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I, AUTHORNAME confirm that the work presented in this thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the thesis.

Abstract

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Acknowledgements

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Abbreviations and Nomenclature

AC	**A**lternating **C**urrent
AEMC	**A**ustralian **E**nergy **M**arket **C**ommission
AEMO	**A**ustralian **E**nergy **M**arket **O**perator
AER	**A**ustralian **E**nergy **R**egulator
AGC	**A**utomatic **g**eneration **c**ontrol
BESS	**B**attery **e**nergy **s**torage **s**ystems
BRP	**B**alancing **r**esponsible **p**arty
BSP	**B**alancing **s**ervice **p**rovider
DC	**D**irect **c**urrent
DR	**D**emand **r**esponse
ENSTO-E	**E**uropean **N**etwork of **T**ransmission **S**ystem **O**perators for **E**lectricity
ESB	**E**nergy **S**ecurity **B**oard
IBR	**I**nverter-**b**ased **r**esources
ISO/RTO	**I**ndependent **S**ystem **O**perator/**R**egional **T**ransmission **O**rganisation
FCS	**F**requency **c**ontrol **s**ervices
FCAS	**F**requency **C**ontrol **A**ncillary **S**ervices
FERC	**F**ederal **E**nergy **R**egulatory **C**ommission
FFR	**F**ast **f**requency **r**esponse
Hz	Hertz

mHz	Millihertz
MW	Megawatts
NEM	**N**ational **E**lectricity **M**arket
NER	**N**ational **E**lectricity **R**ules
NOFB	**N**ormal **o**perating **f**requency **b**and
NSW	**N**ew **S**outh **W**ales
OFGS	**O**ver-**f**requency **g**eneration **s**hedding
PFR	**P**rimary **f**requency **r**esponse
PV	**P**hoto**v**oltaic
QLD	Queensland
RoCoF	**R**ate **o**f **c**hange **o**f **f**requency
SA	**S**outh **A**ustralia
SFR	**S**econdary **f**requency **r**esponse
SO	**S**ystem **o**perator
TAS	Tasmania
TFR	**T**ertiary **f**requency **r**esponse
TNSP	**T**ransmission **N**etwork **S**ervice **P**rovider
TSO	**T**ransmission **S**ystem **O**perator
UFLS	**U**nder-**f**requency **l**oad **s**hedding
UK	**U**nited **K**ingdom
US	**U**nited **S**tates
UFLS	**U**nder-**f**requency **l**oad **s**hedding
VIC	Victoria
VRE	**V**ariable **r**enewable **e**nergy

Chapter 1

Introduction, with a citation

1.1 Background

This is the introduction. Quisque finibus aliquet cursus. Integer in pellentesque tellus. Duis eu dignissim nulla, a porttitor enim. Quisque vehicula leo non ultrices finibus. Duis vehicula quis sem sit amet sollicitudin. Integer neque est, pharetra et auctor vel, iaculis interdum lectus.

To include a citation to the text, just add the citation key shown in the references.bib file. The style of the citation is determined by the ref_format.csl file. For example, in The Living Sea you can find pictures of the Calypso (**Cousteau1963?**).

In neque mauris, maximus at sapien a, iaculis dignissim justo. Aliquam erat volutpat. Praesent varius risus auctor est ultricies, sit amet consequat nisi laoreet. Suspendisse non est et mauris pharetra sagittis non porta justo. Praesent malesuada metus ut sapien sodales ornare.

1.2 The middle bit

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1.2.1 Subsection of the middle bit

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1.3 Summary of chapters

This is a brief outline of what went into each chapter, and a section which shows how to reference headers (which are labelled automatically for you). This chapter, Chapter 1, shows how to use citations and how to reference section headers. Chapter 2 shows how use and reference equations. Chapter **??** shows how to use and reference code. Chapter 4 shows how to use, reference, and resize pdf and jpg figures. Chapter 5 shows how to use and reference tables. Chapter 6 is truly revolutionary (but shows nothing functional). **Appendix 1** shows how to add chapters which are not numbered, and has to be referenced manually, as does **Appendix 2**. See the base `README.md` for how References are handled - leave `*_references.md` alone, and provide it to `pandoc` last.

Proin faucibus nibh sit amet augue blandit varius[1].

[1]The term *balancing services* is used in European systems, whereas the term *operating reserves* is widely used in North America.

Chapter 2

Literature review, with maths

2.1 Introduction

This is the introduction. Duis in neque felis. In hac habitasse platea dictumst. Cras eget rutrum elit. Pellentesque tristique venenatis pellentesque. Cras eu dignissim quam, vel sodales felis. Vestibulum efficitur justo a nibh cursus eleifend. Integer ultrices lorem at nunc efficitur lobortis.

2.2 The middle

This is the literature review. Nullam quam odio, volutpat ac ornare quis, vestibulum nec nulla. Aenean nec dapibus in mL/min^{-1}. Mathematical formula can be inserted using Latex and can be automatically numbered:

$$f(x) = ax^3 + bx^2 + cx + d \tag{2.1}$$

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Later on in the text, you can reference Equation 2.1 and its mind-blowing ramifications. Pellentesque habitant morbi tristique senectus et netus et malesuada fames ac turpis egestas. Sed faucibus pulvinar volutpat. Ut semper fringilla erat non dapibus. Nunc vitae felis eget purus placerat finibus laoreet ut nibh.

2.3 A complicated math equation

The following raw text in markdown behind Equation 2.2 shows that you can fall back on LaTeXif it is more convenient for you. Note that this will only be rendered in `thesis.pdf`

$$\begin{aligned}\hat{\theta}_g = \underset{\theta_g}{\operatorname{argmin}} \Bigg\{ -\sum_{n=1}^{N} \Big(1 - \mathbb{1}[f(\boldsymbol{x}^{(n)})]\Big) \log f \Big(\boldsymbol{x}^{(n)} \\ + g(\boldsymbol{x}^{(n)}; \theta_g)\Big) + \lambda |g(\boldsymbol{x}^{(n)}; \theta_g)|_2 \Bigg\} ,\end{aligned} \tag{2.2}$$

2.4 Conclusion

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Chapter 3

Frequency control arrangements: insights from the National Electricity Market

3.1 Link to thesis

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3.2 Abstract

For restructured electricity industries undergoing energy transition, designing effective and efficient frequency control arrangements is a complex and ongoing task that requires appropriate configuration of controllers, generator technical connection requirements, market arrangements and wider policy settings. In this paper, we provide an overview and assessment of these arrangements in Australia's National Electricity Market - a useful case study given its long-standing frequency control ancillary services markets, yet recent challenges in maintaining secure frequency control. We assess the performance of these evolving arrangements in delivering improved frequency control outcomes, with particular regard to growing renewable penetrations and evident tensions between mandatory requirements and market-based incentives. Based on this assessment, we draw out four key insights on designing frequency control arrangements as power system capabilities and needs change: 1) Understanding control action interactions, 2) Implementing efficient price formation and cost-allocation mechanisms, 3) Monitoring and assessing service provision to better align participant remuneration with service quality, and 4) Considering both regulatory and market mechanisms and their consequences and interactions. In particular, we discuss the trade-offs between effective and efficient outcomes, and provide arguments for more robust and forward-looking frequency control arrangements during energy transition.

