SURVEY ON POWER SYSTEM ANCILLARY SERVICES

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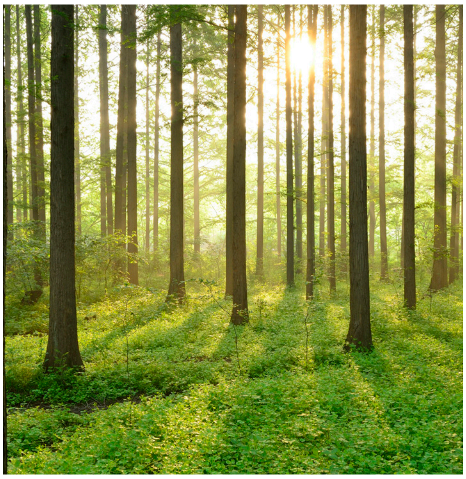

NUCLEAR

GRID INTERFERENCE ON NUCLEAR POWER PLANT OPERATIONS

Energiforsk

Survey on power system ancillary services

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Foreword

There are currently extensive discussions in the Nordics regarding different types of flexible operations. The Swedish and Finnish nuclear fleet has operated as base load for at least 25 years and all investments during this time has been conducted with base load operation in mind.

A changing power system with increased amounts of intermittent production might lead to higher demand of control capabilities, both within the different market mechanisms, but also through grid codes and changed contracts between independent power producers (IPP's) and transmission system operators (TSO's).

The focus of this survey was to gather experiences regarding flexible operation and the evolution of needs of de-regulated and expanded markets as applied in countries outside the Nordic grid. This will enhance the ability to anticipate the demands and impacts on future nuclear power plant operations. The study was carried out by a team with Seppo Hänninen, Corentin Evens and Poria Divshali from VTT Technical research center of Finland, John Millar and Matti Lehtonen from Aalto University and senior consultant Tatiana Salnikova from Framatome. The project is part of the Grid Interference on Nuclear power plant Operations, GINO, program that is financed by The Swedish Radiation Safety Authority, Svenska Kraftnät, Vattenfall, Uniper/Sydkraft Nuclear, Fortum, Skellefteå Kraft and Karlstads Energi.

Sammanfattning

I denna rapport redovisas en undersökning av hur Australien, Irland, Storbritannien och delstaten Texas USA har satt upp sina respektive marknader, regler och tillhörande produkter för att säkerställa ett stabilt kraftsystem. Dessa länder eller regioner har kraftsystemutmaningar som liknar de som finns i Sverige och Finland, med ökad mängd intermittent produktion. De har stora systemviktiga värmeproduktionsenheter och Storbritannien och Texas har kärnkraftverk. Utifrån de internationella erfarenheterna undersöks de nordiska kärnkraftverkens tekniska möjligheter för att tillhandahålla systemtjänster i en nordisk nätkontext.

De tekniska kraven för stödtjänster beror på kraftsystemets egenskaper. I detta avseende är kraftsystemen i Australien, Irland, Storbritannien och USA Texas ganska annorlunda, både från varandra och från det nordiska systemet, och därmed kan inte stödtjänsterna vara exakt desamma. Erfarenheterna från de internationella marknaderna ger dock uppslag för den riktning i vilken stödtjänster kan komma att utvecklas.

Nationella och regionala marknader i Europa blir alltmer integrerade mot en gemensam europeisk marknad. Harmoniseringen pågår på EU-nivå när det gäller stödtjänster. De nordiska systemoperatörerna har identifierat en oroande trend mot minskande systemtröghet och ett resultat har varit en ny produkt, Fast Frequency Reserve (FFR). När det gäller frekvenshållningsreserver (FCR) finns det olika krav för de olika synkronområdena. Till exempel har mindre områden med mindre tröghet, såsom det nordiska systemet, särskilda krav. Gemensamma paneuropeiska marknader med standardprodukter kommer att utvecklas för leverans av FRR-energi (Frequency Restoration Reserve).

Tekniskt sett kan olika ytterligare systemtjänster, såsom frekvens- och spänningskontroll, tillhandahållas av nästan alla kärnkraftverk i framtiden om en adekvat marknadsdesign upprättas. Om aktiveringstid, varaktighet och ramphastighet tydligt kan fastställas som de viktigaste tekniska kriterierna för tilläggstjänsterna kommer kärnkraftverk att ha möjlighet att delta i några av marknaderna för stödtjänster. Aktiveringstiden för FFR är dock troligtvis för snabb för kärnkraften. Det nordiska systemet kräver egna produkter för FCR-nedreglering (FCR-D) och FCR-Normal drift (FCR-N). FCR-D är nu under utveckling, främst utifrån vattenkraftens förutsättningar. Det kan också finnas en roll för kärnkraft i FCR-D. Automatisk FRR (aFRR) och / eller manuell FRR (mFRR) kan mycket väl vara de bästa kandidaterna för de stödtjänster som tillhandahålls av kärnkraften i de nordiska länderna. Ersättningsreserver (RR) kan tillhandahållas av kärnkraften, men detta används inte i det nordiska systemet idag och är inte planerat för framtiden. De nordiska kärnkraftverken kan också delta i olika elmarknader och spänningsreglering, och det finns redan olika exempel på sådan drift, t.ex. Ringhals 1 sommaren 2020, vilket ger spänningskontroll för det svenska nätsystemet.

Summary

This report provides the stakeholders with a survey of how Australia, Ireland, UK and U.S. Texas have set up their respective markets, regulations and ancillary services to ensure a stable power system. These countries or regions have power system challenges similar to Sweden and Finland, with increased amounts of intermittent production. They have large system-important thermal production units and the UK and U.S. Texas have nuclear power plants. Such plants have mostly been run in base-load, but flexible option is now being considered. The technical suitability of nuclear power plants to provide ancillary services in the Nordic grid context is surveyed in general, based on existing advanced operational experience from NPPs in Germany.

The technical requirements for ancillary services depend on the characteristics of the power system. The power systems in Australia, Ireland, UK and U.S. Texas are quite different, both from each other and from the Nordic system, meaning the respective ancillary service products cannot be identical. They provide a forecast, however, of the direction in which the ancillary services are developing. National and regional markets in Europe are becoming increasingly integrated towards a common European market, including harmonization of the ancillary services. The Nordic Transmission System Operators (TSOs) had identified a worrying trend towards decreasing system inertia and one result has been a new product, Fast Frequency Reserve (FFR). Frequency Containment Reserves (FCR) have different requirements for the different synchronous areas, e.g., smaller areas with less inertia, such as the Nordic system. Common PAN European markets with standard products will be developed for the delivery of Frequency Restoration Reserve (FRR) energy.

Technically, grid services such as frequency and voltage control, might be able to be provided by almost all NPPs operating in the future, given an adequate market design. If the activation time, duration and ramping are the main criteria for the ancillary services, NPPs could consider participation in the various ancillary service markets, noting, though, that the activation time for FFR, is likely to be too fast. The Nordic system requires its own products for FCR-Disturbance (FCR-D) and FCR-Normal operation (FCR-N). FCR-D is now under development to better fit the need of the power system with lower inertia. NPPs can likely provide FCR-N and there may also be a role for nuclear in FCR-D, although this looks more challenging. Automatic FRR (aFRR) and/or manual FRR (mFRR) may well be the best candidates for the ancillary services provided by NPPs in the Nordic countries, as this has been proven by German NPPs. Replacement Reserves (RR) could be provided by NPPs, but this is not used in the Nordic system today and is not planned for the future. Overall, service requirements and NPP capabilities should be evaluated in detail, case by case. The Nordic NPPs can also participate in economic dispatch, redispatch and voltage regulation, and there are already various examples of such operation, e.g., Ringhals 1 in the summer of 2020, providing voltage control for the Swedish grid system.

Abbreviations

Term	Description
AC	Alternative Current
ACCC	Australian Competition and Consumer Commission
ACE	Area Control Error
AEM	Australian Energy Market
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
aFFR	Frequency Restoration Reserves with Automatic Activation
AGC	Automatic Generation Control
AS	Ancillary Service
BM	Balancing Mechanism
BSP	Balancing Service Provider
BST	British Summer Time
CENACE	National Center for Energy Control
COVID-19	Coronavirus Disease 19
CPS	Control Performance Standard
CRDM	Control Rod Drive Mechanism
CRU	Commission for Regulation of Utilities
CUSC	Connection and Use of System Code
DAM	Day-Ahead Market
DC	Direct Current
DLH	Dynamic Low High
DRR	Dynamic Reactive Response
DSS	The Dispatch Support Service
DSU	Demand Side Unit
DTU	Demand Turn-Up
EBGL	Electricity Balancing Guideline
EFR	Enhanced Frequency Response
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRS	Enhanced reactive power service
ERCOT	The Electric Reliability Council of Texas
ESO	Electricity System Operator
EU	European Union
FACTS	Flexible Alternating Current Transmission System
FCAS	Frequency Control Ancillary Services
FCDM	Frequency Control Demand Management
FCR-D	Frequency Containment Reserve for Disturbances
FCR-N	Frequency Containment Reserve for Normal operation
FFR	Fast Frequency Reserve
FFR*	Firm Frequency Response
FPFAPR	Fast Post-fault Active Power Recovery
FR	Fast Reserve
FRR	Frequency Restoration Reserves

GB	Great Britain
GCS	Generation Capacity Statement
GEMA	Gas and Electricity Markets Authority
GINO	Grid Interference on Nuclear Power Plant Operations
GKN 1	Neckarwestheim Unit 1
GKN 2	Neckarwestheim Unit 2
HAS	Harmonised Ancillary Service
HVDC	High Voltage Direct Current
IMO	Independent Market Operator
IPP	Independent Power Producer
ISO	Independent System Operator
I&C	Instrumentation and Control
KKE	Emsland nuclear power plant
KKI 2	ISAR nuclear power plant 2
LFDD	Low Frequency Demand Disconnection
LFS	Low Frequency Static
LRRAS	Load Rejection Reserve Ancillary Service
MARI	Manually Activated Reserves Initiative
MBSS	Monthly System Balancing Reports
MFR	Mandatory Frequency Response
mFRR	Frequency Restoration Reserves with Manual Activation
NCAS	Network Control Ancillary Services
NCC	National Control Centre
NG	National Grid
NGET	National Grid Electricity Transmission
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMO	National Electricity Market Operator
NERC	North American Electric Reliability Corporation
NIE	Northern Ireland Electricity
NLAS	Network Loading Ancillary Service
NMAS	Non-Market Ancillary Services
NPP	Nuclear Power Plant
NSCAS	Network Support and Control Ancillary Services
OFGEM	Office of Gas and Electricity Markets
OPRS	Obligatory Reactive Power Service
PCR	Primary Control reserve
PICASSO	Platform for the International Coordination of the Automatic Frequency Restoration Process and Stable System Operation
POR	Primary Operating Reserve
PPA	Power Purchase Agreement
QSE	Qualified Scheduling Entities
REO	Rated Electricity Output
RERT	Reliability and Emergency Reserve Trader
RM	Ramping Margin
RoCoF	Rate of Change of Frequency
RR	Replacement Reserve
RRD	Replacement Reserve – Desynchronised

RRS	Replacement Reserve – Synchronised
RTO	Regional Transmission Operator
RTP	Rated thermal power
SCADA	Supervisory Control and Data Acquisition equipment
SCR	Secondary Control Reserve
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SHET	Scottish Hydro Electricity Transmission
SIR	Synchronous Inertial Response
SONI	Transmission System Operator in Northern Ireland
SOR	Secondary Operating Reserve
SP	Scottish Power
SRAS	System Restart Ancillary Service
SSRP	Steady State Reactive Power
STOR	Short-term Operating Reserve
SVS	Static Var Compensator
SWIS	South-West Interconnected System
TAO	Transmission Asset Owner
TERRE	Trans European Replacement Reserves Exchange
TOR	Tertiary Operating Reserve
TOSAS	Transient and Oscillatory Stability Ancillary Service
TSO	Transmission System Operator
TVO	Teollisuuden Voima Osakeyhtiö
UK	United Kingdom
UREGNI	Utility Regulator in Northern Ireland
URL	Unit Reactive Limits
U.S.	United States
VCAS	Voltage Control Ancillary Service
WANO	World Association of Nuclear Operators
WEM	Wholesale Electricity Market

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1 Introduction

This report provides the stakeholders with a survey of how different countries with power system challenges similar to Sweden and Finland have set up their respective markets, regulations and ancillary products to ensure a stable power system. The study was performed for four different countries or regions with nuclear reactors or other large system-important thermal production units. The relevant countries or regions were Australia, Ireland, UK and Texas in the U.S. The ancillary services analyzed predict their potential development in the Nordic network context.

There are currently extensive discussions in the Nordics regarding different types of flexible operations. The Swedish and Finnish nuclear fleet has operated as base load for at least 25 years and all investments during this time have been conducted with base load operation in mind.

A changing power system with increased amounts of intermittent production might lead to higher demand for control capabilities, both within the different market mechanisms, but also through grid codes and changed contracts between independent power producers (IPPs) and transmission system operators (TSOs).

The focus of the current survey was to gather experiences regarding flexible operation and the evolution of the needs of de-regulated and expanded markets as applied in countries outside the Nordic region. This will enhance the ability to anticipate the demands and impacts on future nuclear power plant operations.

The GINO program supported the progress in the project through:

- Reference group with experts from the participating NPPs. They supported with information from the plants, assisted in discussions on delimitations, priorities, etc., during the project. Furthermore, they reviewed the draft report.
- Steering group with experts from participating NPPs. They took strategic decisions plus reviewed and approved the final version of the report.
- Energiforsk project leader that assisted in administration of the project with formalities, status reports, invoicing etc.

VTT Ltd, Aalto University and Framatome GmbH performed the project. Regarding the profile of the consultant team, VTT and Aalto University are research institutes having competence in the research of power system operation, grid technology, electricity markets, including ancillary services, and in nuclear energy. Framatome is an international leader in nuclear energy, recognized for its innovative solutions and value-added technologies for the global nuclear fleet. For this study, Framatome has provided special competence in the flexible operation of nuclear power plants and nuclear technology.

The project team has been in contact with international experts during the project. An on-line meeting arranged by Ted Hailu, Director, Client Services, The Electric Reliability Council of Texas (ERCOT), was very informative, and provided us with significant material that has been further explored in the ancillary service market of ERCOT. Maja Lundbäck and Göran Lindahl, Svenska kraftnät, have provided

market information from the perspective of the Nordic transmission system operator. Martin Møller, Chief International Policy Advisor at Energinet has provided information on the upcoming European legislation and development of the ancillary service market.

Overall, German Utilities have given strong support to the collection of the required information for Section 4.7. Especially, Preussen Elektra and in particular Frank Sommer, Carsten Müller, and Konrad Schirrmeister kindly agreed to share operational experience and the corresponding figures, which formed the main contributions to Section 4.7. Thereby, Denis Janin and Helmut Panzer gave a feedback on some economical aspects. NPP KRB kindly contributed to the overall understanding of BWR operation during the interview, which was carried out in the plant. Framatome colleagues from Germany, USA and France gave valuable comments to the report: Ulrich Waas, Holger Ludwig, Victor Morokhovskyi, Stefan Bordihn, Alain Grossetete, Tim Stack, Caleb Tomlin, Elmar Wendenkampf. Prof. Rüdiger Kutzner from Hannover University gave his first feedback on capabilities for the FCR-D. Fruitful discussions with a KKL plant manager, Tomas Franke, the previous plant manager of a German NPP, allowed better understanding of flexible operation in general, as he is familiar with both PWR and BWR flexible operations.

Keywords

Ancillary services, nuclear power plant, power system, electricity markets, frequency control, voltage control

2 Background

For the electricity power systems to remain stable, there needs to be a balance between the power produced and consumed, at all times. Traditionally, the adjustments required to keep the balance are provided by highly flexible and controllable power plants, such as hydropower, coal, oil or gas fuelled thermal plants.

Over the past few years there have been lots of investments in non-flexible intermittent power production in the Nordic synchronous area. For example, the installed power capacity from wind turbines has doubled from 2012 to 2018 and the investment rate is still high.

At the same time three nuclear reactors Oskarshamn 2 (2015), Oskarshamn 1 (2017) and Ringhals 2 (2019) have been shut down, Ringhals 1 will be shut down during 2020, and TVO 3 is currently announced to be in commercial use in 2022. This will most likely lead to a greater need for flexibility in the remaining fleet of conventional power production.

The objective of this survey is to provide insights into the markets and regulatory frameworks that other countries with large units of thermal power and high penetrations of wind energy have set up to ensure a stable power system.

The system stability is the responsibility of the operator of the transmission system (in Europe: TSO). In order to achieve it, they purchase services, referred to as “ancillary services”, from various actors. Such services are listed and categorised in Figure 1. Ancillary service providers participate in the market in different categories. Commonly, ancillary services are categorized by the service type (frequency control, voltage control, system start up) (Kaushal & Van Hertem, 2019). Frequency control services are procured by setting up markets in the four regions considered, where the operation of the network has been decoupled from electricity production and retail activities. The other services are typically mandatory, in terms of requirements for the larger units to be allowed to connect to the network.

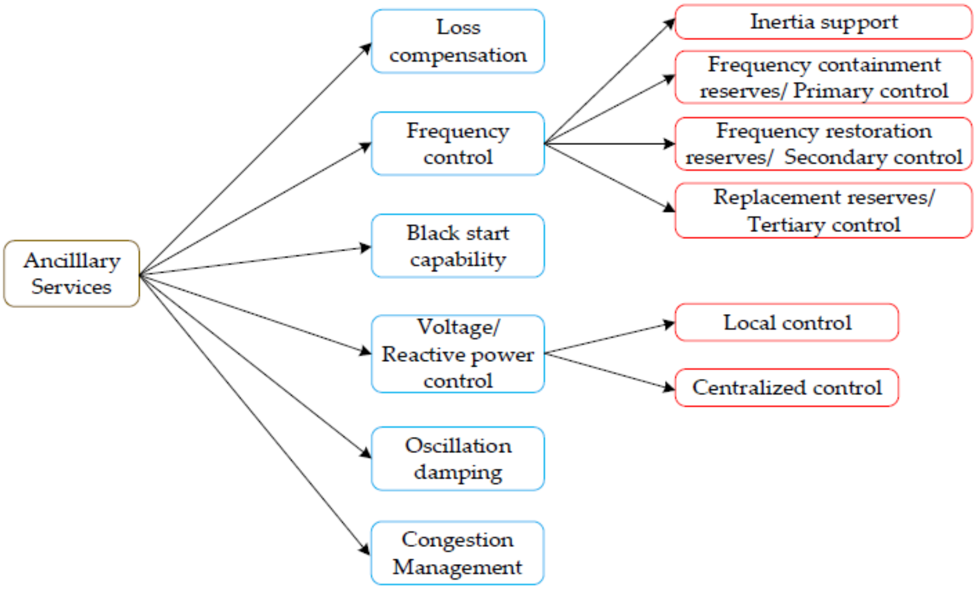

Figure 1 Ancillary Services (Kaushal & Van Hertem, 2019).

The other ancillary services categories listed in Figure 1 are relevant for the continuous operation of the system, whereas the black start capability allows the TSO to bring the system back up into operation after a complete or partial black-out.

2.1 FREQUENCY CONTROL

Frequency control is the subject of many services and products in electricity power systems. Here is a brief introduction as to what their purpose is, and some of the relevant terminology used in the rest of the survey.

In electricity power systems, the frequency has been determined to be 50 or 60 Hz depending on the regions. In order to achieve it, the masses of the generators are synchronized to rotate at the appropriate speed. As long as the energy consumption and production in the network are the same, the frequency remains unchanged. As soon as the load increases (the same reasoning can be applied to a decrease in production or, reverse, to a decrease in consumption or an increase in production), there is a difference between the power injected into and taken from the system. In order to provide that power, kinetic energy is taken from the rotating masses in the system. This has the result of slowing them down and of reducing the system frequency. The speed of this change is related to the inertia in the system. Inertia support services aim to increase the inertia in the system and lower the rate of change of the frequency.

Based on this system inertia, the size of the largest deviation expected in the system and the frequency below which the system shuts down (for technical and safety reasons, the generators cannot maintain rotating speeds below a certain point), it is possible to determine the maximum speed at which the frequency will change and how long the system operators have to fix the situation before the system collapses.

Traditionally, the first reserves to react have been referred to as “primary reserves”. In broader terms, their purpose is to stabilize the frequency and stop the change in frequency. In Europe, the term for such reserves adopted by Entso-E is Frequency Containment Reserves (FCR).

“Secondary reserves”, or Frequency Restoration Reserves (FRR), are activated either automatically or manually when a frequency deviation lasted for a certain time. Their purpose is to bring and stabilise the frequency back to its desired value.

Replacement Reserves (RR), historically called tertiary reserves, as well as balancing markets are activated by the TSO in order to release the other service products and make them available again for future deviations.

Figure 2 below shows the timings of various European balancing products after a large disturbance in frequency, according to Entso-E, the European Network of Transmission System Operators for Electricity (2018).

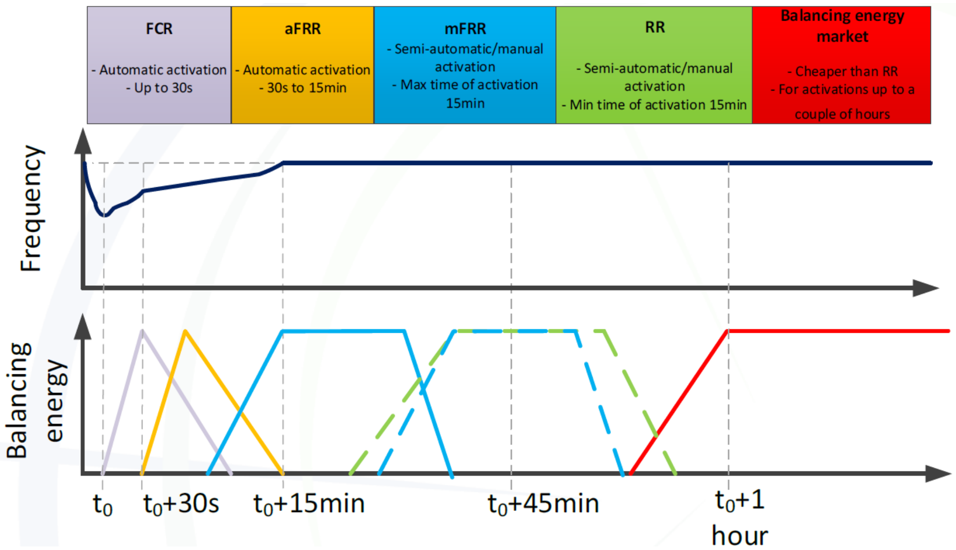

Figure 2 Organization of balancing energy in Europe (Entso-E, 2018).

It should still be noted that FCR services are often separated between services for normal operation, taking care of the small, constantly occurring, deviations in frequency on one hand, and the services for cases of larger disturbances.

In addition, Fast Frequency Reserves services have been recently introduced in some European countries. Their purpose is to counteract the reduction in system inertia by procuring reserves that can react very fast and slow down the changes before FCR reserves kick in.

The way that the system operators determine the quantity of reserves required is calculated based on the system characteristics, taking into account a “plausible disturbance”. By knowing the inertia and other characteristics of the system, the operator can assess how the frequency will change in the case of the largest disturbance that can be expected. In the Nordic countries, such a disturbance is determined as the loss of the largest generating unit. The TSO needs the total inertia and FFR to ensure that the initial frequency deviation will not bring the system outside of its operating limits before the FCR reserves stop the change. The volumes for FFR, FCR, FRR and RR are calculated so that, in such a case, the system behaves as expected.

2.2 VOLTAGE CONTROL

Maintaining the voltage to a determined level is important for the efficiency and good operation of many connected devices. There are two aspects to voltage control. The first one is local voltage control. The voltage on radial distribution lines is set by the DSO at the level of the transformer. As the voltage is measured along the line, its value goes up when active power in injected in the system (distributed generation) and down when active power is taken from the system (consumption). Although this aspect is important at the local level and is the object of a lot of research, it is out of the scope of this report.

The second aspect related to voltage control is that the changes in voltage along transmission lines is mostly dictated by the transfer of reactive power. Reactive power corresponds to the intake or injection of current that is not in phase with the alternating voltage. It is necessary for the operation of most devices, but it does not produce any work. In other words, reactive power can only be exchanged between devices, but cannot be used to produce anything useful. Besides causing voltage deviations, the transport of reactive power causes currents to travel along the power lines and thus causes increased losses over the lines and stress in the transformers and protection devices. Therefore, the strategy used to deal with reactive power is to handle it locally. In the Nordic countries, the TSOs set limitations to the reactive power exchanges that each connected entity (large producer, consumer or a distribution network) is allowed to have. The final balance is taken care of by the TSOs themselves.

There are several ways to produce or consume excess reactive power, but when it comes to larger units, the most common ways are to use reactor or capacitor banks, to modify the excitation settings of synchronous generators or to adjust the control of power electronics converters

There are several reasons why voltage control is typically not the object of a full-fledged market. Some of those reasons are:

- The methods to produce or consume reactive power are implemented with extra investment costs when building the unit. The operating costs are really low, which would lead to low market prices and little incentive to invest in the solutions.
- They cost of purchasing , installing and operating reactor and capacitor banks are low enough that the actor responsible for the reactive control often prefers to purchase them themselves rather than to go through the hassle of operating a market, with its own additional costs.
- Reactive power has less impact when it is dealt with locally: it creates less losses and less voltage drop along the transmission lines. This would limit the

size of the potential market to a few actors, making it difficult to guarantee sufficient liquidity for a fair market operation.

2.3 BLACK START CAPACITY

A black start is the term used to refer to the means by which power is restored in an area after a blackout. After a blackout, the system is divided in islands. Some islands may have sufficient generation and control capacity to restore its own power and stabilize it. Others are not able to perform it on their own, but can be reenergized using their connection to a neighbouring system and drawing enough power from it to restart their own production, which leads to a larger stable area.

Fundamentally, there are two ways in which a system can be black started. The first is the bottom up approach, where one or more islands reenergize and stabilize themselves. The neighbouring islands can then use those as an initial source to restart themselves. Two neighbouring areas which are already reenergized need to synchronize their voltages in order to reconnect to each other.

The second way is the top down approach in which a system uses the neighbouring systems as a stable source to gradually reenergize itself.

A mix of the two approaches is used in the Nordic countries (ENTSO-E, 2014). The main strategy is however to use the neighbouring areas and/or to reenergize first the areas in the North with strong hydro generation equipped with black start capabilities and use them to restart the system (Agneholm 1996).

In the four regions studied in this report (Australia, the U.K., Ireland and Texas), the systems are more isolated, with much weaker interconnection to their neighbours and without a strong controllable generation cluster such as the hydro generation areas in the Nordic countries. For those reasons, they use a strategy that is much more based on a bottom up approach.

3 Scope

The aim of the work has been to provide the stakeholders of the GINO program with a survey of how different countries with power system challenges similar to Sweden and Finland have set up their respective markets and regulations to ensure a stable power system. The requested work was performed for four different countries or regions with nuclear reactors or other large system-important thermal production units. The relevant countries/regions are Australia, Ireland, UK and Texas in the U.S.

The scope includes a survey of power system ancillary services. For each of the countries, the research covered the following topics:

- Markets for ancillary services
- Ancillary services required through Grid codes
- Ancillary services secured through individual contracts between TSO and IPP
- Forced operation by the TSO
- Flexibility due to energy prices
- Evaluation and applicability in the Nordic grid context
- Markets and services technically suitable and applicable to NPPs

The Figure 3 shows the general structure of electricity markets. This work concentrates on the study of ancillary service markets, operating reserves procurement and balancing markets.

