Reliability with Renewable Energy

STRATEGY ABOUT SYSTEM ADEQUACY AND RESERVE MARGIN WITH INCREASING LEVELS OF VARIABLE GENERATION

Report	WORK PACKAGE 1 – System Reserves in the South African Power System and International Utilities
Prepared for	South African National Energy Development Institute
Date	28 January 2016

Contact Details

Name Dr Gerard van Harmelen
Designation Utility Analytics Manager – Enerweb, an EOH company
Cell Phone +27 83 407 5862
E-mail gerard.van.harmelen@enerweb.co.za

Megawatt Park
Maxwell Drive
Sunninghill
2157
Tel: +27 87 803 3900
www.enerweb.co.za |www.eoh.co.za

Name Mikael Togeby
Designation Partner – Ea Energy Analyses Denmark
Cell Phone +45 60 39 17 07
E-mail mt@eaea.dk

FrederiksholmsKanal 4,3. th.
1220 Copenhagen K
DK-Denmark
www.ea-energianalyse.dk
Denmark
Tel: +45 88 70 70 83
www.eaea.dk

Name Jens Carsten Hansen
Designation Head of Wind Energy Systems Section – DTU
Cell Phone +45 2048 2672
E-mail jcha@dtu.dk

Technical University of Denmark, Department of Wind Energy
Risø Campus
Frederiksborgvej 399
Building 118
4000 Roskilde
www.dtu.dk

Statement of Confidentiality

Glossary of Definitions, Terms and Abbreviations

IPS	Interconnected power system
ENTSO-E	European Network of Transmission System Operators for Electricity
NERC	National American Electric Reliability Corporation
UCTE	Union for the Coordination of Transmission of Electricity
AGC	Automatic generator control
ACE	Area control error
VPS	Virtual Power Station
ISO	Independent System Operator
RTO	Regional Transmission Organisation
CE	Continental Europe
ACE	Area Control Error
CPS	Control Performance Standards
FRR	Frequency Restoration Reserve
RR	Replacement Reserve
FRRa	Automatic Frequency Restoration Reserve
FFRm	Manual Frequency Restoration Reserve
ELCC	Effective Load Carrying Capacity
WRF	Weather Research and Forecasting
DMP	Demand Market Participation

Contents

Figures

Tables

1. Introduction

The nature of wind and solar generation is that energy availability can be variable as wind and solar radiation fluctuates.

This literature review is one of the deliverables of Work Package 1 (WP1) of a project launched to address the need to modify the procedures and methodologies in planning for system reserves and system adequacy.

The report was completed through collection of relevant documentation, interviews with stakeholders, and scanning and summarising international literature, studies and reports.

Section 2 of the report details the current Eskom reserve categories, the dimensioning methodologies and the daily processes and procedures to operate the reserved capacity.

Section 3 introduces international organisations involved in standards and governance of reserve level. The terminology and categories used by these organisations are described, and a proposed mapping presented.

Section 4 describes the international methods used for determining the reserve level in the various categories as defined in Section 3. The approach in each category is described and regional variations highlighted.

Section 5 reports on studies completed to evaluate the cost of reserves, approaches to procurement of reserves and methods to estimate the value of these reserves.

Section 6 summarises five wind and solar integration studies that were performed to assess the impact of variable generation on reserve levels. In each study, the approach, data used and key results were summarised.

Section 7 reports on the response of system operators to variable generation and the evolution of tools, processes, data requirement, reserve products and system products.

2. Eskom Reserve Level Setting and Operations

2.1 Overview of Terminology and Reserve Category Definitions used in Eskom

The South African Grid Code [1] details the requirements for different reserve categories and specifies five categories of reserves, as follows:

- **Instantaneous reserves** – Used to arrest the frequency at acceptable limits following a contingency.
- **Regulating reserves** – Used for second-by-second balancing of supply and demand, and under AGC control.
- **10-minute reserves** – To balance supply and demand for changes between the Day-ahead market and real-time, such as load forecast errors and unit unreliability.
- **Emergency reserves** – Used when the interconnected power system (IPS) is not in a normal condition, and to return the IPS to a normal condition while slower reserves are being activated.
- **Supplemental reserves** – Used to ensure an acceptable day-ahead risk.

Instantaneous, regulating and 10-minute reserves are considered to be part of the operating reserve that will be available for reliable and secure balancing of supply and demand within ten minutes and without any energy restrictions.

These categories and their functions have similarity to those found in international organisations and other countries, and correspond closely to the categories as adopted by the European Network of Transmission System Operators for Electricity (ENTSO-E), although the terminologies differ significantly [see Section 3 for a more detailed analysis].

The following figure maps Eskom terminology to ENTSO-E, NERC and UCTE:

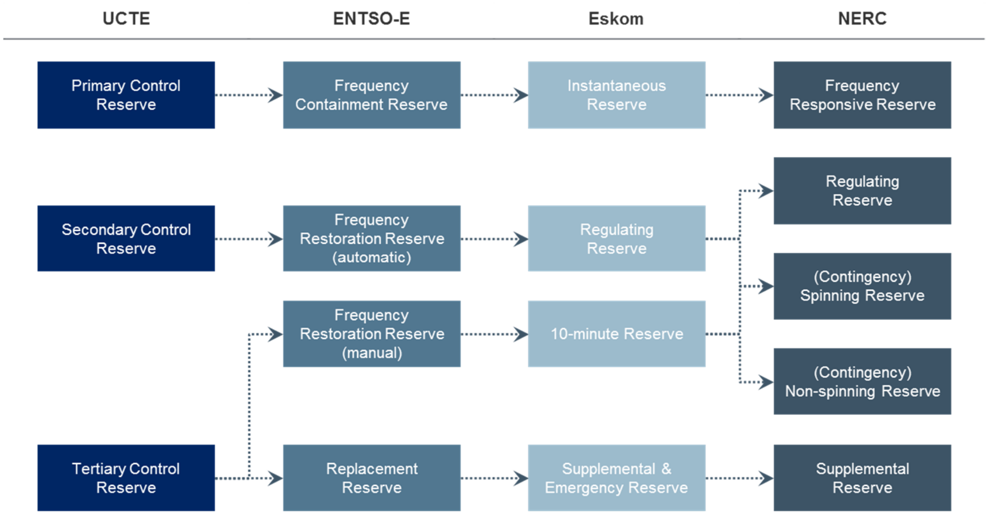


Figure 1 – Mapping between reserve categories and terminology used by Eskom, UCTE, ENTSO-E and NERC [for more details, see Section 3]

In Eskom, Instantaneous and Regulating reserves are operated automatically, while 10 minute, supplemental and emergency reserves are manually dispatched.

During and after an event, the different categories of reserves are utilised with specific time to activation and duration of usage. The following figure shows how the different reserve categories are used during an under-frequency event:

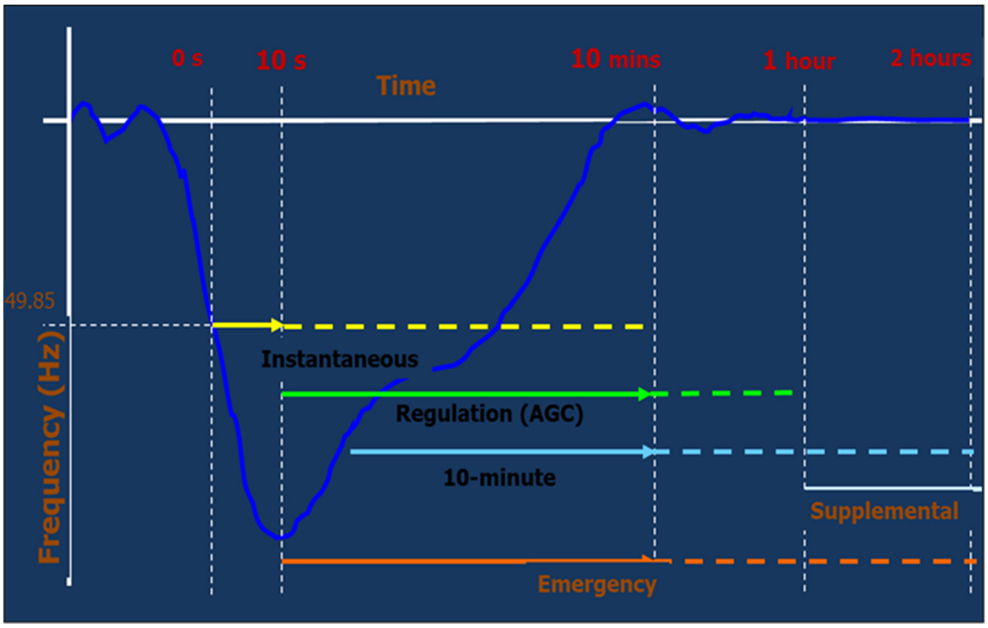


Figure 2 – Different reserve categories as used after a frequency event or contingency

Initially the instantaneous reserves will be activated within 10 seconds to arrest the frequency deviation. The regulating reserve under AGC control will start correcting the frequency deviation and the 10-minute reserve is used to restore the instantaneous and regulating reserves. The emergency and supplemental reserves act slower and will replace and supplement the 10-minute reserves and generation shortage when applicable.

The following table summarises the activation time, purpose and providers for the different reserve categories:

Table 1 – Activation time, purpose and providers for the different reserve categories

Reserve	Maximum Activation Time	Minimum Sustained Time	Purpose	Provider	
				Generators	Demand Response/Load
Operating					
Instantaneous	10 seconds	10 minutes	To arrest a frequency excursion outside frequency dead band	✓	✓(DR)
Regulating (AGC)	10 minutes	1 hour	To maintain frequency within the frequency dead band	✓	
10-minute	10 minutes	2 hours	To maintain frequency near nominal level and restore instantaneous and regulating reserves following disturbances	✓	
Supplemental	2 hours	2 hours	Cater for generation capacity shortages to meet demand and operating reserve requirements		✓(DR)
Emergency	10 minutes	2 hours	Cater for generation capacity shortages	✓	✓ (IL*)

2.2 Level Setting

Reserve levels are reviewed annually and set for the next 5 years, after reviewing historical performance and performing various load, load flow and uncertainty analyses.

Due to overall requirements on operating reserves, i.e. instantaneous, regulating and 10-minute reserve, the latter is calculated as a function of the former two – creating some dependency in the calculations and flow.

Similarly, the emergency, supplemental and operating reserve requirements are related to the worst contingency.

The following table (from [1][3]) shows a summary of the current Eskom reserve levels for each of the reserve categories. The methodology for level setting is detailed in the sections below.

Table 2 – Summary of reserve requirement for Eskom [1][3]

Reserve	**Season**	**Period**	**2015/16 MW**	**2016/17 MW**	**2017/18 MW**	**2018/19 MW**	**2019/20 MW**
Instantaneous	Summer/ Winter	Peak	550	550	500	500	500
		Off peak	850	850	800	800	800
Regulating	Summer	Peak	450	450	500	500	550
		Off peak	450	450	500	500	550
	Winter	Peak	550	550	600	600	650
		Off peak	550	550	600	600	650
Ten minute	Summer	Peak	1000	1200	1200	1200	1100
		Off peak	700	900	900	900	800
	Winter	Peak	900	1100	1100	1100	1000
		Off peak	600	800	800	800	700
Operating	**Summer/**	**Peak/**	**2000**	**2200**	**2200**	**2200**	**2150**

2.2.1 Instantaneous Reserves

From the SA Grid Code [1], the instantaneous reserve should:

- Keep the frequency above 49.5 Hz following all credible single contingency losses. The largest loss is the loss of a Koeberg unit at full load, i.e. 920 MW (the Cahora Bassa infeed is classified as a multiple incident).
- Keep the frequency above 49.0 Hz after credible multiple contingencies, currently being the loss of 1 800 MW generation (typically three coal-fired units or the loss of the Cahora Bassa infeed).

In order to meet these requirements, a system dynamics study using DigSilent [2] was performed to account for the effect of supply and demand-side governing under various scenarios.

Instantaneous reserve levels are published for off-peak and peak – no seasonal differentiation is provided.

2.2.2 Regulating Reserves

There is no requirement for the level of the regulating reserves in the SA Grid Code. However, it is stated that regulating reserve must be under automatic generator control (AGC). The purpose of the regulating reserve is for second-to-second balancing of supply and demand.

The level setting for the regulating reserve is based on two deterministic studies:

- A load variation study;
- Regulating reserve study.
- **Load Variation Study** – The load variation is based on consecutive 10-minute load variations, and outliers were removed. Outliers were found and removed in the morning (night to day transition) and afternoon (day to night transition). The average 10-minute load variations for winter (May – August) and summer (rest of the year) were determined.

  The following figure from [3] demonstrates extraction of the average variation values:

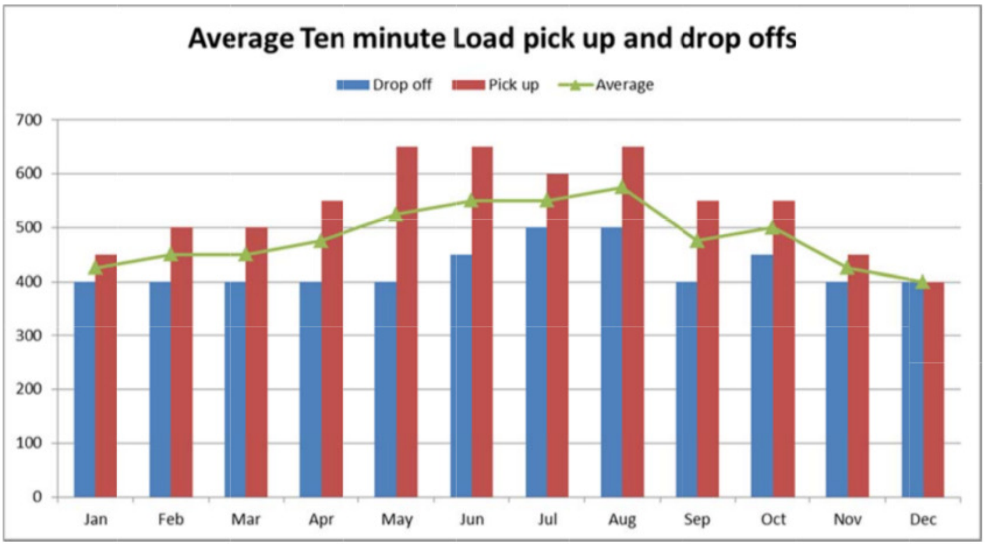


Figure 3 – Average 10-minute load pick up and drop off – ten minute values in MW (y-axis)

- **Regulating Reserve Study** – The regulating reserve study was completed using a reserve 'simulator'model in Matlab. The model was adapted from an operator assessment and training simulator model, to establish the reserve level.Renewable energy as per the integrated resource plan was added and 2014 and 2019were studied in-depth to form a base case from which other years were interpolated.

  The study aimed to obtain the least amount of reserves that satisfy the CPS1 (see section 4.2.1) performance requirement 100% of the time.

  The following figure shows the results for 2014, as an example:

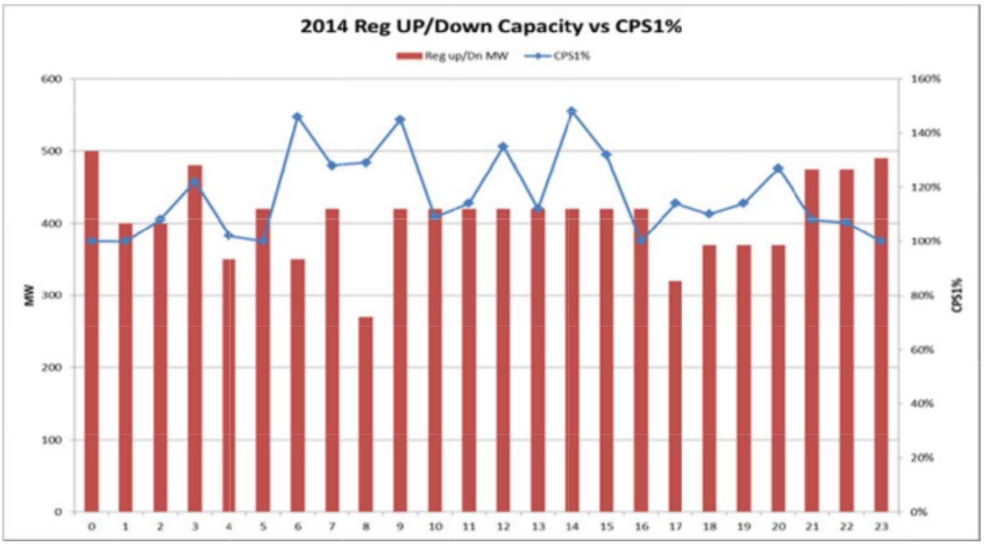


Figure 4 – Regulating reserve that satisfies the CPS1 performance requirement 100%

2.2.3 10-minute Reserves

The reserve level is calculated by considering two deterministic reserve requirements:

- **Credible multi-contingency** – The operating reserve is sized to replace the loss of the three largest power generating units
- **SAPP requirement** – The SAPP operating guidelines require a minimum level of operating reserves from the Eskom control area.

The operating reserve consists of:

- Instantaneous;
- Regulating;
- 10-minute reserves.

In both criteria above, the total operating reserve is specified and the 10-minute reserve derived as:

10-minute reserves = Operating reserves – (Instantaneous + Regulating)

For the 2015-2019 period, the multiple contingency criteria yielded the higher requirement, and is published per season and time-of-use period.

2.2.4 Supplemental and Emergency Reserves

The emergency reserve level is based on the worst contingency in the system – in Eskom's case, this would be the loss of the largest power station. This contingency is then covered by the total operating reserve, supplemental reserve and emergency reserves, i.e.:

$$Emergency\ reserves = Worst\ contingency - Operating\ reserve - Supplemental$$

The supplemental reserve level is based on an economic comparison between running the most expensive generator and reserves provided by demand response through the Virtual Power Station.

2.2.5 Summary of Level Setting

The process for reserve level setting and the interaction between the reserve levels are shown in Figure 5 and the methodology for setting the reserve levels are summarised in the sections below.

The CPS1 is a performance metric on the area control error (ACE), which is based on the difference between the scheduled and actual load as well as the difference between the scheduled frequency and the actual frequency.

A minimum up and down regulating reserve level is set per season (winter and summer) and time-of-use period (peak and off-peak).