3.3 Introduction

As a consequence of growing momentum to address global warming and continually declining technology costs, many power systems around the world are undergoing an energy transition in which significant capacity additions of variable renewable energy (VRE) and other inverter-based resources (IBR) are being accompanied by the progressive retirement of existing fossil fuel generation (International Energy Agency, 2021). Such power systems are currently experiencing or expected to soon experience high instantaneous penetrations of VRE (i.e. beyond 50% of grid demand being met by VRE at any given time), which can pose technical challenges to the stable and secure operation of a power system (Kenyon et al., 2020; Kroposki et al., 2017; Meegahapola et al., 2021). While several of these challenges have technological solutions of various maturities, configuring mechanisms in an effective and efficient manner across power system design layers, which span from how resources are controlled to how grid codes and markets are designed, remains an open and significant challenge.

In this article, we focus on one aspect of power system security: control of AC frequency. Maintaining frequency near the nominal value of a power system (either 50 or 60 Hz) is contingent on the ongoing balance of active power supply and demand within a synchronous area (Grainger, 1994). Power system frequency deviations are a consequence of instantaneous supply-demand imbalances, which typically occur as a result of system variability (predictable changes in supply or demand, such as fluctuations and ramps of generation or load) and uncertainty (unpredicted changes in supply or demand, such as forecast errors or unplanned outages) (Ela et al., 2011). System operators (SOs) achieve short-term active power balancing using reserve capacity. Whilst there are many names for these reserves[1], this article will focus on a common subset that responds to and mitigates frequency deviations over short timeframes (milliseconds to minutes). We will refer to such reserves as *Frequency Control Services* (FCS). If FCS are insufficient or inadequate, the system frequency may deviate beyond acceptable system limits and lead to equipment damage, load shedding, generator trips and cascading failures that lead to blackouts (Kirby et al., 2002; Ulbig et al., 2014).

In electricity industries with competitive markets for energy and FCS, frequency control arrangements consist of control, regulatory and market-based mechanisms (Mancarella and Billimoria, 2021). Control mechanisms specify the technical requirements for FCS. Regulatory and market-based mechanisms are used by the SO to:

1. Mandate or incentivise participant behaviour in the energy market that facilitates system balancing. This includes enforcing dispatch compliance or penalising participant portfolio imbalances; and
2. Procure FCS from capable resources (i.e. generators, loads and network elements).

Regulatory FCS procurement mechanisms are often mandatory and include equipment standards, connection requirements and SO intervention, whereas market-based FCS procurement mechanisms are often voluntary and include remunerative schemes and contract or spot markets. Together, these mechanisms dictate the physical effectiveness and productive, dynamic, price formation and cost-allocation efficiencies of FCS provision and procurement. Well-designed arrangements should be effective and efficient, where *effectiveness*

[1]The term *balancing services* is used in European systems, whereas the term *operating reserves* is widely used in North America.

entails sufficient and robust frequency response to meet physical power system requirements and *efficiency* relates to frequency response being provided at low cost, both now and into the future (Y. Rebours et al., 2007; van der Veen and Hakvoort, 2016).

As power systems transition towards higher instantaneous penetrations of VRE and IBR, SOs are likely to face the following challenges to short-term system balancing that may require existing frequency control arrangements to be revisited:

- VRE adds variability and uncertainty to a power system, particularly if similar technologies are situated within close proximity of one another (i.e. correlated production and/or forecast errors) (Australian Energy Market Operator, 2020a; Keeratimahat et al., 2021). Furthermore, unless an appropriate response is incorporated and enabled in their control systems, VRE and other IBR do not provide FCS. In jurisdictions that do not require, incentivise or allow VRE and IBR to provide FCS, the displacement of synchronous machines in dispatch has led to lower availabilities of resources that provide FCS (Australian Energy Market Operator, 2020b; Denholm et al., 2020; Milano et al., 2018) .

- In jurisdictions with competitive markets for energy and FCS, there is a tension between achieving economically efficient markets and the redundancy, certainty and control afforded to the SO. While the societal and economic costs of power system failure are often very large, it may be difficult for the SO to justify the cost of mitigation measures when they are ongoing or significant and when the joint probability of events or failures is low. The uncertainties associated with energy transition and the impacts of global warming are likely to present additional challenges. Power system security measures may need to be implemented rapidly and be both robust to a range of futures and resilient in the face of shocks, such as severe weather events (Eggleston et al., 2021; Prakash et al., 2021).

In this paper, we provide insights and recommendations on designing more effective and efficient frequency control arrangements based on experience from the Australian National Electricity Market (NEM). The NEM is currently experiencing relatively high system-wide instantaneous VRE penetrations (just over 60% in 2021) and is expected to experience penetrations as high as 75-100% by 2025 (Australian Energy Market Operator, 2021a, 2021b). Though the NEM's frequency control arrangements were once arguably world-leading (Riesz et al., 2015; Thorncraft and Outhred, 2007), the speed at which system capabilities and needs are changing and the removal of mandatory requirements in 2001 as a part of a paradigm shift from obligation to remuneration for FCS have exposed design issues. In attempting to address these issues, the NEM's rule makers have placed FCS obligations on generators and transmission network operators and have undertaken reforms to the NEM's energy and FCS markets, including introducing a new market to procure emergency fast frequency response (FFR) from IBR. Whilst the NEM is an electrically-isolated power system with a relatively simple energy-only market, the insights and recommendations from this paper are likely to be relevant to other power systems and interconnections as their existing conventional generation retires and VRE deployment levels increase.

This paper offers three contributions to the literature. First, we provide a high-level overview and comparison of the key features of frequency control arrangements in North America and Central and Western Europe, and provide a review of the most prominent challenges to designing effective and efficient frequency control arrangements and the potential solutions discussed in the literature. Second, we provide a comprehensive update to previous literature on frequency control in the NEM (Riesz et al., 2015; Thorncraft et al., 2008; Thorncraft and Outhred, 2007). Our analysis benefits from recent experience in the NEM that encompasses deteriorating frequency performance, the reintroduction of mandatory requirements and integrating higher shares of VRE. While several of these aspects have been discussed independently in the literature, this paper seeks to provide a structured and holistic analysis of developments in the NEM and their implications for frequency control arrangement design. Third, this article advocates for designers placing a greater emphasis on delivering forward-looking frequency control arrangements during energy transition through the implementation of more robust regulatory mechanisms and ensuring that market-based mechanisms are capable of supporting FCS investment. As highlighted in the following sections, these design features have received surprisingly little attention in the literature.