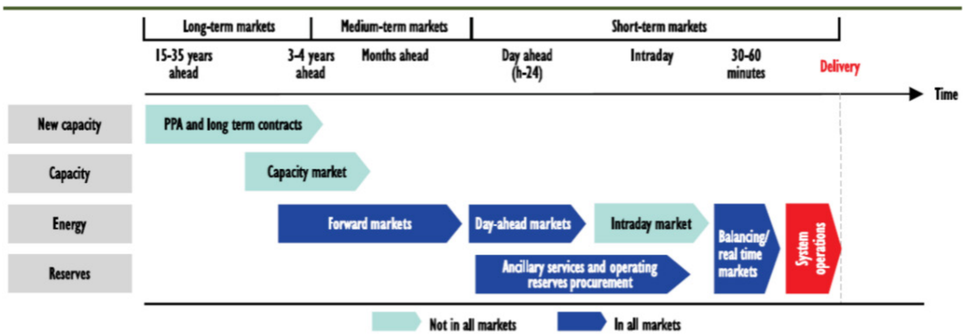

Figure 3 General structure of electricity markets (IEA, 2016).

The project team performed internet and literature surveys based on publicly available information and interviewed grid, nuclear and market experts. As a result of the project, potential markets and services were proposed that are technically suitable and applicable to Swedish and Finnish nuclear power plants.

The work is an exploratory study intended to bring to light phenomena, and the results are indicative and not applicable to business applications as such.

4 Results

4.1 MARKETS FOR ANCILLARY SERVICES

This chapter describes the existing markets for ancillary services in four different countries or regions as follows:

- market operation and prerequisites for participation
- power sources participating in the respective markets
- size of respective markets in relation to the size of the power system
- observable trends in market size, prices, contribution from different power sources

The ancillary service products of 4 regions/counties (Australia, UK, Ireland and U.S. Texas) are mapped and categorized according to their activation time for frequency and voltage control. The categorization responds rather well to the existing Nordic system. The detailed characteristics of different ancillary service products are summarized in ANNEX A.

4.1.1 Australia

The rules of the Australian Energy Market have been developed by the Australian Energy Market Commission (AEMC) and enforced by the Australian Energy regulator (AER), which is a body of the Australian Competition and Consumer Commission (ACCC).

The two largest electricity networks in Australia are the National Electricity Market (NEM) and the South-West Interconnected System (SWIS). The NEM services the eastern states, including Tasmania and South Australia, and accounts for approximately 85 % of the Australian electricity market (TWh). The SWIS in Western Australia accounts for approximately 7 %. The remote (“off-grid”) market accounts for the remaining 8 % of the markets, including both remote industrial and remote community networks. In this report, the focus is on the NEM. The NEM is managed by the Australian Energy Market Operator (AEMO).

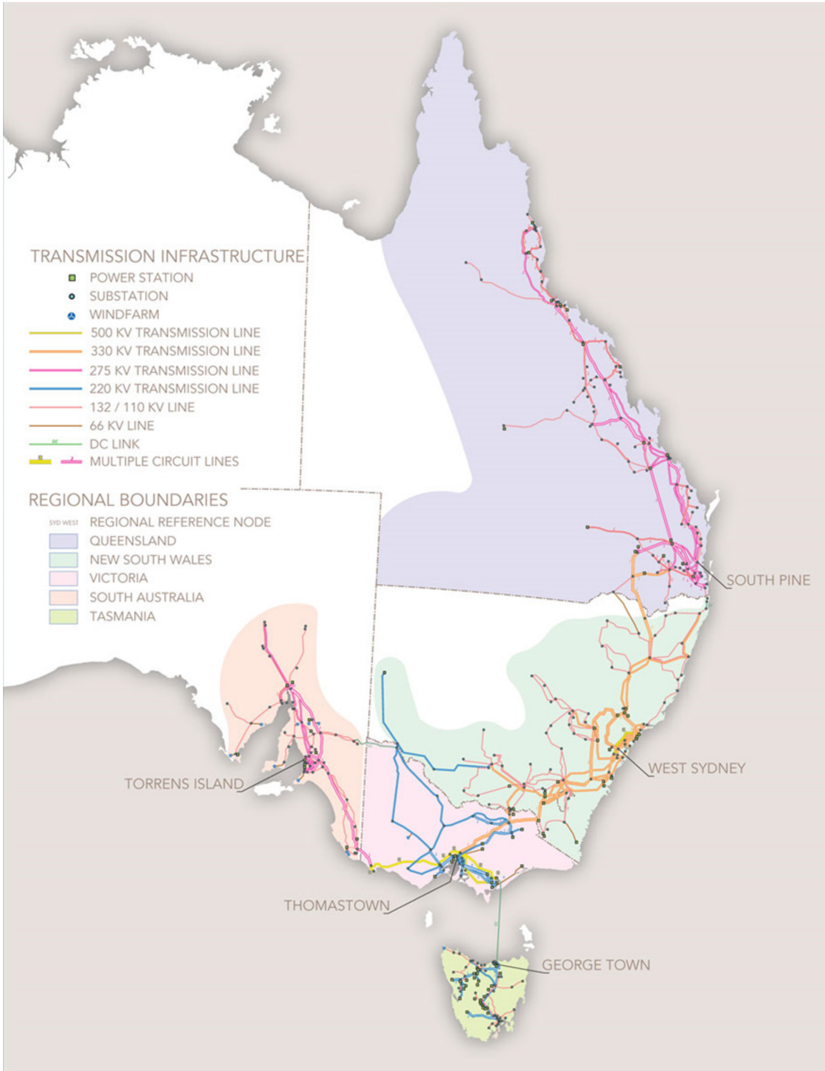

Figure 4 Australian National Electricity Market (NEM).

The NEM interconnected network covers five states of Australia, which also act as price regions. They are: South Australia, New South Wales, Queensland, Victoria and Tasmania, as shown in Figure 4.

In accordance with the National Electricity Rules, AEMO is responsible for the security and stability of the power system, which includes controlling the system frequency and voltage by purchasing ancillary services. These services are provided by market participants by means of either:

- Market Ancillary Service Arrangements; or
- Ancillary Service Agreements.

In the NEM, the ancillary services are divided into three categories (AEMO, 2015):

- Frequency Control Ancillary Services (FCAS)
- Network Support & Control Ancillary Services (NSCAS)
- System Restart Ancillary Services (SRAS).

Only the provision of FCAS is performed by the operation of a market and is detailed in this section, see Figure 5 below. Information about the other services is included in Sections 4.2 and 4.3.

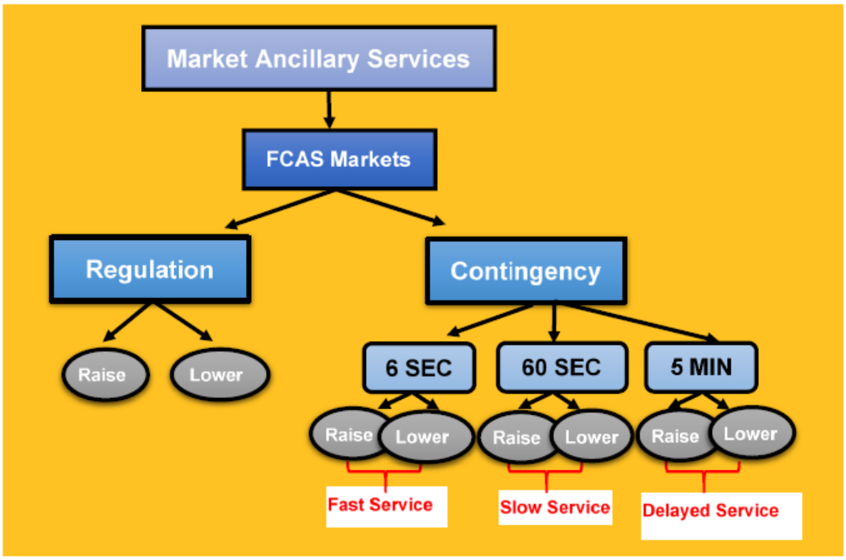

Figure 5 Market ancillary service summary (AEMO, 2020).

In the FCAS, regulation frequency control is applied to maintain the frequency during normal operation whereas contingency frequency control is called to cope with large disturbances. Two AEMO control centres control the regulation services centrally, while the contingency services are locally controlled (AEMO, 2015).

When a "credible contingency" occurs, the rate of change in frequency is slowed by the fast contingency services, stabilisation of the frequency is provided by the slow contingency services and the delayed contingency services return the frequency to the operating band. The aim is that the frequency stays inside the contingency band and returns to the standard operating band within five minutes. (AEMO, 2015).

NEM has eight markets for FCAS operation. Market types and the service provided can be seen in Table 1.

Table 1 NEM markets for securing appropriate FCAS at any moment in time (AEMO, 2015).

Market Category	FCAS market name	Service system
Regulation	Regulation Raise	Correct a small frequency drop
Regulation	Regulation Lower	Correct a small frequency rise
Contingency	Fast Raise	Six seconds response to fix a major frequency drop
Contingency	Fast Lower	Six seconds response to fix a major frequency rise
Contingency	Slow Raise	Sixty seconds response to stabilize after a major frequency drop
Contingency	Slow Lower	Sixty seconds response to stabilize after a major frequency rise
Contingency	Delayed Raise	Five-minute response to fix frequency to normal operating band after a major frequency drop
Contingency	Delayed Lower	Five-minute response to fix frequency to normal operating band after a major frequency rise

The service providers must register for specific services in the AEMO system before working in the FCAS market. After that they can submit bids and offers via the AEMO's Market Management Systems. The National Electricity Market Dispatch Engine (NEMDE) is then able to acquire the required amount of FCAS products for each FCAS dispatch interval. (AEMO, 2015).

There are some bidding policies for FCAS offers and bids. The offers or bids can comprise up to 10 bands encompassing non-zero MW availabilities, the band values should increase monotonically, and prices should be set by 12:30 of the previous day. Re-bid is possible for band availabilities, enablement limits and breakpoints. (AEMO, 2015)

Payments

The price paid to the providers of FCAS services is calculated on a "pay as cleared" principle, where the price for all of the providers corresponds to the most expensive accepted bid. Multiplying the clearing price by the energy from an accepted bid or offer yields the value to be paid for each 5-minute interval (AEMO, 2020).

Cost recovery

Specific rules dictate the sums paid to the service providers following a "causer pays" policy. The loss of large generating units triggers contingency raise services and are paid for by the responsible generators. Customers pay for contingency lower services.

Power sources participating in the ancillary service markets

There were no public sources available showing the technologies which provided FCAS regulation service and their share of each market. Figure 6 shows the technologies which provided FCAS contingency service from 2012 to 2018 (with partial data for 2017 and 2018). The conventional thermal power plants (coal, gas) provided about 50 % and hydro power plants about 30 %. The share of demand response and battery storages have increased to about 20 % of the FCAS contingency services in 2018.

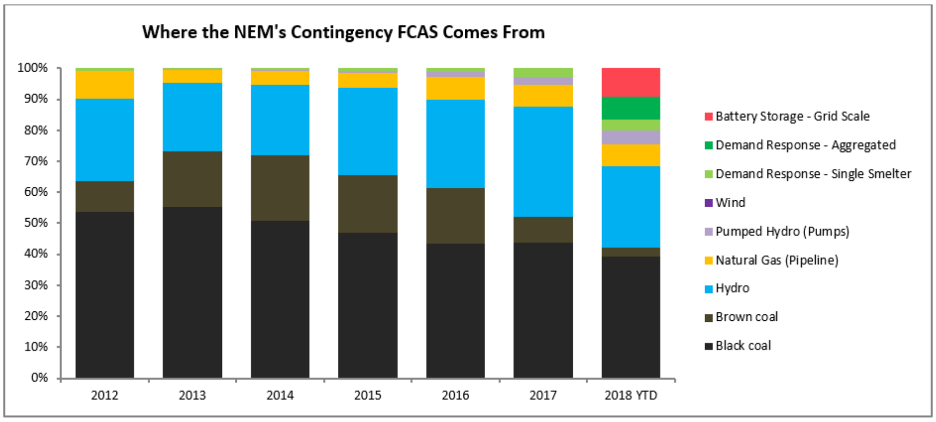

Chart data: *Sum of R6, R60, R5 FCAS |Enabled MWh (NB: not 'energy supplied') by technology type*
Calendar years | 2017 to 30 Sep (pre EnerNOC + Hornsdale PR) | 2018 to 31 May

Figure 6 Technologies providing FCAS contingency services (Renew economy, 2018).

Market size

In the following, information about the system and market sizes and market prices are summarised. Table 2 summarizes the NEM system and Figure 7 shows the registered capacity by fuel source. It should be noted that Australia has no nuclear power installed, and in fact is the only G20 country where nuclear power is banned by Federal law, although there are proponents expounding the benefits of this uranium exporting country using the material locally to help decarbonise the Australian energy sector (Australian Nuclear Association, 2018).

Table 2 NEM facts as of 2017 (AEMO, 2019) and (AER, 2020)

Market type	Competitive wholesale electricity market
Transmission network length	40,000 Kilometers
Supply	200 TWh per year
Generation capacity	The NEM has a total electricity generating capacity, including Rooftop solar PV, of almost 54,421 MW (as at December 2017).
Reserves	Strategic reserves of demand and generation resources of more than 1000 MW for 2017-18.
Generators and retailers	More than 100
Total Customers	More than 9 million
Number of large generator Units	240

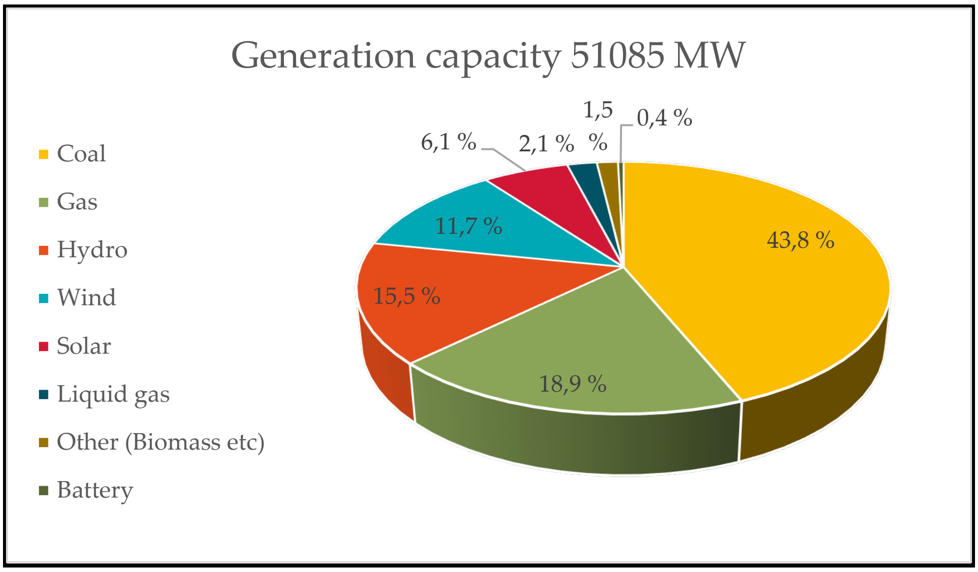

Figure 7 Generation capacity by fuel source, which does not include rooftop solar PV (AER, 2020).

Figure 8 shows the quarterly average FCAS enablement amount by services for the period 2015-2020. The need for enablement has been between 100 MW - 600 MW for the different FCAS products.

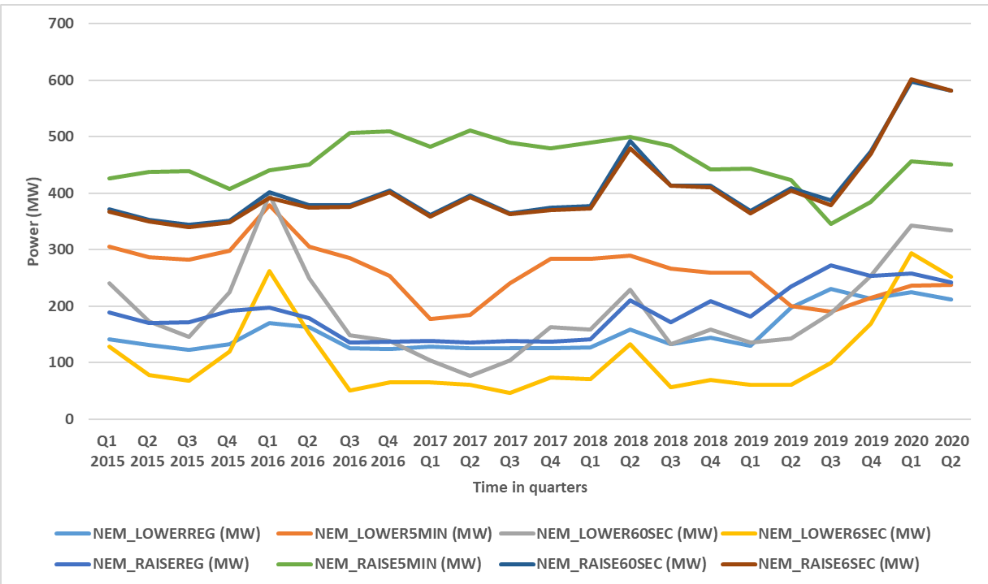

Figure 8 Quarterly average FCAS enablement amount by services (AER, 2020).

Market trends

The temperature is normally very high during the summer (Webb & Hennessy, 2015). The good availability of sunlight makes Australia favourable for solar energy technology. There is evidence that the market is beginning to adapt to provide new sources of FCAS, consisting of energy intelligence software and demand response and battery storages.

The delivery cost for NEM market ancillary services has increased significantly over recent years, with the total FCAS costs increasing from about $25 million in 2012 to $220 million in 2018. The increase was observed for both the raise contingency and regulating services, and the lower regulating service (AEMC, 2019)

Figure 9 shows the quarterly global FCAS costs (AER, 2020). In Q1 2020, NEM quarterly FCAS costs increased to record levels of $227 million, largely due to the extended separation of the South Australian and Victorian power systems, of which $166 million was recovered from generators, and $61 million from retailers. The largest increase in costs was in the Contingency Raise FCAS markets, which increased from $30 million in quarter 4 2019 to $142 million in quarter 1 2020.

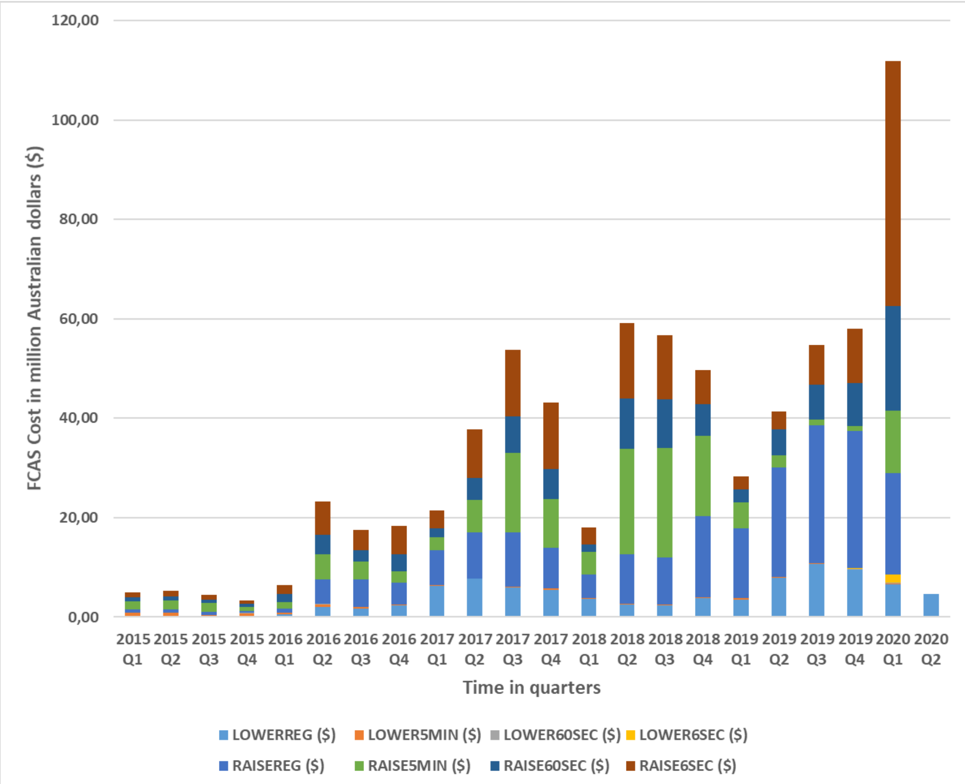

Figure 9 Quarterly global FCAS costs by services (AER, 2020).

4.1.2 United Kingdom

National Grid Electricity Transmission (NGET), Figure 10, is the Electricity System Operator (ESO) for the National Electricity Transmission System in Great Britain (National Grid, 2017a). The Office of Gas and Electricity Markets (OFGEM) is an independent National Regulatory Authority.

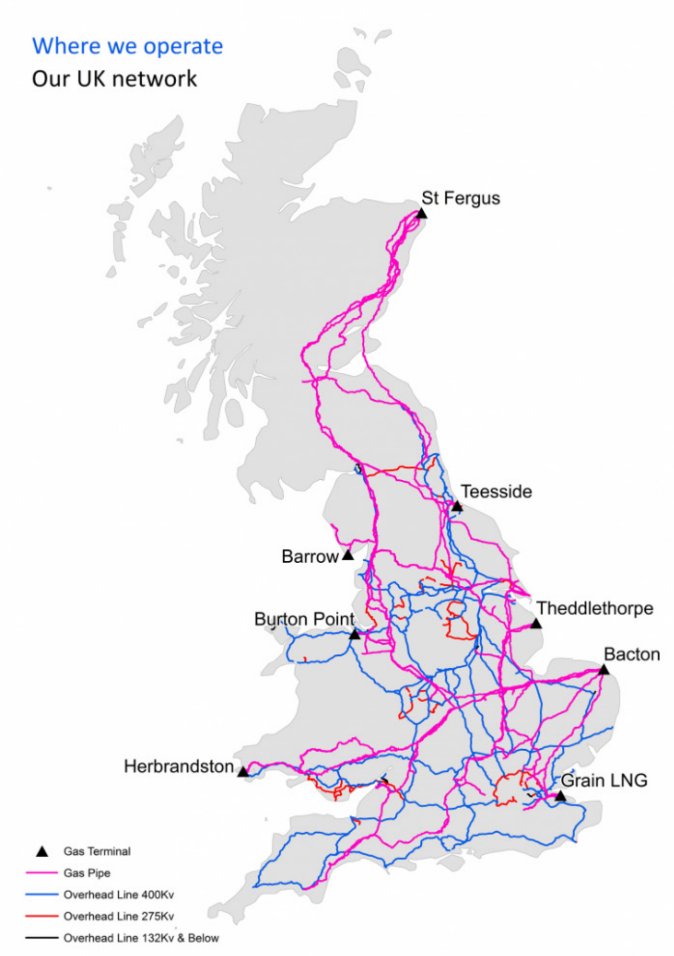

Figure 10 NGET electricity market area (National Grid, 2020a).

The Balancing Mechanism (BM) is a core ESO tool for managing the GB electricity system, typically accounting for 5-15% of all contracted electricity volumes over a year. The settlement period for the ancillary service market is 1 hour, Figure 11.

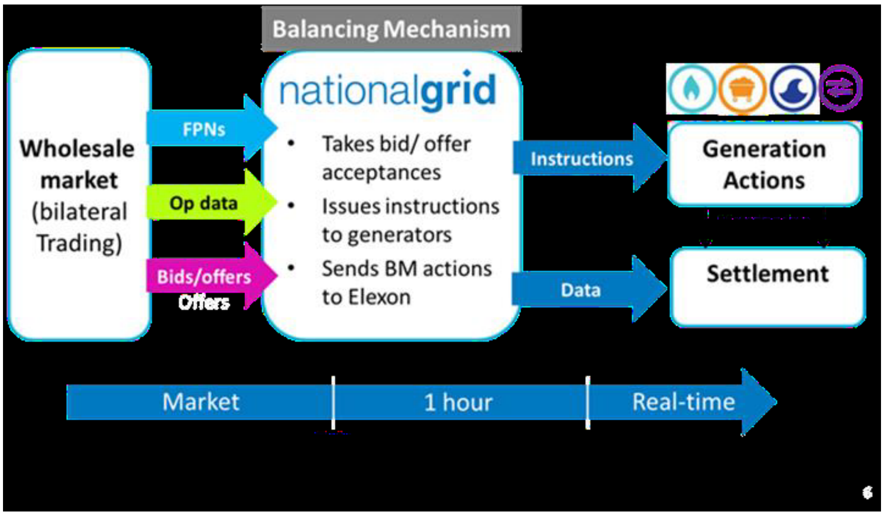

Figure 11 High level overview of the processes in the BM (National Grid, 2018d).

The processes and products have been built up over many years as the needs have gradually shifted, resulting in more than 20 different market or non-market based products that providers can choose from, each with different technical requirements and routes to market, as summarised in Figure 12.

Single or multiple services can be provided to single or multiple buyers. As long as there is no conflict or compromise, assets can even be contracted under two services in the same time period (ESO, 2019, National Grid, 2020b).

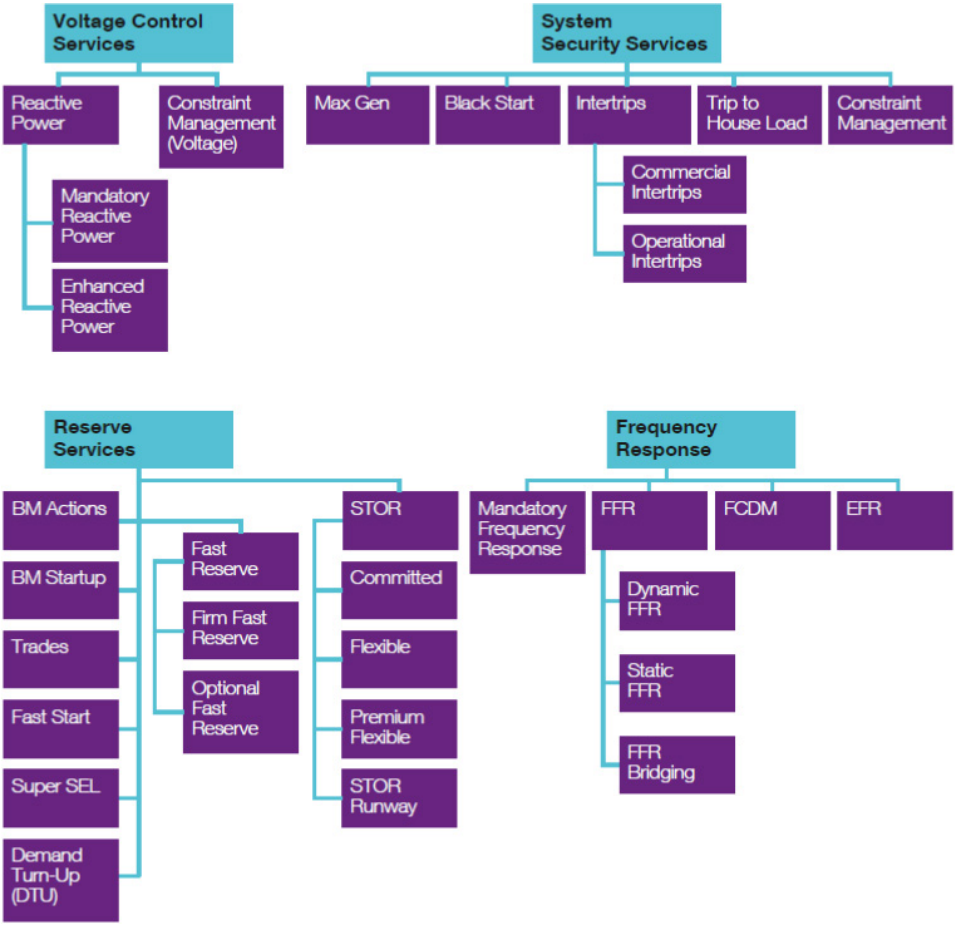

Figure 12 Existing product suite (National Grid, 2017a).