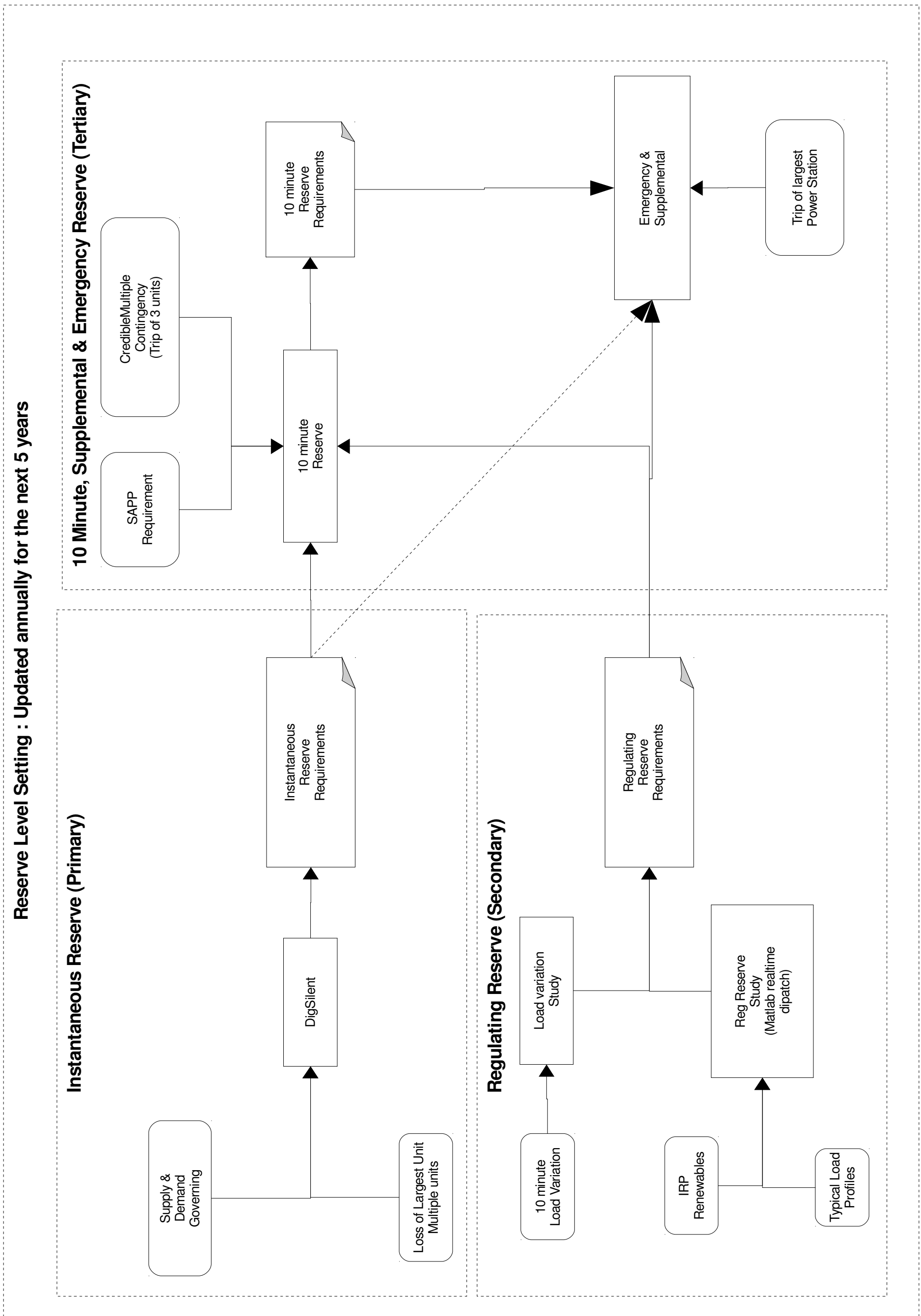


Figure 5 – Overview of the annual planning process to dimension the various categories of reserves in Eskom

2.3 Eskom's Operational Procedures for the Different Categories of Reserves

The activation time and operational requirements for the categories of reserves differ, both in terms of activation mechanism and time.

The following figure, from [3], shows an overview of the different reserve categories, the activation time and the operational requirements:

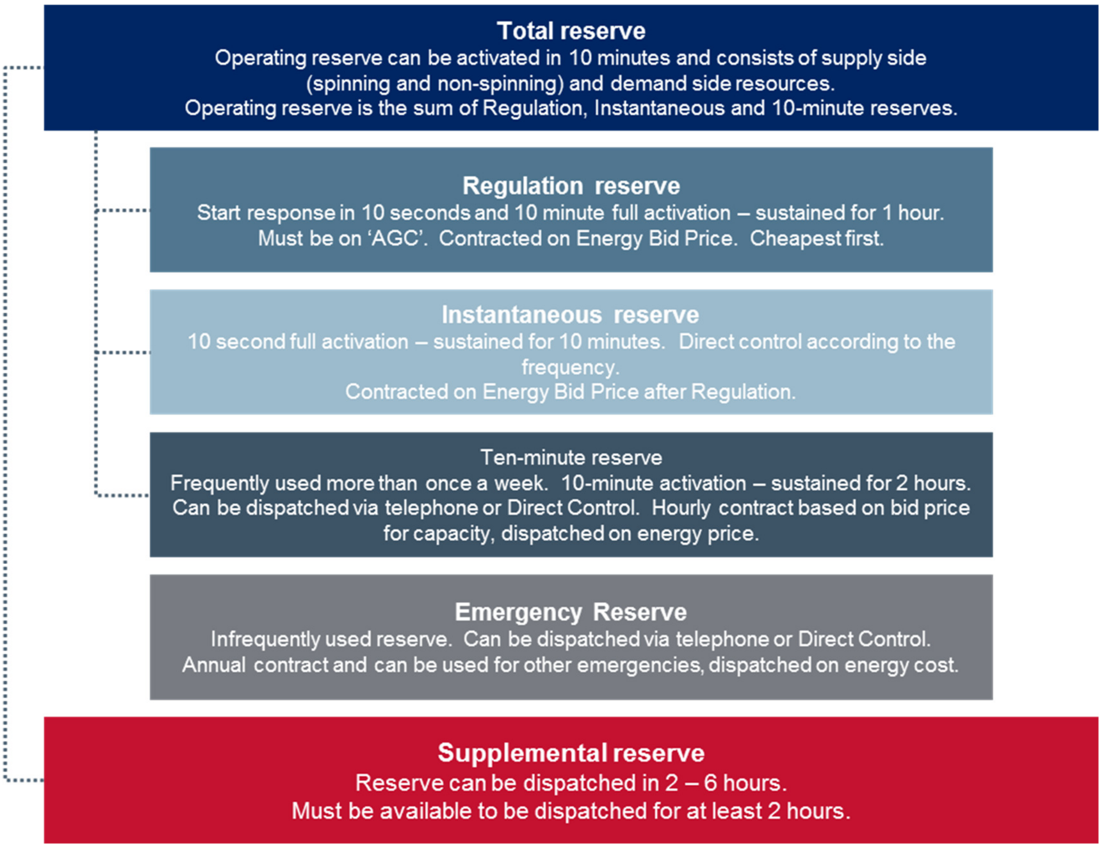


Figure 6 – Summary of the definition of the different reserve categories

Generators and load reduction customers are certified annually, based on the criteria as specified in [4]. The generators and customers are then contracted for the year and their performance monitored.

Figure 7 shows the overall daily operational processes for the different categories of reserves. The operations start on day N-1 where day-ahead planning is performed, on-the-day operations, and settlement and performance monitoring after the operating day. Figure 8 through Figure 10 are extracts and placed at the relevant sections for clarity.

The process for each day is explained in more detail in the sections to follow.

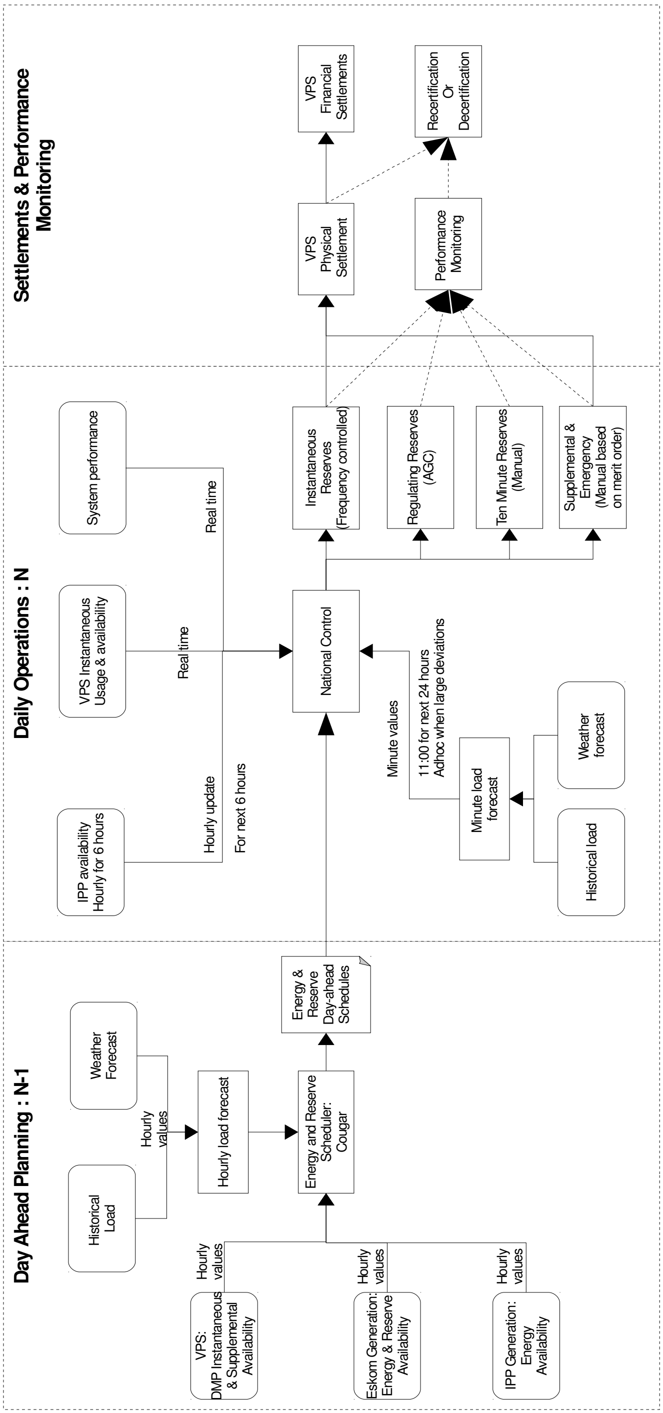


Figure 7 – Operations and activation of the various categories of reserves in Eskom

2.3.1 Day N-1

An hourly load forecast based on historical load data, weather forecast and other system and known events are performed. The reserve levels, as calculated during the annual determination, are then added to the load forecast and used for the scheduling.

Each generator and load aggregator (VPS), provides their availability per hour to the scheduler. A least cost optimisation using Cougar (Eskom's unit commitment scheduler)is performed, which co-optimises the energy and reserve providers.

Based on the optimisation, the scheduler would then generate hourly energy and reserve schedules for the day-ahead and distribute these to the relevant parties.

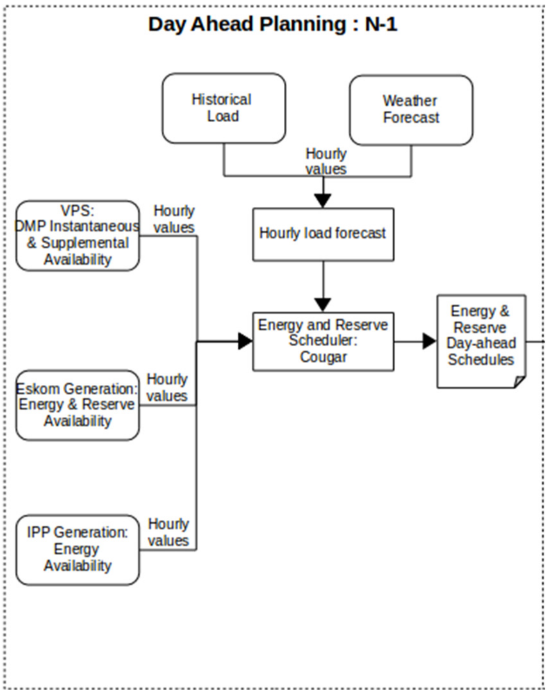


Figure 8 – Day N-1 planning process

2.3.2 Day N

On the day, a 1-minute level forecast is provided by the short term load forecaster.

Instantaneous reserves are automatically dispatched through frequency control (governing and under frequency relays for Demand Market Participation (DMP)). Regulating reserves are automatically utilised through AGC.

10-minute reserves are phoned by the operator, i.e. phone a station and ask to increase generation – it is completely manual and the operator makes a judgement call on the amount to increase.

If large deviations are experienced (400 MW), rescheduling can occur on the day, with new load forecast and generation availability. The load forecast is based on the measured load and short term weather forecasts from external sources.

If a scheduled generator foresees an inability to fulfil their schedule, they would report a load loss to the controller ahead of time.

The nature of the instantaneous demand response contract is that a customer may not be used more than a certain number of times per day, with a minimum time between events. Information about the instantaneous demand response availability is provided in real time to National Control.

If the loading desk at National Control cannot match the load using the scheduled energy and reserves, there is a merit order according to which supplemental and emergency reserves are deployed. This deployment is via telephone or direct control, based on the speed of deployment required and the resources and contracts available.

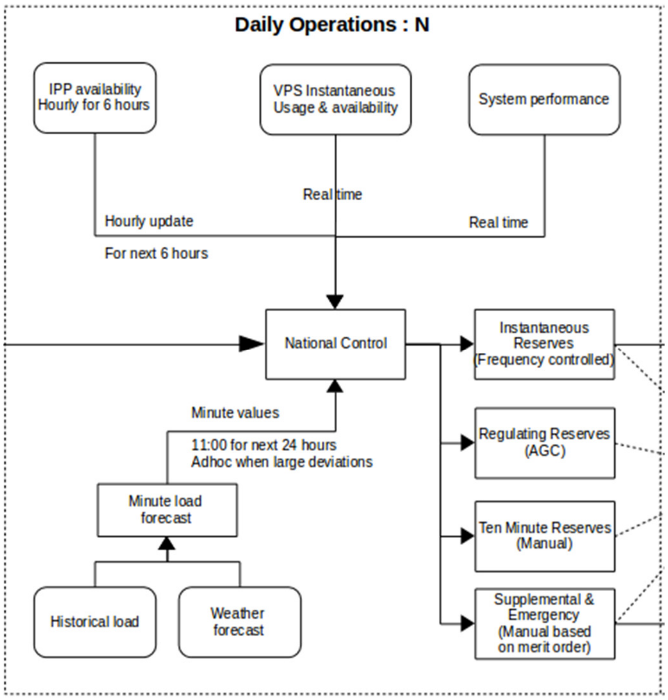


Figure 9 – Day N daily operations

2.3.3 Day N+

In the case of demand response contracts, physical and financial settlements are performed by the VPS. Physical settlements are based on a baseline and comparison of the response to determine the actual load reduction. Financial settlements would then be performed based on the response and the contract with the customer. The physical settlements are also used for performance monitoring for certification purposes.

In the case of generators providing, the performance of the stations are monitored and are used to ensure compliance. De-certification or re-certification of generating units are informed by the performance of the station.

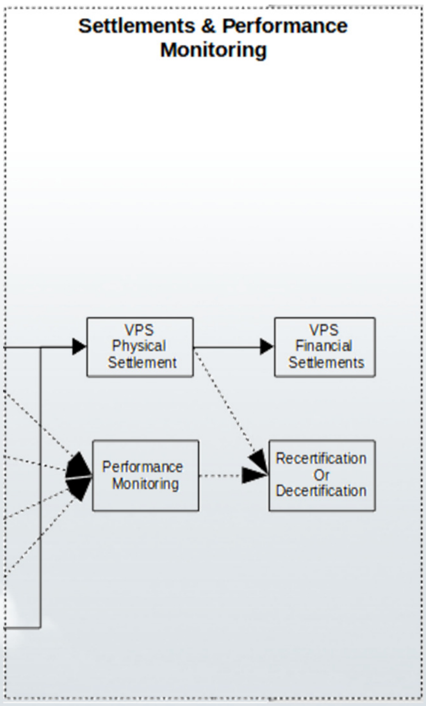


Figure 10 – Day N+ settlements and performance monitoring

3. International Organisations and Terminology

In literature, the following three international organisations are often referred to in conjunction with reserve levels and level setting:

- National American Electric Reliability Corporation (NERC);
- European Network of Transmission System Operators for Electricity (ENTSO-E);
- Union for the Coordination of Transmission of Electricity (UCTE).

Today UCTE is the region Central Europe in ENTSO-E.

3.1 NERC

NERC is an international (USA, Canada and part of Baja California in Mexico) regulatory authority for reliability of the bulk power system in North America and comprises the following Coordinating Councils in North America:

- Florida Reliability Coordinating Council (FRCC);
- Midwest Reliability Organization (MRO);
- Northeast Power Coordinating Council (NPCC);
- Reliability First Corporation (RFC);
- SERC Reliability Corporation (SERC);
- Southwest Power Pool (SPP);
- Texas Reliability Entity (TRE);
- Western Electricity Coordinating Council (WECC).

The following figure shows the Coordinating Councils and the major NERC interconnections:

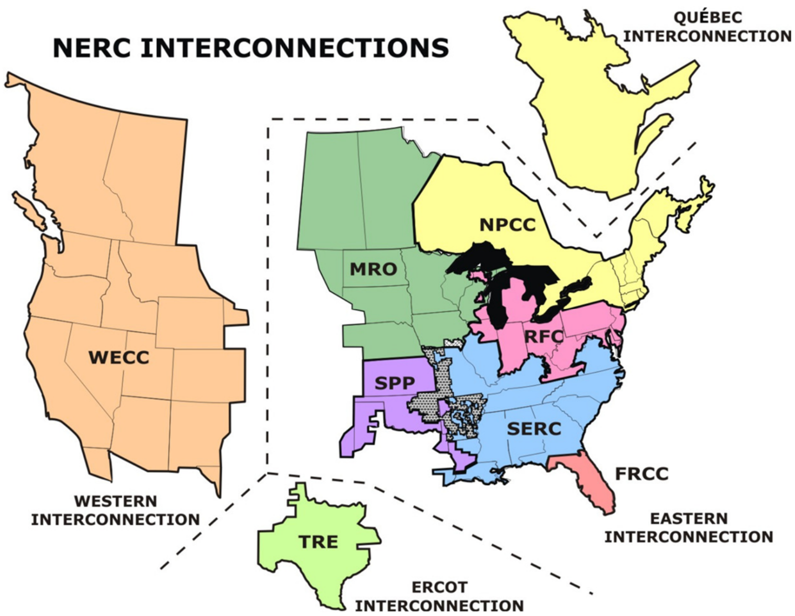


Figure 11 – NERC Coordinating Councils and Interconnectors. The four areas indicate the synchronous areas.

Inside the different Coordinating Councils, a number of regions have Independent System Operators (ISOs) and Regional Transmission Organisations (RTOs):

- California ISO (CAISO);
- New York ISO (NYISO);
- Electric Reliability Council of Texas (ERCOT), also a Regional Reliability Council;
- Midcontinent Independent System Operator (Midcontinent ISO);
- ISO New England (ISO-NE);
- Alberta Electric System Operator (AESO);
- Independent Electricity System Operator (IESO);
- PJM Interconnection (PJM);
- Southwest Power Pool (SPP), also a Regional Reliability Council.

The ancillary level setting and procurement regimes differ by Coordinating Council and ancillary market products, in the case of ISO and RTOs.

