lines mark secondary reserve band.



load, and conventional generator outages. However, in the worst case nearly all of these reserves were deployed.

TABLE IV
RESERVE CALCULATIONS FOR 25 MW WIND FARM

Reserve Class	Frequency Range (Hz)	Up + Down: $2 \cdot P_{\omega_n,\omega_m}$ (p.u.)
Primary	∞-1/3600	0.06
Secondary	1/3600-1/900	0.01

G. Denmark

The need for reserves has recently been studied and reported in [13]. To ensure security of supply the Danish TSO activates so called manual regulation. Up-regulation is activated if supply is insufficient to fully meet demand and down-regulation if the contrary applies. Activation takes place through the Nordic regulating power market. However, sufficient capacity may not be directly available in the market and often has to be contracted prior to activation, e.g. a day ahead of operation. In Denmark manual regulation therefore divides into market-based regulating power and contracted regulating power, also referred to as manual power reserves. Market-based regulation is activated during operation and provided through the regulated power market, paying the regulated market price. On the contrary, when viewed as optioning, contracted regulation is paid an option price on the daily auction to ensure available capacity for the following operation day. Upon activation, producers are obligated to offer the regulating power to the market in the same fashion as market-based regulation. Assuming no bilateral contracting, the aim is to estimate the amount of regulation power to be contracted by the Danish TSO on daily auctions a day ahead of operation.

The modeling framework is based on a partial equilibrium model of the electricity system taking into account equilibria in a day-ahead and an intra-day market. The day-ahead market facilitates delivery of power for the following operation day on the basis of forecasts. In contrast, the intra-day market is used for handling imbalances due to forecast errors. Hence, scheduling decisions divide into stages according to the information flow such that day-ahead decisions are first-stage and intra-day decisions relate to the remaining stages, the result being a mixed-integer multi-stage stochastic programming model for unit commitment and dispatch under uncertainty, see [26]- [28].

Being the main sources of uncertainty, only wind power forecast errors and forced outages of the generating units are considered. All processes are estimated in accordance with the records and the forecast accuracy of the Danish TSO.

The procedure for estimating the amount of manual reserves is based on the difference between social welfare optimization of the system and optimal scheduling of the producers, taking into account an imperfect market. As an attempt to reflect the imperfection of the regulating power market it is assumed that producers schedule unit commitment and dispatch, considering the day-ahead market only, and ignoring the regulating power market. The procedure for estimating the amount of manual reserves necessary to contract by the TSO is the following:

- Run the model without the regulating power market and store the capacity of online units scheduled for the following day. Producers start up capacity for spot market dispatch, ignoring the regulating power market. The resulting capacity may be insufficient for power balancing.
- Run the model with the regulating power market and store capacity of online units scheduled for the following day. From a social welfare perspective, producers should start up capacity for spot market and regulating power market dispatch such as to ensure sufficient capacity for power balancing.
- The difference in online capacity has to be contracted ahead of operation for producers to start up sufficient capacity. Moreover, producers offer idle online capacity as contracted regulating power.

Hence, estimate for the amount of manual reserves is the sum of insufficient and idle online capacity.

The estimation procedure applies to day-ahead planning of manual reserves.

The hourly amounts of manual reserves simulated in Eastern and Western Denmark, respectively, are displayed in Fig. 14 and Fig. 15. In contrast to long-term contracts, daily auctions allow for the amounts to vary over time which is highly valuable in both regions.

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As system imbalances are covered by regulating power (load following reserve in Table I), the amount of manual reserves or contracted regulation tends to vary with imbalances. From Fig. 14 and Fig. 15, it is evident that contracted regulation exceeds average imbalances in order to cover extreme ones. Still, extreme imbalances are not fully covered by regulating power as even from a social welfare perspective this is not economically optimal. Mostly, the amounts of manual reserves are substantially larger in Western than in Eastern Denmark, reflecting a larger variance of imbalances caused by a larger installed wind.