The following markets for providers are accessible for frequency response and reserve services.

<u>Frequency response services</u>

a) Firm Frequency Response (FFR*[1])
   - Dynamic frequency response is continuously provided and is used to manage second by second frequency variations. Dynamic response is automatically delivered for all frequency variations outside of the dead band 50Hz ±0.015Hz (National Grid, 2017b).

[1] The star is added here to differentiate Firm Frequency Response from the Fast Frequency Reserves abbreviation used in the other sections of this document

- Non-Dynamic frequency response is triggered at defined frequency deviations.
- Dynamic and Non-Dynamic FFR* products are procured via monthly tender. A weekly auction trial started in June 2019.
- Min. entry size is 1MW, from a single or aggregated unit

Table 3 The response speeds and duration of FFR* (National Grid, 2017b).

FFR* product type		Response speed	Length of response
Non-Dynamic - Secondary response is the only Non-Dynamic response currently procured		Within 30 secs	30 mins
Dynamic - A dynamic service can provide Primary, Secondary and High response, or Primary and Secondary only or High only	Primary	Response required within 2 secs, with full response by 10 secs	20 secs
	Secondary	Within 30 secs	30 mins
	High	Within 10 secs	Indefinitely unless otherwise agreed

b) Enhanced Frequency Response (EFR)
EFR product is still on development phase. The service is open to both BM and non-BM providers to provide frequency response in one second or less time. The auction trial is an innovation project which is procuring Low Frequency Static (LFS) and Dynamic Low High (DLH) frequency products through the EPEX SPOT Auction Platform on a weekly basis, see technical details in APPENDIX 1.

<u>Reserve services</u>

a) Short-term operating reserve (STOR)
- 3 tender rounds per year, for a committed or flexible service.
- Min. entry size is 3 MW, from a single or aggregated unit.
- Asset(s) must be able to respond to an instruction within 20 mins and sustain the response for up to 4 hours.

b) Fast reserve (FR)
- Procured via monthly tender.
- Min. entry size is 25 MW, from a single or aggregated unit.
- Ramp up rate is 12.5 MW/min so an asset should be at an output of 25 MW in 2 minutes.
- The response must be sustained for 15 mins.

c) The Demand Turn-Up (DTU)
- There are two products, Fixed and Flexible.
- For those wishing to participate in flexible demand turn up, submissions of prices and MW availability will be assessed on Fridays and Tuesdays during British Summer Time (BST).

- The entry threshold for participation is 1 MW. This can be aggregated from sites 0.1 MW and larger and fractions of megawatts are acceptable.
- As with duration of delivery, the speed in which a provider needs to respond is linked to individual providers' capabilities.
- There are two forms of payment that we will make as part of the demand turn up (DTU) service:
  - availability payment – to Fixed DTU providers for being available to provide the service; and
  - utilisation payment – to Fixed and Optional DTU providers for delivering the service when instructed.
- The Demand Turn Up (DTU) service encourages large energy users and generators to either increase demand or reduce generation at times of high renewable output and low national demand. This typically occurs overnight and during weekend afternoons in the summer.

How ESO buys each product is different, but the purpose is to ensure that ESO has the tools available to maintain the quality and security of the electricity supply at the lowest cost to consumers. This complexity creates a barrier to entry. This affects existing providers as well as new providers, new technologies and business models which may not fit into current product structures. Figure 13 illustrates some of the overlaps and interactions between the needs and current suite of products. Figure 13 includes both market and non-market ancillary service products.

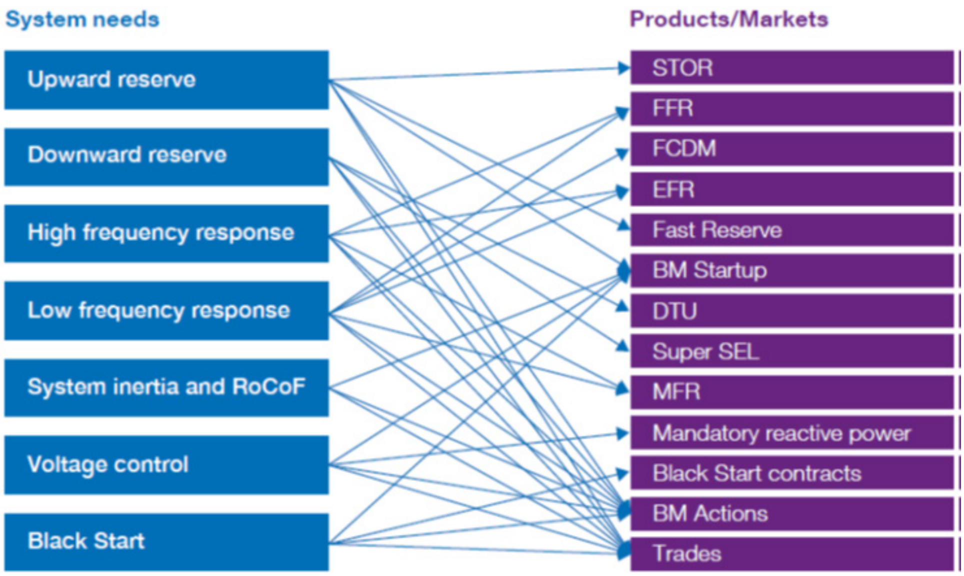

Figure 13 Mapping of current markets and products to system needs (National Grid, 2017a).

When considering individual products, it becomes apparent that there is considerable overlap in terms of what each product is trying to achieve. A further consideration is the way that each one of these overlapping products is procured. Some are tendered, some are bilateral, but all are assessed and contracted for by separate processes. Looking at a snapshot of the products delivering the services in Figure 14, it can be seen that the products with a significant oversubscription are those with the lowest accepted availability price, whereas undersubscribed products have a higher accepted availability price. If the products are very similar in terms of technical requirement and capability, yet they are being procured and valued in isolation, then the markets may not be delivering the optimum economic outcome for the consumer.

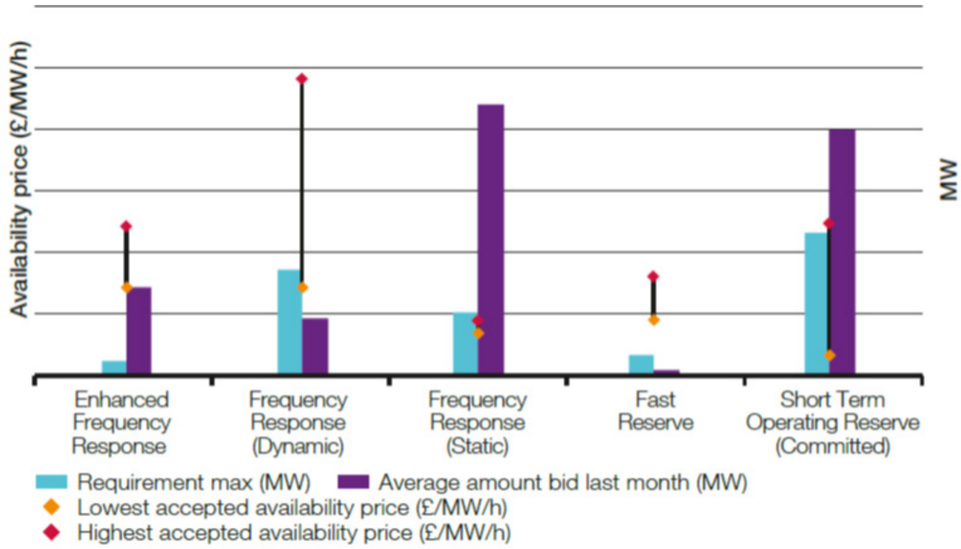

Figure 14 Oversubscribed and undersubscribed markets (National Grid 2017, June).

Firm volumes which are required for managing demand forecasting errors and large losses are procured via regular tenders ahead of time (e.g. Short Term Operating Reserve (STOR) and Demand Turn-Up (DTU)). In addition, variable volumes are required for upward and downward flexibility. These are satisfied closer to real time by part-loaded plant operating in the energy market, instructions in the BM, or trading. There is now less certainty as to how these variable requirements will be satisfied closer to real time as the levels of wind and solar generation have increased.

Market size

All generators total capacity was 82,932 MW in 2018 (GOV_UK, 2020). Total electricity generated in 2019 was 323.7 TWh. Figure 15 shows the total electricity generated by fuel type from the years 2009-2019, and Table 4 the electricity imports and exports in 2019.

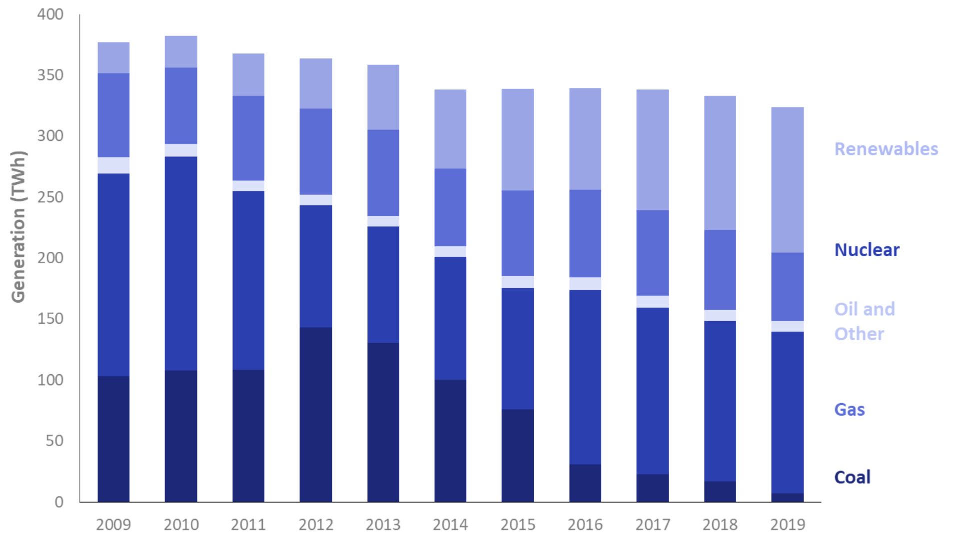

Figure 15 Total electricity generated by fuel type (GOV_UK, 2020).

Table 4 Electricity imports and exports in 2019, (GOV_UK, 2020).

	Export From UK	Import to UK	
France	⇦ 0.7 TWh	11.9 TWh ⇨	UK
Netherlands	⇦ 0.3 TWh	11,1 TWh ⇨	UK
Ireland	⇦ 2.2 TWh	1,5 TWh ⇨	UK
Belgium	⇦ 0.1 TWh	5,1 TWh ⇨	UK

Downward reserve

The firm downward reserve need is stable between 1 and 2 GW (Figure 16). The variable need for this year is between 3 and 7 GW; however, it is expected to increase a little over the coming years. Currently both the firm and variable downward requirements are mostly accessed through the BM or trading, however this availability is reducing, particularly at times of low transmission demand.

Upward reserve

The firm upward reserve requirement is stable and remains between 2 and 3 GW (Figure 17). The firm requirement is expected to be procured in STOR. The variable upward reserve required for flexibility is between 3 and 8 GW now and will show a minor increase over the coming years.

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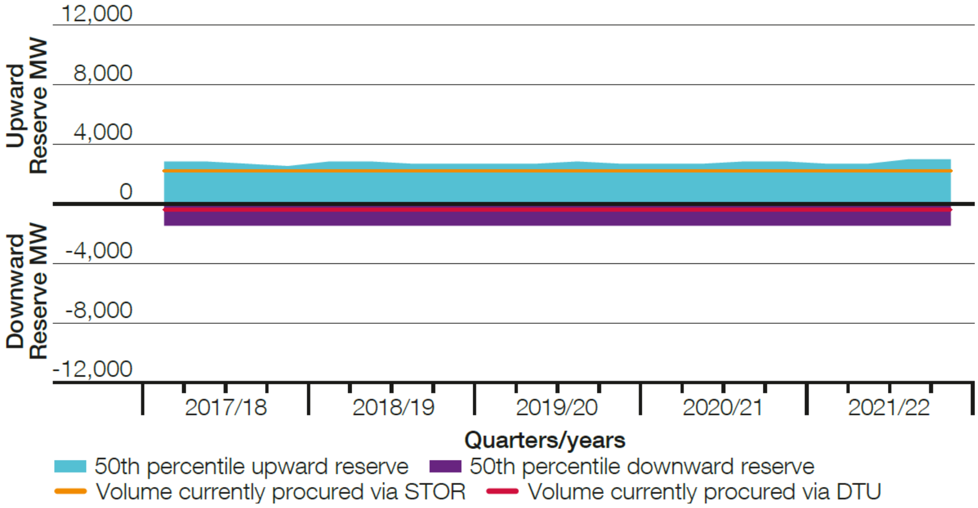

Figure 16 Upward and downward firm reserve requirement (50th Percentile Consumer Power) (National Grid, 2017, June).

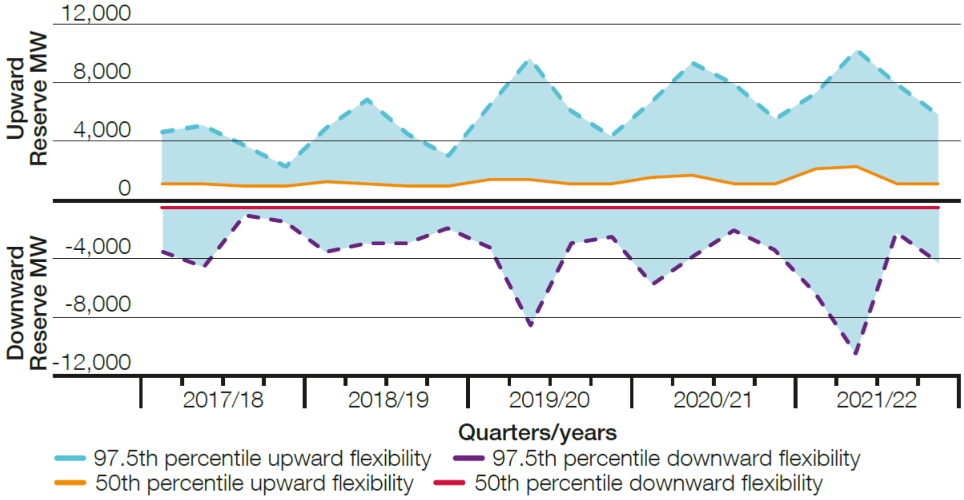

Figure 17 Range of upward and downward flexibility required (National Grid, 2017, June).

The Figure 18 illustrates the daily typical frequency response requirement for MFR. The settlement period is 30 mins.

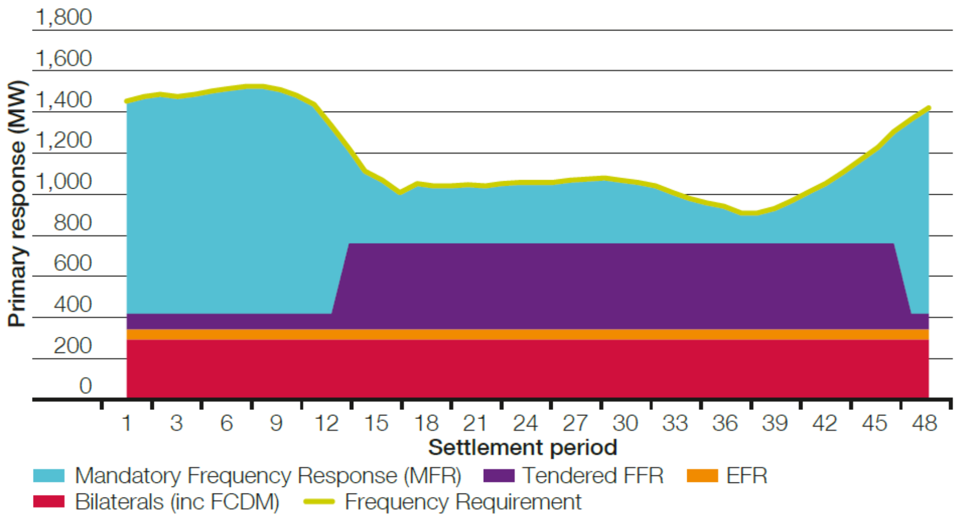

Figure 18 Illustration of typical frequency response requirement components (National Grid, 2017c).

Figure 19 shows the ancillary service cost in January 2020.

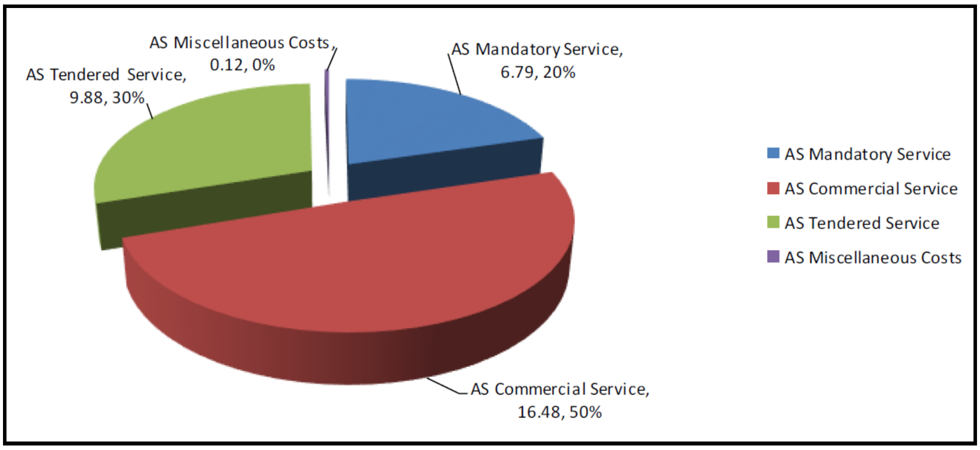

Figure 19 Ancillary Services Cost - Jan 2020 (National Grid, 2020c).

Ancillary service cost was 33,90 £m in January 2020, and the monthly cost from April 2019 to January 2020 varied from 32,17 £m to 36,58 £m.

Market trends

ESO plans reform of frequency response and reserve services. ESO is developing a new suite of three dynamic frequency response services, which will eventually replace the existing response services.

With respect to reserve services, the focus is on the standardisation of the existing service portfolio. The European-wide Project TERRE (ENTSO-E, 2020c), will significantly change the requirements for reserve services (National Grid, 2019).

As the energy mix changes, the availability of flexibility in the BM is reducing or is becoming increasingly costly to access. Figure 20 below shows the percentage of time that National Grid might be required to take actions to reduce the RoCoF. For the majority of time, the RoCoF can be managed by reducing the largest single loss (shown in yellow); however, in the future, it may be increasingly necessary to take action to bring on additional synchronous generation to increase system inertia (in red) or to find an alternative solution. ESO is investigating what a new, faster-acting frequency response product may look like, and how it could form part of a new suite of frequency response products.

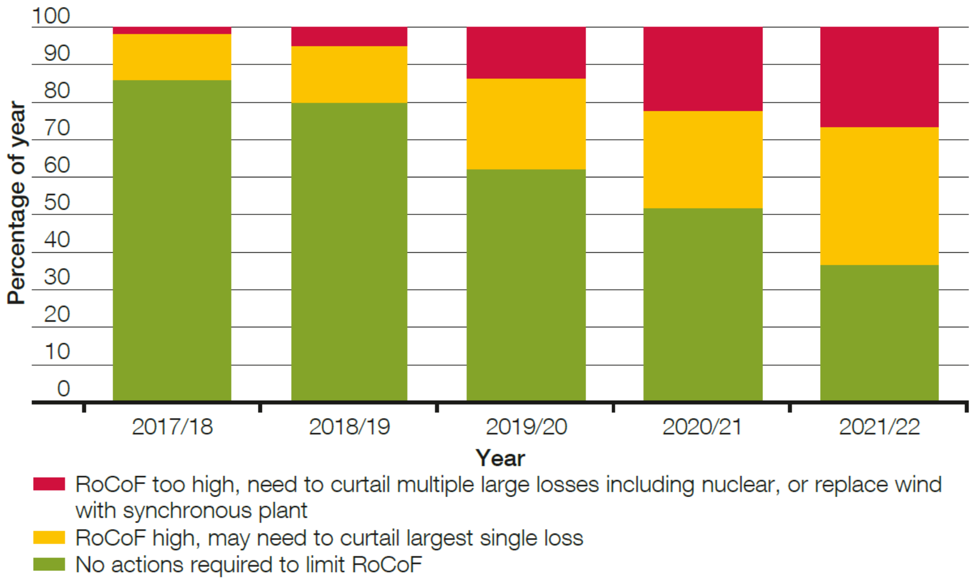

Figure 20 Five-year RoCoF trajectory (National Grid, 2017a).

4.1.3 Ireland

The Commission for Regulation of Utilities (CRU) is Ireland's independent energy regulator. The CRU's primary economic responsibilities in energy are to regulate the Irish electricity and natural gas sectors. This covers electricity generation, electricity and gas networks, and electricity and gas supply activities. The CRU jointly regulates the Single Electricity Market (SEM) with its counterpart UREGNI, Utility Regulator in the Northern Ireland. The market operator in the Republic of Ireland and Northern Ireland is SEMO (Single Electricity Market Operator). A decision-making body known as the SEM Committee governs the SEM. The CRU, UREGNI and an independent member make up the SEM Committee. EirGrid is the Transmission System Operator (TSO), and ESB Networks is the Transmission Asset Owner (TAO) in the Republic of Ireland. SONI is the TSO in Northern Ireland and Northern Ireland Electricity Networks (NIE Networks) owns the electricity transmission and distribution networks, and operates the electricity distribution network, see Figure 21. Both TSOs are required by licence to produce an annual Generation Capacity Statement (GCS), which covers both Northern Ireland and Ireland, and is produced jointly between SONI and EirGrid (EG, 2014).

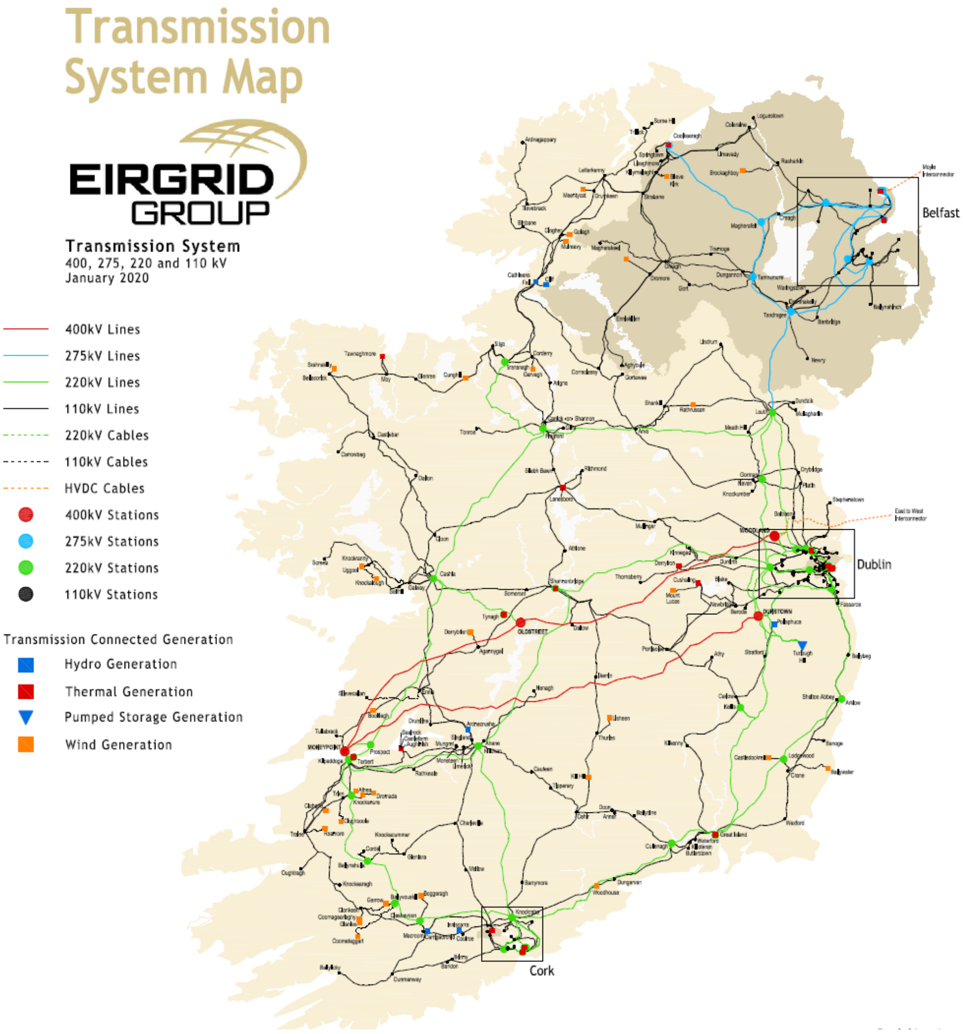

Figure 21 Market area of EIRGRID.

A team of staff operates the grid from National Control Centres (NCCs) in Dublin and Belfast. The TSOs have developed a number of new system service products and have proposed refinement of the definitions of some of the existing ancillary services (EirGrid and SONI, 2014, EirGrid Group, 2017).

<u>New products</u>

- Synchronous Inertial Response (SIR)
- Fast Post-fault Active Power Recovery (FPFAPR)
- Dynamic Reactive Response (DR)
- Fast Frequency Response (FFR)
- Ramping Margin (RM)

<u>Existing products</u>

- Operating Reserves: POR, SOR, TOR1 &TOR2
- Replacement Reserve – minor modification proposed
- Steady-state reactive power – modification proposed

Table 5 shows some details of the system services.

Table 5 Summary of EirGrid and SONI system services (EG 2017a).

Service Name	Unit of Payment	Description and duration
Synchronous Inertial Response, SIR	MWs^2h	(Stored kinetic energy)*(SIR Factor – 15)
Fast Frequency Response, FFR	MWh	MW, delivered between 2 and 10 seconds
Primary Operating Reserve, POR	MWh	MW delivered between 5 and 15 seconds
Secondary Operating Reserve, SOR	MWh	MW delivered between 15 to 90 seconds
Tertiary Operating Reserve 1, TOR1	MWh	MW delivered between 90 seconds to 5 minutes
Tertiary Operating Reserve 2, TOR2	MWh	MW delivered between 5 minutes to 20 minutes
Replacement Reserve – Synchronised, RRS	MWh	MW delivered between 20 minutes to 1 hour
Replacement Reserve – Desynchronised, RRD	MWh	MW delivered between 20 minutes to 1 hour
Ramping Margin 1, RM1	MWh	The increased MW output that can be delivered with a good degree of certainty for the given time horizon
Ramping Margin 3, RM3	MWh	
Ramping Margin 8, RM8	MWh	
Fast Post Fault Active Power Recovery, FPFAPR	MWh	Plant's active power (MW) > 90% of pre-fault output within 250 ms of the voltage being back to 90% of its pre-fault value
Steady State Reactive Power, SSRP	Mvarh	(Mvar capability)*(% of capacity that Mvar capability is achievable)
Dynamic Reactive Response, DRR	MWh	MVAr capability during large (>30%) voltage dips

Figure 22 below illustrates how EirGrid and SONI calculate trading period payments for system service providers.