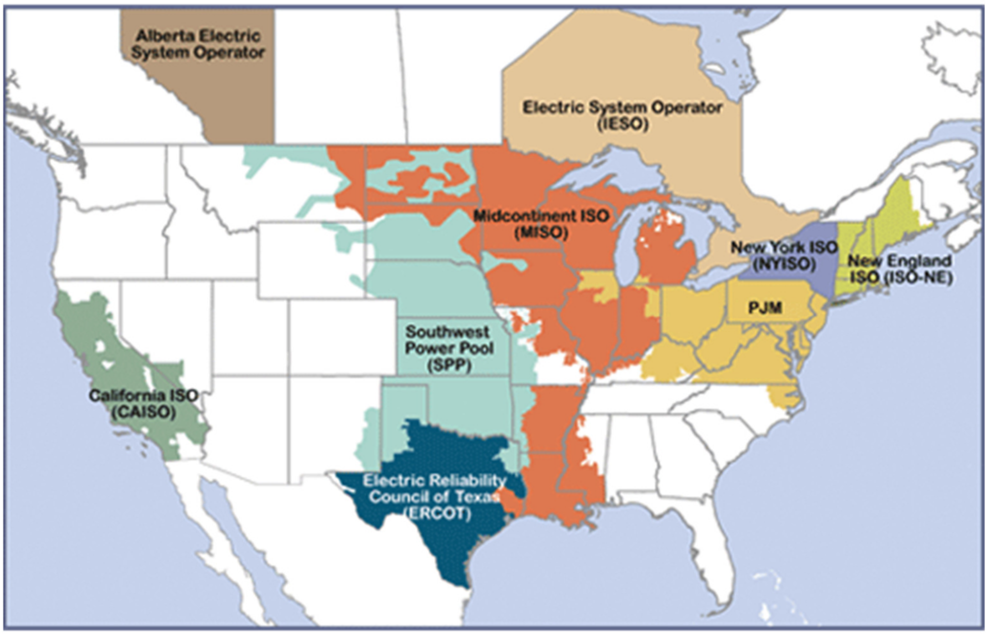


Figure 12 – ISO and RTO regions in North America under NERC

3.2 ENTSO-E

ENTSO-E is a cooperation across Europe's TSOs to support the implementation of EU energy policy and achieve Europe's energy and climate policy objectives, which are changing the very nature of the power system. It currently comprises 34 countries and 41 TSOs, as shown in the following diagram:

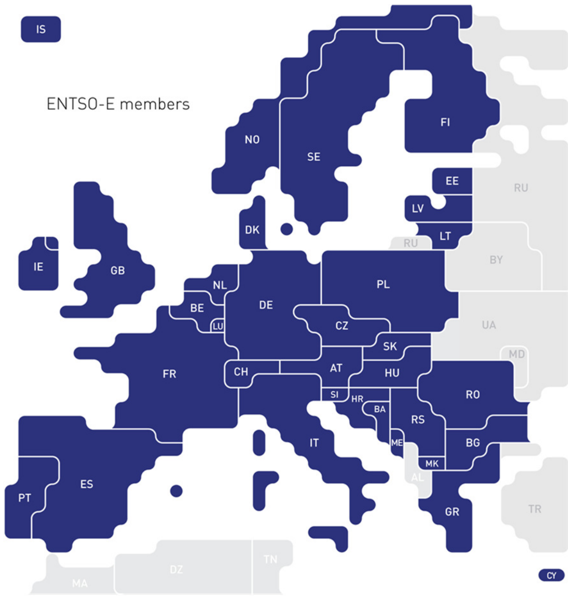


Figure 13 – Diagram depicting the ENTSO-E countries

ENTSO-E is further differentiated into regional groups, with the purpose to ensure compatibility between system operations on the one side, and market solutions and system development issues on the other.

There are currently five regional groups, as illustrated in:

- Continental Europe, former UCTE;
- Nordic, former NORDEL;
- Baltic, former BALTSO (synchronous with Russia);
- UK, former UKTSOA;
- Ireland, former ATSOI.

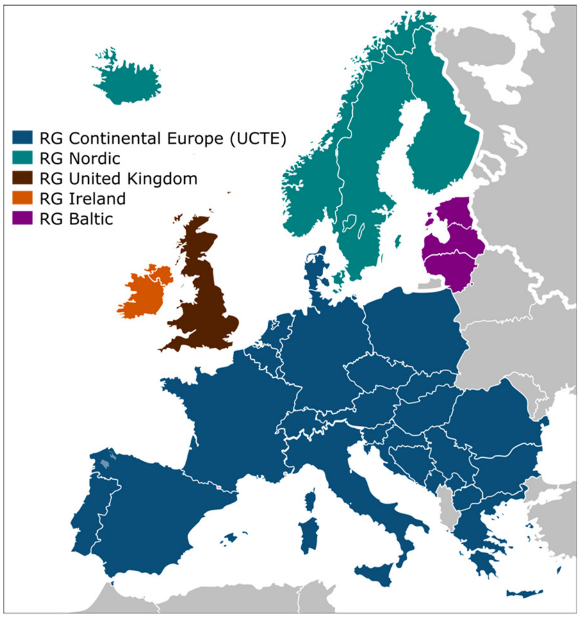


Figure 14 – ENTSO-E regional groups

3.3 Main Difference between Reserve Categories in NERC and ENTSO-E

NERC treats normal operating reserves different to reserves allocated to contingencies:

- **Normal operating reserves**
  - Regulating;
  - Load following.
- **Contingency reserves**
  - Frequency response;
  - Spinning;
  - Non-spinning;
  - Replacement/supplemental.

The following figure depicts the activation time and duration for the contingency reserve categories, as used by NERC:

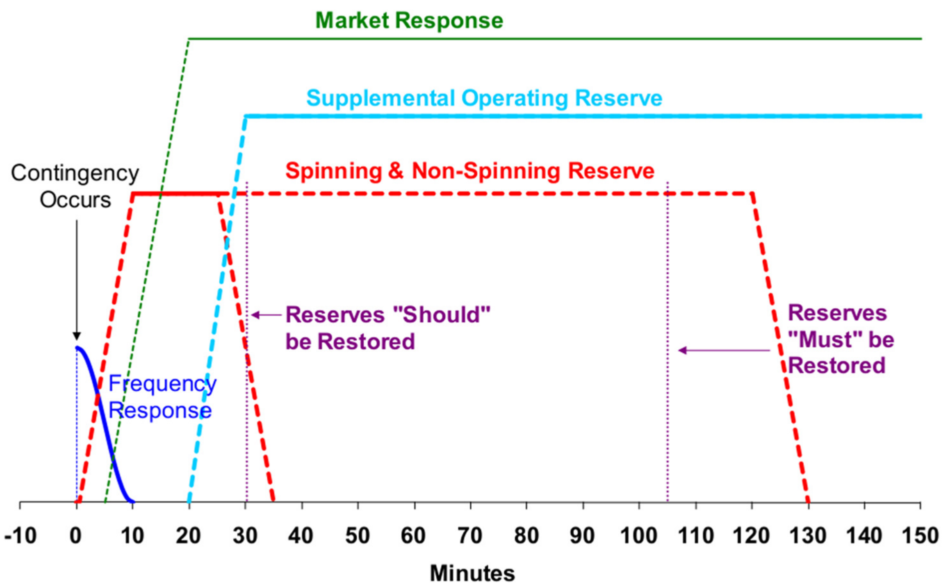


Figure 15 – NERC usage of reserves during an under frequency contingency

ENTSO-E does not make that differentiation and identifies the following categories:

- Frequency containment (FCR);
- Frequency restoration
  - Manual (FRR-m);
  - Automatic (FRR-a).
- Replacement reserve (RR).

The following figure shows the ENTSO-E categories and their application during an under frequency event:

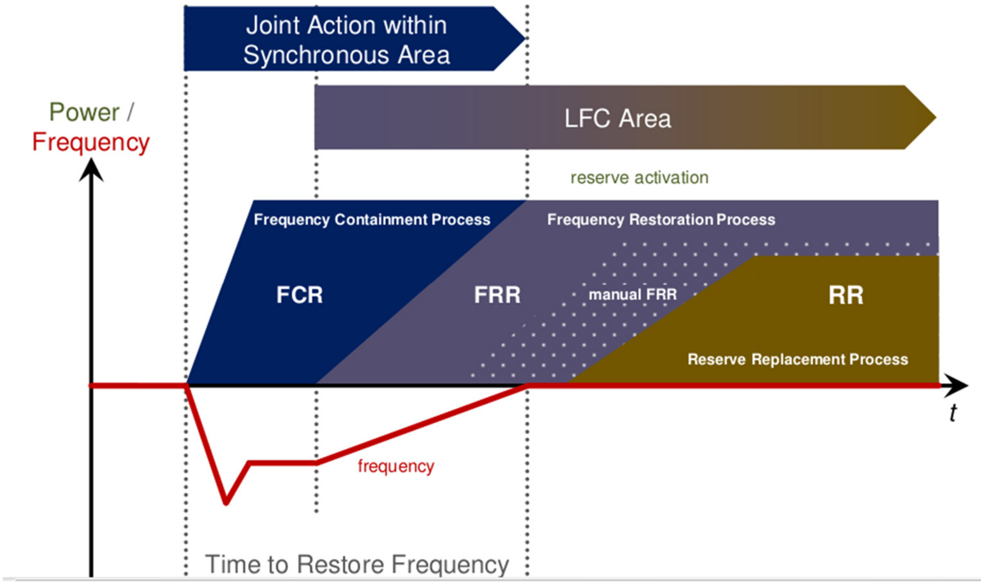


Figure 16 – ENTSO-E usage of reserves during an under frequency contingency

The reserve categories were mapped and compared with Eskom's categories, in the following figure:

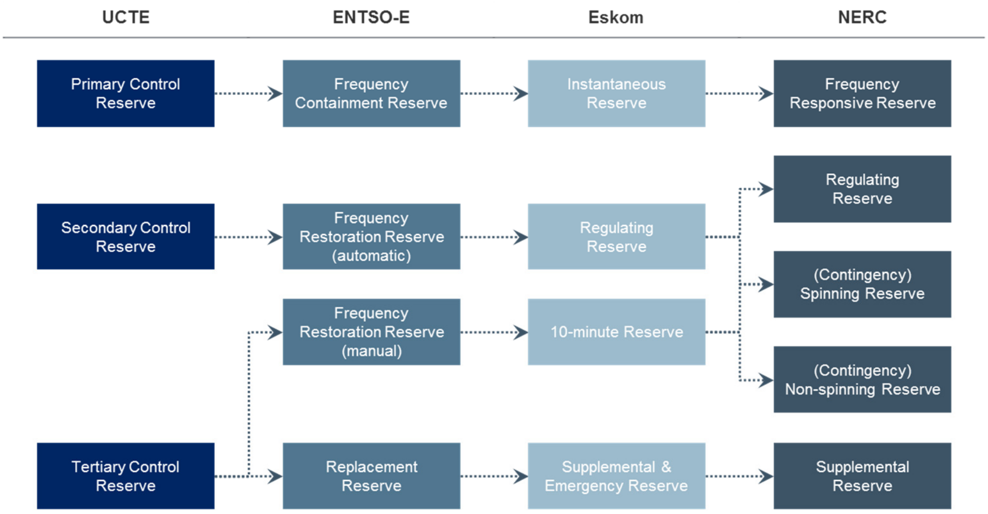


Figure 17 – Mapping between UCTE, ENTSO-E, Eskom and NERC reserve categories

4. Internationally Used Methods for Determining the Reserve Levels in Different Categories

Three level setting approaches have been identified in literature:

- **Deterministic**, e.g. N-1 or N-2 – Using the largest unit or power station as basis for the sizing;
- **Probabilistic** – Using probabilistic methods to estimate a probability distribution and deriving the level by choosing a confidence level or interval;
- **Dynamic** – Adjusting the level based on past performance.

It is not uncommon to see a combination of these approaches.

In the following sections the approaches followed by NERC Coordinating Councils, ISO's, TSO and ENTSO-E regions are discussed and highlighted.

4.1 Primary Reserves (Instantaneous Reserves)

4.1.1 NERC Frequency Response

NERC has no quantifiable requirement for the amount of frequency response reserves required (with the exception of the ERCOT region – see below). A deterministic criterion for the total contingency reserve is specified in[5]:

As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough contingency reserve to cover the most severe single contingency (N-1).

Currently most regions rely on the inertia of the rotating machine mass to arrest the frequency decline. In some regions, governor speed control is mandatory and a setting of 5% droop is typically used.

Standards in various Coordinating Councils are reportedly being developed to ensure adequate frequency response capacity is reserved. This is driven by increased renewable generation which is changing the system dynamics compared to traditional rotating generators.

NERC's BAL-001-TRE-01 [6]provides requirements related to "*the Primary Frequency Response of each resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection, setting Governor deadband and droop parameters, and providing Primary Frequency Response performance requirements.*"

For example, ERCOT[20] has:

- Completed system dynamic studies on net load (i.e. load and wind generation) to assess the requirement for frequency response;
- Developed systems to estimate the daily frequency response requirement.

4.1.2 ENTSO-E Frequency Containment

In ENTSO-E, the Frequency Containment Reserve (FCR)is sized to withstand the reference incident in the synchronous area[7]. The reference incident is normally the loss of the largest power generating/consumption unit or line that may cause imbalance with an N-1 failure.

The N-1 criterion is being applied in the following ENTSO-E regions:

- GB – UnitedKingdom;
- IRE – Ireland;
- NE – Nordic.

However, in the larger Continental Europe (CE) system, the probability of more than one failure is significant. In order to size the frequency containment reserve, a Monte Carlo simulation with 10^8 iterations were executed. In the simulation, plant failure was modelled independently, except where a shared node or network section would affect the supply. From the Monte Carlo simulation the largest FCR needed was 2910MW (equivalent to 1 in 20 year risk) and this agrees in magnitude with the use of an N-2 failure requirement of 3000MW.

To cater for the N-2 contingency, the responsibility to reserve capacity for frequency control is shared amongst the ENTSO-E CE members through the calculation of a contribution factor:

$$Contribution\ Factor = Annual\ Generated\ Energy\ /\ Annual\ Total\ Generated\ Energy$$

4.2 SecondaryReserves (Regulating Reserves)

4.2.1 NERC – Regulating Reserve

The purpose of regulating reserves is to balance supply and demand on a second to second basis. A measure of its performance is the Area Control Error (ACE). This is a term used by NERC to represent the real-time imbalance in supply and demand. It is defined by the ACE equation:

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$$

Where:

NI_A	is Actual Net Interchange
NI_S	isScheduled Net Interchange
B	is Control Area Bias
F_A	is Actual Frequency
F_S	isScheduled Frequency
I_{ME}	isInterchange (tie line) Metering Error

Two statistical performance measures exist to assess performance – CPS1 and CPS2 (Control Performance Standards 1&2). CPS1 addresses 1-minute imbalances, while CPS2 addresses 10-minute imbalances. Neither requires perfect performance, due to the statistical nature.

The CPSsare met by sizing of the regulating reserves or equivalents. Deterministic and probabilistic methods for sizing are in use in various utilities. Further, the levels may be fixed after a determination, or dynamically adjusted.

The following table from [8] summarises additional requirements per balancing area in:

Table 3 – Additional requirements per balancing area

Region	Requirement Definition
PJM	Based on 1% of the peak load during peak hours and 1% of the valley peak during off-peak hours.
NYISO	Set requirement based on weekday/weekend, hour of day, and season.
ERCOT	Based on 98.8th percentile of regulation reserve utilised in previous 30 days and same month of previous year, and adjusted by installed wind penetration (described further below).
CAISO	Use a requirement of 350 MW up and down regulating reserves, which can be adjusted based on load forecast, must-run instructions, previous CPS performance, and interchange and generation schedule changes.
MISO	Requirement made once a day based on conditions and before the day-ahead market closes.
ISO-NE	Based on month, hour of week, weekday/Sat/Sun.

The methodology used by ERCOT caters for wind generation and is based on 5-minute net load changes. Net load is calculated as the difference between the load and any renewable (wind) generation.

ERCOT adjusts the amount of regulating reserves required per month based on the amount of reserves deployed and the amount of time when the reserve levels were exhausted. Additionally, the levels are adjusted based on the amount of variable generation deployed. [9]. The methodology is summarised in this extract from [9]:

"Calculate the 98.8 percentile of the 5 minute net load (load and wind) changes during the 30 days prior to the time of the study and for the same month of the previous year by hour. Also, calculate the 98.8 percentile of the up and down Regulation Service deployed during the 30 days prior to the time of study and for the same month of the previous year by hour. These results will be used to calculate the amount of Regulation Service required by hour to provide an adequate supply of Regulation Service capability 98.8% of the time."

The amount of regulating reserves are calculated each month and adjusted for the amount of wind generation present in the period of study, compared to the period of interest.

Further, based on the performance against CPS1, the regulation levels are further adjusted, to compensate for lack of performance.

4.2.2 NERC – Contingencyor Spinning Reserve

The NERC BAL-002 [5]specifies:*“As a minimum, the balancing authority or reserve sharing group shall carry at least enough contingency reserve to cover the most severe single contingency.”*

Additional requirements are implemented in the different Coordination Councils, for example:

- **WECC**
  - The amount equal to 5% of the total load served by hydro generation, and 7% of the total load served by thermal generation;
  - 50% must be spinning.
- **NYISO**
  - 2% of peak load must be spinning.

4.2.3 ENTSO-E – Frequency Restoration (FRR)

The requirement for frequency restoration reserves is a combination of [10]:

- A deterministic assessment based on the positive and negative dimensioning incident (Article 46(2).e and Article 46(2).f); and
- A probabilistic assessment of historical records for at least one full year (Article 46(2).a and Article 46.2.b).

IRE and GB use a deterministic approach based on the reference incident to size the capacity to be reserved.

CE and NE use probabilistic methods where the sum of the Frequency Restoration Reserve (FRR) and the Replacement Reserve (RR) covers 99% of the LFC block imbalances. The calculation is performed separately for positive and negative deviations.

The minimum level of FRR is increased to ensure FRCE (Frequency Restoration Control Error - historically ACE in CE) compliance.

The second method is known as the ‘probability for reserves deficits’ method and utilises statistical data of the control area imbalances in the form of distribution curves. The reserve size could then cater for, 99.9% (for example) of the historical imbalances.

For example, Elia in Belgium uses this approach, as shown in the following figure from [11]:

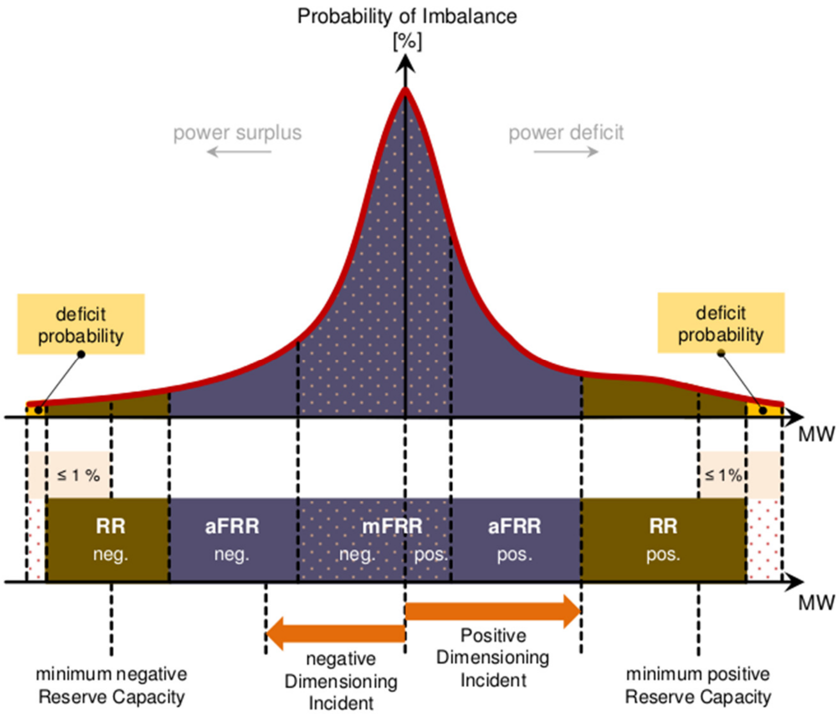


Figure 18 – Probabilistic dimensioning of FRR and RR with deficit probability

FFR-a is based on 15-minute imbalances.