The rest of the chapter is structured as follows. In Chapter 3.4, we provide an overview of typical frequency control arrangements, with a focus on restructured electricity industries in North America and Europe, and the main challenges faced in their design. We describe the NEM, its frequency control arrangements and the specific challenges posed by increasing penetrations of VRE and other IBR in Section 3. In Section [sec:insights], we analyse the performance of the NEM's frequency control arrangements in responding to the challenges explored in Section 2, with primary frequency response and regulation (secondary frequency response) services in the NEM as case studies. Based on our analysis, we conclude by offering four key insights to operators, regulators and market-bodies that include understanding control action interactions; ensuring that arrangements are capable of supporting investment in FCS capability; monitoring, assessing and remunerating FCS performance; and considering both regulatory and market-based mechanisms in the design of effective and efficient frequency control arrangements.

3.4 Context

3.4.1 Conventional frequency control schemes

SOs employ hierarchical and sequential frequency control schemes. In most power systems, such schemes implicitly include inertial response and explicitly define FCS such as primary frequency response (PFR), secondary frequency response (SFR) and tertiary frequency response (TFR). In general, once frequency has deviated from the system nominal value, synchronous machines provide an inertial response that is inherent and immediate in slowing the rate of change of frequency (RoCoF). Within seconds, generators and/or loads provide autonomous and decentralised control action through PFR (Eto et al., 2018; Machowski et al., 2020). PFR arrests the frequency deviation to enable the slower and more centralised control actions of SFR and TFR to return the power system frequency to its nominal value (Ela et al., 2012; Eto et al., 2010). Should system frequency continue to rise or fall beyond the system's allowable limits, emergency protection schemes such as under-frequency load shedding (UFLS) and over-frequency generation shedding (OFGS) relays may be triggered. In some systems, RoCoF relays are also used to prevent high RoCoFs from tripping or damaging equipment and to contain frequency nadirs and zeniths (Akram et al., 2020; DGA Consulting, 2016; Miller et al., 2017).

3.4.2 Procurement of frequency control services

Except for inertial response from synchronous machines, the SO procures FCS capacity from capable resources within its control area and, in the case of SFR and TFR, activates FCS energy if necessary. In electricity industries where the SO owns most if not all the generation assets (i.e. a vertically-integrated utility), the SO is able to jointly schedule generation and FCS capacity with knowledge of the condition of the system and the status and cost structures of their plant. However, many electricity industries have undergone some degree of restructuring, which has created a greater role for competitively-oriented decentralised decision-making (van der Veen and Hakvoort, 2016) . The diverse outcomes of restructuring processes and differences in technical characteristics (e.g. capabilities of resource mix and network topology) have led to a wide range of frequency control arrangements across power systems (Poplavskaya and de Vries, 2019; Y. Rebours et al., 2007) , which have been reviewed and compared extensively within industry and academic literature (Banshwar et al., 2018; Brooks and Lesieutre, 2019; Ela and Hytowitz, 2019; Hewicker et al., 2020; Lopez et al., 2020; Ocker et al., 2016; Y. G. Rebours et al., 2007a, 2007b; Reishus Consulting LLC, 2017; Zhou et al., 2016).

In restructured electricity industries, the provision of more passive FCS (e.g. ride-through capabilities) is usually mandated by regulatory mechanisms such as connection agreements and grid codes, whereas FCS that require additional response capabilities or impose opportunity-costs on suppliers are procured and remunerated by the SO through market-based mechanisms. In Sections 2.2.1 and 2.2.2, we provide an overview of typical features[2] and key developments in market-based mechanisms for procuring FCS in North America and Central and Western Europe, respectively. These regions best represent the two prevailing short-term wholesale electricity market models: central dispatch markets, in which the SO issues dispatch instructions, and decentralised or self-dispatch markets, in which resource dispatch is managed by market participants (**Ahlqvist2018?**). Given that FCS and energy are partially substitutable goods, the characteristics of short-term wholesale electricity markets heavily influence the design of FCS arrangements and thus these regions provide an interesting contrast. However, despite their differences, the SO plays a central role in both of these regions as they determine the area demand for FCS capacity, activate FCS energy as required and are ultimately responsible for ensuring that the power system is balanced and securely operated.

3.4.3 North American markets

In North America, central dispatch wholesale electricity markets are operated by an Independent System Operator (ISO) or Regional Transmission Organization (RTO) and are distributed across three synchronous areas. These markets consist of two short-term centralised platforms: a day-ahead market and a real-time market. In the day-ahead market, the SO solves a security-constrained unit commitment problem using supply offers (single or three-part) and demand bids (quantity or price-quantity) to produce day-ahead locational marginal prices and a financially-binding hourly schedule. In the real-time

[2]We note that there are numerous differences between jurisdictional arrangements and terminology in each of these regions. For a more general overview of potential procurement models, refer to (**Billimoria2020?**).

market, the SO solves a security-constrained economic dispatch problem (typically every five minutes) using generator price-quantity offers and a demand forecast to produce real-time locational marginal prices and a set of physically and financially binding dispatch instructions. Thus, each short-term market is cleared to maximise social welfare whilst respecting network and system security constraints (**Chow2005?**; **Cramton2017?**).

Except for Frequency Responsive Reserves (i.e. PFR), operating reserves (i.e. FCS capacity) are explicitly procured by placing an obligation on load-serving entities to self-provide or purchase their share from SO-run FCS markets (**Ela2012b?**; **Zhou2016?**). These FCS markets are usually integrated into day-ahead market and, in most jurisdictions, the real-time market. Standard products in North American markets include Regulation (i.e. SFR during normal operation), Spinning and Non-Spinning Reserves (i.e. TFR deployed following an event) (**Zhou2016?**; **Ela2019b?**; **Hewicker2020?**). Participants can submit offers for FCS in addition to offer for energy. Unit commitment and economic dispatch permit co-optimisation of energy and FCS procurement. From the perspective of the SO, co-optimisation ensures that the total system cost of achieving an energy supply-demand balance is minimised alongside FCS requirements, subject to network and system security constraints. From the perspective of participants, co-optimisation leads to an FCS price that not only reflects the price offer of the marginal resource, but also any "profit" it forgoes in the energy market (assuming supplier offers reflect their short-run marginal costs) (**Isemonger2009?**; **Ela2012a?**). As such, ISO/RTO FCS markets can compensate opportunity-costs related to the day-ahead and/or real-time market but only allocate costs to load-serving entities through a procurement obligation.