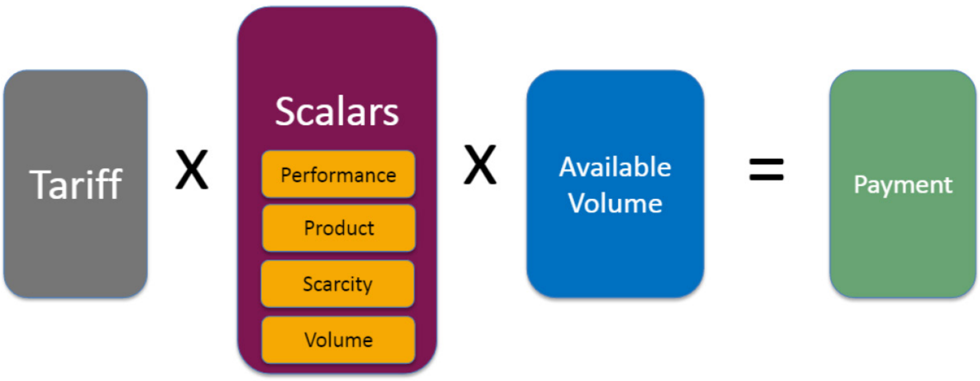

Figure 22 Calculation of trading period payments (EirGrid and SONI, 2016).

Clearly, the scalars will play an important role in determining service provider payments. Only performance and product scalars will be used. The other two scalar types will only apply for the enduring arrangement.

Market size

Figure 23 shows the capacity of the markets by technologies. Gas turbines (59%) and steam turbines (25%) produce about 84% of the electricity generation. Figure 24 shows the trend of market size by technologies. Coal fired generation has been replaced by renewables and other production technologies.

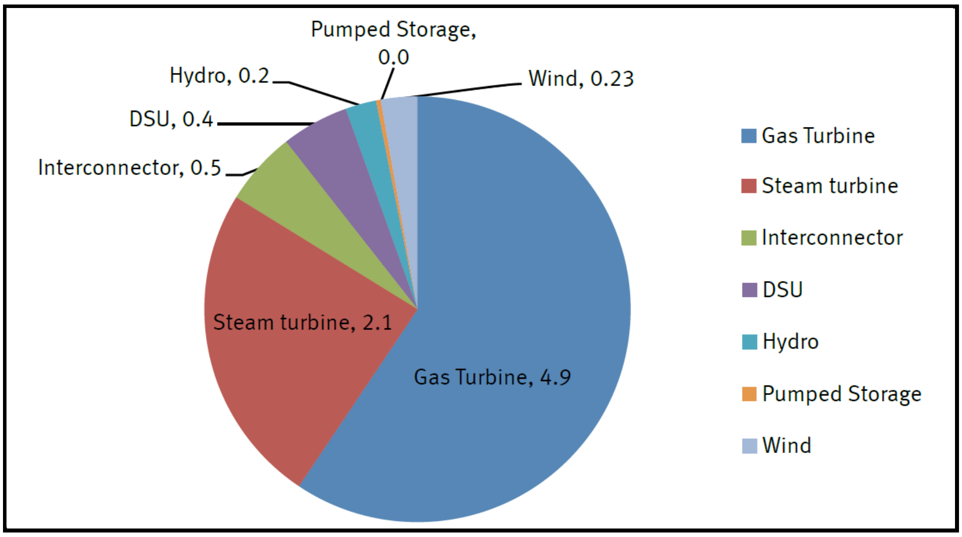

Figure 23 The total amount of de-rated capacity (GW). All-Island Capacity Market auction in December 2018 was 8.3 GW. Here it is divided into the technology categories used in the Capacity Market (EG, 2019).

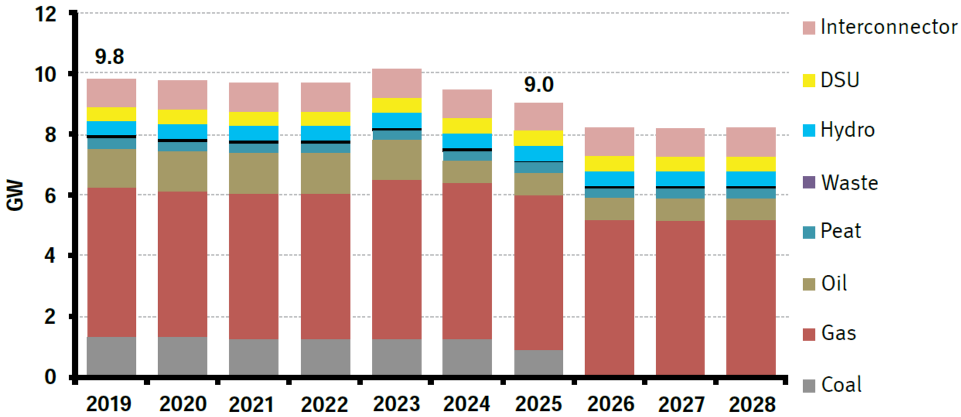

Figure 24 All-Island portfolio of de-rated dispatchable generation and interconnection capacity, as assumed in the reference scenario (EG, 2019).

Table 6 below shows the maximum capability volumes to apply per service (EirGrid and SONI, 2020).

Table 6 Maximum volumes of services.

Service	Max Volume - Normal Operation	Max Volume - Requested by TSO
FFR	75 MW	100 MW
POR	75 MW	100 MW
SOR	75 MW	100 MW
TOR1	75 MW	100 MW
TOR2	75 MW	100 MW
RRD	300 MW	N/A
RRS	300 MW	N/A
RM1	450 MW	N/A
RM3	500 MW	N/A
RM8	500 MW	N/A
SSRP	400 Mvar	N/A
SIR	120,000 MWs^2	N/A

Market trends

Ireland has drafted a 2030 National Energy and Climate Plan, which envisages a target of at least 55% renewable energy in electricity by 2030. In June 2019, the Minister of Communications, Climate Action and Environment committed to raise the amount of electricity generated from renewable sources to 70% by 2030, with no generation from peat and coal in the Climate Action Plan 2019.

In 2017, EirGrid and Réseau de Transport d'Électricité (RTÉ) began investigating a potential interconnector between Ireland and France. It is proposed that the interconnector would transport 700 MW of electricity. (EG, 2017)

4.1.4 U.S. Texas

The United States consists of seven power markets, including Texas, each operated by a Regional Transmission Operator (RTO) or Independent System Operator (ISO) that operates the transmission system in its territory, operates markets for energy and ancillary services, and maintains system reliability. Ancillary service requirements and market mechanisms differ between the separate markets.

The Electric Reliability Council of Texas (ERCOT) manages the flow of electricity to more than 26 million Texas customers - representing about 90 percent of the state's electric load (Potomac Economics, 2020). ERCOT schedules power on an electricity grid that connects more than 46,500 miles of transmission lines and more than 650 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 8 million premises in competitive choice areas. ERCOT is a membership-based non-profit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. As the ERCOT system is wholly contained within a single state and does not have any AC transmission ties to other states, it does not participate in interstate commerce (ERCOT, 2020a). However, there are two (2) commercially operational DC-Ties between ERCOT and the Eastern Interconnection and two commercially operational DC-Ties between ERCOT and CENACE (ERCOT, 2020c), see Figure 25.

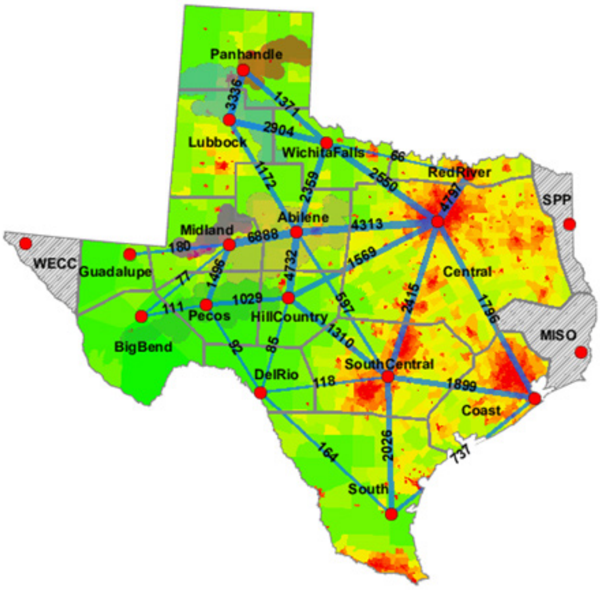

Figure 25 Map of the ERCOT service territory (ERCOT, 2020b).

To ensure extra capacity is available to address variability that cannot be covered by the five-minute energy market, Ancillary Services are procured in the Day-Ahead Market (DAM), where ERCOT establishes an Ancillary Services Plan and publishes relevant system information each day. ERCOT assigns obligations in the Ancillary Services Plan for ancillary services to each Load Serving Entity (based on load ratio shares) during each hour of the following day. AS market is an hourly market. Qualified Scheduling Entities (QSE) can meet their obligations either through self-supply, bilateral trades with other QSEs, or purchases from ERCOT through the DAM. ERCOT determines the MW amount of each ancillary services required for each hour of the operating day. The amount of ancillary services that have not been self-arranged are procured in each DAM by ERCOT. Generators and load resources submit offers into the DAM and they are selected to provide their services based on their offer prices. The DAM clears both energy and ancillary service offers.

ERCOT currently recognizes 3 main types of reserves as commercial products:

- Regulating Reserve, divided into:
  - × Regulation-Up and Regulation-Down (signals to generation on typically a 4 by 4 second basis, known collectively as "regulation AS"),
- Contingency reserves
  - × Responsive Reserve (full deployment within 10 minutes; known as "spinning reserves" or "synchronized reserves" in other U.S. markets; up to 50% of requirements provided by interruptible loads),
  - × Non-spinning reserve (committed and deployable within 30 minutes). Non-spinning reserve restore availability of other reserves if depleted by previous actions.

These three types of ERCOT AS are referred to as "operational reserves".

Time frame:

- Operational reserves cover from seconds up through the length of the real-time economic dispatch cycle (5 minutes currently in ERCOT) and longer for full deployment of responsive reserves and for non-spinning reserve deployment.
- In the 5 minute and longer time domains, generation economic dispatch also helps to follow net load variation, and generation unit-commitment follows daily load periodicity (Andrade et al 2018).

ERCOT uses the previous 30 days' deployed reserves, in part, to determine the required reserves for the next month. The system requirements for regulation-up and Regulation-down are determined as follows:

The largest of:

- The 98.8th percentile of Regulation-up/down deployments over the last 30 days;
- The 98.8th percentile of Regulation-up/down deployments in the same month of the previous year;
- The 98.8th percentile of the positive/negative net load changes over the last 30 days; or
- The 98.8th percentile of positive/negative net load deployments in the same month of the previous year.

Responsive Reserves are calculated in four-hour blocks on the basis of forecasted load and wind patterns, as well as the largest system contingency. Interruptible load resources can provide Responsive Reserves, but their contribution is limited to 50% of the total requirement in each hour.

The system requirement for Non-spinning Reserves is determined by first calculating the 95th percentile of net load uncertainty from both the previous 30 days and the same month of the previous year. Net load is defined as total load minus wind generation, and net load uncertainty is defined as the difference between the realized net load and forecast net load. ERCOT then subtracts the Regulation-up requirement from this 95th percentile to obtain the Non-spinning Reserves requirement. During on-peak hours (hours 07:00 through 22:00 Central time, ERCOT also maintains a minimum Non-spinning requirement that is equal to the largest single unit in the system. The Non-spinning requirement is also never permitted to exceed 2000 MW during all hours of operation. ERCOT procures non-spinning reserves such that the combination of non-spinning reserves and regulation up will cover 95% of the calculated net load forecast error.

Market size

The generating capacity is about 82 430 MW for the year 2020 (ERCOT, 2019). ERCOT record peak demand was 74 820 MW in 2019. Figure 26 below shows the generating capacity by fuels of ERCOT in 2020 and Figure 27 the consumed energy by fuels in 2019.

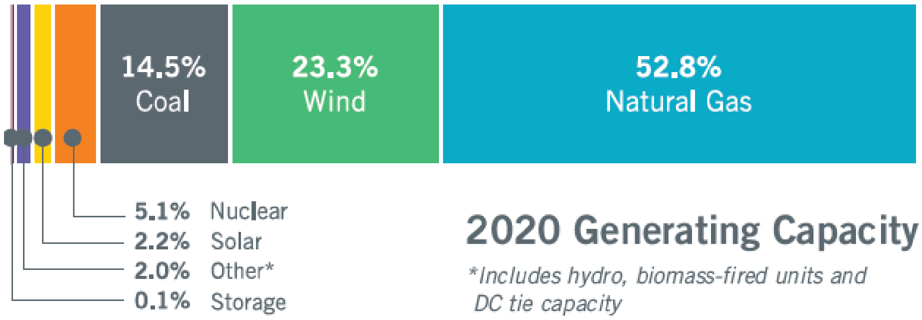

Figure 26 ERCOT generating capacity by fuels in 2020 (ERCOT, 2020d).

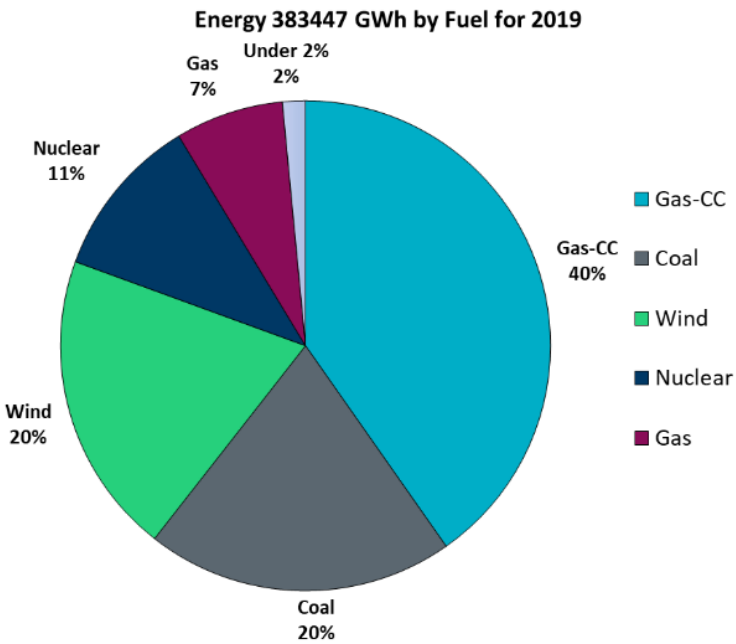

Figure 27 The consumed energy by fuels in 2019 (ERCOT, 2020e).

Market volume (in terms of the average amount of capacity of each service that is provided to a system) follows almost the same order of the prices as systems maintain the most Responsive Reserves capacity followed by Non-Spinning Reserves and Regulation Reserves. The size of most Regulation Reserves markets in terms of capacity stay relatively constant year-to-year, as this is dictated largely by system requirements. (Zhou et al 2016). The average total ancillary services requirement in 2019 was just shy of 4,900 MW, although the quantity of reserves held varies hour to hour. For example, on average ERCOT held roughly 5,500 MW of total reserves in some hours. The primary reason ERCOT holds more reserves in some hours is that the demand for resources which are able to change their output (i.e., to ramp up) is higher in some hours than others, which can cause the system to be more vulnerable to contingencies.

Figure 28 below displays the hourly average quantities of ancillary services procured for each month in 2019.

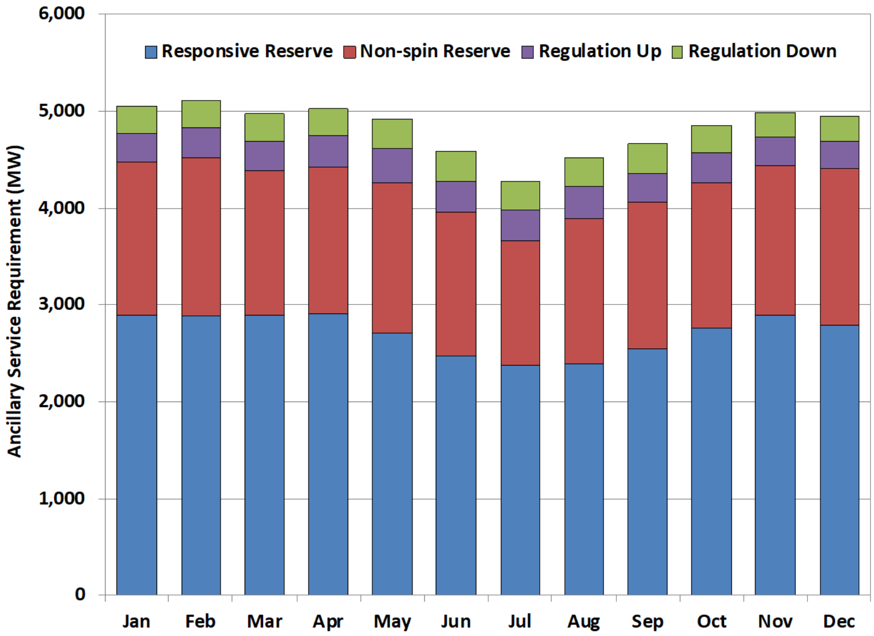

Figure 28 Hourly Average Ancillary Service Capacity by Month (Potomac Economics, 2020).

Market trends

The generation share from wind has increased every year since 2004, reaching almost 20% of the annual generation in 2019. Texas has the largest amount of wind of any U.S. state. The share of generation from coal continues to fall and the output has been replaced by natural gas generation. These trends are expected to continue because of historically low natural gas prices, making gas-fired resources increasingly more economic than coal resources, and the continued growth of zero fuel cost resources, like wind and solar. However, the amount of frequency regulation ancillary service procured has typically decreased over time. (Andrade et al 2018)

There are significant correlations between requirements for Regulation-Up and Regulation-Down reserves and

- Daily minimum demand.
- Daily maximum demand.
- Installed wind power.

Various changes in ERCOT market design have reduced the need for procured Regulation Up and Regulation Down, despite increases in wind. Requirements for regulating reserves have tended to decrease over time in ERCOT, despite the dramatic increase in renewables and improved NERC Control Performance Standard CPS1 scores.

Figure 29 presents the monthly average clearing prices of capacity for the four ancillary services, while the inset table shows the average annual prices over the last three years. The prices for ancillary services were noticeably higher in the months of August and September. These outcomes are consistent with the higher clearing prices for energy in the day-ahead market for those two months, because ancillary services and energy are co-optimized in the day-ahead market. ERCOT has traditionally had the highest prices for Spinning Reserves (called Responsive Reserves in ERCOT) followed by Regulation up, Regulation down and Non-spinning Reserves. The increase in ancillary services prices caused the average ancillary service cost per MWh of load to increase from $1.60 per MWh in 2018 to $2.33 per MWh in 2019.

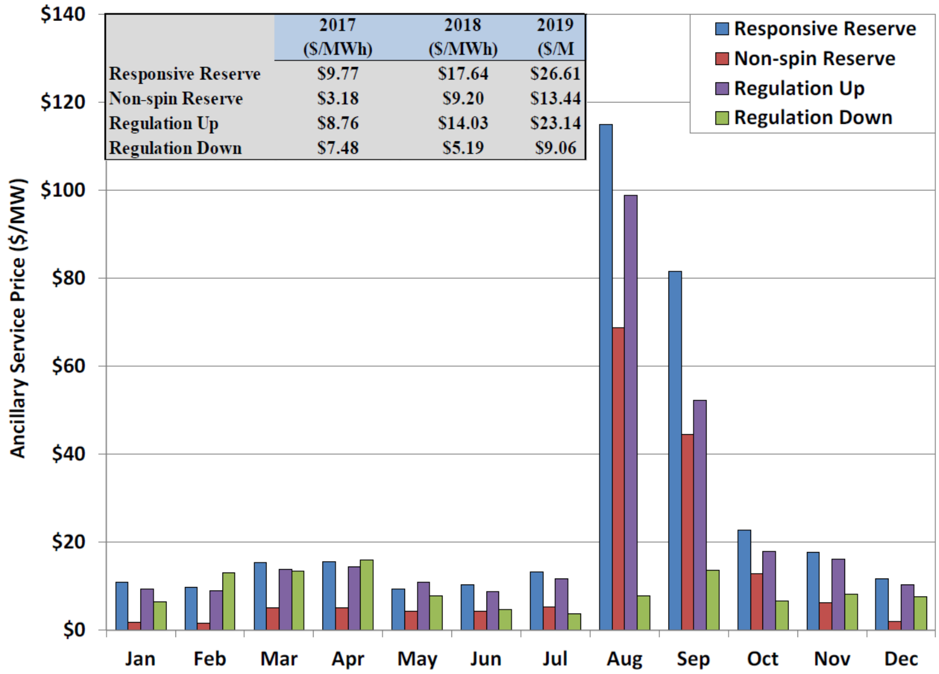

Figure 29 2019 Ancillary Service Prices.

For all 4 regions, the need for upward response services to manage under-frequency has traditionally dominated the suite of system services. In recent years, however, more focus has been placed on over-frequency events and consequently on downward reserve services, in conjunction with under-frequency events. In many countries, symmetrical frequency products are now in existence.

4.2 ANCILLARY SERVICES REQUIRED THROUGH GRID CODES

In this report, we consider ancillary services required through grid codes to be synonymous with non-market ancillary services, and they are the subject of this section. The most common set of ancillary services is related to frequency or load control, which has traditionally often been served by hydropower, if available, noting that hydro is also a very significant balance provider in the power system.

There are many products involved with keeping frequency within acceptable bounds, and most of them are covered by the market mechanisms covered in Section 4.1. As with market-based products, if a participant commits to provide a non-market service, they are required to provide it if it is requested, even though it may not be requested. The fact that some non-market ancillary products are not utilised very often (for example, NLAS in Australia's NEMO has not been called for several years) speaks well to the success of market-based mechanisms, but a power system has to be able to cope with rare but high-impact events, which is when the non-market mechanisms are required. In addition to load or frequency services, the other main mechanisms are voltage (reactive power) control, which has proved very difficult to commercialise, and black-start services.

4.2.1 Australia

From Section 3.11.1 in (AEMC, 2020), the ancillary services are classed as either market or non-market, and this section will focus on the latter.

Non-market ancillary services are acquired by AEMO by tender – in the case of SRAS (System Restart Ancillary Services), according to various ancillary service agreements. With regard to NSCAS (Network Support & Control Ancillary Services), they may be purchased by the relevant Transmission Network Service Provider under connection or network support agreements. Under circumstances where there is an NSCAS gap, AEMO may make the acquisition.

Once a market or non-market participant has entered such an agreement, having classified at least one generating unit or load as an ancillary service generating unit or load and having stated the ancillary service it can provide and the range of operation available, AEMO can issue a dispatch instruction for this service at any time. It is incumbent on the ancillary service provider, whether a market or non-market participant, to ensure that personnel or electronic facilities are available to receive and immediately fulfil the dispatch instructions. Essentially, if a party commits to being able to provide an ancillary service, it must do so when required, subject to certain conditions (e.g., public safety or risk of equipment or environmental damage).

Non-Market Ancillary Services (NMAS)

Figure 30 shows a breakdown of the Non-Market Ancillary Services (ref), which are procured by AEMO to maintain security and availability of supply.

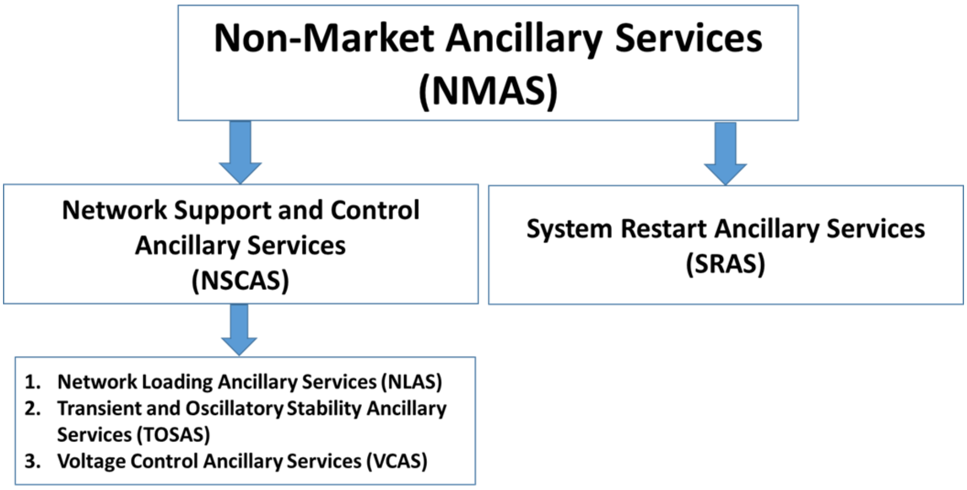

Figure 30 Summary of non-market ancillary services (AEMO, 2020).

Network Support & Control Ancillary Services (NSCAS)

NSCAS has three different categories (AEMO, 2019), NLAS, TOSAS and VCAS.

If there is a flow on inter-connectors exceeding the short-term limits, then AEMO exercises NLAS to control the flow by using Automatic Generation Control or via a Load Shedding event. (AEMO, 2015)

TOSAS can increase the rotating mass inertia connected to the power system, or quickly increase or reduce the load to provide control following a fault event. (AEMO, 2015)

It would seem that neither NLAS nor TOSAS have been procured by AEMO for at least 6 years at the time of writing. (AEMO, 2020b)

Dispatching VCAS is one of the voltage control methods employed by AEMO and is a non-market ancillary service that is procured and deployed quite often, see Table 7, which is Table 5 in (AEMO, 2020b). Generators either absorb reactive power from or inject reactive power to the electricity grid. Two other types of VCAS are: synchronous condenser, and another is static reactive plant such as capacitors or reactors. (AEMO, 2015).

Table 7 Review of utilisation of NSCAS from 2012 to 2019.

Facility	Region	NSCAS	Quantity	Cost 2012-13 ($)	Cost 2013-14 ($)	Cost 2014-15 ($)	Cost 2015-16 ($)	Cost 2016-17 ($)	Cost 2017-18 ($)	Cost 2018-19 ($)	Estimate 2019-20 ($)
Combined Murray and Yass substations	NSW	VCAS	800 MVar[A]	Not procured	3,195,62	9,896,698	10,055,572	10,159,498	10,375,519	10,572,619	Not procured
Combined Murray & Tumut power stations	NSW	VCAS	1,650 MVAr[B]	23,772,200	41,301,706	134,494	171,797	147,088	3,842,236	Not procured	Not procured
Totals				**23,772,200**	**44,497,327**	**10,031,191**	**10,227,368**	**10,306,586**	**14,217,755**	**10,572,619**	**Not procured**

A. The maximum capacity available from this service.
B. The maximum capacity used at any one time over the years shown.

The Murray and Tumut power stations on record as having provided reactive power support in the table above are both large hydro power stations, and while the power sources for ancillary services are not often mentioned in the literature, the efficacy of dispatchable hydro power is indisputable.

System Restart Ancillary Services (SRAS)

If a black-out event occurs, SRAS performs the task of restarting the power system. SRAS uses general restart source technology, i.e. generators that can start and supply to the grid without any external supply, and generators capable of trip to house load. With trip to house load technology, upon detecting a system failure, a generator continues to supply its house load before AEMO is prepared to use it to restart the power system (AEMO, 2015).

Payments

There are four types of payment for the NSCAS and SRAS services. The payment can be a combination of few payment types as well. Payment type and time of those payments is shown in Table 8 (AEMO, 2015).

Table 8 NSCAS and SRAS services payment (AEMO, 2015).