Elia in Belgium uses a probabilistic technique, which is summarised in the following figure from [11],[12]:

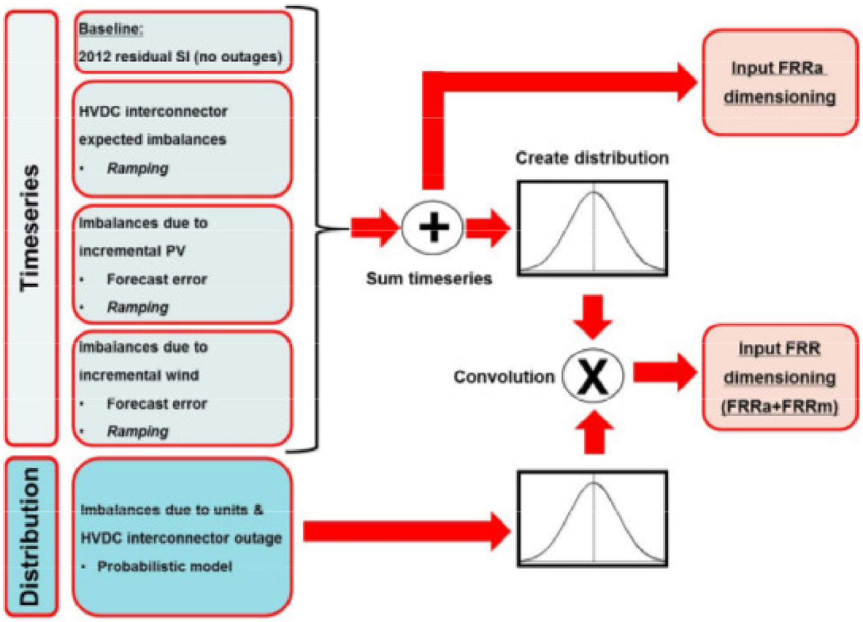


Figure 19 – Process and flow for the Monte Carlo simulation to dimension the FRR and RR

FRR has two categories:

- **FFR-a** – Automatic Frequency Restoration Reserve (regulating reserves);
- **FFR-m** – Manual Frequency Restoration Reserve.

The FFR-a or regulating reserves are sized based on the difference between quarter hourly imbalances, as shown below:

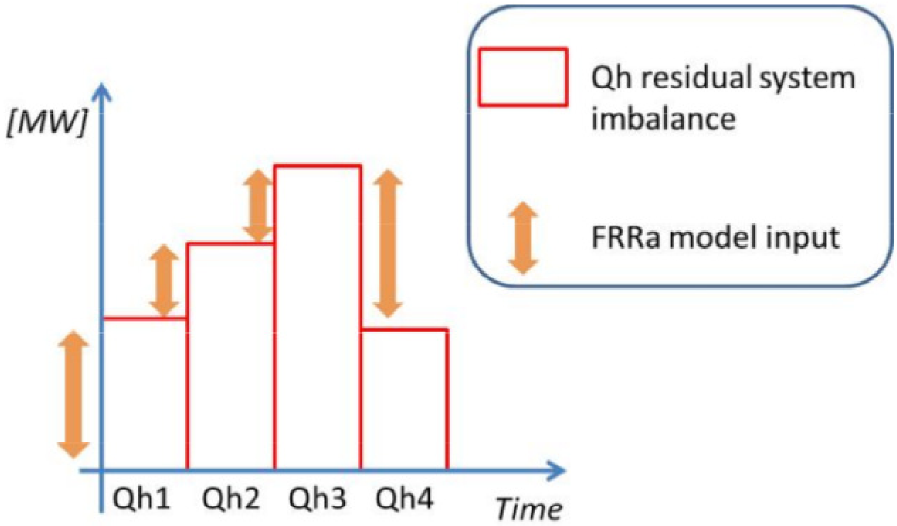


Figure 20 – FFR-a sized based on the difference between quarter hourly imbalances

4.2.4 NEM (Australian National Energy Market)

The Australian National Energy Market [13] dynamically adjusts the reserve levels based on predicted conditions in each 5-minute dispatch period. The adjustment is based on the time error, which is the accumulated deviation of the frequency over time.

If the time error is within the 1.5 second band, the regulation is set to 130/120 MW (raise/lower). If the time error is outside the 1.5 second band, the regulation is adjusted to 250 MW.

The principle is that the system is more vulnerable when the time error is high – it indicates that there is not sufficient regulating reserves to control the frequency such that the accumulated deviation is not within the 1.5 second band.

4.3 Tertiary Reserves (10-minute, Supplemental and Emergency Reserves)

4.3.1 NERC – Non-spinning Reserves

The NERC BAL-002 [5] specifies: *"As a minimum, the balancing authority or reserve sharing group shall carry at least enough contingency reserve to cover the most severe single contingency."*

ERCOT calculates for the 30 days prior to the period of study and the same period in the previous year:

- The 95th percentile of net load uncertainty in 4 hour blocks;
- Average historical regulation up requirements

The non-spinning requirement is then the difference between the 95th percentile of net load uncertainty and the average up regulation. The approach is that between the spinning and regulation reserve, 95% of net load errors can be accommodated.

4.3.2 ENTSO-E – Replacement Reserves

ENTSO-E determines the minimum tertiary reserves level "*to cover the largest expected loss of power (generation unit, power infeed, DC-link or load) in the control area.*"

In CE and NE, the replacement reserves should have sufficient capacity to restore the FRR, and in IRE and GB, sufficient capacity to restore FCR and FRR.

Further, some variations appear per member country, for example in Spain. The minimum reserve level for tertiary reserves is determined hourly, every day. *"This minimum amount is computed hourly as the rated power of the largest unit within the system plus 2% of the forecasted load for each hour."* [14],[19].

Belgium determines the level of the tertiary reserves FRRmas the 99.8 confidence interval of the residual imbalance distribution. This is obtained by convoluting the net load uncertainty probability distribution with a probability distribution of forced outages units [11],[12].

5. Overview of Findings and Impact of Renewables

This section summarises a few results from international studies and internationally published literature on wind power and its effect on reserves.

The purpose is to highlight:

- Previous results obtained;
- General trends in the publications;
- Conclusions drawn by those authors.

The following wind integration studies were reviewed:

- NYISO/NYSERDA – The effects of integrating wind power on transmission system planning, reliability and operations[21];
- Minnesota Wind Integration Study[22];
- All Island Grid Study – Ireland [23];
- Eastern Wind Integration and Transmission Study (US) [24];
- Western Wind and Solar Integration Study [25].

5.1 NYISO/NYSERDA – The Effects of Integrating Wind Power on Transmission System Planning, Reliability and Operations

This was one of the first studies performed on wind power integration and the results were published in 2005. The aim was to study the effects of integrating wind power on transmission system planning, reliability and operations.

The study considered the impact of:

- 3 300 MW of wind generation at 33 locations arranged in 11 zones;
- This represented about 10% of the NY State Peak Load.

As input the following data was used:

- Actual load data;
- Wind data from AWS TrueWind Meso Map System;
- For high resolution data, actual data from an Iowa wind project was sourced and transformed to site conditions.

The following figure from that study summarises the processes and technology issues that were studied:

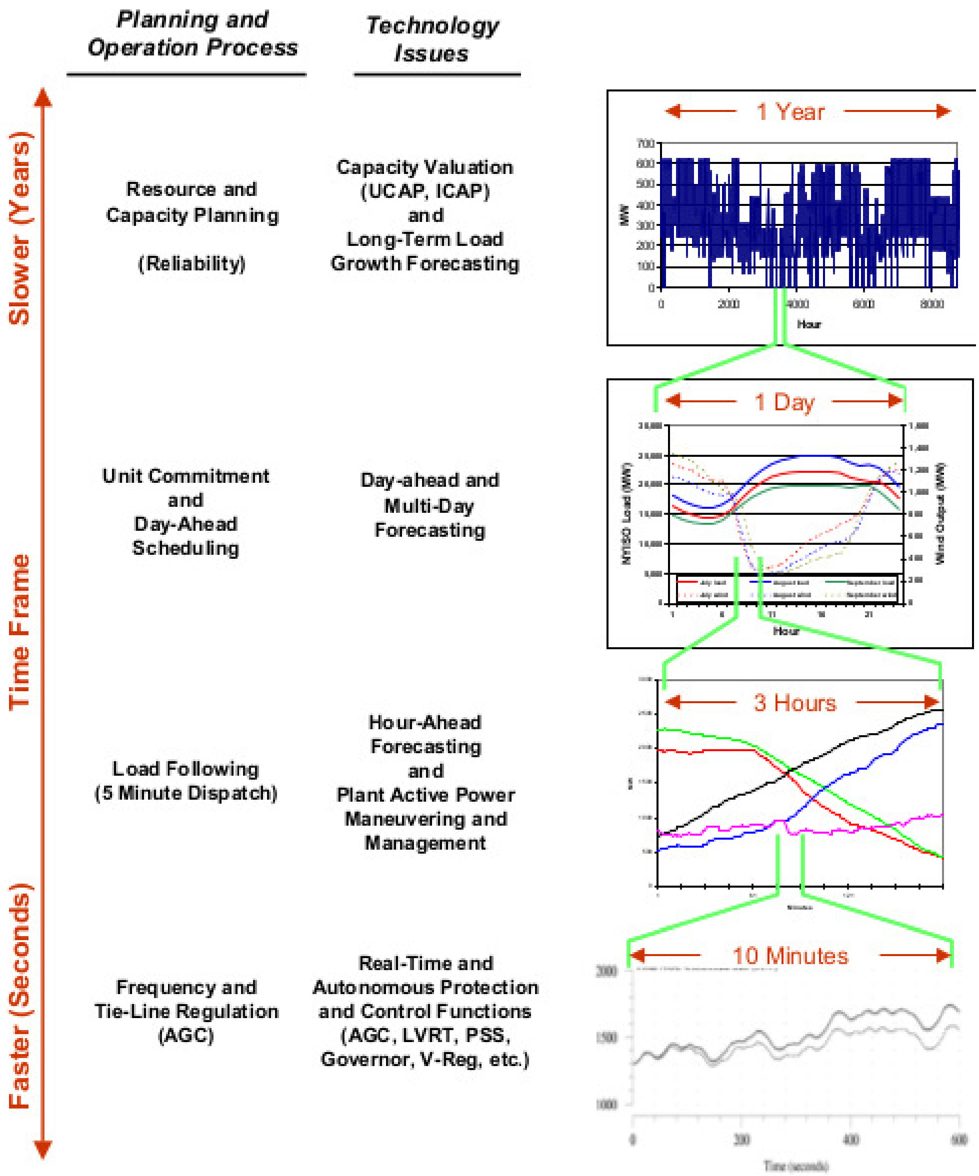


Figure 21 – Areas of the study with corresponding time frames and technology issues considered (ICAP and UCAP are respectively Installed Capacity and Unforced Capacity)

The following diagram from that study shows the key findings in the form of a comparison at various time scale and technical processes:

Table 4 – Table of key findings from the study in the form of a comparison at different time scales and technical issues

Time Scale	Technical Issue	Without Wind Generation	With Wind Generation	Comments
Years	UCAP of wind generation	$\text{UCAP}_{\text{land-based}} \cong 10\%$ $\text{UCAP}_{\text{offshore}} \cong 36\%$ (one site in L.I.)		• UCAP is site-specific. • Simple calculation method proposed.
Days	Day-ahead forecasting and unit commitment	Forecasting error: $\sigma \cong 700\text{-}800$MW	Forecasting error: $\sigma \cong 850\text{-}950$MW	• Incremental increase can be accommodated by existing processes and resources in NY State. • Even without forecasts, wind energy displaces conventional generation, reduces system operating costs and reduces emissions. • Accurate wind forecasts can improve results by another 30%.
Hours	Hourly variability	$\sigma =$ 858 MW	$\sigma =$ 910 MW	• Incremental increase can be accommodated by existing processes and resources in NY State.
	Largest hourly load rise	2 575 MW	2 756 MW	• Incremental increase can be accommodated by existing processes and resources in NY State.
Minutes	Load following (5-min variability)	$\sigma =$ 54.4 MW	$\sigma =$ 56.2 MW	• Incremental increase can be accommodated by existing processes and resources in NY State.
Seconds	Regulation	225 to 275 MW	36 MW increase required to maintain same performance	• .NYISO presently exceeds NERC criteria. • May still meet minimum NERC criteria with existing regulating capability.
	Spinning reserve	1 200 MW	1 200 MW	• No change to spinning reserve requirement.
	Stability	8% post-fault voltage dip (typical)	5% post-fault voltage dip (typical)	• State-of-the-art wind generators do not participate in power swings, and improve post-fault response of the interconnected power grid.

The contingency reserve dimensioning was based on N-1 and was not affected by the introduction of additional wind power.

The additional net load variation due to wind fluctuations had the following impact on the 'normal' reserves:

- Small impact on regulating reserves;
- No impact on the load following reserves.

Additionally, the day-ahead forecasting error increased due to the quality of the wind forecasting.

5.2 Minnesota Wind Integration Study

This study was completed by the Enernex Corporation and the results were published in 2006.Wind penetration levels of 15%, 20% and 25% on a total capacity of 20 000 MW were evaluated to understand the impact of increased wind penetration levels.Wind data from the MM5 mesoscale model was used for 152 sites across 14 regions.

One of the findings from the study was the impact of geographic diversity compared to the wind aggregation time frame, as shown in the following figure from that study:

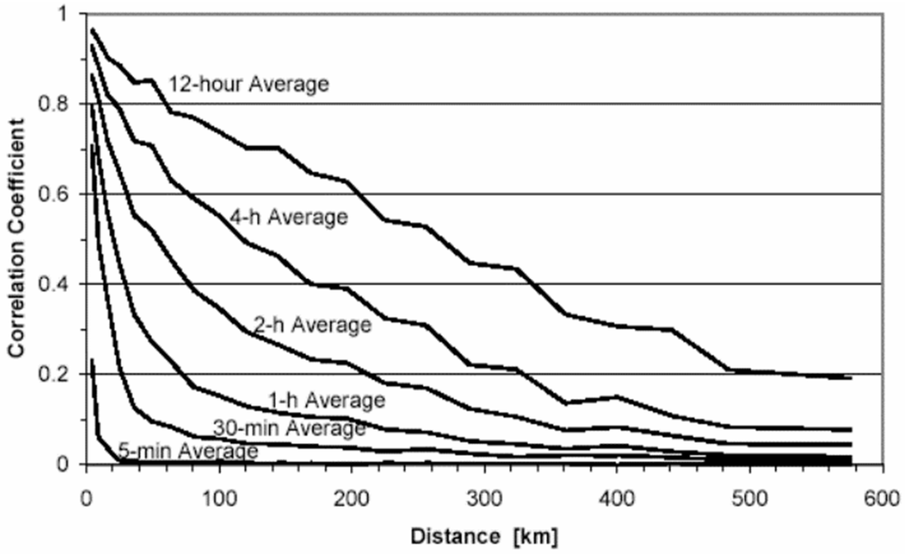


Figure 22 – Geographic diversity measured as correlation coefficient as a function of distance and wind aggregation time frames

High correlation was present at very short distances, and rapidly declined with distance. The larger the aggregation time frame, the higher the correlation coefficient. This suggests that the geographic dispersion of wind farms would impact the effect of wind integration at various planning horizons.The study published a set of curves relating the wind generation level to the power output fluctuations, expressed as 1-hour standard deviation:

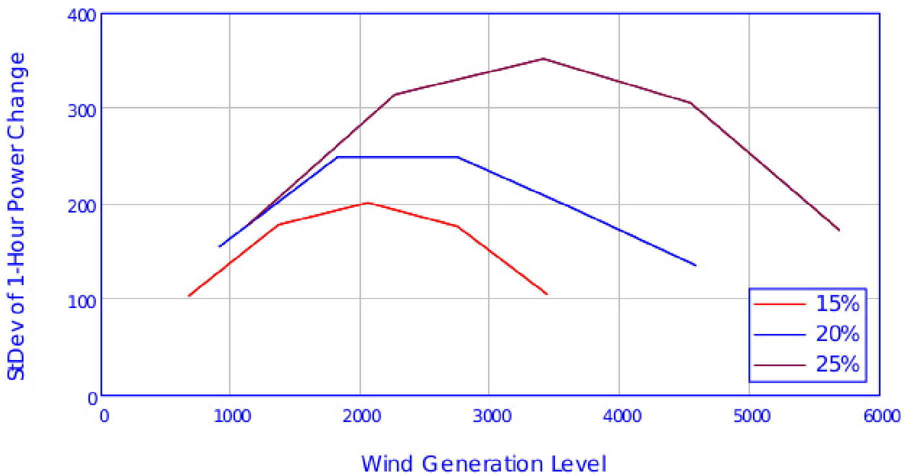


Figure 23 – Standard deviation of 1-hour power change as a function of wind generation level for the 15, 20 and 25% wind penetration.

The non-linear curve is due to the non-linear transfer function of wind speed to wind power generation (the S-form of the power curve).

Based on this model, an adjustment for the regulating requirement based on wind generation was proposed. The adjustment is based on addition of standard deviations when the effects are considered independent. In this case, load variation is assumed to be independent to the wind variation and the wind variations per 100MW wind plant is assumed to be independent. The factor k is the ordinate of the standard normal distribution and the assumption is therefore that the total load variations are normal.

$$New\_Regulating\_Requirement \ = k\sqrt{\sigma_{Load^2} + N(\sigma_{w100^2})}$$

Where:

k	=	a factor relating regulation capacity requirement to the standard deviation of the regulation variations; assumed to be 5
σ_{Load}	=	standard deviation of regulation variations from the load
σ_{w100}	=	standard deviation of the regulation variations from a 100 MW wind plant
N	=	wind generation capacity in the scenario divided by 100

This assumes independence between load variation and wind power generation within the regulating reserve time frame and a normal distribution.

The adjustment was applied to each of the wind generation scenarios and the following table derived:

Table 5 – Regulation capacity requirement for the base case and the three wind penetration scenarios (moderate wind impact)

Scenario	Regulation Capacity Requirement
Base	137 MW
15% wind generation	149 MW
20% wind generation	153 MW
25% wind generation	157 MW

Load following reserves are those reserves required to cater for movements in the underlying load beyond the fast regulating time frame. In order to dimension the load following reserve requirements, two standard deviations of 5 minute load variations were used. The two standard deviations equates to 95% of the variations if a normal distribution is assumed. The following tables lists the 5 minute load variations for increasing amount of wind penetration:

Table 6 – Five minute variability (moderate wind impact)

Scenario	Standard deviation of 5 minute changes
Base	50 MW
15% wind generation	55 MW
20% wind generation	57 MW
25% wind generation	62 MW

The study also noted that increase in wind penetration, increased the standard deviation of 1-hour wind generation change. This was based on persistent hourly forecast of wind, i.e. the wind for the following hour would be the same as the wind for the current hour.