Though North American FCS markets have predominantly procured and remunerated FCS capacity, ISO/RTOs (except Texas' ISO, ERCOT) were ordered to also remunerate Regulation providers for the quantity of energy provided whilst accurately following control signals by the Federal Energy Regulatory Commission's (FERC) Order 755 (**FederalEnergyRegulatoryCommission-FERC2011?**). As such, Regulation providers offer a quantity of capacity, a price for capacity and a price for "mileage", which is the energy delivered. Remuneration for Regulation takes performance (the ability of a resource to follow the ISO/RTO's control signals) into account, though how this is implemented varies between ISO/RTOs (**Ela2019b?**; **Fernandez-Munoz2020?**). A notable example is the PJM RTO, which uses both a standard SFR control signal (RegA) and faster SFR control signal (RegD) intended for battery energy storage systems (BESS). PJM determines how interchangeable a resource's RegD provision is with RegA provision (the marginal benefit factor) to clear the Regulation market and calculates a performance score for use in market clearing and settlement. However, according to the independent market monitor, the omission of the marginal benefit factor from market settlement has led to perverse market outcomes (**Brooks2019?**; **MonitoringAnalytics2021?**).

3.4.4 European markets

Most of the electricity markets of Central and Western Europe are self-dispatch and consist of two short-term platforms: the day-ahead market and the intraday market, which can be continuous, composed of frequently-run discrete auctions or a combination of the two. Each of these platforms is coupled across the majority of market zones in Europe, with a single price coupling algorithm used to simultaneously clear zonal day-ahead markets and a single order book compiled to match cross-zonal intraday orders (EPEX Spot, n.d.; NEMO Committee, n.d.). In contrast to North American electricity markets, the market operator is responsible for market operation and is distinct from the Transmission System Operator (TSO). Generation and load are managed by Balancing Responsible Parties (BRP), which must submit binding operational schedules to the TSO ahead of delivery (often by the day prior to delivery). As BRPs become aware of potential deviations closer to real time (e.g. improved forecasts), they are able to adjust their submitted schedules (i.e. remain "balanced") through trades on the intraday market (**Lago2021?**; **Musgens2014?**). BRPs face financial repercussions if they are imbalanced via an imbalance price and, in some jurisdictions, are legally obliged to be balanced (**ENTSO-EWGAS2021a?**).

Following gate-closure of the intraday market, residual imbalances are primarily addressed by FCS (known as balancing services) procured by the TSO. Standard FCS in Europe include Frequency Containment Reserve (i.e. PFR), automatic Frequency Restoration Reserves (i.e. SFR), and manual Frequency Restoration Reserves and Replacement Reserves (i.e. both TFR), with minimum technical requirements for each specified by the European Network of Transmission System Operators for Electricity (ENTSO-E) (**EuropeanNetworkofTransmissionSystemOperatorsforElectricityENTSO-E2013?**). Depending on the FCS product and the jurisdiction, TSOs may distinguish between FCS capacity (balancing capacity) and the delivery of FCS energy (balancing energy). The provision of one or both is mandated in some cases, but where both are procured competitively, Balancing Service Providers (BSP) typically submit separate offers for FCS capacity and FCS energy (**Abbasy2012?**). FCS capacity markets are often cleared days to months in advance of real-time whereas the FCS energy market, which effectively constitutes merit-order or pro rata activation of capacity for FCS energy provision, is cleared within an hour or minutes of real-time (**Ocker2016?**; **Poplavskaya2019?**; **ENTSO-EWGAS2021a?**). FCS capacity costs are typically allocated to power system users via a grid tariff. FCS energy costs are typically allocated to BRPs based on their schedule deviations and an imbalance price, which may differ from the FCS energy price paid to BSPs (**Vandezande2010?**; **Hirth2015?**). As such, European FCS markets generally disincentivise causers of imbalance through the imbalance price, which may also recover or reflect the cost of FCS energy. However, since FCS capacity markets are typically decoupled from and cleared ahead of short-term energy markets, perceived opportunity-costs based on expected short-term energy market prices must be internalised within participants' FCS offers.

Given the relatively high degree of interconnection between transmission systems in Central and Western Europe, cross-TSO initiatives are in place and being expanded to address imbalances and share FCS across the Continental Europe synchronous area. When sufficient cross-TSO transmission capacity is available, initiatives currently in place enable participating TSOs to jointly procure Frequency Containment Reserve capacity, net imbalances (i.e. reduce the demand for SFR by aggregating individual control area imbalances) and jointly procure automatic Frequency Restoration Reserve capacity and energy (**EuropeanNetworkofTransmissionSystemOperatorsforElectricityENTSO-E2020?**). Further efficiency gains are expected following the implementation of integrated market platforms for imbalance netting and balancing energy for SFR and TFR. The implementation of these platforms is mandated by the European Commission's European Balancing Guideline and requires certain FCS product definitions and market features to be harmonised across the balancing energy markets of participating TSOs (**EuropeanCommission2017?**; **50hertz2017?**).

3.5 Designing frequency control arrangements

As with any policy problem, designing frequency control arrangements in restructured electricity industries requires design principles, variables and performance criteria to be established. The public good characteristics of frequency control have heavily influenced arrangement design principles across jurisdictions, such as the common preference for the SO to centrally coordinate FCS procurement and activation (**Rebours2007b?**; **Musgens2014?**). In contrast, though some design variables are common, others may only apply to particular systems based on their resource mix, network topology and/or market design. (**Rebours2007b?**) discuss design variables for central dispatch markets related to the following arrangement features:

1. FCS procurement;
2. Price formation, which when efficient should lead to FCS prices not only reflecting the true cost of the service, but also its true value to the system; and
3. Allocation of the cost of FCS.

Similarly, (**Abbasy2012?**) discusses the main design variables applicable to European self-dispatch markets. (**VanderVeen2016?**) build upon this work to provide a more comprehensive treatment of design variables in self-dispatch markets. (**Rebours2007b?**; **Abbasy2012?**) and (**VanderVeen2016?**) all propose some variation of effectiveness and efficiency as performance criteria, with van der Veen and Hakvoort analysing the various trade-offs between and within each criterion.

Despite the well-defined nature of the design problem, there are several challenges to achieving effective and efficient arrangements. In Sections 2.3.1 and 2.3.2, we present the most prominent challenges and their treatment in the literature.