Payments type name	Paid for
Enablement	When NSCAS or SRAS is enabled specifically
Availability	Each trading interval when NSCAS or SRAS is available
Testing	Costs for the services annual test
Usage	Each trading interval when NSCAS or SRAS is utilized

Other non-market Ancillary Services

The Dispatch Support Service (DSS) maintains voltage levels throughout the system and provides security and reliability services that are not otherwise covered. AEMO may contract market participants directly for this service, overseen by the Regulator. A similar arrangement covers LRRAS (Load Rejection Reserve Ancillary Services), which requires that generators are able to rapidly decrease output if a system fault results in the loss of load, although costs are set by the Regulator. Confusingly, SRAS may also refer to Spinning Reserve Ancillary Services, which requires that capacity is kept in reserve to respond to forced outage of another unit. Spinning Reserve includes online generation, dispatchable loads, and interruptible loads that can automatically respond to drops in frequency. Costs for this service are also set by the Regulator.

Cost Recovery

The costs for NSCAS payments are ultimately recovered from the customers. Similar to the cost recovery of the SRAS payments, half the amount is recovered from the customers and the other half is recovered from the generators (AEMO, 2015).

Figure 31 shows the payment types for both VCAS and SRAS services

Service	Payment
Voltage Control Ancillary Service (VCAS)	
Synchronous Condensor	Enablement + Testing
Static Reactive Plant	Availability
System Restart Ancillary Service (SRAS)	
Generator Restart, Trip to House Load	Availability + Testing + Usage

Figure 31 VCAS and SRAS payments (AEMO, 2015).

In a quite recent document on renewable energy production (AEMO, 2020c), which may have some impact on ancillary services, three issues impacted by the penetration of renewables are identified. The first is network congestion. The second, which is interesting in that it implies an impact that ancillary services may have on other generation, namely the curtailment of renewables, is the need to keep generation on-line that is capable of providing inertia, frequency control, voltage control, etc. The third is participant spill due to market signals, for example, when spot prices become negative and/or real-time ancillary prices, e.g. FCAS, are high.

4.2.2 UK

This section will mostly be concerned with what are defined in the UK as system (rather than commercial) ancillary services, which may be implicit in the connections for generators, or may be separately agreed via bilateral agreements

Frequency

National Grid has a statutory obligation to maintain the frequency of the National Electricity Transmission System within ±1% of 50Hz (49.5 to 50.5Hz).

Mandatory Frequency Response (MFR), an automatic change in active power output in response to a change in frequency, is becoming a more common requirement in many transmission systems, and MFR is becoming mandatory in the UK, depending on size and location, and can be offered according to or as a combination of the following response times.

- MFR - Primary Response (within 10 seconds, sustained for a further 20 seconds)
- MFR - Secondary response (within 30 seconds, sustainable for a further 30 minutes)
- MFR - High frequency response (providable within 10 seconds, sustainable indefinitely)

A provider of MFR may offer other balancing services if the ability to deliver MFR if and when required is not compromised. The provider must have a 3 to 5 percent governor droop characteristic and be capable of continuous automatically modulated power responses to counter frequency changes. The service is mandatory for large generators and so there is no tender process. Mandatory Frequency Response is an automatic change in active power output in response to a frequency change and is a Grid Code requirement. Some volume from the MFR market will be entered into the FFR Auction trial, started in June 2019, and discussed below.

Depending on their size and location, a power station may be obliged to have the capability to provide MFR. Summary of connection agreement capability for MFR is in Table 9.

Table 9 Connection agreement capability for MFR.

	National Grid	Scottish Power	Scottish Hydro Electricity Transmission
Small	< 50 MW	< 30 MW	< 10 MW
Medium	50 MW =< 100 MW	N/A	N/A
Large	=> 100 MW	=> 30 MW	=> 10 MW

A new service, Firm Frequency Response (FFR), is now coming into operation, which is intended to provide a route for providers who may not gain access to

MFR, for example. The requirements and response times are more or less the same, but with FFR there is a further division into dynamic and non-dynamic frequency response, depending on whether the service provides continuous service to manage real-time normal operation frequency deviation or whether it is only triggered at a defined frequency deviation. The service seems to be directed towards storage and aggregated demand response providers, where the minimum level is 1 MW (from a single unit or aggregated from several smaller units). This is an example of a service that transmission operators will increasingly require from grid-scale and distributed storage, and aggregated load from the distribution level.

Voltage control service

Voltage increases (or decreases) when Reactive Power (Mvar) generation is greater (or less) than Reactive Power absorption. However, unlike active power for frequency control, Reactive Power generation and absorption requirements for voltage control are regional and vary significantly across the electricity system (Figure 32). For example, demand for active power in one region of the electricity system could be met by active power generation by any other region. This is not true for Reactive Power. Absorption of Reactive Power within a region of the electricity system needs to be met by generation of Reactive Power from that region. The Reactive Power market is less mature than either the response or reserve markets. Where technically possible, providers can participate in reactive power services and provide active power in other balancing services – the onus is on the provider to ensure that the requirements of both contracts can be fulfilled. As an ancillary service, we are here referring to reactive power that is not supplied by synchronous or static compensators. More than £150m per annum is currently spent by National Grid's ESO on these services.

GB procures reactive power (RP) at fixed prices in accordance with the Obligatory Reactive Power Service (OPRS). Reactive power services (National Grid, 2018) are summarised in the following paragraphs.

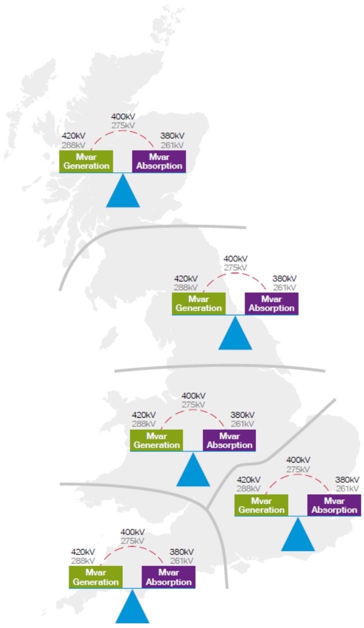

Figure 32 Division of grid into regions for reactive power management. The regions marked are for illustrative purposes only and do not reflect actual regional reactive requirements.

More specifically, the "Connection and use of System Code (CUSC)" outlines the ORPS and must be provided by all generators with a Mandatory Services Agreement. Generally, power stations greater than 50 MW must be able to provide this service, as set out in the Grid Code CC 6.3.27. Service payments are specified in the CUSC.

A parallel auction process, the Enhanced Reactive Power Service (EPRS), seems to have withered away due to no useable offers, but was intended for providers who can exceed the obligatory requirements, or, who are not obliged to offer ORPS but can meet or exceed the ORPS performance standard. ESO have not had a contract for this service since October 2009 and have received no tenders since January 2011.

Voltage Constraint management (voltage) can be managed using following services:

1. Regional voltage constraint contracts (Constraint Management Services). These are tendered commercial services in regions where there is a voltage constraint to synchronise ORPS providers.
2. Forward energy trades under a Grid Trade Master Agreement (GTMA) to synchronise ORPS providers.

Accepting offers from participants in the Balancing Mechanism (BM) to synchronise ORPS providers. In all of these cases, services designed to procure active power are used, often when active power is not needed, to ensure the availability of ORPS providers. Reactive Power generation or absorption is then procured through ORPS.

<u>Restoration services</u>

a) Black start (National Grid, 2018b)
   - Historically the Black Start Capability requirement has been met by procuring Black Start services through bilaterally negotiated contracts with a number of strategically located power stations across Great Britain.
   - to achieving an average Restoration Time across the year of 24 hours to restore 60% of national demand, providing that this can be procured economically and efficiently.

At the time of writing, Black Start providers tend to be large conventional fossil fuel power stations. In order for them to be ready to re-energise in two to three hours, a certain amount of this has to be kept idling (hot), and, as such generation is not always required anymore for normal operation, a part of the generation must be able to started and become ready for operation (e.g. in 89 minutes). (National Grid, 2018c.) The procurement of Black Start service provision is carried out across six zones within the GB network, and involves the capability to accept instantaneous loading of demand blocks, preferably in the range 35 to 50 MW, and control frequency and voltage levels within acceptable limits during the block loading process (under these conditions, frequency can be within the range 47.5 to 52 Hz). Black Start services are procured by a market mechanism or bilateral negotiations.

System Ancillary Services are sub-divided into two parts; part one services are the Mandatory services required from all licenced generators, and; part two services, such as Black Start, which are only provided by some generators on a site by site basis to meet specific system requirements. These services are set out and described in condition 8.1 of the Grid Code.

Further comments

Upward reserve, black start, voltage control, system inertia and RoCoF are provided by the BM (Balancing Mechanism – soon to be superseded by the Electricity Balance System), involving bilateral agreements based on generic contracts. ESO contracts BM start up services throughout the year. The providers can submit changes to their prices up to once per week by 12:00 on Thursdays to take effect from midnight the following Sunday. Both economics and the technical capabilities (e.g., time to synchronise and minimum run time) of each unit are assessed by the Control Room when deciding which units to dispatch.

Also, the requirement for Reactive Power generation has consistently decreased for the last 10 years and ESO expects this trend to continue. As patterns of generation and demand have changed on the system, the availability of ORPS providers at the times when they are needed most has become more challenging. This is most frequently seen during low active power demand periods in the summer, when conventional thermal plant that provides ORPS is less likely to run. This leads to some regions of the country not having enough ORPS providers available when needed, making those areas more challenging to manage and potentially giving rise to a voltage constraint. (National Grid, 2018b)

A fully competitive Black Start procurement process is envisioned by the mid-2020s, which will allow submissions from a wide range of technologies connected at different voltage levels on the network. DNOs will have a more active role.

4.2.3 Ireland

Ancillary services in Ireland are an important component in achieving high penetration of non-synchronous (dominated, presumably, by wind) generation without deleterious effects on system balance and stability. There are, as mentioned in Section 4.1.3, seven established products (POR, SOR, TOR1, TOR2, SSRP, RRS, and RRD) and four more introduced in 2016 (SIR, RM1, RM3, and RM8). Most recently, three new products have been added, FFR, DRR, FPFAPR. These newest three are not required at present to be provided by the Grid Code, whereas the others presumably are, and are procured via the Harmonised Ancillary Services (HAS) arrangements. It seems that prices for services and penalties for failing to deliver are clearly outlined and published by EirGrid (EirGrid, 2020), and that there is continuous updating of the conditions to take part in these activities, especially in allowing smaller entities, less than 1 MW, to take part in FFR.

A necessary development in Ireland, given that the instantaneous penetration of renewables has now reached 75%, is that renewable generation, storage and demand response programmes are now providing ancillary services, in particular FFR, POR, SOR and TOR1. A special programme, known as DS3, has been formed to facilitate the rapid transition to renewable energy and the need for renewable energy itself to take over some tasks traditionally performed by synchronous generation. As earlier noted in this report, a new 700 MVA HVDC link directly between Ireland and (nuclear-dominant) France is being planned, which will presumably help fulfil some of the functions lost as fossil fuel generation is decommissioned (EG 2017).

Voltage Control: A lot of the recent literature from Eirgrid understandably focuses on the reactive power support available and required from wind parks (WFPS), and the means of testing this capability, related to the active power range over which the support can be provided. Reactive power support seems, once again, to be a mandatory requirement in Ireland, and any market-driven initiatives seem to be dormant or non-existent. (What has happened to the Steady-State Reactive Power product proposed in 2014?)

Black Start: Mandatory for Northern Ireland for certain plant types (Hydro, Pump storage, interconnectors, open cycle gas turbines).

4.2.4 U.S. Texas

ERCOT procures 3 ancillary products, regulation service (seconds), response reserve (10 minutes), and non-spin reserve (hours) in a day-ahead market. Load service operators that enter this market are tested for capability (including unannounced testing) and if they fail to deliver when required, they are penalised with the (higher) cost incurred by ERCOT to procure the service from another provider.

There are two non-market ancillary services, voltage support and black start.

Voltage Control: Generators larger than 20 MW are required to provide reactive power services and are only compensated if they are called to exceed the Unit Reactive Limits (URL). The 20 MW lower bound applies to single units, or multiple units, e.g. aggregated wind and solar generation. The power factor requirement is between 0.95 lead/lag at maximum power output at the POI (point of interconnection). The corresponding Mvar range should be available at all times, or at least at partial power, it should be capable of producing the rated range multiplied by the ratio of the active power to rated power. The reactive range must correspond to the voltage profile given by ERCOT. Generators must follow a voltage schedule, dictated by the generator's reactive capability and operate in voltage regulation mode at real power output levels above 10% unless otherwise directed by ERCOT.

Black Start: These are contracted services that are procured on an annual basis. Note that ancillary contracts are capacity contracts – they are not necessarily utilised.

4.3 ANCILLARY SERVICES SECURED THROUGH INDIVIDUAL CONTRACTS BETWEEN TSO AND IPP

In the context of deregulated energy markets, the assumption is that the trading of energy services is made using market mechanisms whenever beneficial. Technical requirements for the connection of devices can also be set in the grid code in order to guarantee the provision of some services which are best suited to be provided in small amounts by each unit connected. There are however also very specific cases where the TSO needs to have resources available in a way that is not suited for market trading or to be made compulsory by grid codes. In those cases, the TSO can sometimes procure them with individual contracts with some resource operators. An example of that is the Reliability and Emergency Reserve Trader (RERT) function used by AEMO in Australia and defined in the National Electricity Rules, chapter 3.20 (AEMC 2020).

RERT providers are required to provide services when notified between 3 hours to ten weeks before the activation. The purpose of RERT is for the TSO to be able to activate power reserves for times when the expected consumption and production cannot be matched by using the conventional market mechanisms. It should be noted however that the selection of the reserves to be activated in case of need is still made based on their location and price, making it ultimately also a form of market-based mechanism. The difference here is that the market is limited to a number of predetermined possible providers.

Another example that can be seen as secured through individual contracts is the provision of black start capacity. A black system refers to an electricity network where there no production or consumption. If the area concerned is small compared to the rest of the system, it can be connected directly and the rest of the system reacts to the connection as it does with any other power deviation (see the frequency services described before). If the area is too large or if it covers the entire system, some generating units have to start producing with no inputs from the grid. They can be used to power up sections of the grid and be either reconnected with the main grid or synchronized with the neighbouring areas in order to restore the system as a whole. In Australia, the UK and Ireland, black start capacity is contracted when a generating unit is installed or, in rare cases, if it is retrofitted with the ability. In Ireland, it is compulsory for specific types of generators (Hydro, Pump storage, interconnectors, open cycle gas turbines) while in the UK it is contracted with each resource individually. In Texas, the procurement of black start services is market-based every two years.

Another interesting ancillary service secured through individual contracts is, in Finland, the agreement between Fingrid (TSO) and TVO, the operator of the upcoming Olkiluoto 3 nuclear power plant (scheduled to be in operation in February 2022, as of August 2020). The TSO has agreed to allows the installation of a generating unit which would otherwise be too large for the safety of the system under the condition that TVO provides a determined amount of fast reacting reserves which would balance out some of the power lost in case of a unit disconnection.

4.4 FORCED OPERATION BY THE TSO

This section relates some of the enforced actions by the TSOs of the regions concerned in this report, namely: the forced production of active or reactive power (up or down), what were the circumstances and which technologies were involved, and what, if any, compensation was made.

Reactive power capability is generally required from significant generators (and clusters of wind-turbines are nowadays significant!), so this could be classed as forced (but mostly automated) operation if the service provider commits that capability for a given trading period, given that a condition to participates the need to keep enough head-room to be able to provide the reactive power support if required.

As far as active power generation is concerned, if a generator opts in to an ancillary service or places an offer to supply via whatever market mechanism, the generator is obliged to deliver, even if, in the case of ancillary products, the generation may not be required (or, in the case of market products, the generation offer may not be competitive). There is a clear push in many countries to try and commodify ancillary services and indeed some non-market ancillary products have not been used for some years, indicating that the market-based mechanisms are working well most of the time. The rapid increase in stochastic renewable production, however, may, in a competitive market paradigm, increasingly push balance and capacity providers into the ancillary sector, and it does seem very difficult to garner interest in market participation for reactive power for voltage support.

There are case studies of load shedding and why that occurred, but for Ireland and Texas, there is not much information available through public sources. Finland, for example, has some 1 300 MW of reserve power available (diesel, coal, natural gas, etc. - owned by Fingrid or leased) for use during a disruption in generation or during extremely cold weather. If there is an imminent risk of a power shortage, Fingrid can force reserve plant to run in idle in advance, to allow quick ramping up if needed, and it is presumed that all countries have such capabilites.

What follows is a review of the four countries, specifically narrowing down on forced operation by the TSO and mentioning load shedding events where this is available.

4.4.1 Australia (AEMO)

The specific AEMO mechanism for forced operation, other than the Non-Market Ancillary Services (NMAS) described in section 4.2.1, is RERT (Reliability and Emergency Reserve Trader), (AEMO, 2020d). This consists of either non-scheduled load or generation, subject to: availability (i.e., available at the relevant time of year, and not available for anything else) and not less than 10 MW for at least 30 minutes. The availability, pre-activation (for non-scheduled generators) and early termination are coved by RERT contracts. RERT is often used, especially in the summer. For example, on January 23, 2020, 520 MW of short notice reserve was contracted in New South Wales, lasting 9.5 hours. (AEMO, 2020e). AEMO notes that load shedding due to hot weather conditions is different to planned local outages due to maintenance and unplanned outages due to line faults caused by storms, bushfires or accidents. In order to avoid load shedding, AEMO will try to import more power from other states, or utilise emergency reserves (such as South Australia's diesel-powered generators, which were switched on for the first time in the summer of 2019-20.

The need for cooling in Australia in the southern hemisphere summer corresponds to the need for heating in the Nordics, at the same calendar time of the year! The summer 2019-20 activation of RERT services is shown in Table 10.

Table 10 RERT services activated during summer of 2019-20 (AEMO, 2020f)

Activation date	NEM region	Maximum capacity of RERT activated (MW)	Volume of RERT activated (MWh)	Total RERT cost ($ million)[A]	Estimated avoided cost of load shedding based on VCR ($ million)[B]
30 December 2019	Victoria	92	283	$3.72	$11.66
4 January 2020	New South Wales	68	232	$8.36	$9.77
23 January 2020	New South Wales	152	456	$7.54	$19.21
31 January 2020	Victoria	185	697	$7.54	$28.72
31 January 2020	New South Wales	134	418.5	$10.93	$17.63
Total	-	-	**2,086.5**	**$38.09**	**$86.99**

The other side of the equation, if generation cannot be quickly enough dispatched when there is, for whatever reason (storms, forest fires, extreme prolonged weather events, generator outages, line faults, transformer failure…), a shortfall in supply with respect to load, is of course load shedding. This is always kept as a last resort, in order to prevent uncontrollable cascading black-out. The cost of avoiding load shedding is also given in Table 10, and the reference also mentions that demand response measures helped prevent the need for load shedding during the summer of 2019-20, although there had been shedding in previous years.

4.4.2 UK (National Grid)

The mandatory response services STOR (Short Term Operating Reserve) and DTU (Demand Turn-Up) are market based and are described in subsection 4.1.2

A rather amusing political debate following load curtailment in England in 1950 can be found at (Hansard, 1950).

More seriously, on August 9 in 2019, following a record day for wind generation, an offshore wind farm tripped, losing 790 MW (scheduled frequency response mechanisms arrested the drop in frequency at 49.2 Hz) followed by the loss of a gas-powered 660 MW plant, which was too much for the scheduled frequency response products (MFR in subsection 4.2.2) to cope with. What is known in the UK as Low Frequency Demand Disconnection (LFDD) then commenced, affecting over a million customers from 15 to 45 minutes, and causing disruptions to the transport infrastructure that took even longer to sort out. (UKERC, 2019) LFDD is managed by the distribution network operators (DNOs) and governed by Ofgem and is very rarely used.

4.4.3 Ireland (EirGrid)

The main curtailment that seems to have occurred frequently in Ireland in recent years is the curtailment of wind generation, due to transmission congestion and the necessity of keeping a minimum amount of dispatchable generation running for system stability. Ireland still is in a relatively comfortable position of supply surplus, but with the decommissioning of fossil fuel generation and a projected increase in demand, in good part due to data centres, this will soon be under threat. So, there is no recent literature about demand curtailment, which is quite impressive, noting the high penetration of wind generation in Ireland.

4.4.4 U.S. – Texas (ERCOT)

Impressively, Texas, with its high wind penetration, has come close but has avoided demand curtailment. In the summer of 2018, the public were asked to curtail the use of air-conditioning, but forced curtailment was not necessary.

4.5 FLEXIBILITY DUE TO ENERGY PRICES

The flexibility due to energy prices is a direct consequence of the operation of the power markets. Producers and consumers, or their representatives, put bids in the market which consist of a curve specifying how much they are willing to produce or consume for each specific clearing price on the market. Detailed market curves are not publicly available because they could be used by some participants in order to take unfair advantage of the market and to attempt to adapt their prices based on what the other actors are offering, leading in inefficiencies in the market operation. In general, however, producing units are incentivised to submit bids corresponding to their operating cost which are, in turn, close to the cost of the fuel used in the production process. In consequence of this, generators are encouraged to produce when the market price covers their operating costs and to stop the production when the price goes too low.

In practise, the situation is a bit more complex. For example, wind or solar powered generating units, with no fuel costs and very small operating costs are sometimes encouraged to produce even with negative prices as their costs would be recovered through various support mechanisms in place to increase the capacity provided by such units.

Another type of plant where this reasoning applies only to a limited extent are units where the physical characteristics of the plant make it very expensive to turn down or off the production and to bring it back up a short while later. A good example of this are older nuclear power plants, which were designed to provide the base load capacity and are not very efficient when working at partial capacity or present very high costs and ramp times if they were to be tuned down.

4.6 EVALUATION AND APPLICABILITY IN THE NORDIC GRID CONTEXT

We now attempt to assess which of the covered ancillary services in the four regions studied would be applicable in the Nordic grid, and what their strengths and weakness might be.

The technical requirements for ancillary services depend on the characteristics of the power system. The TSOs of interconnected areas agree on the technical boundaries that need to be implemented in order to guarantee a satisfying level of security in the system (dimension of the largest faults, number of them that can occur simultaneously, the maximum frequency and voltage deviation required to keep the system running, etc.). Based on those technical requirements and on the regulation in place (degree to which the solution need to be procured on a direct market basis, obligation to treat market actors equally or fairly, etc.), the TSO sets up its various ancillary markets. The characteristics of the power systems in the regions under consideration are different and thus, the ancillary service products for them cannot be precisely the same. Although they constitute power systems of quite different magnitudes, both in terms of geography and load density, Australia, U.S. Texas, UK and Ireland indicate the development in which ancillary services could be going in the future, as they have a lot of renewable and variable generation. These four regions or countries have developed specific ancillary service products for their systems. The main criteria are the activation time, ramping rate and duration of the ancillary service product when assessing the suitability of the four-region ancillary services products to the Nordic grid context. The mapping of ancillary services products for frequency and voltage is set out in Annex A using the following categorisation.

4.6.1 Fast Frequency Response (FFR)

For the FFR category, the corresponding Irish ancillary service products most closely resemble the corresponding services in the Nordic system. The generic functionality is similar between the various FFR services, but the activation and duration times are different. In other countries, the activation time requirement is shorter or the duration requirement is considerably longer. If the duration is longer, it eliminates many technologies. For example, in the Nordic system, the FFR activation period is longer than the Irish one, but the duration is shorter. A short activation time and a shorter duration in their own markets will lead to lower prices for ancillary services products, as it will enable these services to be provided by many technologies**.**

In the Nordic electricity system, FFR has been defined in general in accordance with EU regulations, but the time and duration of activation of services have been decided on the basis of the technical requirements of the Nordic power system. The existing larger European power systems do not yet need so much FFR, because of the high penetration of nuclear, large coal and gas fired power plants, which provide a lot of inertia. The FFR products of the Nordic system depend on the hydrological situation, the nuclear system, the loads and the system's largest dimensioned fault for which reserves are needed. The Nordic electricity system has less inertia, more and more loads in southern Sweden and southern Finland, more wind power in Denmark, Sweden and Finland, as well as in Norway, and more DC cables and long-distance transmission lines that affect the stability of the system. Regarding the inertia, it is not possible to give accurate indication where (geographically) in the Nordic system the inertia has decreased the most. Fingrid and Energinet web pages give historical hourly inertia values for Sweden, Norway, Finland and Denmark (price area DK2) only for the years 2019-2020. During this period most average decrease of inertia was in Sweden. Future inertia estimations for different future scenarios, presented in Ørum et al, 2017, show that with 99 % probability, the kinetic energy will be more than 120 GWs or 134 GWs in 2020 and 2025, respectively. In the current Nordic power system (2010–2015), the estimated kinetic energy was below 140 GWs 4 per cent of the time or less. Hence, the inertia levels will not change drastically from the present level (ENTSO-E, 2019c).

In this respect, the electricity systems in the four regions under consideration are different and are developing differently, and therefore, AS products cannot be the same. Australia, for example, has a lot of coal fired thermal power. Australia has a very sensitive power system and it is difficult to maintain system stability, so they need fast FFR to avoid imbalance. The FFR product is under preparation in Australia, and the following technologies are to be used: batteries, flywheels and super-capacitors, wind turbines and wind pitch control and PV set point operation. Generators, batteries and demand side units provide this service in U.S. Texas. Proven technologies providing FFR service in UK and Ireland are conventional generators, different types of storages, industrial demand side units and also HVDC interconnectors.

4.6.2 Frequency Containment Reserves (FCR)

In the Nordic system, FCR-N (normal operation) and FCR-D (disturbances) apply. FCR-D is designed to react to larger dips in the system frequency, corresponding to the loss of a more significant generating unit. In the four regions studied, only “the Mandatory Frequency response - Secondary response” and “the Firm Frequency Response – Dynamic, Secondary response” in the UK are in the same time frame. These services also provide down regulation in order to react to more important increases in frequency, caused for example by wind resources. In the future, as the penetration of variable production units increases in the Nordic countries, the system may experience sudden upswings in production, leading to a need for fast down-regulation. This could be included in the FCR-D products or beaded as a separate one similar to, for example, Ireland's "Secondary Operating Reserve (SOR)".

This FCR-N category includes a lot of ancillary services products in the four regions, such as in the UK, where there are overlapping products. The activation time in other countries is considerably shorter than in the Nordic countries and, also the requirement for duration of the ancillary service is shorter. Many ancillary products mean a more sensitive electrical system, so the electrical system needs a variety of automated and manual ancillary services products. In an emergency, a slow linear ramping of the power plant is also required. The TSOs in the Nordic countries are planning to increase the use of the "automatic Frequency Restoration Reserve (aFFR)" standard product (Fingrid, 2020a), and as a result, it is expected that the use of FCR-N in the Nordic countries will gradually be reduced. Typical technologies providing this service are conventional generators, demand side units and different types of storage. EirGrid also uses HVDC interconnectors.

4.6.3 Frequency Restoration Reserve (FRR) and Replacement Reserve (RR)

The Nordic system does not have replacement reserves. Between the operation of the FRR reserves, of the intra-day market and of the balancing market, the Nordic system does not require specific RR services.

Frequency Restoration reserves products are activated automatically or manually. The manual products are required when the system is out of normal operation. In this category, the Fast Reserve (FR) UK is somehow close to the Nordic FRR product regarding the time frame. If the market develops from an hourly balance settlement period to a 15-minute balance settlement period in the future, it will be no longer necessary to cover very slow reserves. If the activation period for products is, for example, 15 ---30 minutes, they will be covered by the energy markets. In the Nordic system, the hydro power plants are the primary source for FRR and also load disconnections are used. The Nordic market is not very developed in this category, but it can be observed that at least in Finland, more down regulation is being provided than upregulation in the FRR markets. Conventional thermal power plants and demand side units primarily provide both up- and down regulation in the four regions. U.S. Texas and Ireland use also HVDC interconnectors, and Ireland and the UK exploit different types of energy storages.