The resulting net load deviation is presented in the following table:

Table 7 – Increase in next hour wind generation change with increase in wind penetration

Scenario	Standard Deviation of 1-hour Wind Generation Change
15% wind generation	155 MW
20% wind generation	204 MW
25% wind generation	269 MW

The total operating reserve margin was calculated and showed a significant increase in the operating reserve margin as the wind penetration increased:

Table 8 – Impact of increasing wind penetration on the total reserve margin

Reserve Category	Base		15% Wind		20% Wind		25% Wind	
	MW	%	MW	%	MW	%	MW	%
Regulating	137	0.65%	149	0.71%	153	0.73%	157	0.75%
Spinning	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Non-spin	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Load following	100	0.48%	110	0.52%	114	0.54%	124	0.59%
Operating reserve margin	152	0.73%	310	1.48%	408	1.94%	538	2.56%
Total operating reserves	**1 049**	**5.00%**	**1 229**	**5.86%**	**1 335**	**6.36%**	**1 479**	**7.05%**

Note that requirements for load following and reserve margin was based on two standard deviations of the five minute variability (see Table 6) and next hour forecast error (see Table 7), respectively.

The study also considered the seasonal variation in wind patterns and expresses the impact in terms of effective load carrying capacity (ELCC). ELCC of a power generator represents its ability to effectively increase the generating capacity available to a utility or a regional power grid without increasing the utility's loss of load risk. The study observed that the effective load carrying capacity (ELCC) varied significantly between 20% in 2003 and 5% in 2005.

The following figures shows the wind generation for the hundred highest load hours in 2003 and 2005 respectively. The wind production in 2003 correlates much better with the highest load hours for that year, than the 2005 wind production during the highest load hours.

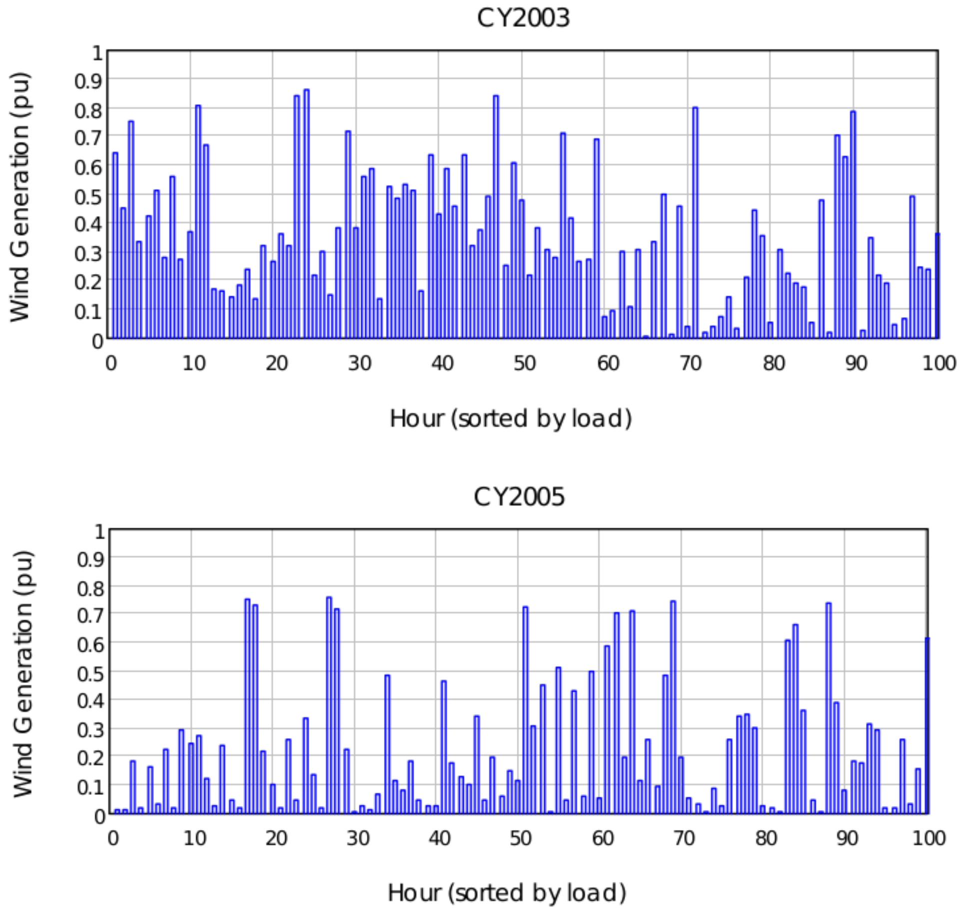


Figure 24 – Effective load carry capacity of 20% for 2003 compared with 5% for 2005

In summary, some key observations from this study:

- Geographic diversity and its interaction with aggregation time frames, impacted the correlation between wind generation output.
- There was a non-linear relationship between the wind generation output level and the size of the output fluctuations – this was due to the non-linear wind-to-power curve.
- No impact was observed regarding contingency reserves, as these were based on the largest contingency (N-1).
- Regulation reserves increased by a modest amount with an increase in renewable penetration.
- A method for estimating the additional reserve requirements due to increased wind penetration was derived. The method assumed independence between load and wind fluctuations, as well as that the nett load distribution was normal.
- A large increase in the hour-ahead operating reserve margin was observed.
- The ELCC varied significantly per year.

5.3 All Island Grid Study

The All Island Grid study was published in 2007 and focused on the effect of increased wind generation in Ireland.

The study considered six portfolios of generation mix, with 2 GW, 4 GW, 6 GW and 8 GW penetration of wind on a peak of 9.6GW, as shown in the following table from that study publication:

Table 9 – Six scenarios of varying wind power and generation mix considered in the All Island Grid study

	P1	P2	P3	P4	P5	P6
CO_2price [Euro/Ton CO_2]	30	30	30	30	30	30
Fuel price scenario	Central	Central	Central	Central	Central	Central
New Coal [MW]	0	0	0	1 163	0	0
New OCGTs [MW]	1 450	828	1 968	311	829	518
New ADGTs*[MW]	89	535	535	0	111	0
New CCGTs [MW]	1 294	1 200	0	1 200	1 200	1 200
Base Renewables [MW]	182	182	182	182	360	392
Tidal stream [MW]	72	72	72	72	200	200
Wind power [MW]	2 000	4 000	4 000	4 000	6 000	8 000
Wave power [MW]	0	0	0	0	0	1 400

* ADGT is Aero Derivative Gas Turbine

A stochastic scheduling tool was used, which estimated the optimum schedule under uncertainty. The results of the scheduling tool were verified and calibrated using Plexos.

Wind data used in the study was as measured at various sites in Ireland, including offshore measurements.

The spinning reserve was calculated using the largest generating unit. The following figure shows the spinning reserve for a full year for each of the port folios. The spinning reserve was sized based on the largest unit scheduled and as more wind generation was utilised, the largest unit was scheduled more often, leading to an increase in the demand for spinning reserve [see P6]. Overall the impact is very modest.

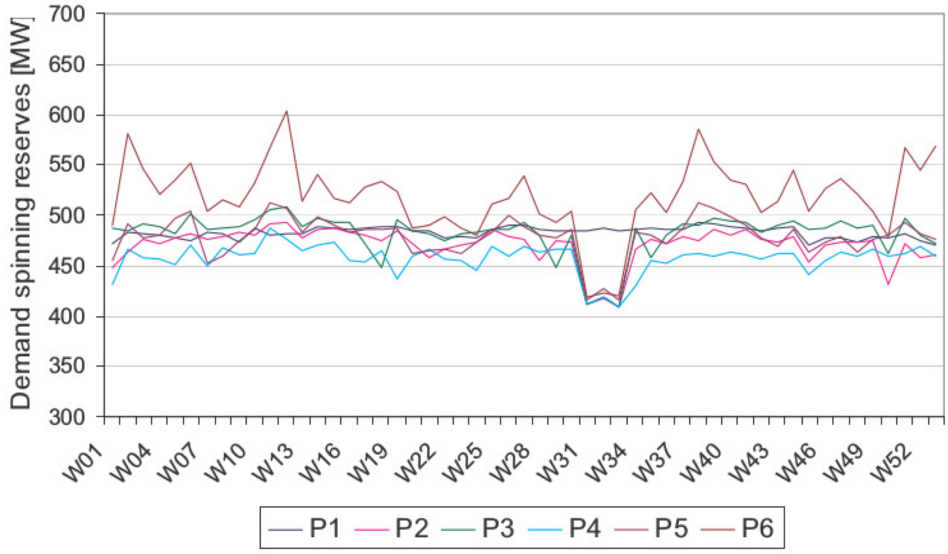


Figure 25 – Spinning reserve (Frequency Restoration Reserves-automatic) for the different portfolios throughout the year

The replacement reserves were found to be very sensitive to the generation mix per portfolio and increases with the forecast horizon:

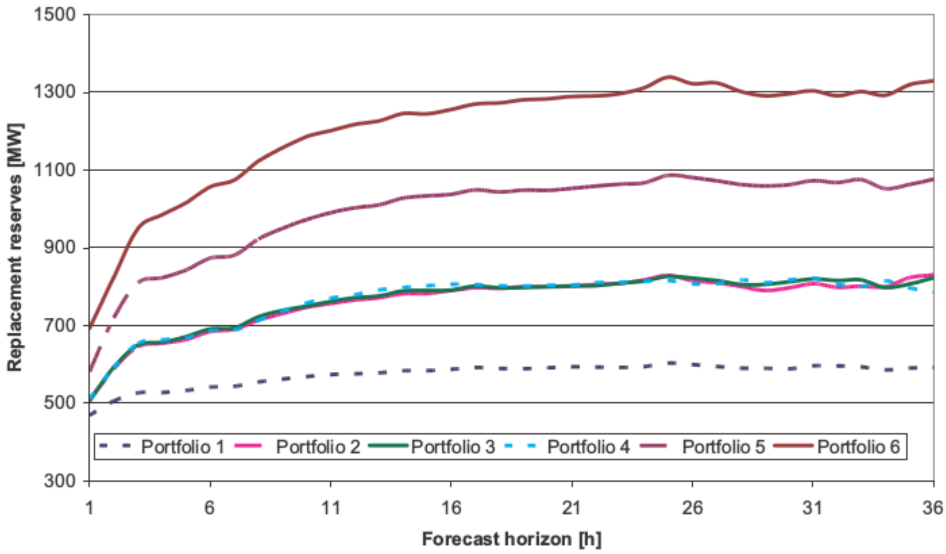


Figure 26 – Replacement reserve for the different portfolios and forecast horizons. This corresponds to the inputs for the Wilmar Planning Tool (a stochastic unit commitment scheduler)

The replacement reserves were based on the 90th percentile of the forecast error and therefore dependent on the forecasting methodology used.

In summary:

- Spinning reserve or contingency reserve was determined by the size of the largest contingency as scheduled.
- Due to the specific generation mix portfolios, more variable generation lead to more use of largest contingency and increase on average spinning reserve.
- Replacement reserve was calculated based on the forecast error and significantly increased with additional wind generation as well as forecasting horizon.

5.4 EWITS – Eastern Wind Integration and Transmission Study

This study was completed by the Enernex Corporation and the results published in 2010.

The study considered 3 scenarios with 20% wind penetration for the Eastern Interconnection, varying by mix of onshore and offshore. A fourth scenario with 30% wind penetration was also included. The total installed capacity was 1000GW.

Wind data was obtained from the NREL database as derived from the AWS TrueWindmesoscale model.

Their approach was to:

- Statistically analyse historical wind and net load measurements to assess impact on operating reserves;
- Utilise chronological production simulations;
- Perform Monte Carlo based chronological resource adequacy assessments.

A key driver for reserve margin under increased variable generation was the wind forecast errors. In the figures below, the short term load forecast and short term wind forecast are shown and the nature of the error depicted:

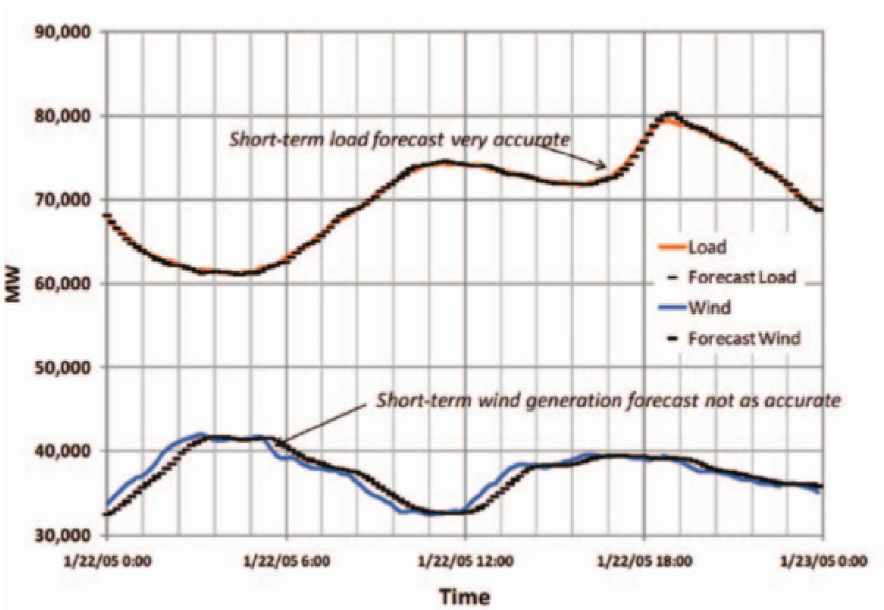


Figure 27 – A comparison of the short term load forecast and the short term wind generation forecast

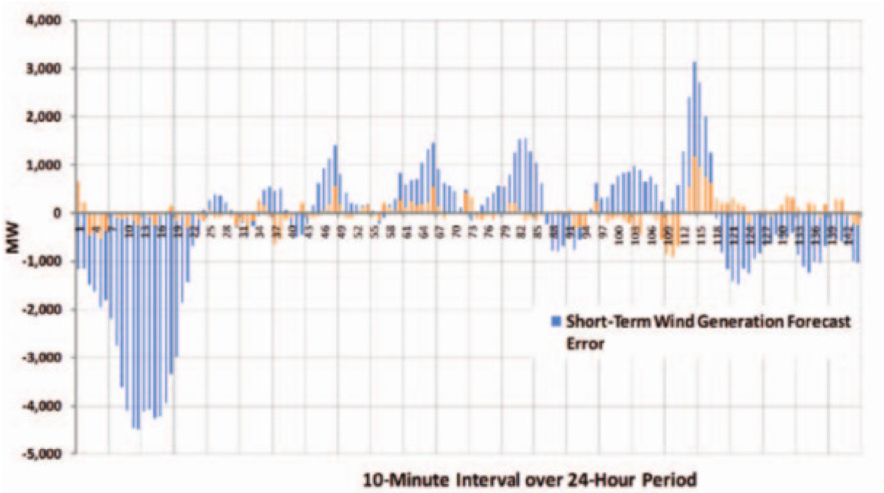


Figure 28 – Comparison of the 10-minute forecast errors for a persistent forecast, - persistent forecast is assuming the same wind generation to the period before

The forecast errors were based on a persistent forecast and dominated the nett load forecast.

The relationship between the standard deviation of the fluctuations in wind and average hourly production was modelled as a second order polynomial:

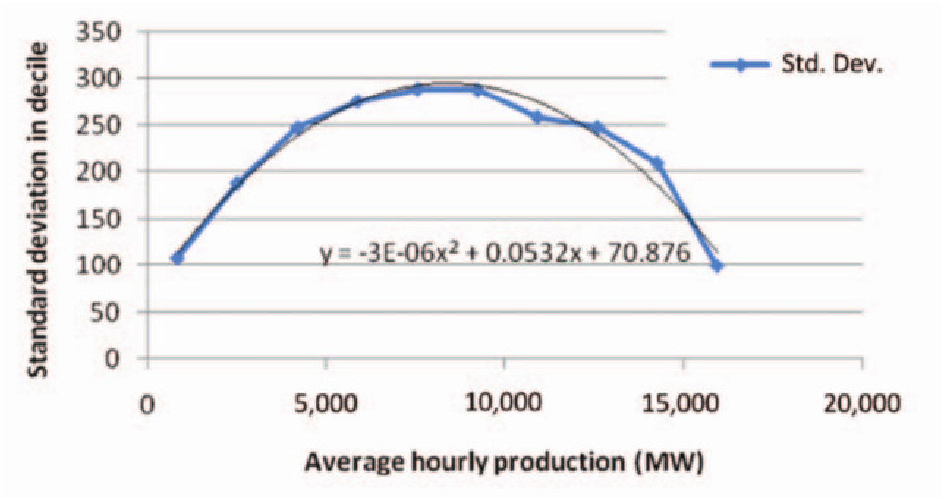


Figure 29 – Standard deviation of 10 minute wind production as a function of average hourly production. The S-form of the power curve gives this form.

This became the input into estimating the regulating reserve requirements, using a similar approach as for the Minnesota Wind Integration Study.

is calculated from the relationship in is the hourly loadThe team also studied the wind generation capacity value (expressed as % of aggregate name plate rating) and found variations between different years for each of the wind penetration scenarios. The results were enhanced by modelling additional transmission capacity overlay:

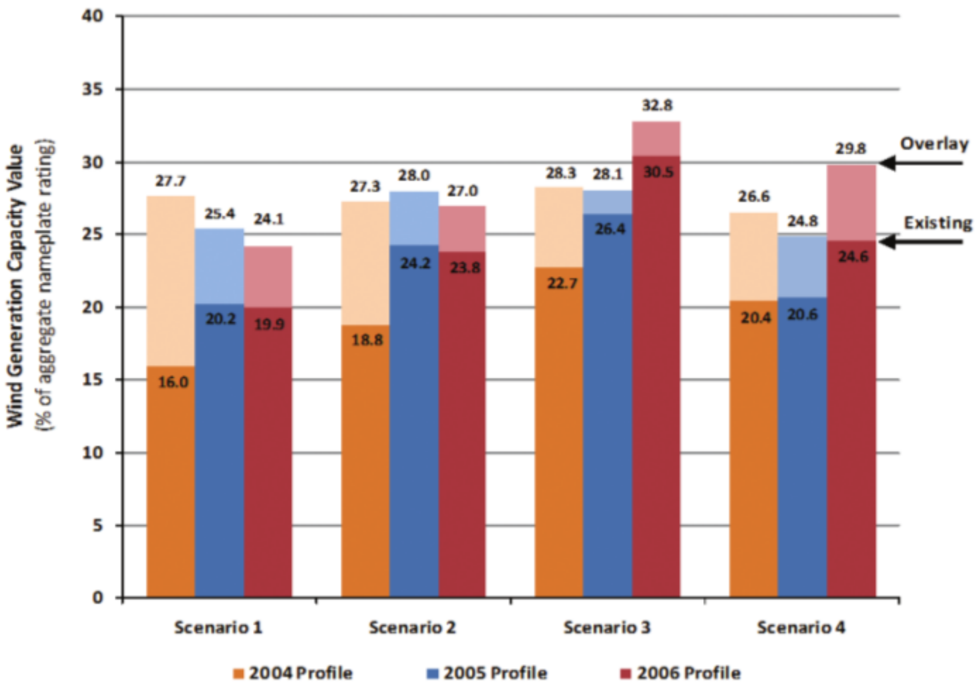


Figure 30 – Wind generation capacity value for each scenario for three consecutive years. Additionally, the impact of additional transmission capacity is also shown (marked Overlay in the figure).

In summary:

- Wind forecast error was much larger than load forecasting errors and dominated the nett load forecasting error at 20 and 30% wind penetration.
- The wind generation capacity value varied by geographic location and per year – between 15 and 30%.