3.5.1 The influx of VRE and other IBR in power systems

As discussed in Section 1, VRE adds variability and uncertainty to power systems which, at the very least, can lead to increased procurement and activation requirements for PFR and SFR during normal operating conditions (**Ela2011?**). Three proposals to address this issue and thus reduce FCS requirements with growing penetrations of VRE have been discussed in the literature. The first is to shorten energy market trading/dispatch intervals (**Riesz2015a?**; **Ocker2017?**) and the time between market gate closure and dispatch (**Katz2019?**), thereby enabling scheduling based on up-to-date system conditions and forecasts. The second is to increase coordination between control areas within a synchronous area by netting imbalances (**King2011?**), jointly procuring and dispatching FCS (**Scherer2013?**) or aggregating them into a single market region (**Milligan2010?**; **Riesz2015a?**). These two proposals alone have delivered significant system savings in Germany despite growing penetrations of VRE (**Hirth2015?**; **Ocker2017?**). The third is for the SO to determine the required quantity of FCS capacity (*dimensioning*) using dynamic and probabilistic approaches (as opposed to static and deterministic) that adequately reflect current or expected power system conditions and an acceptable level of risk, such as a reliability standard (**Holttinen2013?**; **DeVos2019?**; **Ortega-Vazquez2020?**).

In recent years, SOs have become increasingly concerned with growing penetrations of asynchronous IBR leading to higher RoCoFs and fewer resources offering conventional FCS (**DGAConsulting2016?**; **Hartmann2019?**; **Denholm2020?**). However, VRE and other IBR are able to provide tunable conventional FCS, FFR and/or an inherent response that strongly resembles the inertial response of synchronous machines[3] if this is facilitated by arrangement design (**Miller2017?**; **Fernandez-Munoz2020?**; **Mancarella2021a?**). Following a contingency event in a low-inertia power system, rapid FCS from IBR can mitigate higher RoCoFs, which when unabated can lead to deeper frequency nadirs and zeniths and the subsequent activation of UFLS or OFGS (**Tielens2016?**; **AustralianEnergyMarketOperator2017a?**; **NERCInverter-BasedResourcePerformancetaskForceIRPTF2020a?**).

3.5.2 Achieving economic efficiency

Achieving short-run efficiency entails supplier costs being reflected in their offers and adequately propagated to FCS prices, and the SO assigning at least some portion of FCS costs to system users that create a need for procurement or activation. A widely used pricing approach in ISO/RTO co-optimised FCS markets is a marginal price which incorporates the marginal resource's

[3]The terms *virtual, emulated and synthetic* inertia have been used in the literature to refer to a proportional active power response to RoCoF. However, these terms do not distinguish whether the inverter control scheme provides an inherent response (i.e. from inverters operated as a voltage source which are commonly referred to as *grid-forming inverters* (**Lin2020a?**; **Cherevatskiy2020?**)) or a controlled response following frequency measurement (**Tielens2016?**; **Eriksson2018?**).

short-term market opportunity-costs and their offer, which could reflect potential mileage or wear-and-tear costs (**Zhou2016?**; **Frew2021?**). Though improving cost-allocation has been repeatedly proposed in North American literature (**Isemonger2009?**; **Milligan2011a?**; **Ela2012a?**), FCS costs are predominantly socialised across loads based on demand or consumption. In Europe, however, much attention has been given to FCS market pricing, scoring (the order in which offers are selected) and cost-allocation. Specifically, literature on European FCS markets has explored whether pay-as-bid or uniform pricing better facilitates suppliers revealing their true costs (**Musgens2014?**; **Hirth2015?**; **Ocker2018?**), the particular offers scoring should consider (**Musgens2014?**; **Ehrhart2021?**) and the design of imbalance prices to sufficiently incentivise short-term balancing (**Vandezande2010?**; **Hirth2015?**; **Papavasiliou2020?**). Regardless, both European and North American literature suggest that increased competition in FCS markets is a priority. This could be facilitated by enabling distributed and utility-scale VRE and IBR to qualify for FCS provision, reducing minimum offer quantities, separating raise and lower (positive and negative) products and increasing market clearing frequency and the time resolution of FCS products (**Hirth2015?**; **Poplavskaya2019?**; **Lago2021?**; **Frew2021?**). Despite the typically "shallow" nature of FCS markets (i.e. additional supply can significantly reduce prices (**Riesz2015a?**)), dynamic efficiency has received considerably less attention. Notable exceptions include (**Papavasiliou2020?**) and (**Frew2021?**), who briefly discuss the potential for FCS scarcity pricing to better reflect the true value of system reliability and support investment in FCS.

An additional challenge in implementing efficient FCS markets involves the trade-offs that must be considered. As outlined in Section 1, some mechanisms that improve efficiency may come at the expense of visibility, control and redundancy afforded to the SO, which typically does not own any FCS-capable assets. The former is typically achieved using market-based mechanisms and the latter through regulatory mechanisms. (**Ela2012b?**), (**Billimoria2020?**), (**Mancarella2021a?**) and (**Lal2021a?**) discuss several prerequisites for implementing market-based mechanisms and stress that balance between market-based and regulatory mechanisms may be required. However, achieving this balance can be challenging due to the asymmetry between the risk of an event and its consequences, and that between the benefits of market efficiency and the cost of resilient and robust mitigation measures (**Mancarella2021a?**; **Lal2021a?**). Another trade-off is the arbitrary definition of FCS products. Market-based mechanisms will work best when FCS are ”discrete” commodities and fungible. However, this ignores the wide “spectrum” of resource technical capabilities. Favouring fungibility may obscure physical and control interdependencies between FCS and restrict or fail to incentivise higher quality provision, thereby leading to an inefficient overall outcome (**Gimon2020?**; **MacGill2020?**).