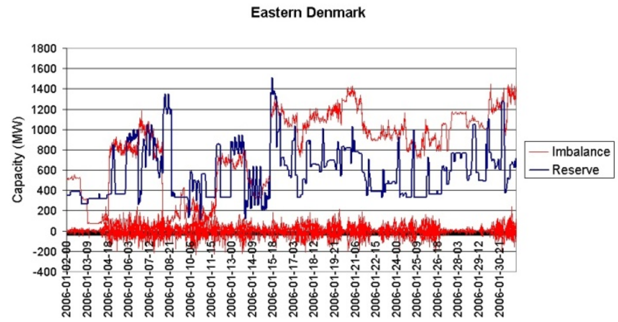

Fig. 14. Hourly amounts of manual reserve capacity and system imbalances simulated for Eastern Denmark, January 2006. The lower red line is the average imbalance in simulations. The higher red lime is the extreme, maximum imbalance from the simulations. The model does not always choose to cover the maximum possible imbalance when it is costly as it is highly improbable.

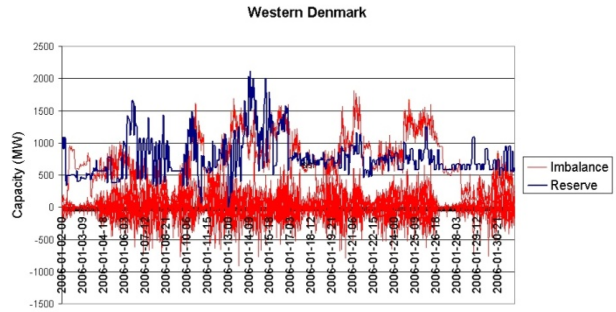

Fig. 15. Hourly amounts of manual reserve capacity and system imbalances simulated for Western Denmark, January 2006.

In a perfect market, system imbalances should be covered by regulating power offered directly to the regulating power market. However, since producers optimize bids to the day-ahead market, ignoring the regulating power market, regulating power is frequently insufficient. Moreover, option payments incite producers not to offer directly to the market.

Since electricity reserves constitute serious costs of the system, estimation of the need for these reserves continue to be highly relevant, e.g. in further exploring the structure and the imperfections of the market.

H. Quebec

Hydro Quebec has completed separate studies to determine the integration impacts first on regulating reserves and load following using statistical analysis and simulation and second on ramping or balancing reserves using a risk based methodology.

1) Regulating Reserves and Load Following Reserves

To prepare for large scale wind integration into its system operations processes, the ISO undertook a preliminary analysis of the impact of wind variability and uncertainty on operational time frame reserves requirements within the one hour horizon. It was rapidly clear that the first three reserves categories are not sensitive to wind energy integration essentially because wind plants are limited in size (less than 200 MW) and geographically spread over relatively large areas (1000 km stretch). In this context, the most relevant quantities requiring further investigation were the AGC and load following reserve capacities. After reviewing the pros and cons of the statistical versus simulation approach for assessing these quantities, Hydro-Quebec's ISO opted for the simulation approach, due to the following reasons:

1. Unlike many other North-American jurisdictions, TransÉnergie's ACE is dependent only on the frequency deviation. The statistical methods do not involve the frequency deviation and are therefore less precise in the case of isolated systems which are never subjected to generation-demand imbalance, but only frequency deviations.
2. Simulation provides a means to obtain important results for measuring many other impacts of wind power such as the frequency of stop-starts, the efficiency degradation of AGC units and, in particular, the AGC's regulating range.

The simulation approach is currently under development at IREQ [29] with the goal of applying load flow calculations and optimal generation dispatch to reproduce the system behavior with a 1-min time step. Meanwhile, for benchmarking purposes, it was decided to apply the statistical analysis approach used by BPA for its Rate Case 2010 [30] to Quebec Interconnection. The hourly demand data are 2016 forecasts provided by the load serving entity while the hourly wind generation data comes from 11-year historical reconstitutions of the first two tenders, 3000-MW wind plants production. The minute by minute data demand, wind generation and forecasts were derived according to [31]. Following BPA and CAISO studies, real-time wind forecasts are based on a simple 2-h persistence model. The Hydro-Québec results (for 11 year min/min calculation) are superposed in Fig. 16 on BPA results taken from [30], in the case of a 3155 MW wind capacity.