5.5 Western Wind and Solar Integration Study

This study was published by the National Renewable Energy Laboratory (NREL) in 2010 and a Phase 2 study was published in September 2013.

The following penetration scenarios for about 40 000 MW of total capacity were considered:

- No renewable (0% wind , 0% solar);
- TEPPC scenario (9.4% wind, 3.6% solar);
- High Wind Scenario (25% wind, 8% solar);
- High Solar Scenario (8% wind, 25% solar);
- High Mix Scenario (16.5% wind, 16.5% solar);

Wind data was sourced from the Weather Research and Forecasting (WRF) mesoscale model.

Weather predictions at a 2 km resolution were obtained using a Numerical Weather Prediction Model over the western United Stated at 10-minute resolution.

In order to derive the additional reserve requirements, the team studied the net load variability for different renewable scenarios and at 5-minute variation:

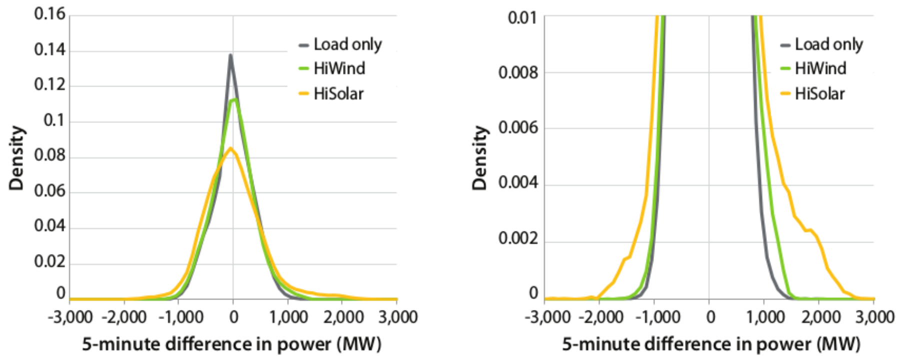


Figure 31 – Distributions of 5-minute difference in power for Load only, High Wind and High Solar scenarios. In this case high-solar gives the largest 5 minute-variation

The High Wind scenario increased the 5-minute difference moderately, and the High Solar scenario caused a large increase in the 5-minute difference.

The net load forecasting error for day-ahead and four hour-ahead for different renewable scenarios was also analysed. The result is shown below:

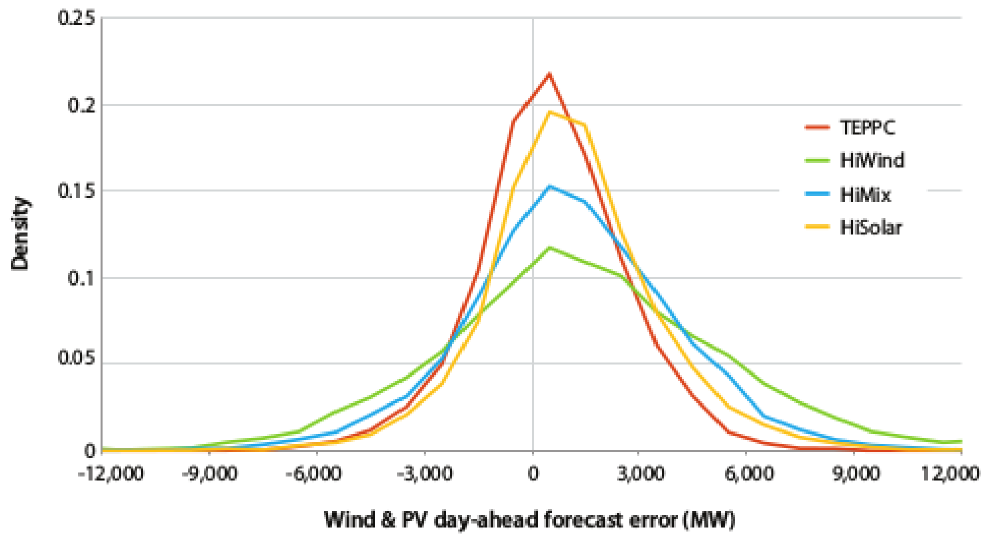


Figure 32 – Net load day-ahead forecasting error for the different renewable generation scenarios. In this case high-wind realises the largest day-ahead forecast error.

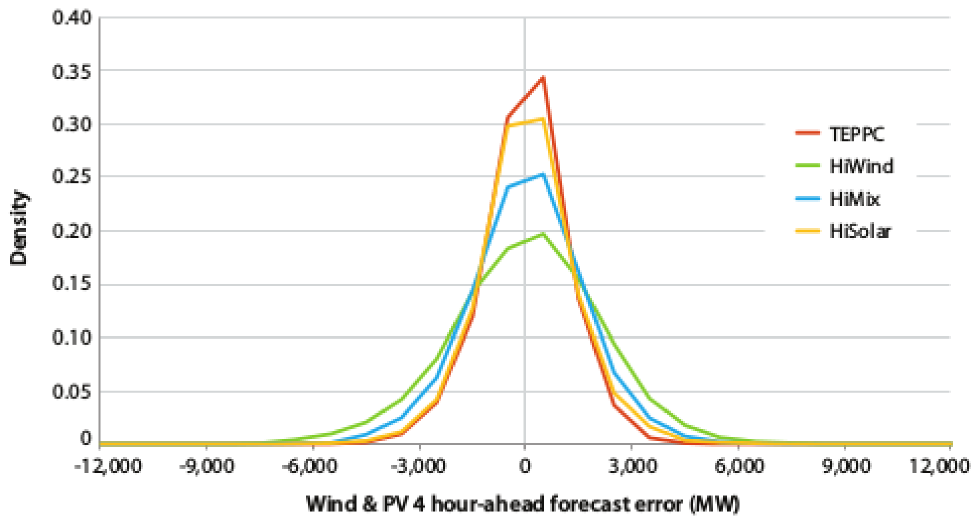


Figure 33 – Net load four hour-ahead forecasting error for the different renewable generation scenarios

In both the day-ahead and four hour-ahead analyses, the High Wind scenario had the greatest forecasting error. The forecast error was reduced for shorter time horizons.

In summary:

- The five minute fluctuations were largest for the high solar scenario;meaning that solar penetration would have the largest impact on regulating reserve.
- Day-ahead and four hour-ahead forecasting errors were the largest for the High Wind scenario. The day-ahead error was larger than the four hour-ahead forecast.
- The reserve requirements varied per site and the impact of wind generation could vary significantly per site due to variations in the wind fluctuations.

6. Costing and Paying for Reserve

6.1 Cost of Reserves

A comprehensive assessment of markets for frequency and voltage control ancillary services was completed by [15]. The author analysed the various cost components associated with reserves and summarised it as:

- **Fixed Costs**
  - Investment cost;
  - Manpower cost.
- **Variable Costs**
  - Capacity reservation (de-optimisation and opportunity cost);
  - Utilisation of reserved capacity.

The cost due to capacity reservation was the most complex to quantify. Capacity reservation lead to de-optimisation and loss of opportunity costs

In a study completed by [16], a methodology was used applying Plexos to calculate the difference in energy cost with reserves included and excluded. The following figure from that study shows how the energy dispatch is modified due to reserve provisioning:

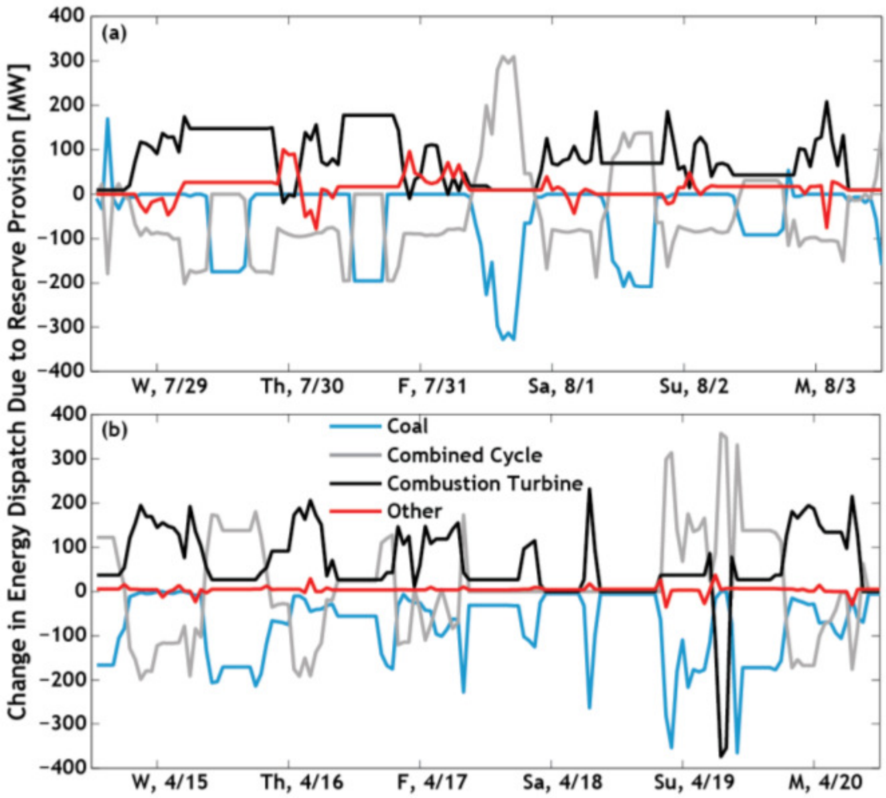


Figure 34 – Energy dispatch is modified due to reserve provisioning

The following figure shows how the load factor of various generation technologies was affected by the reserve capacity provisioning:

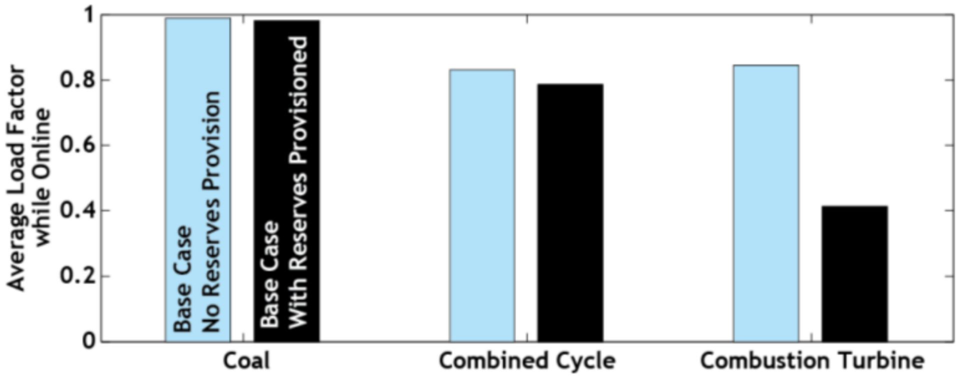


Figure 35 – Average load factor while online is modified due to reserve provisioning

The change in energy dispatch due to reserve provisioning and the change in average load factor while online are examples of de-optimisation and opportunity cost.

The study also evaluated the impact of increasing amounts of renewable generation using this methodology. The renewable energy penetration was varied from 15% to 35% as shown in the following figure

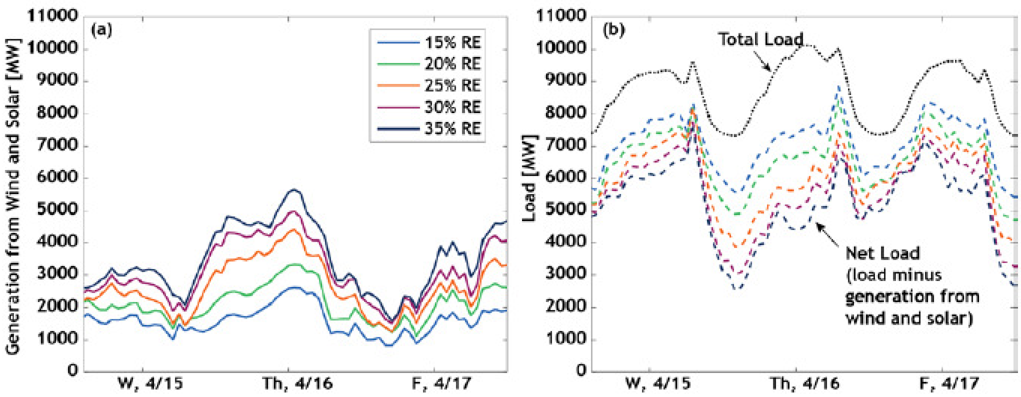


Figure 36 – Increased renewable energy and calculated net load, to estimate the cost impact of renewable energy on reserves

The impact on the costing is shown in the following table, with the percentage increase in total cost due to renewable penetration varying between 2 and 3%.

Table 10 – Impact of renewable energy penetration on cost and price of reserves

Scenario	Total Production Cost (M$)	Cost of Providing Reserves (M$)	Percent Increase in Total Generation Cost Associated with Reserves	Increase in Generation Cost per Total Reserves ($/MW-h)	Price of Reserves ($/MW-h) Regulation Mean/ Median	Contingency Mean/ Median	Flexibility Mean/ Median
15% PV and Wind Generation (Base Case)	1,427.1	27.4	2.0%	5.4	15.48 / 13.81	6.15 / 3.32	1.62 / 0
20% PV and Wind Generation	1,309.3	29.1	2.3%	5.5	16.31 / 14.61	6.14 / 3.09	2.05 / 0
25% PV and Wind Generation	1,170.3	32.3	2.8%	5.8	16.95 / 14.58	5.88 / 2.81	2.21 / 0
30% PV and Wind Generation	1,071.8	32.1	3.1%	5.6	16.81 / 14.52	5.31 / 2.61	2.3 / 0
35% PV and Wind Generation	1,003.3	31.2	3.2%	5.3	16.53 / 14.52	5.04 / 2.51	2.18 / 0

It should be noted that the costs increases are directly related to the increased usage of .reserves and that the contingency capacity requirement is unchanged, as shown in the following table from the same study:

Table 11 – Reserve Requirements by Renewable Penetration Scenario

System Property	RE = 15% (Base case)	RE = 20%	RE = 25%	RE = 30%	RE = 35%	No RE Case[a]
Total Generation [GWh]	78,761	79,449	79,454	79,426	79,375	79,369
PV Generation [GWh] (% of Demand)	1,834 (2.3%)	2,556 (3.2%)	3,168 (4%)	3,750 (4.7%)	4,260 (5.4%)	0
Wind Generation [GWh] (% of Demand)	10,705 (13.6%)	13,838 (17.4%)	18,097 (22.8%)	21,433 (27%)	23,752 (29.9%)	0
Regulation Requirement [GW-h]	1,050	1,134	1,281	1,364	1,422	782
Regulation Requirement Due to Renewables [GW-h][b]	700	822	1,015	1,118	1,187	0
Contingency Requirement [GW-h]	3,548	3,548	3,548	3,548	3,548	3,548
Flexibility Requirement [GW-h]	502	600	769	855	918	0

[a] *No RE Case Regulation requirement is based on 1% of Load*

[b] *Regulation requirement based on the 95th percentile of 5-minute variability of wind and solar power and 1% of load. We calculated the regulation requirement due to solar and wind power variability by taking the square root of the total regulation requirement squared minus the 1% load requirement squared.*

6.2 Integration Costs

Integration costs are the additional costs that the power system incurs due to the introduction of wind and solar generation [31]. The following figure from [32] shows different balancing authorities and the costs impacts considered in estimating the integration costs:

Table 12 – Components of estimating integrations costs from [32]

	Regulation	Load-Following	Contingency Reserves	Energy Imbalance	Unit Commitment Impacts	Opportunity Costs	Coal Cycling and Natural Gas Storage
APS	X	X	X		X		
Avista	X	X	X				
BC Hydro	X	X		X		X	
BPA	X	X		X			
Idaho Power	X						
NorthWestern	X						
PacifiCorp 2007, 2008			X	X			
PacifiCorp 2010	X	X	X	X			
PacifiCorp 2012	X	X	X	X	X		
PGE	X	X	X	X			
PSCo (Solar)					X		
PSCo (Wind)	X				X		X
PSE	X						
WACM	X						
Westar	X						

In order to estimate the integration costs, different methodology are used by balancing authorities as summarized in the following table from [32]:

Table 13 – Determination of wind integration impacts [32]

	Compare With Flat Block	Compare With Ideal Generator	Compare With Net Load	Other Methodology
APS		X		
Avista		X		
BC Hydro		X		
BPA				X
Idaho Power	X			
NorthWestern				X
PacifiCorp	X		X	
PGE				X
PSCo	X		X	
PSE				X
WACM				X
Westar				X

The methodologies can be summarized as:

- Compare with flat block – the "without wind generation" case is calculated by substituting the wind generation with a flat block of energy as shown in Figure 37.
- Compare with Ideal Generators – the ideal generator has no variability in its output
- Compare with Net Load – the net load is calculated as the difference between the Load and any variable generation.
- Other methodologies – A variety of other methodologies are used, for example, scenario simulations, statistical comparisons of 10 minute load and wind measurements and high resolution calculations

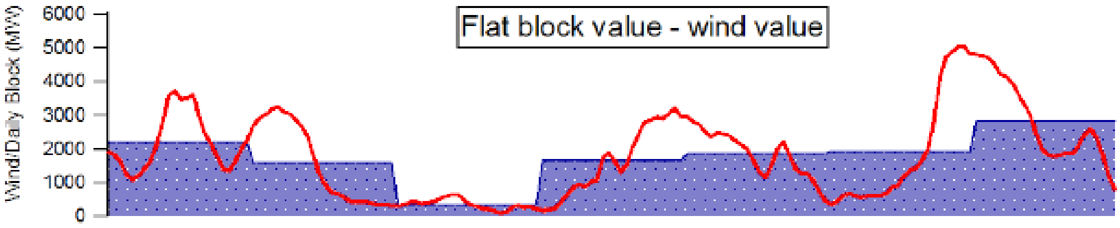


Figure 37 – Flat block value for wind integration cost comparison

The following figure summarizes increases in balancing cost as a function of wind penetration from a number of studies [30]:

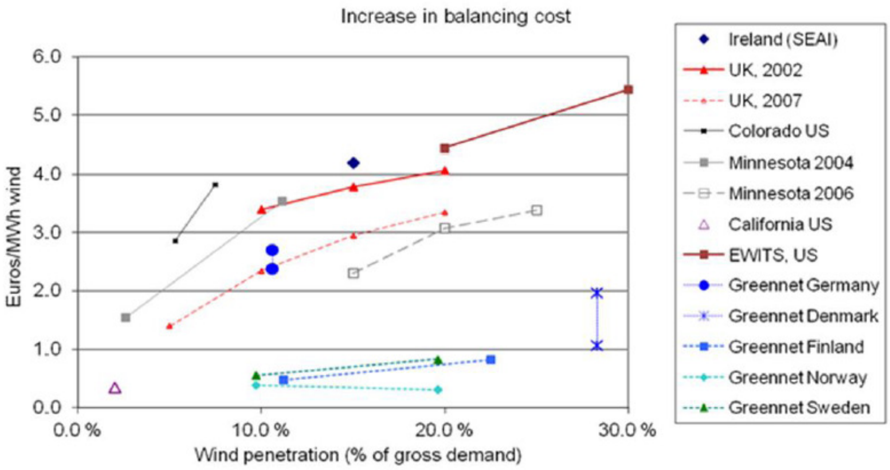


Figure 38 – Increase in balancing cost as a function of wind penetration

In most cases, balancing costs increase with an increase wind penetration – the study notes that: *“a general conclusion is that if interconnection capacity is allowed to be used for balancing purposes, then the balancing costs are lower compared to the case where they are not allowed to be used”.*

Further that other important factor for reducing costs were:

- Wind aggregation over large geographic areas
- Scheduling the power system closer to the delivery hour

6.3 Causer Pay

In [cost-causation], the authors notes that contingency reserve cost allocations are typically not based on relative contributions, but are more socialized in nature. This has the effect that larger generators are subsidized at the expense of smaller generators. The following figure demonstrates this:

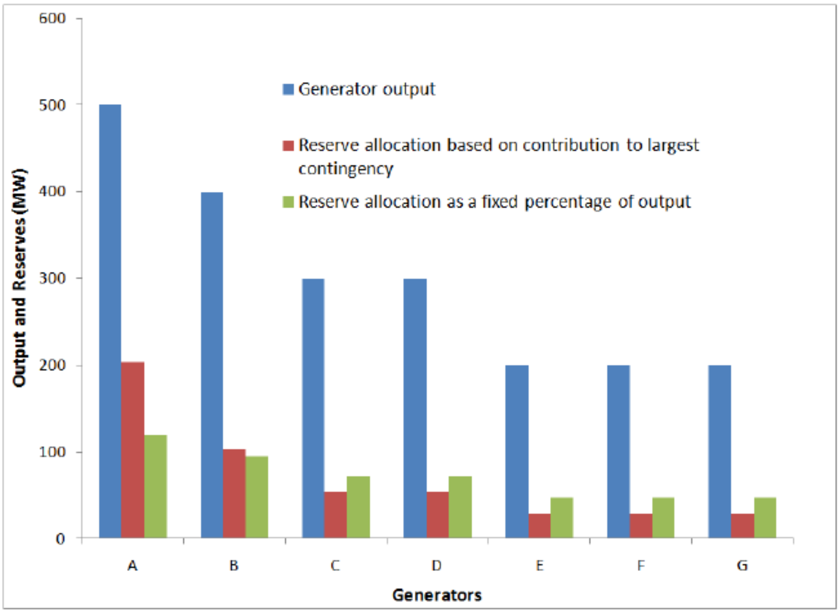


Figure 39 – Comparison of reserve allocation methods for generators of different sizes

The principle of "causer pays" has been adopted in the Australian National Energy Market (NEM) [13]. Three components are considered:

- Contingency Raise (up regulation during generator failure) – paid by generators based on energy output during the trading interval
- Contingency Lower (down regulation during load disconnect) – paid by loads based on energy consumed during the interval
- Regulation – a contribution factor is calculated monthly and is based on variations from a reference trajectory as dictated by central dispatch. Four second variations from the trajectory are aggregated to a monthly value and only nett negative contribution factors are used to recover regulation payments from participants

6.4 Value of Reserves

A method for estimating the value of reliability was proposed by [17]. The source of value was similar to that of an option or insurance premium. To estimate the value, the probability and loss were used to estimate the expected value, which was derived from the demand cost curve.