Chapter 4

Research containing a figure

4.1 Introduction

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4.2 Method

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4.4 Discussion

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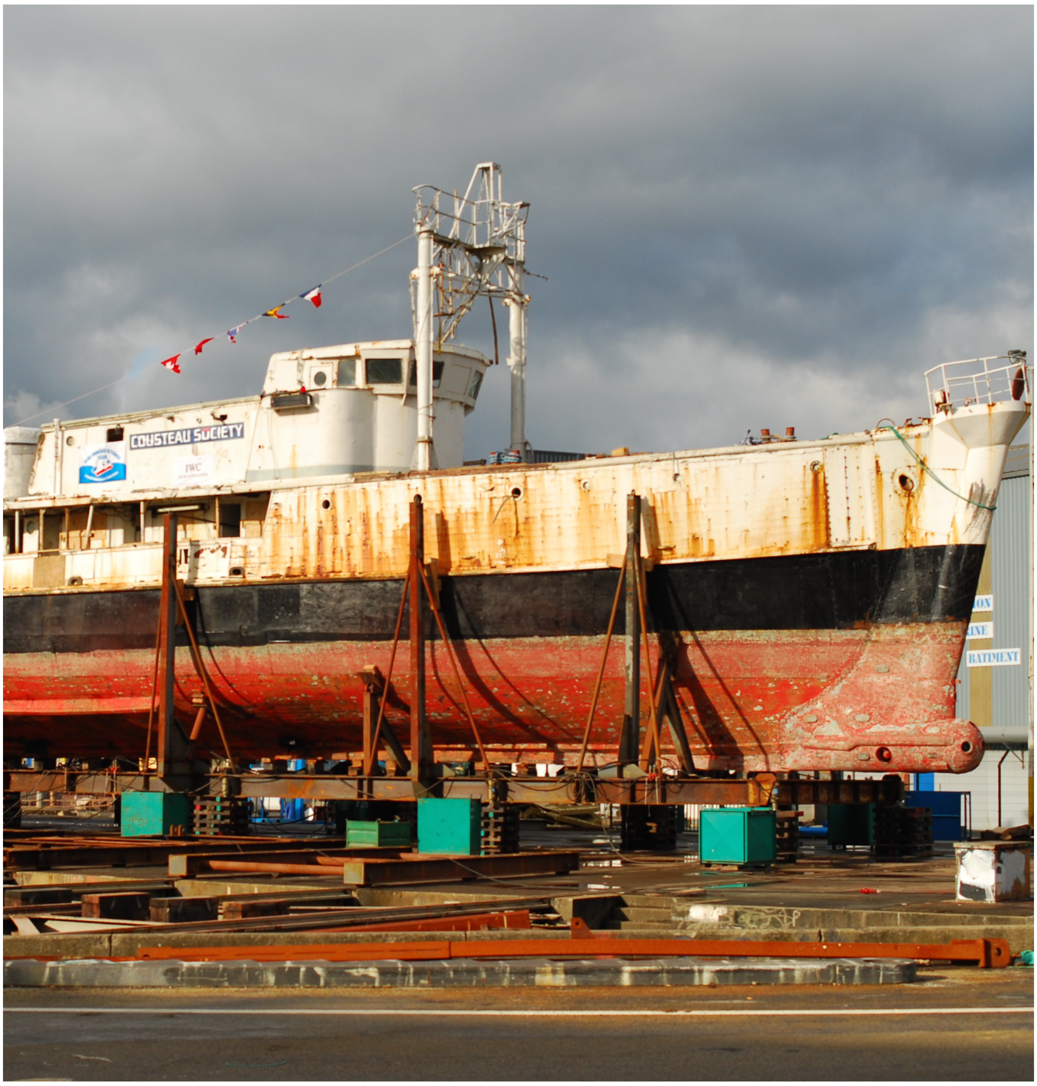

Figure 4.1: RV Calypso is a former British Royal Navy minesweeper converted into a research vessel for the oceanographic researcher Jacques-Yves Cousteau. It was equipped with a mobile laboratory for underwater field research.

4.5 Conclusion

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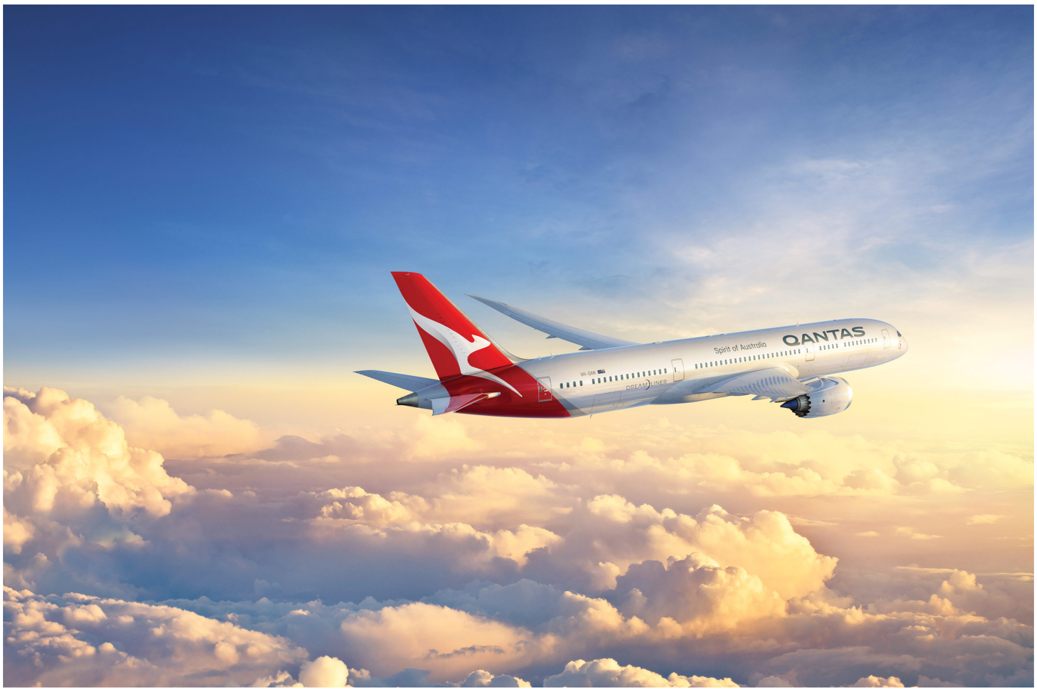

Figure 4.2: This is not a boat

Chapter 5

Research containing a table

5.1 Introduction

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5.2 Method

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5.3 Results

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Table 5.1: Important data for various land masses.

Landmass	% stuff	Number of Owls	Dolphins per Capita	How Many Foos	How Many Bars	Forbidden Float
North America	94%	20,028	17,465	12,084	20,659	1.71
Central America	91%	6564	6350	8,189	12,012	1.52
South America	86%	3902	4127	5,205	6,565	1.28
Africa	84%	2892	3175	3,862	4,248	1.1
Europe	92%	20,964	17,465	15,303	24,203	1.58
Asia	87%	6852	6350	8,255	11,688	1.47
Oceania	87%	4044	4127	5,540	6,972	1.28
Antarctica	83%	2964	3175	4,402	4,941	1.13

5.4 Discussion

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5.5 Conclusion

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Chapter 6

Final research study

6.1 Introduction

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6.2 Method

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6.5 Conclusion

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Chapter 7

Conclusion

7.1 Thesis summary

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7.2 Future work

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Appendix 1: Some extra stuff

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Appendix 2: Some more extra stuff

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Chapter 8

References

Chapter 9

Context

9.1 Conventional frequency control schemes

SOs employ hierarchical and sequential frequency control schemes. In most power systems, such schemes implicitly include inertial response and explicitly define FCS such as primary frequency response (PFR), secondary frequency response (SFR) and tertiary frequency response (TFR). In general, once frequency has deviated from the system nominal value, synchronous machines provide an inertial response that is inherent and immediate in slowing the rate of change of frequency (RoCoF). Within seconds, generators and/or loads provide autonomous and decentralised control action through PFR (**Eto2018?**; **Machowski2020?**). PFR arrests the frequency deviation to enable the slower and more centralised control actions of SFR and TFR to return the power system frequency to its nominal value (**Eto2010a?**; **Ela2012b?**). Should system frequency continue to rise or fall beyond the system's allowable limits, emergency protection schemes such as under-frequency load shedding (UFLS) and over-frequency generation shedding (OFGS) relays may be triggered. In some systems, RoCoF relays are also used to prevent high RoCoFs from tripping or damaging equipment and to contain frequency nadirs and zeniths (**DGAConsulting2016?**; **Miller2017c?**; **Akram2020?**).