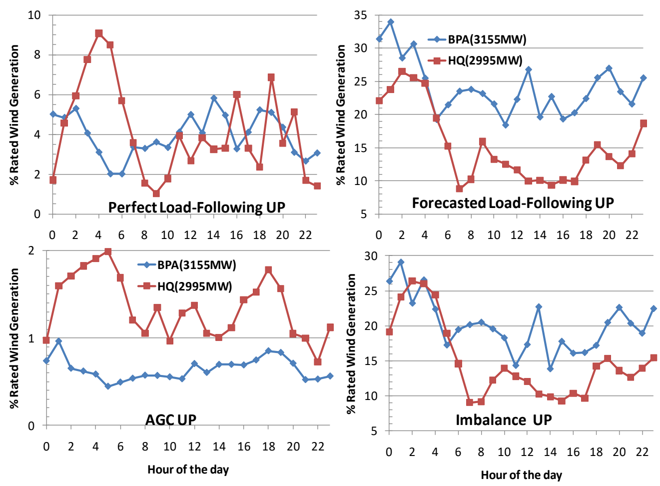

Fig. 16. Comparison of Hydro-Quebec and BPA supplemental reserves at 3000MW wind generation (up-regulation).

According to the BPA method, the supplementary AGC and LF reserves to accommodate 3000MW of installed wind capacity will amount to 2 and 22% respectively on a yearly average basis. However, there is a considerable disparity between the winter months and other months: the additional LF requirements increase from 17% of the installed wind capacity in winter to 30% during the summer. On the other hand, the nxsigma criterion [32] resulted in much lower incremental reserves requirements with only 0.4% and 7% increase of the AGC (n=4) and LF (n=2) respectively.

Currently, there exists an agreement covering all the ancillary services provided by Hydro-Québec Production to ensure the reliability and security of the provincial power supply. This agreement includes a frequency regulation service which is specified in terms of the availability of a regulating range of the AGC system (up and down) which can vary between 500 and 1500 MW. This practice has always allowed the ISO to maintain a very high level of conformity with the NERC frequency control standards (CPS1 and CPS2). It is generally accepted that the evaluation of the impacts using a statistical approach is not as accurate as the method based on simulation, which is founded upon far more realistic system operation hypotheses. IREQ has been working on such a simulator since 2006 but the initial results on the 3000MW-integration will be published separately [29]. The system operations simulator is the proper tool for refining these paper's estimations and, in particular, relating them to the terms of the agreement currently covering the frequency regulation service in the Quebec interconnection.

2) *Ramping or Balancing Reserves*

In Hydro Québec Balancing Reserves $\left(BRs\right)$ assure the short-term reliability to its power system over a time horizon of one hour to 1 to 48 hours ahead. Recently, several studies in the literature have re-evaluated the actual reserve levels required when incorporating wind generation into their systems and have proposed increasing their levels, some of which are [2], [16], [32], [17].)

One methodology to compute balancing reserves, integrating several sources of uncertainties, is power system reliability theory [33]. It is based on the criterion of loss of load probability (LOLP) which is the probability that the available generation, including reserves, will not completely meet the demand, or equivalently risk. Reserves are computed such as to meet a specific LOLP target.

The methodology adopted here borrows from the traditional reliability theory and adapts it to the time-horizon of 1 to 48 hours ahead. In its final formulation, the balancing reserve requirement is a function of a distribution of a net forecast error composed of load, wind generation and generation unavailability forecast errors rather than the forecasts themselves [34],[35].

Distributions of all forecast errors, over the lead times from 1 to 48 hours, were developed a posteriori by comparing past forecasts to the corresponding measurements. Having at hand the distributions of forecast errors facilitates both the aggregation of the individual forecast errors into a net forecast error and the graphical representation of results. The anticipated risk was then computed at each forecast lead time. It is the value of a function of the net forecast error distribution corresponding to a predetermined level of balancing reserves. Alternatively, given a target level of risk, the associated balancing reserve requirements can be quantified. Repeating this computation for each lead time over a given time horizon, it reveals the temporal evolution of risk or of balancing reserve requirements.

This methodology was used to evaluate additional balancing reserves required to integrate 3000 MW of wind power capacity into the Hydro-Québec (HQ) system. This was done by comparing the balancing reserves required to maintain the same level of risk before and after the integration of wind generation over numerous system conditions.