4.6.4 Voltage control

In Sweden, the Svk has had an agreement with NPP, such that, if system limit was exceeded, compensation was paid for the NPPs to provide reactive power. However, this agreement has not been implemented in the past years and is no longer in force. Fingrid's guidelines for voltage and reactive power control apply primarily to 110 kV network-connected 10 MW power plants as well as to distribution networks, where the DSO applies the same type of principles. If the use of reactive power at an individual connection point, as determined on the basis of the application instruction (Fingrid, 2020) is exceeded, Fingrid will invoice the customer or DSO monthly for the hourly average reactive power output and input and the reactive energy. For reactive power requested from the customer to support the main grid, Fingrid shall pay compensation for the monthly biggest hourly mean power in excess of the reactive power limit, and for the excess reactive energy.

Each of the 4 regions have somehow similar obligatory requirements for generators based on grid codes that generators shall support the system voltage by means of the reactive power reserves during faults and disturbances occurring at power plants and in the grid. There are no functioning markets for voltage control and reactive power at the time of writing. Compensation is based on bilateral contracts. For example, AEMO has different types of payments: enablement, availability, testing, and usage of reactive power reserves. UK has fixed payments for "Obligatory Reactive Power Service (ORPS)" etc. ERCOT (U.S.) has no compensation method. For generators over 20 MW, it is mandatory to provide reactive power. The compensation is paid if the reactive power limits are exceeded and if extra reactive power over the standard reactive power of the generator is required. In those regions there have been attempts to create reactive power markets, but they have not yet succeeded.

It is very hard to create reactive power markets and very difficult to get real competition on the markets, because voltage control is needed locally and markets should be also local. For example, if there is only one connection in each point, it is hard to create real markets. How to create the market depends on the structure of the power system and the future construction of the power system.

The technologies providing voltage control and reactive power support are synchronous generators, synchronous condensers, capacitors or reactors, power flow and voltage control FACTS devises such as SVCs and series compensation.

4.6.5 Black start capacity

Historically, in Europe, black start capacity has been contracted bilaterally between the TSO and the possible providers. There is however a trend to procure such services on a market basis. Black start capacity has been the object of long-term (a few years) markets in Australia and Texas for a long time, it has seen a change from bilateral contracts to a market in the UK. It is a compulsory service for the plants able to provide it in Ireland.

In the Nordic system, there is a heavy reliance on the neighboring systems or on the clusters of hydro generators with good black start capacity to reenergize an individual region. Larger plants are required to be available and help to restore the system, but the neighboring regions are the primary source of power (ENTSO-E 2014, Fingrid 2014).

Market based mechanisms such as in the 4 regions examined could possibly be adapted to the Nordic system, but the use of strongly interconnected neighbors with stable systems would make it difficult to implement in a fair way.

4.6.6 EU policy for future ancillary services and European market integration

The European power system is transforming rapidly to integrate more renewables, develop flexibility and enable consumers to play a more central role. National and regional markets are becoming increasingly integrated towards a common European market (ENTSO-E, 2018). EU Commission regulation 2017/2195 lays down a detailed guideline on electricity balancing including the establishment of common principles for the procurement and the settlement of frequency containment reserves, frequency restoration reserves and replacement reserves and a common methodology for the activation of frequency restoration reserves and replacement reserves (EU, 2017).

The harmonization is going on at EU level (including Nordic) regarding ancillary services. The future regulation will base on the Balancing Guideline, the System Operating Guideline and all the decisions that are coming from these. Ancillary service products applicable in the Nordic power systems are being developed in the following direction.

Fast Frequency Reserve (FFR)

The Nordic Transmission System Operators (TSOs) had identified a worrying trend towards decreasing system inertia. Decreasing system inertia which in a case of e.g. a large loss of production leads to a rapid and deep drop in frequency. Occasionally, the inertia level is so low that the current frequency containment reserves cannot guarantee frequency stability after an incident. This usually occurs in situations with low proportion of production from synchronous generators in combination with a high proportion of wind power and import. Situations like this can occur during summer and during hydrological dry years. In order to participate in the FFR markets, it is necessary for FFR providing entities, to be prequalified. Technical requirements for FFR provision in the Nordic synchronous area specify formal technical requirements for FFR providers as well as requirements for compliance verification and information exchange.

The FFR volume is quantified in MW. At maximum 50 MW of FFR provision is allowed to lie behind a single point of failure. The activation requirements for both long and short support duration FFR are the same. The activation may be a step or a ramp or something similar.

There are three different combinations for frequency activation level and maximum full activation time, that are equally efficient for FFR provision, and the FFR provider can freely choose the most suitable combination for each specific providing entity:

- 0.7 s maximum full activation time for the activation level 49.5 Hz
- 1.0 s maximum full activation time for the activation level 49.6 Hz
- 1.3 s maximum full activation time for the activation level 49.7 Hz

FFR has to be suitable to the power system frequency stability needs, providers' capability to provide FFR and market solutions for auctions and trading. Therefore, two different FFR support durations are specified:

- Long support duration FFR (with a support duration of at least 30 seconds)
- Short support duration FFR (with a support duration of at least 5 seconds)

It has been concluded that underfrequency situations are much more critical than overfrequency situations. Therefore, FFR is defined only for underfrequency situations (ENTSO-E, 2020). The prequalified FFR capacity and the FFR overshoot are illustrated in Figure 32 and recovery in Figure 33.

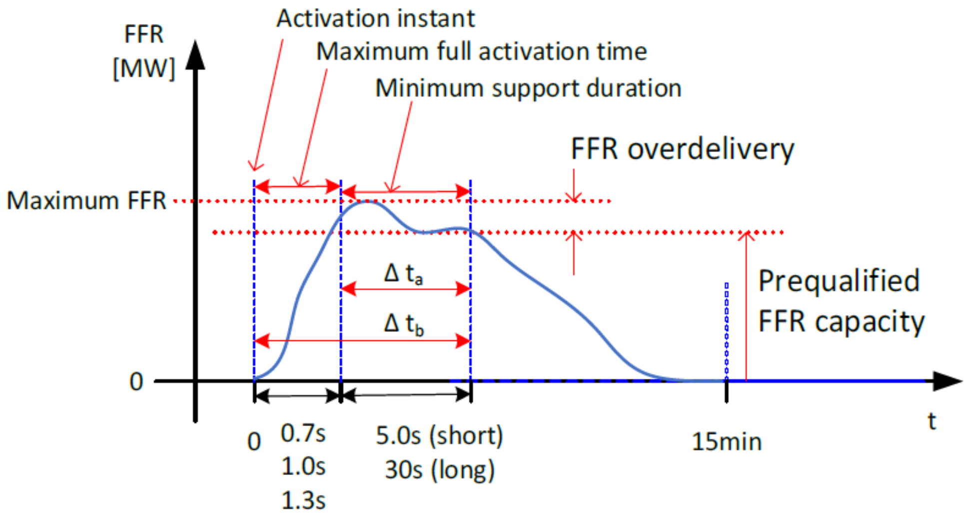

Figure 32 FFR capacity and overshoot (ENTSO-E, 2020).

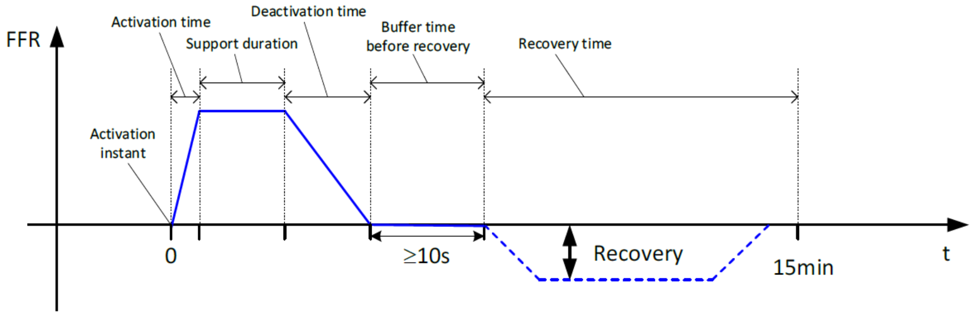

Figure 33 FFR recovery requirement, activation time at t=0 (ENTSO-E, 2020).

The FFR providing entity must be ready for a new FFR activation cycle within 15 minutes after the activation instant. Irrespective of this requirement of readiness for a new cycle within 15 minutes, the FFR may stay active as long as the frequency is below 49.8 Hz and start the deactivation sequence when the frequency exceeds 49.8 Hz.

Frequency Containment Reserves (FCR)

The common market for procurement and exchange of FCR (FCR Cooperation) aims at the integration of balancing markets (ENTSO-E, 2020a). Regarding the FCR there are different requirements for the different synchronous areas, and especially the smaller areas with less inertia like Nordic system have special requirements. Nordic system is planning to increase the use of the aFRR standard product, and it is expected that the use of FCR-N in the Nordic will gradually be reduced, as more aFRR is introduced. The Nordic FCR-Design project aims to revise the FCR-D requirements where the overall goal was to relax the FCR-D requirements and thereby qualify more capacity to receive sufficient liquidity in the future FCR-D market (ENTSO-E, 2019a & ENTSO-E, 2019b). The FCR-Design project contains the following main parts:

- Revision of the FCR-D design requirements to qualify more hydro FCR-D capacity
- Switch-over between FCR-N and FCR-D and vice versa to secure acceptable behaviour when delivering both FCR services from a hydro unit.

Currently Nordic TSOs are however re-evaluating these requirements, and some changes are expected, however it has not yet decided (ENTSO-E, 2017).

The dimensioning FCR-D capacity shall be 1450 MW for all levels of system kinetic energy.

Three FCR products are defined and can be provided independently:

- FCR-N, in the range of 49.9 – 50.1 Hz
- FCR-D upwards regulation, in the range of 49.9 – 49.5 Hz
- FCR-D downwards regulation, in the range of 50.1 – 50.5 Hz

In the FCP project the performance requirements were divided into following parts:

- Steady state power change when exposed to a frequency step change of ±0.4 Hz
- Power and energy requirements 5 s after a frequency ramp of 0.3 Hz/s with 3 s duration is applied

FCR-N dynamic performance requirement applies to time periods from 10 s to 300 s.

FCR-D entity must be able to fully activate its FCR contribution for at least a time period in the interval 15 to 30 minutes (ENTSO-E, 2019a & ENTSO-E, 2019b).

Frequency Restoration Reserves (FRR)

For both aFRR and mFRR there have been identified some standard products that TSO's have to be used in the common markets. For delivery of aFRR and mFRR energy there will be established common PAN European markets, look for either the PICASSO platform for aFRR or the MARI platform for mFRR (ENTSO-E, 2020b). As this is PAN EU decision it will most likely not be changed in any near future. Nordic TSOs have to use these products as well. If a country for its local conditions will need something different, it can procure a specific product, but these products cannot be traded cross border, and will not be a part of any common market. The definition of the aFFR and mFFR balancing energy product are in the Table 10.

Table 11 Standard aFRR and mFFR balancing energy product characteristics (ENTSO-E, 2018b, ENTSO-E, 2018c).

Standard product	**aFFR**	**mFFR**
Mode of activation	Automatic	Manual
Activation type		Direct or scheduled
Full activation time ("FAT")	5 minutes	12.5 minutes
Minimum quantity	1 MW	1 MW
Bid granularity	1 MW	1 MW
Maximum quantity	9,999 MW	9,999 MW
Minimum duration of delivery period	15 minutes	5 minutes
Price resolution	0.01 €/MWh	0.01 €/MWh
Validity Period	The validity period shall be 15 minutes. The first validity period of each day shall begin right after 00:00 CET. The validity periods shall be consecutive and not overlapping.	A scheduled activation can take place at the point of scheduled activation only. A direct activation can take place at any time during the 15 minutes after the point of scheduled activation

Each TSO shall define the full activation time of the standard aFRR balancing energy product for the time period until 17th December 2025 in their terms and conditions for BSPs in accordance with Article 18 of the EBGL (EU, 2017). The full activation time of the standard aFRR balancing energy product shall be 5 minutes starting from 18th December 2025. The deactivation period shall not be longer than the full activation time.

Some of variable characteristics of the standard mFRR balancing energy product bid shall remain under national responsibility, including, but not limited to, minimum duration between the end of deactivation period and the following activation and maximum duration of an activation.

Replacement reserves (RR)

The aim of Trans European Replacement Reserves Exchange (TERRE) is to build the RR Platform and set up the European RR balancing energy market in order to create a harmonized playing fields for the Market Participants (ENTSO-E, 2020). From a commercial point of view, the RR standard product is a 15-minutes scheduled block product that can be activated for a fixed quarter hour or a multiple of a fixed quarter hour. The Nordic TSOs are not using RR product and haven't joined this activity. The Table 11 contains the main characteristics of the RR standard product.

Table 12 Standard RR balancing energy product characteristics (ENTSO-E, 2018d).

Standard RR	
Mode of activation	Manual and scheduled
Preparation Period	From 0 to 30 min
Ramping Period	From 0 to 30 min
Full Activation time (FAT)	30 min
Deactivation period	Under national responsibility
Minimum quantity	1 MW
Maximum quantity	In case of divisible bid, no max is requested only technical limit (IT limit). In case of indivisible bid, national rules will be implemented
Minimum duration of delivery period	15 min
Maximum duration of delivery period	60 min[1]
Location	Bidding Zones
Validity Period	Defined by BSP and respecting the min and max delivery period
Minimum duration between the end of deactivation period and the following activation	Recovery Period = determined by BSP
Divisibility	Divisible and/or indivisible bids allowed (Resolution for divisible bids = 0,1MW)
Price of the bid	Defined by the BSPs €/MWh
Timeframe resolution	15 min

[1] The maximum delivery period depends on the number of daily gates.

4.7 MARKETS AND SERVICES TECHNICALLY SUITABLE AND APPLICABLE TO NPPS

In the previous section, the status and possible trends for the ancillary services provision in the Nordic countries were presented. This chapter focuses on the potential for the provision of ancillary services by Nuclear Power Plants (NPPs), based on existing operational experience.

The motivation for going flexible and the flexibility modes in use for a Nuclear Power Plant can vary significantly according to the regional context, depending strongly on the development of the grid requirements in the region and the corresponding current market conditions. For the purpose of this report:

In the regions under consideration (Australia, UK, Ireland, U.S. Texas), only UK and US Texas have NPPs.

- Overall, current U.S regulations only allow a licensed reactor operator to change reactor power which, in turn, changes the plant electrical output. As a result, U.S. nuclear plants cannot participate on remote-controlled grid services. Despite these restrictions, most U.S. nuclear plants were originally designed to accommodate flexible operating modes in their original design. These inherent flexible operations capabilities are, in fact, now being utilized at several U.S. nuclear plants as a means to accommodate the significant introduction of renewables and to avoid negative power prices in the market. Other NPPs, including the NPPs in U.S. Texas are still operating at base load, but are evaluating this option. NPPs in US are required to produce/accept voltage regulation.

- In the UK, NPPs have also been mainly operating in base load. Currently, the need for nuclear flexibility has strongly increased. EDF Energy has been asked to temporarily reduce output at its Sizewell B nuclear plant in the east of England to help balance the grid and prevent blackouts, in accordance with a special agreement with grid operator. Leading to part load operation at half output throughout the summer of 2020, further flexibility is under investigation. In UK all large power stations including NPPs are required to participate in voltage regulation. New NPPs, e.g. UK EPR, should incorporate advanced flexibility in the future.
- Overall, in the chosen regions, NPPs have been running mostly in base load operation, however, so they don't have a strong operational experience in flexible operation. Currently, the flexibility option is under discussion for their NPPs.

- France and Germany, on the other hand, are leading countries in applying flexible operation modes for NPPs. Notably, the German grid has a very strong penetration of volatile renewable energy and has already recorded hours with 100 % of demand provided entirely by renewable sources. Furthermore, it is important to note that the regions of Germany (in terms of transmission operator jurisdiction), or even Germany as a whole, do not have such a large nuclear fleet as EDF in France, which has 58 NPPs. That is why much more flexibility is required from each particular plant in Germany. Taking into account these facts, Germany is probably the best example and reference for the Nordic system.

4.7.1 Introduction to services in Germany

This chapter gives a summary of the services in Germany, which have been provided by NPPs for several years in a safe and reliable manner.

Germany has a liberalized market that employs zonal pricing. The German TSOs maintain balance between their control areas at all times with control reserves of various types:

- Primary Control reserve (PCR) equivalent to European Frequency Containment Reserve (FCR), could be in general comparable to Nordic FCR-N
- Secondary Control Reserve (SCR) equivalent to European Frequency Restoration Reserve with automatic activation (aFRR), exists in Nordic system
- Minute Reserve (MR) equivalent to European Frequency Restoration Reserve with manual activation (mFRR), exists in Nordic system

They are commonly procured across their control areas and partly in cooperation with neighbouring countries, e.g., via the open internet platform www.regelleistung.net. Such close cooperation of TSOs should be further extended in the coming years across all TSOs in Europe, via the establishment of European balancing platforms.

It still has to be mentioned that the proportion of generation procured together via

- short term capacity reserves, including back-up (RR) and FCR/FRR, and
- short term and intraday market participation, including the ancillary services discussed in this report

is relatively small compared to the generation procured on the mid-term scale (2-3 years in advance to 1 month in advance). Overall, these new pricing models, including procurement of ancillary services, comprise about 5 % of the NPP generation, which can, however, be very profitable for the NPP. For the NPPs supplying ancillary services, the revenues these services amount to in relation to energy revenues is not available.

Table 13 gives a short description of the existing flexible operation modes of NPPs that provide various market-based balancing services for the grid, with operating examples from various plants and utilities. Further on they will be visualized to get an overall picture. Other ancillary services provided by NPPs are voltage regulation, providing reactive power, and participation in operational services, such as dispatch/redispatch or emergency services are also presented in the table.

Table 13 Definition of the existing flexible operation modes including German examples.

NPP Mode/Grid Service in Germany	Description and Examples
Load Following (LF) as a result of portfolio optimization **(Economic dispatch)**	Depends on demand/supply balance • E.g., LF is required by European Utilities' Requirements in the range from 100% REO down to 50 % REO (lower levels can be agreed, but not lower than the minimum load of the unit) with a typical ramp rate of electric output of 3% of REO/min. Thereby, the defined number of transients are two per day, five per week, and cumulatively 200 per year. Scheduled and unscheduled LF should be allowed during 90 % of the cycle (NEA, 2011). • This works on the predefined variable load programs, i.e., reductions or increases in power output agreed in advance. • The load program is defined by the load dispatcher (day ahead) according to availability and cost optimisation for all generators of this utility (portfolio optimisation). Results from the Intraday-market can change the load plan, several times during the day. • Results from the Intraday-market can also change the load plan, several times during the day. • It is typically requested more than one hour in advance. • It can be performed manually or automatically with the help of corresponding software. The ramp rate is set by the reactor operator on request of the load dispatcher and is typically in the range of 10 to 30 MWel/min – and could be lower, e.g., depending on the time in the fuel cycle. • Minimum power level is specified in advance.

NPP Mode/Grid Service in Germany	Description and Examples
	LF could be performed by a German NPP from full power till minimum load, approximately 30%- 40%, but typically the minimum level for LF is defined at about 50%-60% REO for PWRs and approximately 60% REO for BWRs to reduce the possible impact on the plant.
Primary Frequency Control (PFC) providing **PCR / FCR**	Depends on the current grid demand, performed as a step change of the grid supply or in the load • E.g. European Utilities' Requirements require PFC for new builds as an instant automatic response giving the full contribution in 30 s, lasting up to 15 minutes and with the typical range of ± 2 % of the rated electrical output (REO) (mandatory), but higher values up to ± 5 % REO may be agreed between system operators and plant operators (NEA, 2001). • German transmission code requires ± 2 % REO linear provided in 30 s, in accordance with European grid code (German transmission code, 2007). • Primary balancing is procured as a symmetric capacity service and since July 2020, daily (4 h production), with minimum quantity of ±1 MW (previously it was a weekly procured service) and is determined at the European level. • The production of the up/down PCR can be carried out by different generators. • Grid frequency is linked directly to the turbine power controller in order to compensate the energy misbalance in the grid directly. • The prequalified range for PFC varies considerably plant by plant, from 2 % to 10 % REO (maximum for a German NPPs was realised during the test for a load drop of 14 %). Typical range would be ±50 MWel. • Depending on the optimum dispatch, the typical response is much lower. • PFC is initiated by plant shift on demand of grid dispatcher, resulting from market auction & TSO requirements. • PFC can be performed within a specified power level range, thereby the minimum power level is typically defined at 50% - 60% REO
Secondary Frequency Control (SFC) providing **SCR/aFRR**	Depends on current grid demand (stochastic load changes, supplier outages) and is performed as an automatic remote-controlled ramp in a specified power range (by the grid dispatcher) • E.g. European Utilities' Requirements for new builds requires that the variation rate shall be 1 % of REO/min, although values up to 5 % REO/min may be agreed between system operator and plant operator (NEA, 2011). • Participation in the SFC is optional. Since 2015, SFC has been defined as an automatic response in 5 minutes. (Previously it was the response within 15 minutes). • SFC is procured as a capacity and energy (performed) service, can be positive and negative with a duration up to 15 minutes. Since July 2018 daily (4 h production), with minimum quantity of ±1 MWel (previously it was 5 MW and a weekly procured service). Additionally, a reaction time of 30 s is defined.

NPP Mode/Grid Service in Germany	Description and Examples
	• The activation of the SFC is carried out by a plant shift on request of the grid dispatcher, resulting from market auction & TSO requirements. • Ramp rate (rate of change in power) is also set by the reactor operator and is typically in the range between 10 and 30 MW/min in Germany. • The dispatcher directly governs the target set point of the turbine load within the mentioned range (limited in the turbine control). • Some NPPs are taking part mostly or only on the negative SFC. • SFC can be performed within a specified power level range, thereby the minimum power level is typically defined at 50% - 60% REO.
Tertiary frequency control (TFC), **called** **Minute Reserve (MR)** providing **MR / mFRR**	Depends on current grid demand and can be performed as an automatic or manual actuated ramp • Activation time of this reserve is between 7.5 and 15 min and the duration is from 15 minutes to a few hours. It can be requested, at the latest, 7.5 min in advance. • This service is daily procured as a capacity and energy (performed) service, can be positive and negative. Since July 2018 daily (4 h production), with minimum quantity of ±1 MW (previously it was 5 MWel and a weekly procured service) and with six 4-hour time slices • The activation of the MR is carried out by a plant shift on request of the grid dispatcher, resulting from market auction & TSO requirements. • The ramp rate is also set by the reactor operator and is typically, in Germany, in the range between 10 and 30 MW/min (depending on the ramp duration at the low level). • Often NPPs are taking part only on the negative MR. • PFC, SFC and MR can be superimposed. • MR can be performed within a specified power level range, thereby the minimum power level is specified and typically defined at 50% - 60% REO
Voltage regulation providing **reactive power**	Secures voltage stability of the grid • Activated by short-term grid dispatcher request via telephone • Grid dispatcher can have access to the tap changer of the NPP • It can be defined in the grid code requirement or agreed via bilateral contracts. It is a local service and in Germany has prices approved by the regulator, e.g., under excited mode of NPP is not rewarded (adequate payment, e.g., via own market is needed from utility point of view). • Currently various generators are operating in the under excited mode most of the time, e.g. annual participation in voltage regulation of a single NPP • typical inductive activation of approximately 150 Mvar (up to approx. 450 Mvar) • mostly in under excited mode, typical activation of about approx. 200 Mvar (up to approx. 350 Mvar)
Extended Low Power Operation (ELPO) **as a**	Performed with single power reduction and is applied to adapt to a longer-term demand forecast. • Power level and duration are forecast. After performing the ramp, the NPP returns back to full power on request of the load dispatcher. • Definition is country dependent with typical duration of > 24 h, but, e.g., in France the duration > 12 h at a low level is defined as ELPO.

NPP Mode/Grid Service in Germany	Description and Examples
result of portfolio optimization **(Economic dispatch)**	• Fuel conditioning / deconditioning is an important limitation factor for the return to full load. • The ramp rate and minimal power level is set by the reactor operator on request of load dispatcher. • Ramp rate depends on Boron concentration and strongly differs between up- and downwards. • Existing operation experience for daily, weekly, monthly ELPO, e.g., several months, at less than 40% RTP (100% = RTP - rated thermal power) in addition to extensive load following for about 2,5 years • Overall, ELPO at minimum power level is used only in some German NPPs and in very specific cases (e.g. very high negative prices)
Redispatch **(Overload mangement)**	Defined as a shift in the planned power production to avoid network bottleneck, leading to a short-term agreed change in the predefined load program - single power reduction • Start of ramp down by plant shift on demand of grid dispatcher, resulting from TSO requirements • Ramp rate and minimum power level is specified • Typically, the same ramps and power levels as for economical dispatch are defined example of PWR with relatively rare redispatch participation would be a range from no requests in 6 months up to 10 requests in 1 month
Emergency acccess	Applied in the case of grid emergency situation (imminent danger, danger of grid safety) • Expanded control rights are given to grid dispatcher/authority to issue instruction to reduce power (via telephone) • Minimum load level is specified. • Grid dispatcher typically gives info about level, ramp rate required, reason and planned duration • Maximal ramp rates are at maximal design values e.g. 10% /min for PWRs and 30% /min for BWRs, lower rates can be agreed, e.g., 60 WM/min for BWR (1344 MWel)

4.7.2 Load following (LF)

Although perhaps surprising to many, German NPPs are among the most flexible plants in the grid**.** **LF** operation is typically performed with a power ramp rate of 2% per minute in the range from 50% up to 100% REO. The design margin could even allow greater values, up to 5 or even 10 percent per minute, depending on the power range (Ludwig, H., Salnikova T., and Waas, U., 2010). Such values were proven during the commissioning phase, e.g., Konvoi NPP, with a ramp rate of up to 140 MWel/min (Fuchs, M., 2013)

There are some defined limitations for LF during the cycle, e.g., due to the calibration of in core instrumentation (about 4 weeks), for some NPPs after start up and at the end of the cycle (e.g., during “fuel conditioning” at the beginning of the cycle or at low boron concentration at the end of cycle for PWRs) – altogether approximately 6 weeks. In the case of fuel rod damage, the NPP should not be operating in flexible operation mode at all during the whole cycle (Timpf, W. and Fuchs, M., 2012).

NPPs of the predecessor company of today's Framatome GmbH, German KWU, had already been designed for enhanced capability for LF, PFC, SFC and MR, and with part load capability (ELPO) in the 1980s. For a long time these capabilities were only occasionally used to cope with some grid-related events, although, as shown in the following figure, NPP Unterweser (KKU) had already systematically experienced dynamic power adjustments during the warm months due to the cooling temperature limitations of the river Weser.

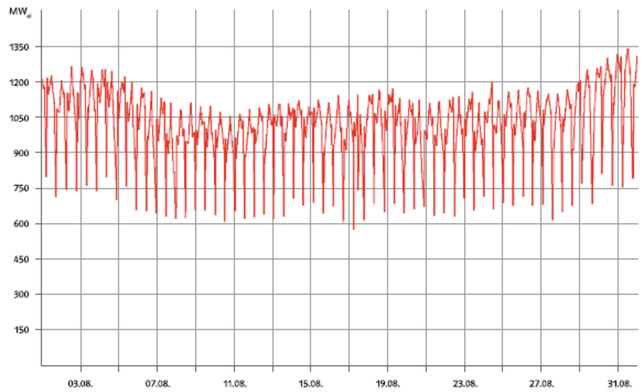

Figure 34 Electrical output in MWel over a 1-month period of time, provided by KKU NPP, X-axis = Time, Y-axis = Power (MW) (Fuchs, M., 2013).