9.2 Procurement of frequency control services

Except for inertial response from synchronous machines, the SO procures FCS capacity from capable resources within its control area and, in the case of SFR and TFR, activates FCS energy if necessary. In electricity industries where the SO owns most if not all the generation assets (i.e. a vertically-integrated utility), the SO is able to jointly schedule generation and FCS capacity with knowledge of the condition of the system and the status and cost structures of their plant. However, many electricity industries have undergone some degree of restructuring, which has created a greater role for competitively-oriented decentralised decision-making (**VanderVeen2016?**). The diverse outcomes of restructuring processes and differences in technical characteristics (e.g. capabilities of resource mix and network topology) have led to a wide range of frequency control arrangements across power systems (**Rebours2007b?**; **Poplavskaya2019?**), which have been reviewed and compared extensively within industry and academic literature (**Rebours2007?**; **Rebours2007a?**; **Zhou2016?**; **Ocker2016?**; **ReishusConsultingLLC2017?**; **Bansh-**

war2018?; **Brooks2019?**; **Ela2019b?**; **Hewicker2020?**; **Lopez2020?**). In restructured electricity industries, the provision of more passive FCS (e.g. ride-through capabilities) is usually mandated by regulatory mechanisms such as connection agreements and grid codes, whereas FCS that require additional response capabilities or impose opportunity-costs on suppliers are procured and remunerated by the SO through market-based mechanisms.

In the Sections 2.2.1 and 2.2.2, we provide an overview of typical features[1] and key developments in market-based mechanisms for procuring FCS in North America and Central and Western Europe, respectively. These regions best represent the two prevailing short-term wholesale electricity market models: central dispatch markets, in which the SO issues dispatch instructions, and decentralised or self-dispatch markets, in which resource dispatch is managed by market participants (**Ahlqvist2018?**). Given that FCS and energy are partially substitutable goods, the characteristics of short-term wholesale electricity markets heavily influence the design of FCS arrangements and thus these regions provide an interesting contrast. However, despite their differences, the SO plays a central role in both of these regions as they determine the area demand for FCS capacity, activate FCS energy as required and are ultimately responsible for ensuring that the power system is balanced and securely operated.

9.2.1 North American markets

In North America, central dispatch wholesale electricity markets are operated by an Independent System Operator (ISO) or Regional Transmission Organization (RTO) and are distributed across three synchronous areas. These markets consist of two short-term centralised platforms: a day-ahead market and a real-time market. In the day-ahead market, the SO solves a security-constrained unit commitment problem using supply offers (single or three-part) and demand bids (quantity or price-quantity) to produce day-ahead locational marginal prices and a financially-binding hourly schedule. In the real-time market, the SO solves a security-constrained economic dispatch problem (typically every five minutes) using generator price-quantity offers and a demand forecast to produce real-time locational marginal prices and a set of physically and financially binding dispatch instructions. Thus, each short-term market is cleared to maximise social welfare whilst respecting network and system security constraints (**Chow2005?**; **Cramton2017?**).

Except for Frequency Responsive Reserves (i.e. PFR), operating reserves (i.e. FCS capacity) are explicitly procured by placing an obligation on load-serving entities to self-provide or purchase their share from SO-run FCS markets (**Ela2012b?**; **Zhou2016?**). These FCS markets are usually integrated into day-ahead market and, in most jurisdictions, the real-time market. Standard products in North American markets include Regulation (i.e. SFR during normal operation), Spinning and Non-Spinning Reserves (i.e. TFR deployed following an event) (**Zhou2016?**; **Ela2019b?**; **Hewicker2020?**). Participants can submit offers for FCS in addition to offer for energy. Unit commitment and economic dispatch permit co-optimisation of energy and FCS procurement. From the perspective of the SO, co-optimisation ensures that the total system cost of achieving an energy supply-demand balance is minimised alongside FCS requirements, subject to network and system security constraints. From the perspective of participants, co-optimisation leads to an FCS price that not only reflects the price offer of the marginal resource, but also any "profit" it forgoes in the energy market (assuming supplier offers reflect their short-run marginal costs) (**Isemonger2009?**; **Ela2012a?**). As such, ISO/RTO FCS markets can compensate opportunity-costs related

[1] We note that there are numerous differences between jurisdictional arrangements and terminology in each of these regions. For a more general overview of potential procurement models, refer to (**Billimoria2020?**).

to the day-ahead and/or real-time market but only allocate costs to load-serving entities through a procurement obligation.

Though North American FCS markets have predominantly procured and remunerated FCS capacity, ISO/RTOs (except Texas' ISO, ERCOT) were ordered to also remunerate Regulation providers for the quantity of energy provided whilst accurately following control signals by the Federal Energy Regulatory Commission's (FERC) Order 755 (**FederalEnergyRegulatoryCommissionFERC2011?**). As such, Regulation providers offer a quantity of capacity, a price for capacity and a price for "mileage", which is the energy delivered. Remuneration for Regulation takes performance (the ability of a resource to follow the ISO/RTO's control signals) into account, though how this is implemented varies between ISO/RTOs (**Ela2019b?**; **Fernandez-Munoz2020?**). A notable example is the PJM RTO, which uses both a standard SFR control signal (RegA) and faster SFR control signal (RegD) intended for battery energy storage systems (BESS). PJM determines how interchangeable a resource's RegD provision is with RegA provision (the marginal benefit factor) to clear the Regulation market and calculates a performance score for use in market clearing and settlement. However, according to the independent market monitor, the omission of the marginal benefit factor from market settlement has led to perverse market outcomes (**Brooks2019?**; **MonitoringAnalytics2021?**).

9.2.2 European markets

Most of the electricity markets of Central and Western Europe are self-dispatch and consist of two short-term platforms: the day-ahead market and the intraday market, which can be continuous, composed of frequently-run discrete auctions or a combination of the two. Each of these platforms is coupled across the majority of market zones in Europe, with a single price coupling algorithm used to simultaneously clear zonal day-ahead markets and a single order book compiled to match cross-zonal intraday orders (EPEX Spot, n.d.; NEMO Committee, n.d.). In contrast to North American electricity markets, the market operator is responsible for market operation and is distinct from the Transmission System Operator (TSO). Generation and load are managed by Balancing Responsible Parties (BRP), which must submit binding operational schedules to the TSO ahead of delivery (often by the day prior to delivery). As BRPs become aware of potential deviations closer to real time (e.g. improved forecasts), they are able to adjust their submitted schedules (i.e. remain "balanced") through trades on the intraday market (**Lago2021?**; **Musgens2014?**). BRPs face financial repercussions if they are imbalanced via an imbalance price and, in some jurisdictions, are legally obliged to be balanced (**ENTSO-EWGAS2021a?**).