Fig. 17 illustrates the risk, R_0, of 17%, corresponding to some nominal balancing reserves level, $BR_{nom} = 500\ MW$ (obtained by reading on curve, R_{d+u}), the additional risk incurred, ΔR, and the additional reserves ΔBRs required following the integration of two different wind generation capacities at a given instant, with the wind forecast error uncertainties being modelled as zero-mean Gaussian processes. Adding a certain amount of wind generation into the system, and keeping the same amount of balancing reserves, increases the system risk by an amount of ΔR. See full and dotted curves, R_{d+u-w} and R_{d+u-W}, corresponding to small and large wind generation respectively with wind forecast error uncertainties modelled as zero-mean low and large variance Gaussian processes. In order to maintain the same risk before and after the additions of wind generation, it is necessary to provide the system with additional balancing reserves of the amount of ΔBRs.

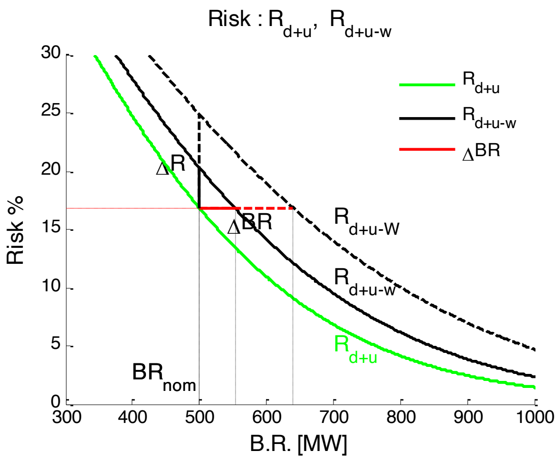

Fig. 17. Qualitative illustration of the risk and additional balancing reserves for two different wind generation penetration levels.

We note that at each instant the original risk without wind generation, R_0, presented to the system depends on the statistical characteristics of the uncertainties on the load forecast and the forecast of unavailable power and the nominal balancing reserves level, BR_{nom}.

Further, looking at the time evolution of the variables, since the forecast uncertainties may vary over time, the hour during the day and the season, it follows that the risk R_0 incurred with constant nominal balancing reserves varies over time.

Alternatively, the balancing reserves BRs required to maintain a given risk level also varies over time. The additional risk, ΔR, sustained by the system when integrating wind generation, and therefore the additional

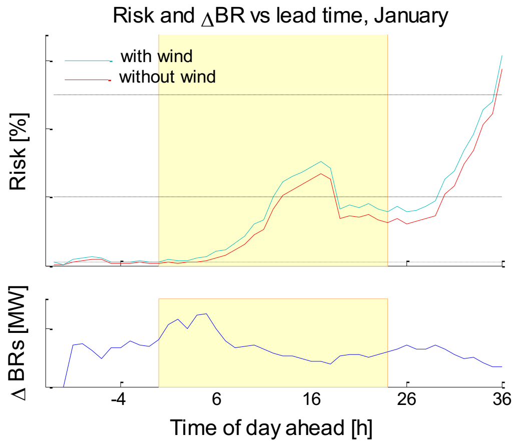

Fig. 18. Risk with and without wind generation, and added balancing reserves to maintain the same risk as before the incorporation of wind generation.

balancing reserves, ΔBRs, depend on the original risk, R_0, corresponding to the given level of reserves, BR_{nom}, and on the statistical characteristics of the added wind generation forecast error. The two quantities ΔR and ΔBRs also vary over time.

Fig. 18 shows the risk encountered with and without wind generation, and the required ΔBRs beyond the predetermined balancing reserves to maintain risk over a horizon covering the next day. The bump in the curves around 16:00h reflects the particular signature of load forecast errors.

Using Hydro-Québec data, risk levels encountered in balancing reserves reach up to 5% over the day-ahead horizon. This may seem unusually high, but contrary to the regulating reserves, acting in the intra-hour time horizon, utilities have the leisure to accept larger risk levels here because looking forward they can still call on uncommitted yet available resources to remedy undesirable occurrences. Since the remedies are implemented at extra cost, the choice of risk level is essentially an economic consideration associated with the deployment of resources committed at the last minute.