The strong need for frequent flexible operation has appeared only in the last two decades, in order to compensate the rapidly increasing but fluctuating power generated by renewable energy sources. These developments led to the first modernization projects related to the improvement of the turbine instrumentation & control (I&C) systems, e.g., GKN II (2002), Biblis A (2003), Biblis B (2005).

Since 2008, the German electricity market allows negative electricity prices. On the one hand, the annual volume of electricity sold at negative prices is worth millions of euros. On the other hand, the reserve and balancing markets together, with re-dispatching and intraday trading allows new price models, resulting in new business cases for NPPs.

In Figures 35 and 36, two operational examples from the year 2008 for two PWRs KKU NPP (LF, about 500 ramps a year – top figure) and Biblis A (LF; 17 ramps a year – bottom figure) are shown to illustrate how German NPPs have begun to perform in the new market situation. These examples also include ELPO during one month for KKU and some weekends for Biblis A.

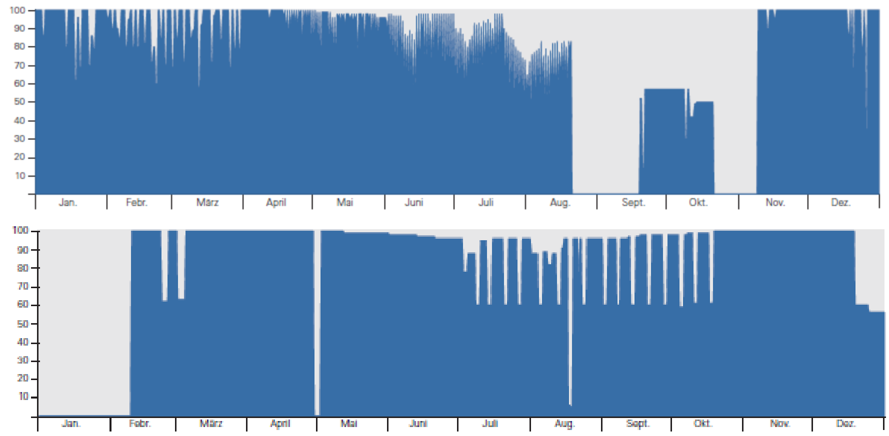

Figure 35 Electrical output in % provided by two German PWRs in 2008, X-axis = Time, Y-axis = Power in % (ATW, 2009).

One of the most advanced load-following cycles in Germany for PWR and BWR respectively, were performed during the year 2009 by GKN 1 (top) and KKP1 (bottom) mostly due to strong negative prices on the market (Figure 36).

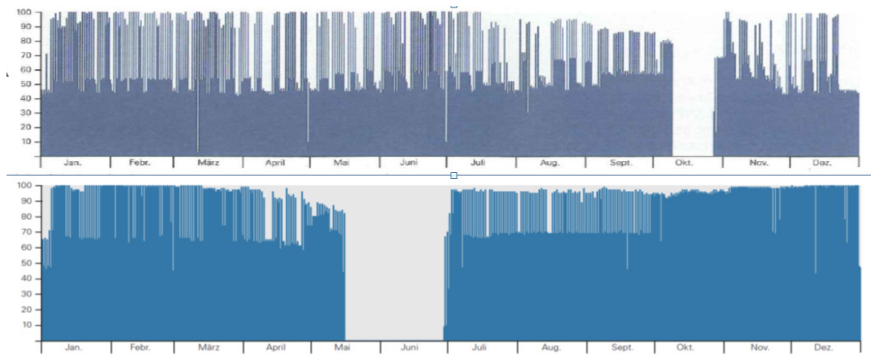

Figure 36 Electrical output in % provided by two German LWRs in 2009, X-axis = Time, Y-axis = Power in % (ATW, 2010).

Figure 37 shows the fleet (PWRs and BWRs of various designs) of two different large German utilities in Load Following mode during Christmas 2009, with overall power reduction of 4700 MWel, avoiding negative price production due to low demand combined with increased wind energy production.

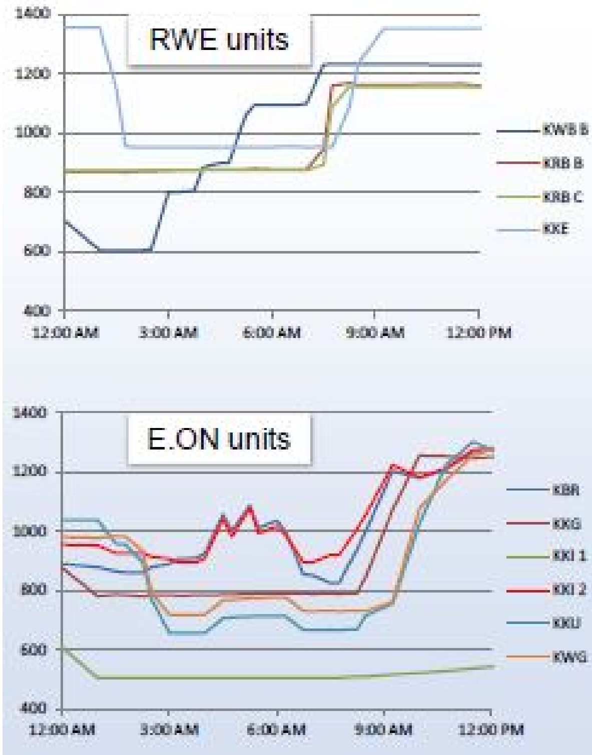

Figure 37 Electrical output in MWel provided by two German utilities over a 12 hour period of time at Christmas, 2009, X-axis = Time, Y-axis = Power (MW) (Fuchs, M. and Timpf, W., 2011).

Figure 38 shows the entire fleet in Load Following mode, with the typical rate of 25 MW/min and overall power reduction of 2800 MW, avoiding negative price production on the first day of the year 2011 with KKE mostly at the minimum power level.

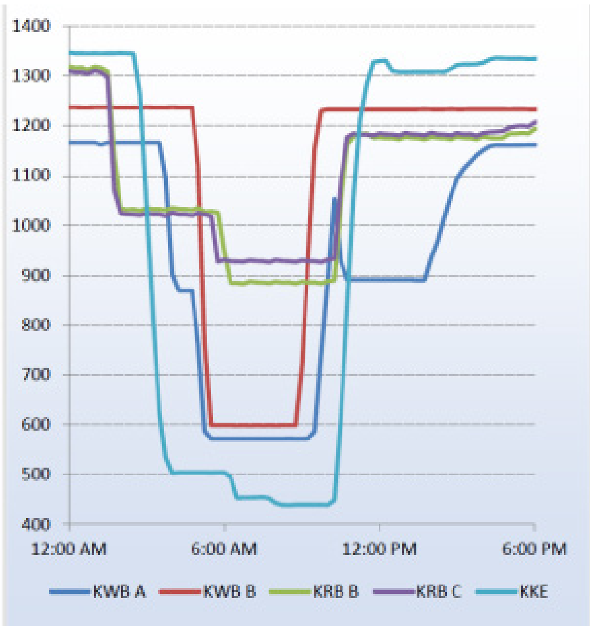

Figure 38 Electrical output in MWel provided by one German utility over an 18-hour period of time on the first day of the year, 2011, X-axis = Time, Y-axis = Power (MW) (Fuchs, M. and Timpf, W., 2011).

The flexible operation impact on the annual production of the German NPPs is demonstrated by ISAR-2 (KKI 2) PWR, which produces about 12 % of the overall demand in Bavaria, Germany. It strongly supports the integration of the intermitted renewables, stabilizing the grid due to its advanced flexibility. In 2017, power reduction due to flexible operation led to 8 full days of production at zero power (PEL, 2018).

As shown in the Figure 39, the amount of grid services required and provided by NPPs increased extremely over the last two decades (Müller, C., 2020). This was made possible by I&C (Instrumentation and Control System) modernizations. The commissioning of Advanced Load Following Control (ALFC) for KKI-2 was carried out in August 2014, with ramp rates of up to 40 MWel/min. Later, the set point was reduced to 30 MWel/min (Kuhn, A. and Klaus, P., 2016 and IAEA, 2018). As previously shown in Figure 38, the services were performed with a ramp rate of 10 MWel/min.

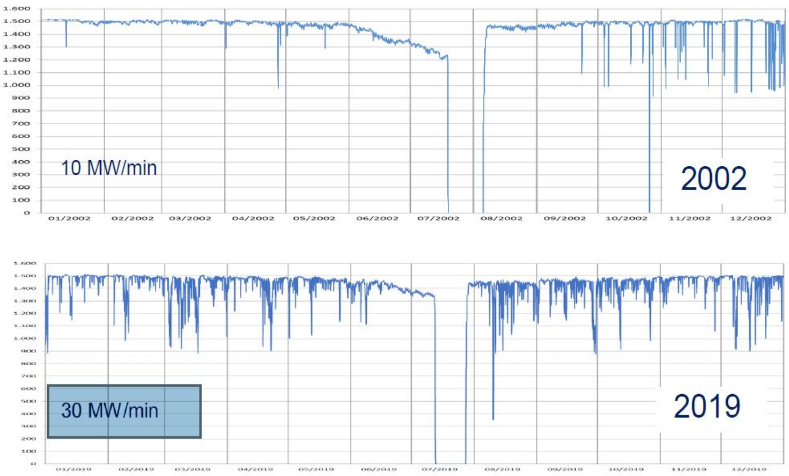

Figure 39 Electrical output in MWel provided by KKI-2 in the year 2019 compared to 2002, X-axis = Time, Y-axis = Power (MW) (Müller, C., 2020).

Various German and one Swiss operator of pressurized water reactors opted for full automation of plant operation to achieve maximal flexibility (with respect to the core loading as well). The introduction of digital technology in the field of I&C was very beneficial for the needed upgrade of reactor control, including introduction of the World Association of Nuclear Operators (WANO)-favoured reactivity management. The automated reactivity management was improved by a new predictive feature, which allows. e.g., further reduction in the boron and demineralized water injections. These injections are used to compensate the Xenon reactivity. Improved visualization of the complete reactivity balance for the operator was added as well (Salnikova T., 2017).

Overall improvements, together with other advantages in normal operation, allowed an increase in the range of power levels for the grid services, including successful performance of the necessary prequalification procedure. This created more commercial opportunities in the energy and balancing market. Typically, the ranges for the provided ancillary services were increased incrementally, which is related in the following text.

Corresponding to the ancillary services, in the case that there are several owners of such services provided by NPPs, each of them can have their own procurement strategy. Quite often the NPP is producing the service downwards and the upwards service will be provided, e.g., by hydro, within the fleet optimization process.

4.7.3 Primary frequency control (PFC)

The first PWR plant to begin with the ALFC modernization of reactor controls was KKP-2 in 2008, achieving a world record in August 2015 in PFC downwards regulation of -200 MWel, approximately 14 % REO within 30 seconds, and back to full power in 15 minutes within 30 seconds. This prequalification is illustrated in Figure 40 by the corresponding change of the generator power in MWel over the mostly 1-hour test period.

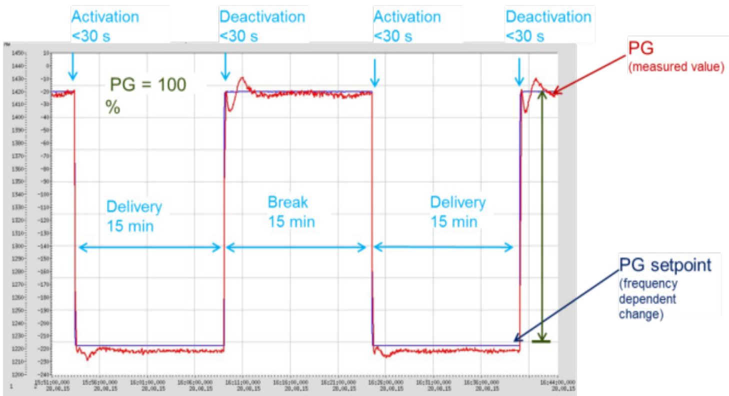

Figure 40 Prequalification test of asymmetric downwards PFC of 200 MWel, German pre-Konvoi NPP, X-axis = Time, Y-axis = Power (MW) (Kuhn, A. and Klaus, P., 2016).

An example of a strong stepwise increase of the qualification range for the services can be given by a single German PWR of approximately 1500 MWel. NPP has increased the licensed range of the PFC stepwise over the years, reaching a factor of mostly four. Thereby, SFC and MR could be superimposed.

With KKI-2, a PWR of approximately 1500 MWel, the first pilot for symmetric PFC was carried out already in 1992 for ± 40 MWel (Müller, K., 2003). In 2015 asymmetric PFC was implemented and since then the performed range of PFC up- and downwards can also have a different value. Later on, optimizations of the control achieved successful prequalification of PFC in the range of approximately ± 100 MWel. The prequalification process of such symmetric primary regulation is illustrated in Figure 41.

Thereby, the change of the generator real power (green curve) in MWel is shown compared to the set point (blue curve), dependent on frequency deviation from 50 Hz (grey curve) (Müller, C., 2020). Typical performed values for PFC are within a range of approximately ± 20 MWel, however a range of approximately ± 65 MWel is also partially activated and in some individual cases values of up to approximately ± 85 MWel can be reached.

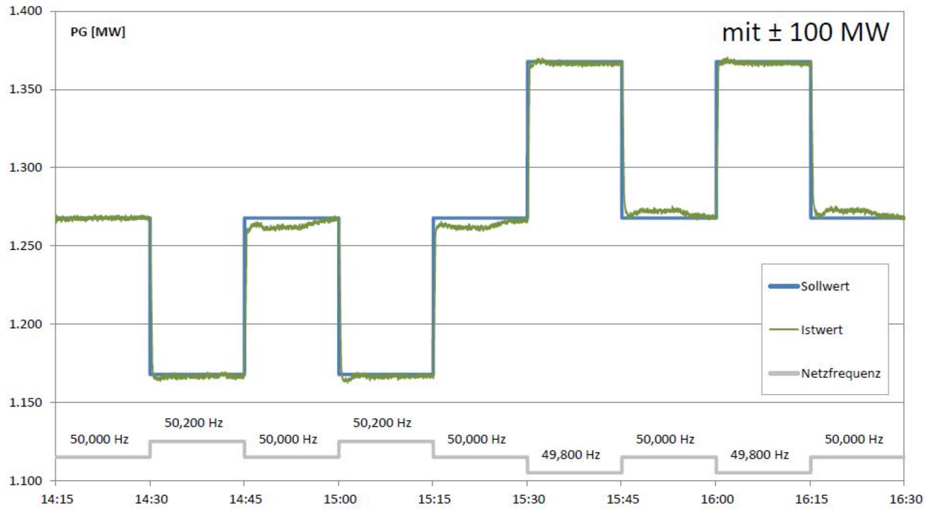

Figure 41 Prequalification test for PFC (symmetric, approx. 100 MWel) (Müller, C., 2020).

Also for BWRs, the NPP power controllers were improved to fulfil the increased flexibility needs from the grid, e.g., a BWR of approximately 900 MWel (KKI 1) was retrofitted in 2001 with an increased level of automation, including the addition of functions relevant for flexible operation mode. The primary controller was integrated and preparation for the secondary controller was also started. After 2002, PFC was procured within the band 23 MWel and the minimum load level was defined to be approximately 60 % REO on the market, which commenced after the conditioning of the core about 1 week after the beginning of a new fuel cycle (Frank, M., 2003).

There is also an example of 1300 MWel BWR, with PFC qualified in the range of ± 40 MWel.

4.7.4 Secondary frequency control (SFC)

With the help of the performed modernizations and optimizations the range for the remote secondary control was also increased stepwise in various NPPs.

For example, remote SFC in KKI-2 NPP was realized already in 2003 (Müller, K., 2003). But, in 2014, remote secondary control achieved the value of 150 MWel, reaching a ramp rate of up to 30 MWel/min. The following example shows the prequalification test of SFC with a comparison of the change in the generator real power (green curve) and the corresponding generator power set point (red curve), both in MWel within the required 5 minutes. The blue curve is showing additional reactor power (second maximum) in %. This service is performed in a specified range with a defined minimal level currently of approximately 60 % REO.

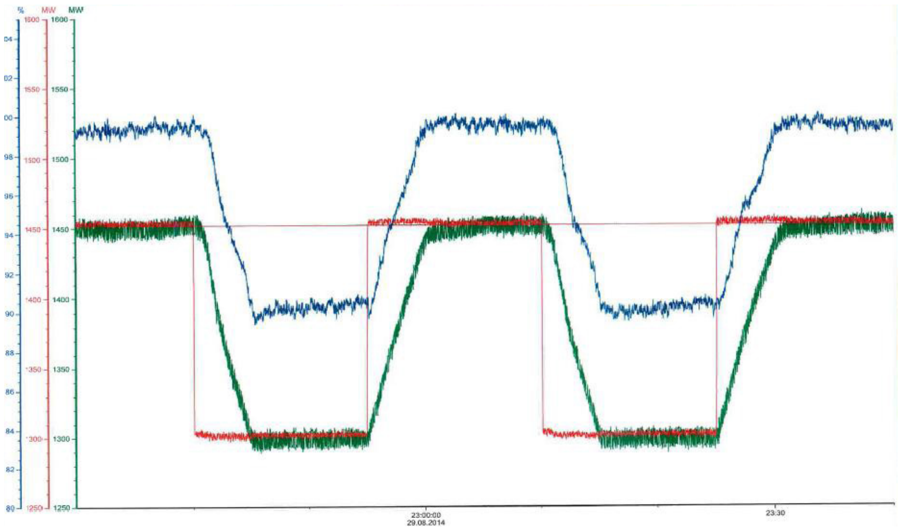

Figure 42 KKI-2 prequalification SFC with ramp rate of 30 MWel/min and 5 min duration, X-axis = Time, Y-axis = Power (MW) (Müller, C., 2020).

An example of SFR in a BWR is provided by KKI 1 of approximately 900 MWel, whereby SFR was planned to be added already in 2003. It was qualified for ± 50 MWel in the specified level range with minimum power level at 540 MWel (net). Thereby the ramp rate downwards was set at 20 MWel/min and the ramp rate upwards was defined at 10 MWel/min from the minimum power level to 780 MWel, and further from 780 MWel to full power at 1,5 MWel/min.

4.7.5 Minute reserve (MR)

Figure 43 gives an example of two other NPPs providing negative **MR** in 2011 during one day.

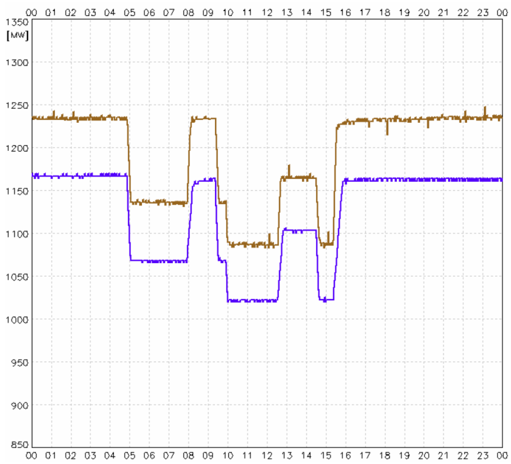

Figure 43 Electrical output in MWel generated by the two NPPs over a 24-hours period, providing negative MR, X-axis = Time, Y-axis = Power (MW) (Fuchs, M. and Timpf, W., 2011)

A PWR of 1200 MWel (Fuchs, M. and Timpf, W., 2011) have stated for MR the qualified range of 225 MWel with a ramp rate of 15 MWel/min.

In KKI-2, a PWR of approximately 1500 MWel MR was stated to be procured in a range of up to approximately ± 300 MWel, provided mostly downwards, and this PWR is remote controlled on the request of the grid dispatcher, resulting from market auction & TSO requirements in a specified range with a defined minimal level, currently of approximately 60% REO.

4.7.6 Overview on flexible operation of the German NPPs

The next example, Figure 44, from the year 2013 shows, for the NPP fleet (PWRs and BWRs of different types), one day with a strong penetration of wind and solar, when five of six NPPs from the nuclear fleet were participating on economic dispatch (required by load dispatcher), four were additionally providing SFC and one additionally participated on redispatch measures required from the grid dispatcher. One plant was performing a start-up after a short operation at zero power (Fuchs, M., 2013).

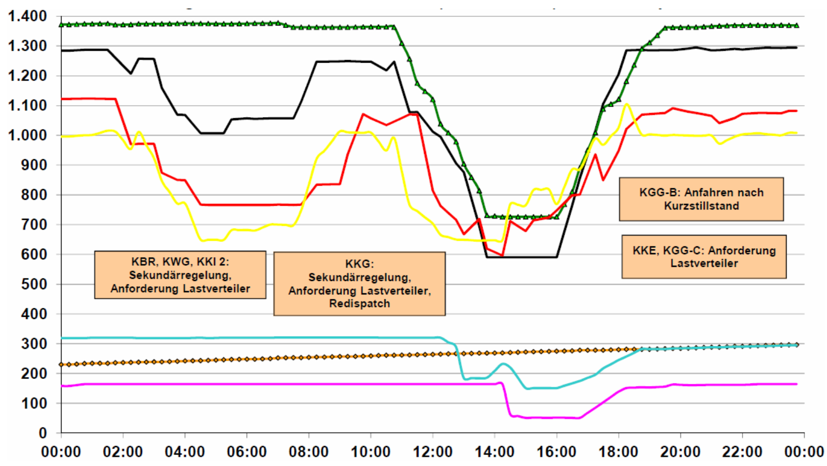

Figure 44 Electrical output in MWel generated by the fleet over a 24-hour period in September 2013, providing various Grid services, X-axis = Time, Y-axis = Power (MW) (Fuchs, M., 2013)

If the plant is operating in the remote secondary control mode the reactor operator can hardly differentiate between the various ramping products, e.g., **SFC**, **MR** or **LF** (economic dispatch) being performed by the NPP. The ramp rate and the range for the performed services are defined by the reactor operator, whereby the minimum level is typically fixed for all market-based services during the year and the upper level is dependent on the outdoor temperature, e.g. for KKI 2 the minimal level is defined currently at the net value of 875 MWel (approx. 60 %) and a ramp rate of 20 MW/min. The overall power range of the performed services varies between 475 and 565 MWel. Thereby, redispatch is also performed with the same rules. Grid services within such a maximal power range are shown in the following figure.

Figure 45 illustrates the plant operation in the fully automated remote secondary control mode during a period of almost one month, with a ramp rate of approximately 30 MWel/min. The graph depicts the changes in the generator power within a band of approximately 560 MWel and the fully automatic compensation of the long-term reactivity effects of the Xenon reactivity with boric acid and demineralized water (BODE), according to the basic design of any PWR. Additionally, the correlation of Xenon in the upper and lower core half is to be noted, as the result of the installed ALFC power distribution (PD) controller which inhibits any axial oscillation of the axial power distribution in the beginning (Kuhn, A. and Klaus, P., 2016).

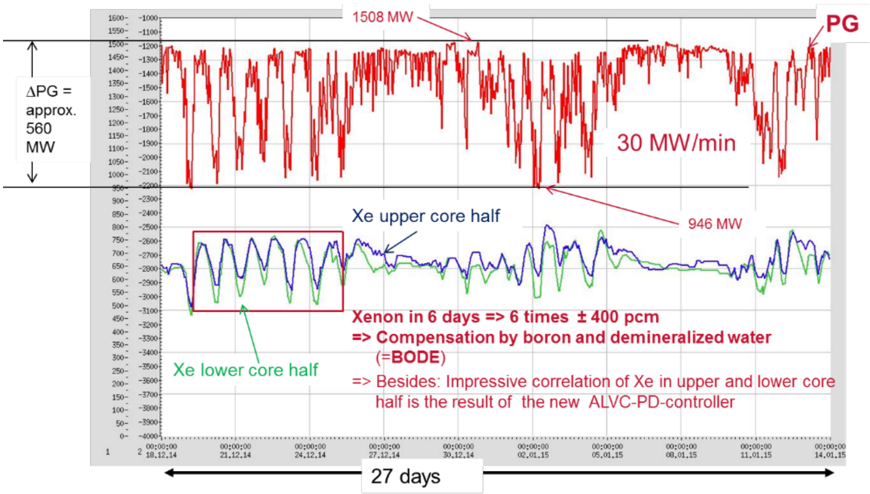

Figure 45 Electrical output (gross) in MWel generated by Konvoi NPP over a 27-day period, providing fully automated remote secondary control, X-axis = Time, Y-axis = Power (MW) (Kuhn, A. and Klaus, P., 2016).

Overall, renewables integration has been strongly supported by NPPs in Germany over the past two decades, providing various grid services in a safe and reliable manner. NPPs were further developed with respect to the advanced flexibility, providing an adequate answer to the increased grid requirements over the years, increasing the ranges of the performed services.

The overall analyses show that Germany PWRs mostly fulfil the required range for all grid services to be performed from full power to approximately 50 % in PWRs and approximately 60 % for BWRs, to reduce the possible negative impact on the plant. Thereby PWRs are operating mostly in the range of the constant average temperature of the primary coolant to reduce the impact on the components of the primary circuit. German BWRs in the above-mentioned range are mostly regulated via recirculation control (by changing the speed of the forced circulation pumps and thus the coolant flow rate), without manoeuvring of the control rods. The advantage of such control is that the relative power distribution in the core is not significantly affected by load changes, minimizing stressing of the fuel rods (Ludwig, H., Salnikova T., and Waas, U., 2010).

4.7.7 Suitability of ancillary services provided by NPPs to Nordic grid context

A paradigm change for other NPPs worldwide (Salnikova T., 2017) will be required if the goals for renewables' penetration and carbon neutrality are taken seriously. Indeed, the COVID-19 situation has shown in many countries already today such a situation, due to the overlapping of a strong demand decrease and already quite high existing production from volatile renewable sources. So, the theoretical future has, to some extent, become a reality already today.

Technically, various additional grid services could be provided by almost all NPPs in the future if an adequate market design is established. German Utilities are nowadays also mentioning a need for a reactive power/voltage regulation market or the possible participation of NPPs in providing capacity reserves, payments for spinning reserves or better compensated redispatch measures.

If the activation time, duration and ramping rate can be chosen as the main technical criteria for the first comparison between the ancillary services required by EU for the Nordic system, described in subsection 4.6.1 "EU policy for future ancillary services and European market integration", and the existing experience from Germany, summarized in Table 13 of this sub-chapter, the generic results could be following

- activation time for the FFR is not applicable for NPPs
- FCR is generally possible by NPPs, as it is shown by the German example providing FCR activated linear within 30 seconds (subsection 7.4.3). The Nordics have their own products, FCR-D and FCR-N
  - × The current policy in the Nordic countries is to increase the volume of aFRR resources in order to shift to an activation based on ACE (Area Control Error). An increased volume of aFRR could possibly also enable a decrease of the FCR-N volume but is too early to say at the moment. FCR-N is likely to be applicable for NPPs.
  - × FCR-D is now under development by the FCR-D project, mostly to better fit the need of the power system with lower inertia. The nuclear option should be analysed in detail for each plant, even if it seems to be very challenging, especially due to the requirement for the provision of 50 % of the services already in 5 seconds. It also has to be mentioned that NPPs are often participating in symmetrical or only downwards services and FCD-D is an upwards service.
- aFRR and/or mFRR may well be the best candidates for the ancillary services provided by NPPs in the Nordic countries. Corresponding experience is available, e.g., in Germany (Chapter 4.7.4 and 4.7.5).
- RR could be provided by NPPs but is not used in the Nordic system today and is not planned for the future.