6.5 Procurement Methods

In his assessment of markets for frequency ancillary services, [15] identified the following procurement methods:

- Compulsory provision;
- Self-procurement;
- Bilateral contracts;
- Tendering;
- Spot market.

The author provided the following comparison of the different methods and consequences:

Table 14 – Table of consequences for different procurement methods

	Compulsory Provision	Self-Procurement	Bilateral Contracts	Tendering Process	Spot Market
Mitigate the influence of dominant players	+ + +	+ + +	+	– –	– – –
Facilitate entrance into the market of new AS providers	+	– – –	–/+	+ +	+ + +
Hedge against risk	+ +	+ +	+ + +	+	– – –
Lower transaction costs	+ +	+	–	–	–
Secure enough AS	+ + +	+ + +	+ + +	+ + +	+
Increase the global welfare	– – –	– –	+	+ +	+ + +
Increase market transparency	+ + +	– –	– –	+	+ + +
Recognise the externality of AS	– – –	–	+ + +	+ + +	+ + +
Integrate demand response as an AS	– –	+ + +	+ + +	+ +	+

In a study, conducted annually for the period 2012-2014, completed by [18], the procurement and settlement practices by ENTSO-E members were surveyed.

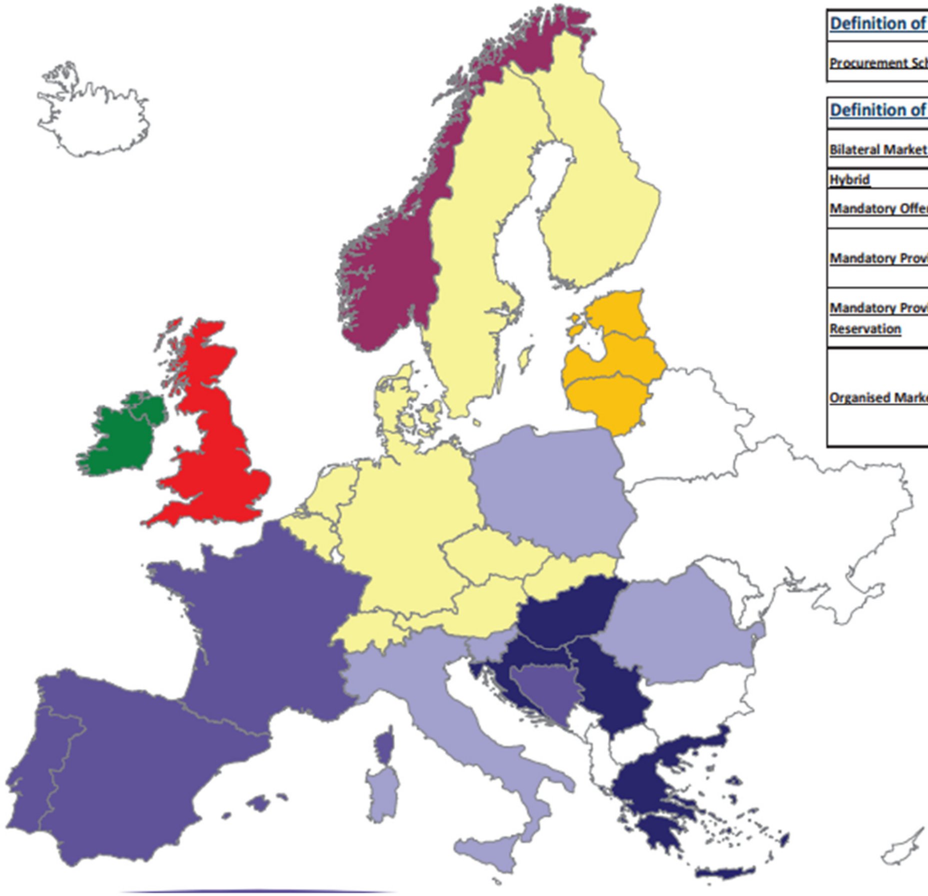
The following four figures show the procurement methods used for Frequency Containment Reserve Capacity, Frequency Restoration Reserve Manual Capacity and Replacement Reserve Capacity.

The usage of the different procurement methods varied per member and per reserve category. Similar results were found for settlement methods and energy procurement for ancillary services for frequency control.

Frequency Containment Reserve - Capacity - Procurement Scheme

Definition of question	
Procurement Scheme	Background of the offer, which is closest to the real operation time.

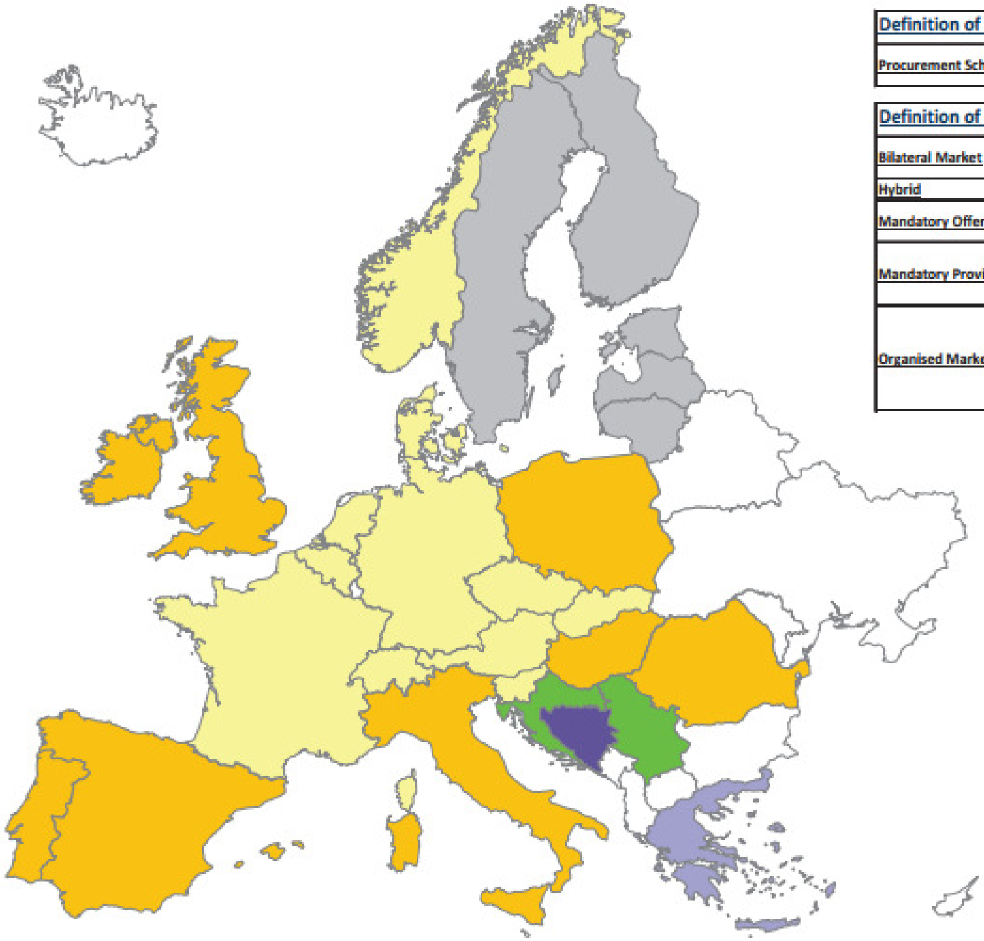
Definition of answer	
Bilateral Market	A grid user and TSO negotiate a contract regarding the offered service and price/price system.
Hybrid	Combination.
Mandatory Offers	Generators connected to the grid are obligated to offer the remaining capacity/available capacity.
Mandatory Provision	Generators connected to the grid are obligated to reserve a certain amount of capacity in order to meet TSO requirements, for a fixed price set by TSO, NRA or for free.
Mandatory Provision without Reservation	It is mandatory for dispatchable units to be able to provide frequency cintainment reserve, but these units are not required to reserve capacity to provide this service.
Organised Market	There is no contract or obligation for a grid user to offer the reserve (before the offer). The grid user can voluntary participate in the market (e.g. tender, auction, market platform (like PX)) and bid a price or customize his offer (e.g. the volume, timeframe). The market result may lead to a bilateral contract.



Key:
- Missing data
- N/A
- Mandatory Offers
- Mandatory Provision
- Mandatory Provision without Reservation
- Bilateral Market
- Organised Market
- Hybrid
- Other
- Pre-contracted Offers only
- Pre-contracted and Mandatory Offers
- Pre-contracted and Free Offers

Figure 40 – Procurement Scheme for Frequency Containment Reserve – Capacity from [18]

Frequency Restoration Reserve (Manual) - Capacity - Procurement Scheme

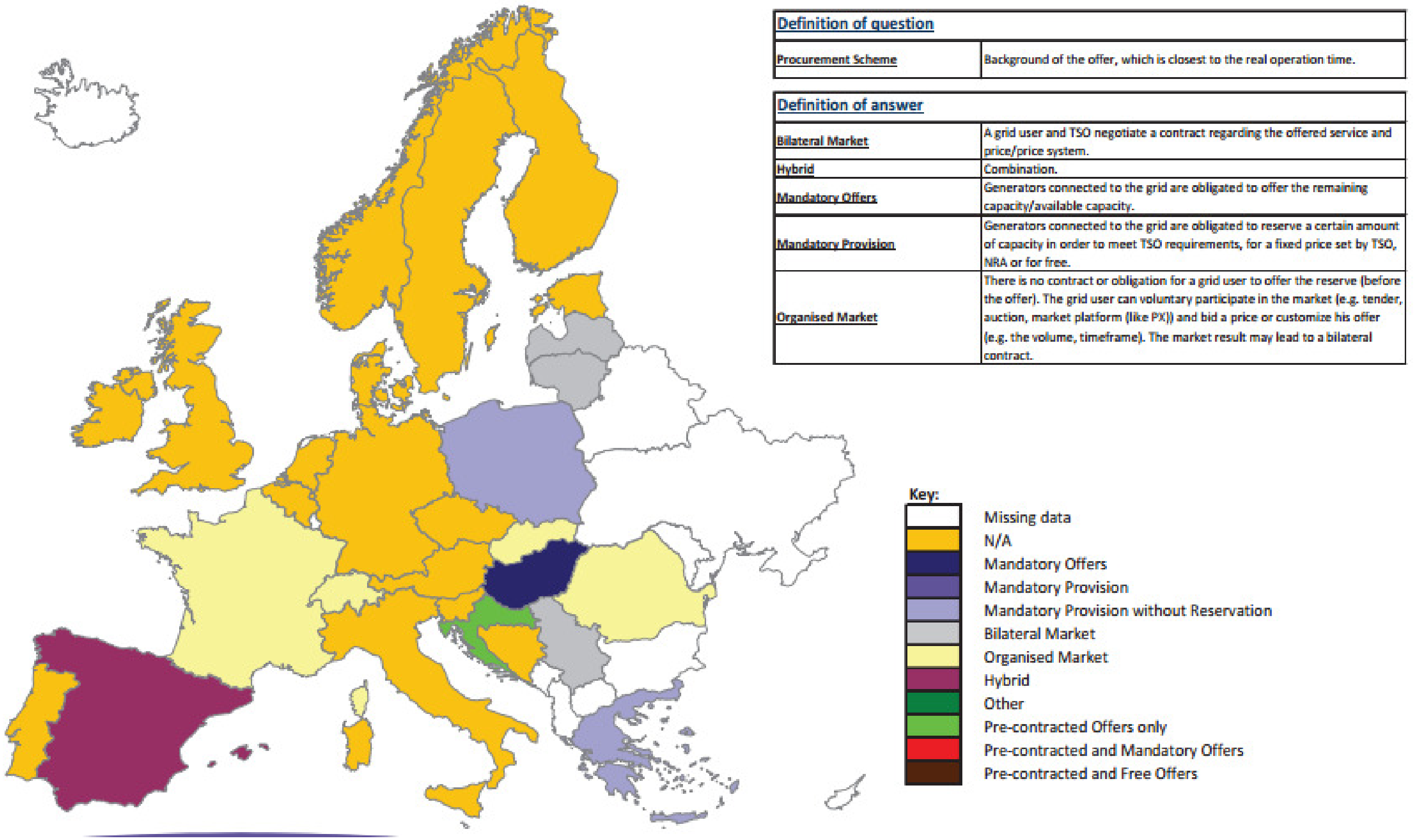


Definition of question	
Procurement Scheme	Background of the offer, which is closest to the real operation time.

Definition of answer	
Bilateral Market	A grid user and TSO negotiate a contract regarding the offered service and price/price system.
Hybrid	Combination.
Mandatory Offers	Generators connected to the grid are obligated to offer the remaining capacity/available capacity.
Mandatory Provision	Generators connected to the grid are obligated to reserve a certain amount of capacity in order to meet TSO requirements, for a fixed price set by TSO, NRA or for free.
Organised Market	There is no contract or obligation for a grid user to offer the reserve (before the offer). The grid user can voluntary participate in the market (e.g. tender, auction, market platform (like PX)) and bid a price or customize his offer (e.g. the volume, timeframe). The market result may lead to a bilateral contract.

Key:
Missing data
N/A
Mandatory Offers
Mandatory Provision
Mandatory Provision without Reservation
Bilateral Market
Organised Market
Hybrid
Other
Pre-contracted Offers only
Pre-contracted and Mandatory Offers
Pre-contracted and Free Offers

Figure 41 – Procurement scheme for Frequency Restoration (Manual) Reserve – Capacity from [18]



Definition of question	
Procurement Scheme	Background of the offer, which is closest to the real operation time.

Definition of answer	
Bilateral Market	A grid user and TSO negotiate a contract regarding the offered service and price/price system.
Hybrid	Combination.
Mandatory Offers	Generators connected to the grid are obligated to offer the remaining capacity/available capacity.
Mandatory Provision	Generators connected to the grid are obligated to reserve a certain amount of capacity in order to meet TSO requirements, for a fixed price set by TSO, NRA or for free.
Organised Market	There is no contract or obligation for a grid user to offer the reserve (before the offer). The grid user can voluntary participate in the market (e.g. tender, auction, market platform (like PX)) and bid a price or customize his offer (e.g. the volume, timeframe). The market result may lead to a bilateral contract.

Figure 42 – Procurement Scheme for Frequency Replacement Reserve – Capacity from [18]

7. System Operator Experience and Response to Variable Generation Integration

7.1 Experience by Energinet.DK

The Danish electricity demand is 33TWh/year with a peak demand of 6,200 MW. The installed wind power capacity in Denmark is 4.800 MW and solar is 620 MW. Interconnectors of 6,000 MW exist to the neighbouring countries (Sweden, Norway and Germany).

This section is based on dialogue with Energinet.dk, the Danish TSO. Two issues that can be relevant for the future situation in South Africa, will be presented below:

- Energinet.dk's procedures to predict imbalances, and react beforehand.
- Presentation of the Danish and ENTSO-E's view on the needed amount of reserves. Surprisingly, the booked reserves in Denmark have not been increased after the introduction of the 4,800 MW wind power (the amount of activated reserves has increased, however).

7.1.1 Procedure in relation to the activation of reserves

In many areas a common practice is to activate reserves "in real time", as the events occur. If the main drivers for imbalances are random and essentially unpredictable outages of generators, this is a relevant procedure.

As the installed wind power capacity in Denmark was increasing, however, Energinet.dk started developing a system to predict the imbalances. A system called Operational planning system, DPS, was created. The system collects data from numerous sources and presents a single curve for the operators in the TSO control room. The curve shows the predicted imbalance in the system.

The data used to collate the predicted imbalance in the system is as follows:

- Wind power. Each five minutes a new prognosis is produced. The frequent updating uses online measurements to correct the meteorological predictions (these are only updated every four hours). The online measurements represent a large sample of all the wind power units and are up-scaled to represent the entire generation.
- Solar power. A similar system is used to predict the power from the PV systems.
- Demand. Also for demand, the prognosis is frequently updated based not onlyon historic data, but also on online measurements (of generation and import/export).
- Plans for the market participants. Detailed plans are received e.g. for all major generators. These plans have information about the expected generation in five minute intervals[1].

The predicted imbalance curve will cover the coming day (at hour 17 of D-1 the predicted imbalance curve for day D is collated). When significant imbalances are foreseen, the control room operators will:

[1]This is in contrast to the spot market, Nord Pool Spot, which operates with hourly values.

- Discuss with neighbouring TSO's if imbalances can be exchanged (at no cost), e.g. if Sweden has a positive balance and West Denmark a negative balance – and if transmission capacity is available, the two imbalances can offset each other. This also applies to the exchange between the two Danish areas (DK1 and DK2, West and East – that are a part of two different synchronous systems).
- Activate tertiary reserves (regulating power) to outweigh the expected imbalance. This is done from a common Nordic system (with bids from four countries), the NOIS list.