In summary with this study, we quantified balancing reserve requirements, with and without wind generation, based on a risk criterion. Using this procedure we have determined the added reserve requirements to maintain a specified level of risk before and after the integration of 3000 MW of wind power capacity.

The conclusion to be drawn is that with current HQ balancing reserves being relatively high and risk levels relatively low, little additional balancing reserves are required to integrate 3000 MW of wind power capacity. The 5% maximum risk level revealed in our simulations was not predetermined, but rather was revealed by the present study. It seems to be acceptable, since current practice in operations planning seems satisfactory.

V. Comparison of Methods and Conclusion

This paper began by establishing a common naming convention to describe the different types of reserves used in system operations and wind integration studies. These reserve types, frequency response reserves, regulating reserves, ramping reserves, load following reserves and supplemental reserves, allow comparison across systems.

As shown in Section III, the types of reserves (frequency, regulating, load following and supplemental) used are common across the power systems in the European and North American systems considered. The choice to use load following reserves or supplemental reserves (or to use both) is the main discrepancy between systems. The types of reserves considered across integration studies are also consistent. Of the studies discussed, all consider regulating and ramping reserve and some combination of load following reserve and supplemental reserve. Only the Netherlands considered frequency response reserves in its study. It should be noted, however, that though four integration studies considered ramping reserves, only one system operator, Spain, currently uses ramping reserves in operations today.

Although the integration studies discussed in this paper considered similar types of reserves, the methods for

TABLE VI
Summary of Integration Study Reserve Calculation Methodologies

Study	Regulating Reserve Methodology	Ramping or Load Following Reserve Methodology
Minnesota	Statistics, standard deviation of wind variability	Function of wind output (dynamic)
New York	Statistics, standard deviation of wind variability	n/a
EWITS	Statistics, standard deviation of wind variability	Statistics, standard deviation of wind forecast error
WWSIS	Statistics, standard deviation of wind variability	
Ireland		Stochastic Optimization
Spain	Time-step Monte-Carlo simulation	
Quebec	Statistical analysis	Statistical analysis, Risk-based (dynamic)
Netherlands	Frequency domain peak-to-peak analysis, Scenario analysis	n/a
Denmark	Market-based risk model	n/a

TABLE V
Summary of Reserve Types Used in Integration Studies

	Types of Reserve Considered *(corresponding reserve name used in study)*			
Study	**Frequency Response Reserves**	**Regulating Reserve**	**Ramping Reserve**	**Load Following Reserve**
Minnesota		*X* *(Regulating Reserve)*	*X* *(Operating Reserve)*	*X* *(Load Following)*
New York		*X* *(Regulating Reserve)*		
EWITS		*X* *(Regulation, variability and short-term wind forecast error)*		**X** *(Regulation, next-hour wind forecast error & Additional Reserve)*
WWSIS		**X** *(Regulating Reserve)*		**X** *(Load Following Reserve)*
Ireland		*X* *(Spinning Reserve)*		**X** *(Replacement Reserve)*
Spain		**X** *(Secondary Reserve)*	**X** *(Deviation Reserve)*	**X** *(Tertiary Reserve)*
Quebec		**X** *(AGC)*	**X** *(Balancing Reserve)*	**X** *(Balancing Reserves Load Following)*
Netherlands	*X* *(Primary Reserve)*	**X** *(Secondary Reserve)*		
Denmark		**X** *(Tertiary Reserve)*		

determining the quantity of required reserves varied widely. Each of these studies used different data in this calculation based on different assumptions of their system operations. In the Minnesota, New York, EWITS, and WWSIS studies, regulation reserves were determined statistically using the standard deviation of wind variability. In the Dutch system, a methodology of transforming the data into the frequency domain and considering peak-to-peak analysis was demonstrated for one wind farm data. The ramping reserves in the Minnesota and Quebec integration studies were analyzed dynamically. In the Minnesota study, the requirements changed as a function of wind output; in the Quebec study the balancing reserves changed dynamically as a function of the statistical characteristics of net load forecast uncertainties and risk level. On the other hand, ramping reserves in the All Ireland Study and Danish study were determined using stochastic optimization. Most studies a priori concluded that no change in supplemental reserves was necessary as the largest contingency on the system remained the single largest generator.

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VII. References

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