Nordic NPPs in general can also participate in economic dispatch/redispatch and voltage regulation, as was proven by, e.g., German NPP (see the overview presented in Table 13), but a positive business case has to exist for such an NPP decision. There are already various current examples of grid services provided by NPPs in Finland and Sweden, e.g., Ringhals 1 secured the voltage stability and short-circuit power in south Sweden this summer, via bilateral agreements as existing market solutions were not sufficient. Appendix A shows the technical requirements of services provided in the countries /regions studied. Table 14 summarizes the frequency and voltage control ancillary service products of the Nordic system and whether the four countries or regions studied have similar products. The table also shows also NPP's ability to provide these services on the basis of the experience of German nuclear power plants.

Table 14. Similarities of ancillary service products of Nordic system and four studied countries/regions and NPP service candidates

	FFR	FCR-N	FCR-D	aFRR	mFRR	Voltage control
Australia	-	-	-	-	-	X
Ireland	X	-	-	-	-	X
UK	-	-	X	X	-	X
U.S. Texas	-	-	-	-	-	X
NPP service candidates in Nordic	-	X	?	X	X	X
Available experience with NPPs e.g. in Germany	-	X (linear in 30s)		X	X	X

It is very important to take each of the plant-specific flexible capabilities into account for every moment in the fuel cycle. It is not only design features, but also already performed modernization changes, e.g., power uprate and operational history, that play a role. As an example, two NPPs of the same design can have strongly different flexibility, corresponding to the types and ranges of the performed services, and they also have a different minimum power level for manoeuvring. The reason can be, e.g., upgrades of the control system giving new capabilities on one hand and existing vibration issues at part load as a limitation on the other hand.

The design of all new-builds, e.g. EPR (Grossetete A., 2014), in the case of Finland, is stated to be capable of an advanced level of flexibility, thanks to a fully automatic T Core Control mode, with power variations of up to 5 % REO/min in the range to the minimum load (25 % REO) and of up to ± 10 % REO for the instantaneous power variations (SFC) in the same range, comparable to some German NPPs equipped with advanced flexibility. PFC is defined with a step of ± 2,5 % REO and can be superimposed. More details can be found e.g. in (NEA, 2011).

In some cases, if no technical solution is yet implemented, the required adaptations should be relatively minor. At the same time, for the old NPPs, a feasibility study including various detailed analyses is required to define the level of flexibility existing and achievable, including design and existing operational limitations. Such a study should include evaluation of the entire NPP, including fuel design. If the NPP is planning a life-time extension, the required flexibility in the middle and long term should be taken into account already in the starting phase of the project.

Once, after the level of current flexibility is defined, the overlap with the required services can be analysed in detail, giving proposals for optimization and modernizations to bridge the gap.

Another aspect where existing experience has shown to be of extreme importance for the Grid services range the plant is to participate at, is the introduction of the preventive maintenance concept based on sufficient monitoring and diagnostics. If the NPP is clear about the "fully healthy" status of the plant and that any deviation from that will be noticed at an early stage, they will be able to provide more flexibility to the grid. But if they get the needed information late, when the problem occurs, then high costs associated with flexible operation, e.g., due to required repair or replacement, could be expected.

To give a positive example, German NPP with the highest level of flexibility, has shown no impact on "number of internal events" in the plant, thanks to the right level of instrumentation and an optimized maintenance program, which was previously updated for flexible operation, see Figure 46. Of course, additional HW/SW and optimizations, as well as required verifications and analyses have their costs, so provision of such services has to be monetized to ascertain whether or not such investments are feasible.

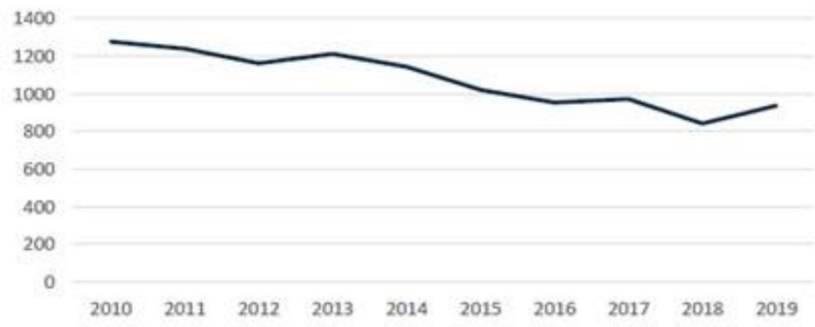

Figure 46 Number of internal events over decade in the German PWR with increased flexibility over the years (Müller, C., 2020).

The first preliminary feedback for FCR-D could be that a 5 s activation time for 50 % of the service after the start of the frequency ramp seems to be very challenging for NPP (as well as, e.g., for a coal plant). Often, at low and middle load, a higher performance can be achieved in comparison to operating points close to maximum load. Special adaptions are necessary to meet this challenge.

According to aFRR, for the BWRs the implementation of the remote secondary control feature, in the case of the existing digital recirculation control, could allow provision of aFRR, which is stated to be important for the Nordic Grid in this report. For the PWRs, the digitalization of the I&C would also be very favourable and, in addition, advanced load following control functions with predictor technology could be implemented, to provide aFRR in a high power range in a safe and reliable manner. Introduction of automatic boron/demineralized water injection can be a first step for PWR to improve its flexibility level. Also, reactivity management (predictor technology) is a key factor for the reliable flexible operation in PWRs, and can be added to each NPP (e.g. Morokhovskyi V., 2020).

As already mentioned, each NPP has to be individually analysed with the goal of defining the current capabilities to provide particular ancillary services. The existing experience also shows the following steps connected to the required pre-qualifications to be feasible:

- performance of close-loop simulator experiments during the outage. Turbine control and turbine valves will be included in the loop with a real-time simulator. As a result, the current capability of the plant will be summarized, and improvement ideas collected.
- As a final result, various optimizations, e.g., of the rotational speed measuring device, power controller, primary frequency controller, valve positioner, can be required. Finally, such a test will be repeated to be prepared for the pre-qualification.
- A similar procedure is required if a new control function has been introduced to increase the probability of the successful prequalification.

Last but not least it is worth mentioning that there is always an additional cost behind flexible operation, e.g., corresponding to chemistry or water management as well as to increased inspection costs or even component exchange, such as in the case of CRDM, in addition to costs for specific optimizations and upgrades (if required). Overall operation at power levels below maximum output leads to a lower efficiency, in for example the turbine, bringing additional costs. This will be addressed in the lower load factor reached by the plant. Appropriate fuel management must take this into account.

Positive particular business cases for each plant based on detailed plant-specific analyses is the key to NPP participation in flexible operation to support the Nordic grid.

5 Conclusions and future work following this project

This report provides the stakeholders with a survey of how Australia, Ireland, UK and Texas have set up their respective markets, regulations and ancillary products to ensure a stable power system. These countries or regions have power system challenges similar to the observable trends for the future in Sweden and Finland, with nuclear reactors or other large system-important thermal production units and with increased amounts of intermittent production.

The technical requirements for ancillary services depend on the characteristics of the power system. In this respect, the power systems in Australia, Ireland, UK and U.S. Texas are different, and ancillary service products cannot be the same, but they are forecasts into which direction the ancillary services are developing in the future. Transmission system operators procure services on the market through bilateral agreements, or they are mandatory under grid codes without compensation.

The products in the different regions all differ to some extent, and it is difficult to justify the application of a specific product from one region directly to another. There is no doubt, however, that the products from different areas can be used as an example or a template when a new problem is recognized by a TSO. For example, when the Nordic TSOs designed their FFR products in 2019, with its operation starting in May 2020, the existing Irish product was used to provide background information.

In the FCR category, there is a plethora of similar services for normal operation in the various regions. For disturbances however, only “the Mandatory Frequency Response - Secondary response” and “the Firm Frequency Response – Dynamic, Secondary response” in the UK are in the same time frame. In this case, the Nordic system currently has only up regulation. Down regulation may need to be added in the future if resources such as the share of wind powered generating units increases. The current policy in the Nordic countries is to increase the volume of FRR resources in order to reduce the need for some of the FCR resources.

The “Fast reserve (FR)” in UK is somehow near regarding the time frame of the corresponding Nordic aFRR product. If the market develops from an hour's balance settlement period to 15 minutes of balance settlement period in the future, it will no longer be necessary to cover very slow reserves. If the activation period for products is 15 - 30 minutes, they will be covered by the energy markets. Currently, in the Nordic system, the hydro power plants are the primary source for FRR, along with load disconnections. This is however expected to change when the volumes of contracted FRR increase. The Nordic system does not have replacement reserves.

It is very hard to create reactive power markets and very difficult to get real competition on the markets, because voltage control is needed locally, markets should be local and reactive power is relatively simple and cheap to produce or consume. The survey showed somehow similar obligatory requirements for generators based on grid codes. Generators shall support the system voltage by means of the reactive power reserves during faults and disturbances occurring at power plants and in the grid. There are no markets for voltage control and reactive power. Compensation is based on bilateral contracts.

The restoration in the case of a black out in a region of the Nordic system is performed following a top-down approach, with the result that all the plants able to contribute are required to do so by the TSO, but also that there is no strict requirement for a single plant to be able to restart the system on its own. With reduced demand, there is no incentive for the TSOs to move towards anything other than bilateral contracts or compulsory contribution.

National and regional markets in Europe are becoming increasingly integrated towards a common European market. The harmonization is going on at the EU level regarding ancillary services. The Nordic Transmission System Operators (TSOs) had identified a worrying trend towards decreasing system inertia and a new product, “Fast Frequency Reserve (FFR)”, was set up. Regarding the “Frequency Containment Reserves (FCR)” there are different requirements for the different synchronous areas, and especially the smaller areas with less inertia, such as the Nordic system, have special requirements. For “Frequency Restoration Reserve (FRR)”, common Pan-European markets with standard products will be established in the coming years.

Regarding the role of nuclear power plants, based on experience in Germany, grid services such as frequency and voltage control could technically be provided by almost all NPPs in the future. This would however require adequate market designs.

If, as a first approximation, only activation time, duration and ramping rate are chosen as the main technical criteria for the ancillary services, then NPPs have the possibility to participate in various ancillary markets, as has been proven by the German NPPs.

- Nordic requirements have their own products for “FCR-Disturbance (FCR-D)” and “FCR-Normal operation (FCR-N)”. FCR-D is now under development to better fit the need of the power system with lower inertia. Whether NPP can likely provide FCR-N and FCR-D should be looked into in a case-by-case study, but it seems to be challenging due to the 5 s criteria for activation of 50 % of the service. The possible activation time for FCR-D has to be analysed in a case by case study. FCR is linearly activated by German NPPs in 30 s, and FCR is procured as upwards and downwards regulation.
- Automatic FRR (aFRR) and/or manual FRR (mFRR) could be the best candidates for the ancillary services provided by NPPs in Nordic countries with the current requirements.
- “Replacement Reserves (RR)” could be provided by NPPs, but RR are not used in the Nordic system today and are not planned for the future.
- Activation time for the FFR is too fast for NPPs.

The Nordic NPPs can also participate on economic dispatch, redispatch and voltage regulation and there are already various examples of such operation, e.g., Ringhals 1 in the summer of 2020, providing voltage control for the Swedish grid system.

Future work following this project:

- **Study of scenarios** about how the Nordic power system will develop in the future regarding energy mix and the share of renewable variable generation. Analysis of the need for flexible operation of NPPs for balancing the power system.
- **Establish and analyze future business models** for the flexible operation of NPPs. Therefore, detailed feedback on costs and benefits can be collected via interviews provided by German utilities that have implemented various types of flexibility in the past. When the scenario required by the Nordic Grid in the future is clear, the plant or plants should be chosen that already have had a strong operational experience in this mode. An additional advantage would be a high level of monitoring systems installed, to be able to see the effects. E.g., BWRs in Germany have a comparable design to the ABB plants and various experience can be transferred for different types of flexible operation including part load. German PWRs experience with the highest level of flexibility and the overall impact is very interesting as it could be the projection of the long term or even middle term needs of the Nordic Grid. Also, it would be very valuable to analyze the experience with PWRs that have been retrofitted for flexible operation in the next stage of the project, in particular that provided by French PWRs for the plants applying the same control mode as the Nordic PWRs (A-mode). Knowing which levels were reached, which kind of limitations exist and a detailed feedback on costs and benefits would be very valuable.
- **Transfer the above knowledge** to understand the costs and benefits of flexible operation of Finnish and Swedish nuclear power plants in the future.
- **Assess all relevant parameters** required by nuclear plants in order to perform the various ancillary services.
- **Technical capabilities** to provide Ancillary services could be compared to requirements. Modern grid codes impose high requirements on the I&C of the turbosets of NPP, both for turbine control and voltage regulation. By means of a hardware-in-the-loop test, the I&C can be checked before commissioning in order to meet all requirements. It is common practice to check the control loops separately. This means an individual test for the automatic voltage regulator and for the turbine governor. But in some cases of grid faults, it is necessary to combine these separate tests in order to analyze the mutual impact of the control loops. Hence the real-time simulator needs to be extended to check both controllers simultaneously or needs to include very detailed models of the controllers. In addition, the real-time simulator should be adapted in order to check the special requirements of all ancillary services according to the Nordic Synchronous Area. Moreover, a model of the power system that is capable to simulate frequency changes and especially various frequency gradients (rate-of-change-of-frequency) can be integrated to the simulator in order to check these new I&C requirements.

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Appendix A: Comparison of ancillary services of Australia, UK, Ireland, Texas U.S.

Fast Frequency Response, frame about 1-2 sec

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
Fingrid, Svenska kraftnät	Fast Frequency Reserve	1,3s / 49.7 Hz, 1,0s / 49.6 Hz or 0,7s / 49.5 Hz	5 sec or 30 sec	National hourly market based on inertia forecast	Minimum duration 5 sec if deactivation speed is max. 20 % of FFR capacity per second, otherwise 30s. Estimated maximum volume 300 MW in the Nordics FFR need is strongly dependent on the hydrological situation
Australia	Fast Frequency Response 3) (under preparation) 1)	0,04-2	not decided	Batteries, flywheels and super-capacitors, wind turbines and wind pitch control, PV set point operation	Management of credible contingency and the non-credible separation of a region
UK	Enhanced Frequency Response	1	900	Generators, Storage, Single or Aggregated units Min of 1 MW and max of 50 MW	Tendered, Payments; availability12)
Ireland	Fast Frequency Response	2	8	Conventional generators, CH, Biomass, wind farms, batteries, flywheels, PHES, CAES, HVDC ICs, AGUs, DSUs13)	Response to automated frequency trigger
U.S. Texas	Fast Frequency Response, FFR 6)	0,25	900	Generators, batteries	Triggered at 59.85 Hz and full response in 15 cycles

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
U.S. Texas	Responsive reserve Load, UFR [6)]	0,5	10800	Load	Load disconnection if frequency drops to 59.70 Hz. • Sustain until recalled. Once recalled, restore within 3 hours • Beyond the minimum PFR, up to 60% of total RRS can come from Load Resources on UFR or FFR

Frequency Containment Reserve, time frame about 5…30 sec

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
Fingrid, Svenska kraftnät	FCR-N	180 sec after frequency step change of ± 0,1 Hz	As long as frequency is out of band, at least 1800 sec for a reserve unit whose activation capability is limited, e.g. battery storage system	Generators. Yearly market Hourly market Other Nordic countries Vyborg DC link Estonia, Estlink 1 & 2	Dead-band 49.99 – 50.01, fully activated when frequency is out of 49.90 – 50.10 Hz min bid size 0,1 MW Symmetric product capable of managing upward and downward regulation Volume obligation approx, 120 MW (Fingrid)
Fingrid, Svenska kraftnät	FCR-D (Power plants)	5 s / 50 % 30 s / 100 %, after frequency step change of -0,50 Hz	1800 sec, Same as FCR-N	Power plants Yearly market Hourly market Other Nordic countries	Just up-regulation when the frequency is less than 49.9 Hz, fully activated when frequency is less than 49.5 Hz min bid size 1 MW, Volume oblig. Approx. 290 MW for (Power plants and relay connected loads) Fingrid

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
Fingrid, Svenska kraftnät	FCR-D (relay connected resources)	Option 1: piecewise linear regulation 5 s / 50 % 30 s / 100 %, after frequency step change of -0,50 Hz Option 2: immediate disconnection when frequency 5 s ≤ 49,7 Hz OR 3 s ≤ 49,6 Hz OR 1 s ≤ 49,5 Hz	900 sec, Same as FCR-N	Relay connected loads, min bid size 1 MW	Option 2. Reconnection of load is allowed when the frequency has been at least 49,9 Hz for 3 minutes
Ireland	Primary Operating Reserve, POR	<5	15	Conventional generators, CHP, Biomass, Hydro, wind farms, batteries, flywheels, PHES, CAES, Sync comps, HVDC ICs, AGUs, DSUs, [13)]	Response to automated frequency trigger
Australia	FCAS Regulation Raise, FCAS Regulation Lower (Normal operation)	5 AGC,~1 second response to AGC signals (4 second AGC signals (~5 second total cycle response time) 3 MW/min [2), 4)]	Used continuously for minor imbalances	Generators, batteries, load shedding. FCAS volumes 180/170 MW [11)] raise/lower up, min gen size 30 MW [1),] automatic Frequency band: 49.85Hz…50.15 Hz	Tendered, Payments: Availability and Utilisation
Australia	FCAS Fast Raise	6	60	Generators, batteries loads	Tendered, Payments: Availability and Utilisation
Australia	FCAS Fast Lower	6	60	Generators, loads	Tendered, Payments: Availability and Utilisation

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Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
UK	Mandatory Frequency response - Primary Response	10	20	Transmission Network dependant: NG ≥ 100MW SP ≥ 30MW SHET ≥ 10MW generators	Tendered, Payments: Availability and Utilization, Automatic change[12)]
UK	Mandatory Frequency response - High frequency response	10	Indefinite	Transmission Network dependant: NG ≥ 100MW SP ≥ 30MW SHET ≥ 10MW Obliged to generators	Tendered, Payments: Availability and Utilization, Automatic change[12)]
UK	Firm Frequency Response – Dynamic, Primary response [8)]	10	20	Generators, loads ≥10MW	Tendered, Payments: Availability and Utilization, Automatic change
UK	Firm Frequency Response – Dynamic High frequency response [8)]	10	Indefinitely unless otherwise agreed	Generators, load. min 1MW	Tendered, Payments: Availability and Utilization, Automatic change
Ireland	Secondary Operating Reserve, SOR	15	90	Conventional generators, CH, Biomass, Hydro, wind farms, batteries, flywheels, PHES, CAES, Sync comps, HVDC ICs, AGUs, DSUs[13)]	response to automated frequency trigger
U.S. Texas	Primary Frequency Response, PFR, Load Resources on Under Frequency Relay, UFR, 10 min ramp [7)] (Normal operation)	15-30	300	"PFR capable capacity reserved on generators or Controllable Load Resources (CLR) • Minimum 1,150 MW must be provided by resources capable of PFR"	2,300 to 3,200 MW, Mandatory all generator, not market product
UK	Mandatory Frequency response -	30	1800	Transmission Network dependant: NG ≥ 100MW	Tendered, Payments: Availability and Utilization,

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
	Secondary response			SP ≥ 30MW SHET ≥ 10MW generators	Automatic[12)]
UK	Firm Frequency Response – Dynamic, Secondary response [8)]	30	1800	Generators , loads ≥10MW	Tendered, Payments: Availability and Utilization, Automatic change[12)]

Frequency Restoration Reserve, time frame about 30 -300 sec and Replacement reserves > 300 sec

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
Fingrid, Svenska kraftnät	Automatic Frequency Restoration Reserve (aFRR)	120		Hourly market Sweden, Min bid size 5 MW	Hourly market with capacity payment based on availability and activation payment for energy. Obligation of volume 60-80 MW
Fingrid	Manual Frequency Restoration Reserve (mFRR) (fast disturbance reserce)	900		Balancing energy and balancing capacity markets. Own reserve power plants and reserve power plants procured with long-term contracts. Reserve power plants are not in use in electricity markets (leasing), from neighbouring TSOs.	Up-regulation, Obligation of volume 880 – 1100 MW
Australia	FCAS Slow Raise [10)]	60	300	Generator /load to stabilize after a major frequency drop.	Tendered, Payments: Availability and Utilization,
Australia	FCAS Slow Lower [10)]	60	300	Generator /load to stabilize after a major frequency rise	Tendered, Payments: Availability and Utilization

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
Ireland	Tertiary operating reserve 1, TOR1	<90	300	Conventional generators, wind farms, storages, DSU, HVDC interconnectors	Response to automated frequency trigger
UK	Fast reserve (FR)	120	900	Generators, loads min 25 MW/min, min 50 MW	Tendered, Payments: Availability and Utilization, Automatic change [12)]
Ireland	Tertiary Operating Reserve 2, TOR2	300	1200	Conventional generators, storages, DSU, HVDC interconnectors	Response to a control / dispatch instruction
Australia	FCAS Delayed Raise [10)]	300	-	Generator /load to normal operating band	Tendered, Payments: Utilization
Australia	FCAS Delayed Lower [10)]	300	-	Generator /load to normal operating band	Tendered, Payments: Utilization
U.S. Texas	Responsive Reserve, Spinning reserve [7)]	300	6300	"It may be provided from the following: Unloaded Generation Resources that are On-line, Resources controlled by high set under-frequency relays, or Direct Current (DC) tie-line response. The DC tie-line response must be fully deployed within fifteen (15) seconds on the ERCOT System after the under frequency event."	2300 MW -2800 MW. Demand side resources can provide up to 50% of this MW requirement
Ireland	Replacement Reserve (De-Synchronised) RRD	1200	3600	Thermal conventional generators, storage, loads	Response to a control / dispatch instruction
Ireland	Replacement Reserve, (Synchronised) RRS	1200	3600	Thermal conventional generators, storage, loads	Response to a control / dispatch instruction

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
UK	Short-term operating reserve (STOR)	1200	14400	An single or aggregated unit, min 3MW	Tendered, Payment: Availability and Utilisation
U.S. Texas	Non-spinning reserve	1800	1800	Off-line Generation Resource capacity, or reserved capacity from On-line Generation Resources, capable of being ramped. Loads acting as a Resource that are capable of being interrupted within thirty (30) minutes	0 to 1,180 MW
UK	Demand turn up	1800	depend on provider, not defined	CHP and any other type of generation, energy storage (such as batteries), min 1 MW. F.ex. over weekend	Bilateral agreement. Payments: Availability, utilisation
UK	BM Start Up	Between 1800 and 5400 sec		Start enable generators to synchronise in 89 min or cold in hot standby	Bilateral agreement, Payments: Readiness

Voltage control _Steady state and dynamic

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
FINGRID, Svenska kraftnät	Reactive power reserve			Generators	Generators > 10 MVA are obliged, while they are connected to the grid, to support the system voltage by means of the reactive power reserves during faults and disturbances at power plants and in the grid. No markets for reactive power

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
Australia	Voltage Control Ancillary Service (VCAS)	A rise time no greater than 30 milliseconds (ms) and a settling time no greater than 60 ms applies to reactive current injection requirements [2)]		Generators, synchronous condenser, capacitors or reactors	No markets for reactive power. Bilateral contracts
Ireland	Steady State Reactive Power, SSRP	0,04			Reactive power response within 40ms of a voltage fault
Ireland	Fast Post Fault Active Power Recovery, FPFAPR	0,25			Active power recovery within 250 ms of a voltage fault
Australia	Network Loading Control Ancillary Service (NLCAS)			"Standby generators, fast runback of scheduled generating units; Automatic Generation Control or via a Load Shedding event	Bilateral contracts. A flow on inter-connectors exceeding the short term limits.
Australia	Transient and Oscillatory Stability Ancillary Service (TOSAS)			Synchronous condensers; Power flow and Voltage control FACTS devises such as SVCs , series compensation reducing system impedance; and/ or breaking resistors.	Bilateral contracts. During events like short-circuit and other severe disturbances. Service increases rotating mass inertia or quickly increases or reduces the load.
UK	Obligatory Reactive Power Service, ORPS			Obligatory for all grid connected power plants with a capacity greater than 50 MW.	Bilateral agreement, Payments: Utilisation[12)]

Country or region	PRODUCT	Full Activation Time (sec)	Required Duration (sec)	Providers	Comments
UK	Enhanced Reactive Power Services, ERPS			Exceeds the minimum technical ORPS, Can be provided by any site that can absorb or inject/generate reactive power, including demand-side providers.	No markets for the time being. No tenders since 2011 nor contracts since 2009.
Ireland	Dynamic Reactive Response, DRR				MVAr capability during large (>30%) voltage dips [5)]
U.S. Texas	Reactive power support [9)]			"Single units larger than 20 MVA or multiple units (such as wind and solar generators) with aggregated capacity of 20 MVA connected to the transmission system. The required power factor range is 0.95	Reactive power support [9)]

Black Start

Country or region	Min capacity	Full Activation Time (h)	Required Minimum Duration	Providers	Comments
Australia [14, 15]	• North Queensland 825 MW • South Queensland 825 MW • New South Wales 1500 MW • Victoria 1100 MW • South Australia 300 MW • Tasmania 330 MW	3,5 3 2 3 2,5 2,5	-	• Open cycle gas turbines (OCGT); • Hydro plants; • Small embedded open cycle gas turbines; • Coal fired generators with black start capability; and • Baseload coal-fired generators that are fitted with trip to house load (TTHL) equipment	• Required Aggregate Reliability 90..95% • Capability in providing power to a de-energised busbar • Ability to operate at zero export load for a minimum period specified in the SRAS • Ability to supply a contracted level of generation output to the Delivery Point

Country or region	Min capacity	Full Activation Time (h)	Required Minimum Duration	Providers	Comments
					• Aability to control network voltage and Frequency within limits to meet the minimum requirements specified by AEMO
UK [16]	30-50 MW (single generator)	2	3-7 days	Generators	• Frequency range 47,5-52 Hz • The ability to provide at least three sequential black starts. • Ability to start-up and shut-down without the use of external power supplies. • The ability to maintain high service availability of 90 %. • The reactive power capability will depend on the local system configuration, but typically generating plant connected at 400kV or 275kV with a capability of at least 100MVAr leading.
Ireland [17, 18]	500MW EIRGRID East-West VSC-HVDC interconnector	1-12 h	-	Generators (mainly hydro generators) HVCD connectors	• Ability to start-up and shut-down without the use of external power supplies. • Frequency should be at least 50.0 Hz (preferably higher) before

Country or region	Min capacity	Full Activation Time (h)	Required Minimum Duration	Providers	Comments
					restoring any load
U.S.Texas [19]	ERCOT define the needed capacity	0,5 h	8 hours	• Generators • Black-start capable Direct Current Tie (DC Tie),	• Presuming an 85% availability to start without assistance from the ERCOT System. • No protection devices shall trip the Black Start Resource within the required reactive range. • Each black-start unit must be able to demonstrate that it can start another unit in close proximity. in order to begin the islanding and synchronization of the grid.

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SURVEY ON POWER SYSTEM ANCILLARY SERVICES

This report provides a survey on how Australia, Ireland, UK and U.S. Texas have set up their respective markets, regulations and ancillary service products to ensure a stable power system due to increased amounts of intermittent production.

The technical requirements for ancillary services depend on the characteristics of the power system. The four regions provide a forecast, however, of the direction in which the ancillary services are developing. Technically, various additional grid services, such as frequency and voltage control, could be provided by almost all nuclear power plants, NPP, in the future, if an adequate market design is established.

Automatic and/or manual Frequency Restoration Reserve products may well be the best candidates for the ancillary services provided by NPPs in the Nordic countries. The Nordic NPPs can also participate in economic dispatch, redispatch and voltage regulation, and there are already various examples of such operation, e.g., Ringhals 1 in the summer of 2020, participated in voltage control for the Swedish grid system.

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