The traditional procedures for activating reserves can be called reactive, while the Energinet.dk approach can be called proactive. In popular terms the new procedure can be described as "driving looking through the front window" in contrast to "driving looking in the rear view mirror".

Energinet.dk's activation of reserves to reduce predicted imbalances takes place 20 to 30 minutes before the start of the operating hour. The reason why Energinet.dk is waiting until this time is because commercial markets (hour-ahead market) exist. Market participants may activate transactions that can reduce their imbalances. It is important for the TSO not to interfere with the commercial activity. The hour-ahead trade ends one hour before the start of the operating hour, and the market participants have 20 minutes to update their plans and send these to Energinet.dk.

7.1.2 System-wide need for reserves

Energinet.dk reports that the introduction of 4,800 MW wind and 600 MW solar power *has not yet influenced the amount of planned reserves used in the system.*

The background is that prognosis errors from wind and solar may be large on a day-ahead perspective, but will gradually be reduced as the time is approaching the operating hour and second. The hour-ahead error will be much smaller than the day-ahead error. And, below the hour-ahead the actual (and partly un-predicted) generation from wind and solar will influence the frequency and the flow on the interconnectors. Thereby reserves will be activated and balance will be re-established.

For tertiary reserve (regulating power), the situation is that there typically is a large surplus of this. The hydro power in the other Nordic countries typically has a large unused capacity. Depending on the expected operation and availability of the cross-border transmission capacity, Energinet.dk may reserve capacity for the tertiary reserve. Typically, Energinet.dk reserves 200-300 MW up regulation and no down regulation[2] (Denmark, West, 2014-2015).

On a day-ahead scale the typical forecast error for wind power in Denmark is in the order of 20%, (Mean Absolute Percentage Error, MAPE) however, this is continuously reduced as the time is approaching the operating second. While the output from a single wind farm may change rapidly, the aggregated output from a large area as ENTSOE-E's Continental Europe Regional Group (2,500 km from North to South) will develop quite smoothly. With continuously expanding capacity of wind and solar, at some point this will result in extra need for reserves. ENTSOE-E Continental Europe RG is not at this point, yet.

[2]Energinet.dk shares reserves between Denmark West and Denmark East. 600 MW is bought in Denmark East (long-term contract) and 300 MW is shared with Denmark West so on daily auction in Denmark West, only 682-300-100= 282 MW (the dimensioning error in Denmark is 682 MW) are being purchased. 100 MW are secondary reserves, which also comprise a part of the tertiary reserves

7.2 Experience reported in literature

7.2.1 Variable Generation, Reserves, Flexibility and Policy Interactions

With the introduction and increase of variable generation, system operators have adapted their processes, reserve products and tools. This was the topic of a study published in 2014 [26].

The following changes were discussed:

- **Incorporation of wind generation into reserve sizing** – For example the probabilistic methods used by ENTSO-E and ERCOT;
- **Better forecasting tools** – For example a ramp event tool developed by ERCOT [see Figure 43];
- **Development of reserve market ramping products** – For example CAISO, MISO and Ireland;
- **Flexibility products** – For example demand response and energy storage;
- **Inertial market products** – For example New Zealand and Ireland, to ensure sufficient primary response.

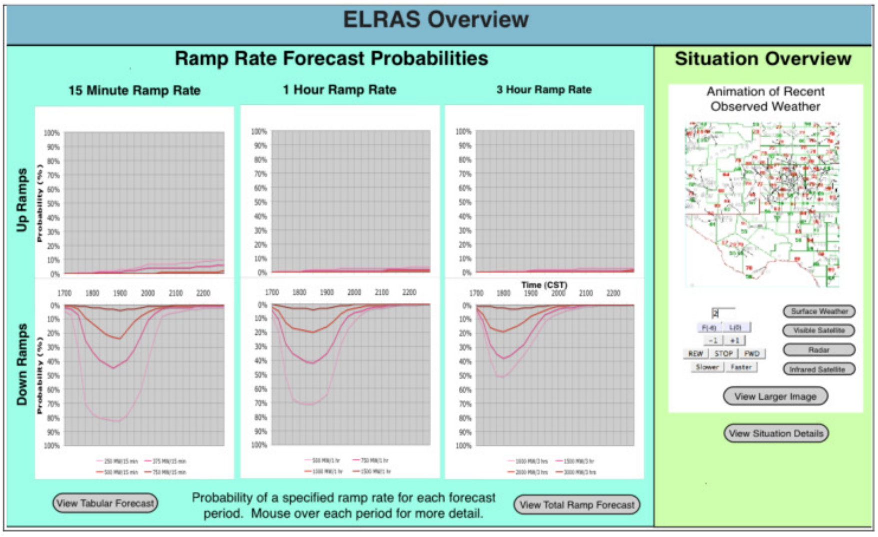


Figure 43 – Ramp rate forecasting model developed by ERCOT to cater for ramping events due to variable generation

7.2.2 NERC IVGTF Task 2.4

The NERC Integration of Variable Generation Task Force [20] surveyed and reported on operating practices, procedures and tools. The response to increased variable generation was detailed into three sections:

- Observe;
- Analyse;
- Act.

During the *Observe* and *Analyse* sections, the following information was considered:

- **Meteorological information** – Wind speed, direction, temp, pressure, humidity);
- **Power output, wind turbine outage/availability information** – Including icing-related issues;
- **Plant curtailment information** – Including deployment instructions in MW and/or estimated MW output available if a current curtailment is lifted.

This could include real time data, for example ERCOT requires wind plants to supply real-time SCADA data including:

- Net MW output;
- Number of turbines available;
- Estimated 'un-curtailed' net MW output;
- Wind speed;
- Wind direction;
- Barometric pressure;
- Temperature.

In terms of the *Act* section, the following options were discussed:

- **Flexibility**–Delaying commitments of flexible units and possibly even sub-hourly scheduling;
- **Inter balancing area scheduling** – Reducing the diversity between regions to have a more certain nett load forecast;
- **Better control equipment and procedures for variable generation**
  - Curtailment of wind power, in light of expensive reserves;
  - Ramp rate control;
  - Synthetic inertia;
  - Regulation.

7.2.3 ENTSO-E Target Methodology for Adequacy Assessment

For longer term planning, ENTSO-E published the following approach [27]:

- Probabilistic simulation approach;
- Chronological hourly simulation;
- The simulations should have these main indicators, LOLE, LOLP, ELCC and CO2.

A similar approach was published in a 2011 report by the NERC Integration of Variable Generation Task Force, recommending the usage of simulation methods and identifying the need to simplify the planning process to create intuition.

7.2.4 NREL - Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned

In a recent report [1][29], NREL reports on operational experience with reserves under increasing levels of renewable (wind and solar) penetration. Three key lessons learnt are highlighted under the following sections:

- Reserve needs and costs based on operating experience;
- Value of efficient operating procedures;
- Wind power forecasting.

Reserve needs and costs based on operating experience

ERCOT and MISO has sufficient wind power on their grids to empirically determine the amount of additional reserves requirements. Both entities report very little to very modest impacts in both additional cost and reserve needs.

Value of efficient operating procedures

1

Wind power forecasting

In most North American markets, wind is very predictable in the dispatch time frame and experience shows that wind can follow the dispatch curve at least as well as conventional generators. In that case the dispatch time frame would be within 10 minutes of flow.

7.2.5 IEA Wind Task 25Summary of experiences and studies for Wind Integration

In this conference paper [1][30], the experiences of three European countries are discussed:

- **Ireland** – no additional reserves were required during periods of high wind variability. However, due to frequency and voltage stability constraints, a number of conventional stations are required to remain online
- **Spain** – the impact on automatic reserves has been minimal, but significant impacts on the automatic reserves have been experienced. Spain is building experience and confidence in using probabilistic methods for dimensioning manual reserves.
- **Portugal** – existing reserve allocation has been increased by 10% of predicted wind power. The additional reserves are supplied through hydro generation and tie-line balancing with Spain.

8. System Adequacy Evaluation in IRP 2013

The system adequacy evaluation in the Integrated Resource Plan (IRP) 2013 update [3] contains an assessment of the system adequacy for the planning horizon 2019 to 2028. The purpose of the adequacy evaluation was to interrogate the adequacy of different scenarios, should that scenario occur and does not address the long term uncertainties, which is addressed as part of the main IRP process.

Only certain scenarios were evaluated:

- Weathering the Storm
- Moderate Decline
- Big Gas

The following table [33] summarizes the adequacy measures against which the plans were measured:

Table 15 – Adequacy metrics and thresholds used for the evaluation

Adequacy Metric		Threshold	Detail
AM1: UE GWh	Unserved Energy (UE)	< 20 GWh per annum	The amount of energy in a year that could not be supplied due to system supply shortages.
AM2: GLF (OCGT)	Open-cycle Gas Turbine (OCGT) Load Factor	< 6% per annum	The Gross Load Factor (GLF) of the combined OCGT plant in operation in a year.
AM3: GLF (EBLS)	Expensive Base Load Stations (EBLS) Load Factor	< 50% per annum	The Gross Load Factor (GLF) of the combined expensive Base-load Stations (Majuba Dry and Majuba Wet) in a year.

Two of these adequacy metrics are based on load factor, i.e. how often the OCGT's or most expensive base load stations are utilized.

The first two adequacy metrics are capacity based and the third energy based. The capacity based metrics measures the likelihood that the system can meet the load during a capacity type contingency. The energy based metric measures the system's ability during an energy type contingency.

The results of the assessment for each scenario were [33]

- **Weathering The Storm** – shows a likelihood of inadequacy regarding energy type contingencies in the last two years of the study horizon, indicating a slight shortage of base load capacity in those years.
- **Moderate Decline** – a likelihood of inadequacy in both energy and capacity were reported for certain years (2023, 2024 and 2028) indicating a shortage of base load and peaking capacity in those years.
- **Big Gas** – a likelihood of inadequacy for both energy and capacity in a larger range of years (2023, 2024, 2027 and 2028), indicating a shortage of base load, mid-merit and peaking capacity in those years.

From the integration studies and practical experience by System Operators, the impact of renewable generation would be that the usage of reserves are increased to cater for variability in the net load, without necessarily affecting the capacity requirement, which is related to the size of the largest contingency.

The adequacy metric (AM2) is based on the load factor of the OCGT's as an indicator of capacity adequacy. In the light of the expected increased usage of reserves with an increase in renewable generation (especially for the slower tertiary reserves), the usage and associated load factor of the OCGT's may be increased without necessarily having an corresponding increase in capacity requirement.

9. Conclusion

The reserve categories employed by Eskom align strongly in function and purpose to those used internationally, especially with those used by ENTSO-E – although the terminology differs significantly.

Eskom is using statistical approaches to reserve dimensioning and are following the same trend as being observed internationally. As the variable generation penetration increases, more statistical and probabilistic methods are being employed in NERC and ENTSO-E to reflect the inherent uncertainty.

Eskom currently performs a daily load forecast on day N-1 and on day N. The results of the renewable integration studies show that the forecasting errors due to increased variable generation can be significant, and that additional data is required to improve the forecasting. In the absence of improved forecasting methods and inter-regional scheduling, the impact on reserve margin can be significant.

The reserve categories and dimensioning approaches of NERC and ENTSO-E were compared. The key difference is that NERC recognises reserve requirements for 'normal' operations as well as those for contingency operations. With the introduction of increased variable generation, the need for additional 'normal' operating reserves has been identified, for example ramping reserves which are not related to a contingency, but rather allows the system to follow the ramping of wind within or between hours.

Dynamic dimensioning of reserves is a practice employed in, for example, Australia and ERCOT. The reserve levels are regularly evaluated and adjusted if necessary, based on performance. ERCOT integrated this approach into their probabilistic assessment.

In the five wind integration studies reviewed, it can be concluded that most of the impact on system capacity reserves are on dimensioning of the tertiary reserves, e.g. load following, replacement reserves, etc., and not the faster response categories, e.g. primary and secondary.

Seasonal and inter-decade variation of energy availability has a significant impact on the effective available capacity of wind generating plant and impacts longer term system adequacy assessment.

In these integration studies, moderate increases are reported in regulating reserves and larger increases in the reserve requirements for load following and replacement. These studies assume that the operating procedures are unchanged when estimating these impacts.

In practice however, System Operators have responded to the negative impacts due to the net load variability associated with high wind penetration by countering through

- improved operating procedures (i.e. sub hourly markets);
- continuous wind power forecasting with dispatch adjustments;
- flexibility (and smoothing) which is derived from geographic diversity and other flexible sources.

Where these measures and operational procedures are applied, system operators generally experience null to very modest impact on the dimensioning (of contingency) reserves.

However, as renewable energy penetration increase, an increase in the usage and associated costs of system reserves are experienced. Costs impacts can be reduced through the usage of interconnection capacity, scheduling over large geographic areas and scheduling closer to the delivery hour.

The costs associated with increased usage in system reserves (typically regulation and load following reserves) are a key component of the total integration costs of renewable generation. Integration costs can be estimated in a number of ways which differ primarily on the method in which the reference case is modelled (i.e. without renewable generation). The causer-pay methodology of cost allocation attempts to assign reserve costs in a manner that reflects objective measures of causation and severity (to the degree that is practical).

The system adequacy evaluation in the IRP2010 (2013 Update) uses the load factor of the OCGT's as a metric for capacity adequacy. This metric may be influenced by the increase in system reserve usage, which is a normal consequence of the increase in renewable capacity and may not signal an increase in the reserve capacity requirements.

10. References

[1] "The South African Grid Code: The System Operator Code", Rev 8.0 July 2010.

[2] "Instantaneous Reserves Requirements for 2014 - 2016", Document Number 342-289

[3] Eskom System Operator, "Ancillary Services Technical Requirements for 2015/16-2019/20", Rev 1, Reference no 342-297

[4] Eskom Transmission/System Operator, "Certification and performance monitoring of generation reserves", Rev 2, Reference no 46-8

[5] National American Electric Reliability Corporation, "Disturbance Control Performance", Document BAL-002-01, available online http://www.nerc.net/standardsreports/standardssummary.aspx

[6] National American Electric Reliability Corporation, "Primary Frequency Response in the ERCOT Region", BAL-001-TRE-1, available online http://www.nerc.net/standardsreports/standardssummary.aspx

[7] European Network of Transmission System Operators for Electricity, "Operational Reserve Ad Hoc Team Report", final version as of 23/05/2012

[8] Erik Ela, Michael Milligan, and Brendan Kirby, "Operating Reserves and Variable Generation", National Renewable Energy Laboratory, Report NREL/TP-5500-51978, August 2011

[9] "ERCOT Methodologies for Determining Ancillary Service Requirements", Effective Date of 04/01/2013, available online http://www.ercot.com/content/meetings/ros/keydocs/2013/1114/05._ERCOT_Methodologies_for_Determining_Ancillary_Service_Re.doc

[10] ENTSO-E,"Network Code on Load-Frequency Control and Reserves",final 28/06/2013, available online http://networkcodes.entsoe.eu/wp-content/uploads/2013/08/130628-NC_LFCR-Issue1.pdf

[11] ELIA, "Evolution of ancillary services needs to balance the Belgian control area towards 2018", available online http://www.elia.be/~/media/files/Elia/Grid-data/Balancing/Reserves-Study-2018.pdf

[12] ENTSO-E,"Supporting Document for the Network Code on Load-Frequency Control and Reserves", final 28/06/2013, available online https://www.entsoe.eu/fileadmin/user_upload/_library/resources/LCFR/130628-NC_LFCR-Supporting_Document-Issue1.pdf

[13] Riesz, J., MacGill, I., "Frequency Control Ancillary Services - Is Australia a Model Market for Renewable Integration?", Centre for Energy and Environmental Markets, University of NSW, Sydney, Australia

[14] Miguélez, E.L., Cortés, I.E., Rodríguez1, L.R., Camino, G.L.,"An overview of ancillary services in Spain", Electric Power Systems Research, Volume 78, Issue 3, March 2008, Pages 515–523

[15] Rebours, Y., "A Comprehensive Assessment of Markets for Frequency and Voltage Control Ancillary Services", PhD Thesis, University of Manchester, 2008

[16] Hummon, Denholm, Jorgenson, Palchak, Kirby and Ma, "Fundamental Drivers of the Cost and Price of Operating Reserves", report NREL/TP-6A20 58491 (2013)

[17] Prada, J., "The Value of Reliability in Power Systems – Pricing Operating Reserves", MIT Energy Lab report EL99-005 (1999)

[18] ENTSO-E Working Group, "Survey on Ancillary Services Procurement & Balancing market design", January2015

[19] Rahim, N.F.A., Ir. Dr Ab, T., Abdullah, R.T., Dr Razali, N.M.M., "Comparison of Spinning Reserve Allocation in Various Power Systems", Journal of Energy and Environment, Vol 6, No 1 (2014)

[20] NERC IVGTF Task 2.4 Report Operating Practices, Procedures, and Tools, available online http://www.nerc.com/files/ivgtf2-4.pdf

[21] Piwko, R., Bai, X., Clark, K., Jordan, G., Miller, N., Zimberlin, J., “The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations: Report on Phase 2,” Prepared for The New York State Energy Research and Development Authority, Mar. 2005.

[22] Enernex Corporation, “2006 Minnesota Wind Integration Study Volume I,” Nov. 2006. Available: http://www.uwig.org/windrpt_vol%201.pdf

[23] Meibom, P., Barth,R., Brand, H., Hasche, B.,Swider, D.,Ravn, H., Weber, C., “All Island Grid Study Workstream 2B: Wind Variability Management Studies,” July 2007

[24] Enernex Corporation, “Eastern Wind Integration and Transmission Study,” Prepared for the National Renewable Energy Laboratory, January 2010.

[25] GE Energy, “Western Wind and Solar Integration Study,” Prepared for the National Renewable Energy Laboratory, May 2010

[26] Ryan, J. ; Univ. Coll. Dublin, Dublin, Ireland ; Ela, E. ; Flynn, D. ; O'Malley, M, “Variable Generation, Reserves, Flexibility and Policy Interactions”, System Sciences (HICSS), 2014 47th Hawaii International Conference on, 6-9 Jan. 2014

[27] “ENTSO-E Target Methodology for Adequacy Assessment”, ENTSO-E, 14 October 2014, Updated version after consultation, document 141014

[28] Milligan, M. et al, “Operating reserves and wind power integration, an international comparison,” 9th Annual International Workshop on Large-Scale Integration of Wind Power into Power Systems, Quebec, Canada, October 2009.

[29] M. Milligan et al, “Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned”, NREL NREL/TP-5D00-61911, March 2015

[30] Holttinen, H et al, “Summary of experiences and studies for Wind Integration – IEA Wind Task 25”, In Proceedings of WIW2013 workshop London, 22-24 Oct, 2013

[31] Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby (Consultant), and Debra Lew, “Cost-Causation and Integration Cost Analysis for Variable Generation”, Technical Report, NREL/TP-5500-51860, June 2011

[32] K. Porter, S. Fink, M. Buckley, J. Rogers, B.-M. Hodge, “A Review of Variable Generation Integration Charges”, NREL/TP-5500-57583, March 2013

[33] “INTEGRATED RESOURCE PLAN FOR ELECTRICITY (IRP) 2010-2030 –Update Report 2013”, available online http://www.doe-irp.co.za/content/IRP2010_updatea.pdf