Following gate-closure of the intraday market, residual imbalances are primarily addressed by FCS (known as balancing services) procured by the TSO. Standard FCS in Europe include Frequency Containment Reserve (i.e. PFR), automatic Frequency Restoration Reserves (i.e. SFR), and manual Frequency Restoration Reserves and Replacement Reserves (i.e. both TFR), with minimum technical requirements for each specified by the European Network of Transmission System Operators for Electricity (ENTSO-E) (**EuropeanNetworkofTransmissionSystemOperatorsforElectricityENTSO-E2013?**). Depending on the FCS product and the jurisdiction, TSOs may distinguish between FCS capacity (balancing capacity) and the delivery of FCS energy (balancing energy). The provision of one or both is mandated in some cases, but where both are procured competitively, Balancing Service Providers (BSP) typically submit separate offers for FCS capacity and FCS energy (**Abbasy2012?**). FCS capacity markets are often cleared days to months in advance of real-time whereas the FCS energy market, which effectively constitutes merit-order or pro rata activation of capacity for FCS energy provision, is cleared within an hour or minutes of real-time (**Ocker2016?**; **Poplavskaya2019?**; **ENTSO-EWGAS2021a?**). FCS capacity costs are typically allocated to power system users via a grid tariff. FCS energy costs are typically allocated to BRPs based on their schedule deviations and an imbalance price, which may differ from the FCS energy price paid to BSPs (**Vandezande2010?**; **Hirth2015?**). As such, European FCS markets generally disincentivise causers of imbalance through the imbalance price, which may also recover or reflect the cost of FCS energy. However, since FCS capacity markets are typically decoupled from and cleared ahead of short-term energy markets, perceived opportunity-costs based on expected short-term energy market prices must be internalised within participants' FCS offers.

Given the relatively high degree of interconnection between transmission systems in Central and Western Europe, cross-TSO initiatives are in place and being expanded to address imbalances and share FCS across the Continental Europe synchronous area. When sufficient cross-TSO transmission capacity is available, initiatives currently in place enable participating TSOs to jointly procure Frequency Containment Reserve capacity, net imbalances (i.e. reduce the demand for SFR by aggregating individual control area imbalances) and jointly procure automatic Frequency Restoration Reserve capacity and energy (**EuropeanNetworkofTransmissionSystemOperatorsforElectricityENTSO-E2020?**). Further efficiency gains are expected following the implementation of integrated market platforms for imbalance netting and balancing energy for SFR and TFR. The implementation of these platforms is mandated by the European Commission's European Balancing Guideline and requires certain FCS product definitions and market features to be harmonised across the balancing energy markets of participating TSOs (**EuropeanCommission2017?**; **50hertz2017?**).

9.3 Designing frequency control arrangements

As with any policy problem, designing frequency control arrangements in restructured electricity industries requires design principles, variables and performance criteria to be established. The public good characteristics of frequency control have heavily influenced arrangement design principles across jurisdictions, such as the common preference for the SO to centrally coordinate FCS procurement and activation (**Rebours2007b?**; **Musgens2014?**). In contrast, though some design variables are common, others may only apply to particular systems based on their resource mix, network topology and/or market design. (**Rebours2007b?**) discuss design variables for central dispatch markets related to the following arrangement features:

1. FCS procurement;
2. Price formation, which when efficient should lead to FCS prices not only reflecting the true cost of the service, but also its true value to the system; and
3. Allocation of the cost of FCS.

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Despite the well-defined nature of the design problem, there are several challenges to achieving effective and efficient arrangements. In Sections 2.3.1 and 2.3.2, we present the most prominent challenges and their treatment in the literature.

9.3.1 The influx of VRE and other IBR in power systems

As discussed in Section 1, VRE adds variability and uncertainty to power systems which, at the very least, can lead to increased procurement and activation requirements for PFR and SFR during normal operating conditions (**Ela2011?**). Three proposals to address this issue and thus reduce FCS requirements with growing penetrations of VRE have been discussed in the literature. The first is to shorten energy market trading/dispatch intervals (**Riesz2015a?**; **Ocker2017?**) and the time between market gate closure and dispatch (**Katz2019?**), thereby enabling scheduling based on up-to-date system conditions and forecasts. The second is to increase coordination between control areas within a synchronous area by netting imbalances (**King2011?**), jointly procuring and dispatching FCS (**Scherer2013?**) or aggregating them into a single market region (**Milligan2010?**; **Riesz2015a?**). These two proposals alone have delivered significant system savings in Germany despite growing penetrations of VRE (**Hirth2015?**; **Ocker2017?**). The third is for the SO to determine the required quantity of FCS capacity (*dimensioning*) using dynamic and probabilistic approaches (as opposed to static and deterministic) that adequately reflect current or expected power system conditions and an acceptable level of risk, such as a reliability standard (**Holttinen2013?**; **DeVos2019?**; **Ortega-Vazquez2020?**).

In recent years, SOs have become increasingly concerned with growing penetrations of asynchronous IBR leading to higher RoCoFs and fewer resources offering conventional FCS (**DGAConsulting2016?**; **Hartmann2019?**; **Denholm2020?**). However, VRE and other IBR are able to provide tunable conventional FCS, FFR and/or an inherent response that strongly resembles the inertial response of synchronous machines[2] if this is facilitated by arrangement design (**Miller2017?**; **Fernandez-Munoz2020?**; **Mancarella2021a?**). Following a contingency event in a low-inertia power system, rapid FCS from IBR can mitigate higher RoCoFs, which when unabated can lead to deeper frequency nadirs and zeniths and the subsequent activation of UFLS or OFGS (**Tielens2016?**; **AustralianEnergyMarketOperator2017a?**; **NERCInverter-BasedResourcePerformancetaskForceIRPTF2020a?**).

9.3.2 Achieving economic efficiency

Achieving short-run efficiency entails supplier costs being reflected in their offers and adequately propagated to FCS prices, and the SO assigning at least some portion of FCS costs to system users that create a need for procurement or activation. A widely used pricing approach in ISO/RTO co-optimised FCS markets is a marginal price which incorporates the marginal resource's short-term market opportunity-costs and their offer, which could reflect potential mileage or wear-and-tear costs (**Zhou2016?**; **Frew2021?**). Though improving cost-allocation has been repeatedly proposed in North American literature (**Isemonger2009?**; **Milligan2011a?**; **Ela2012a?**), FCS costs are predominantly socialised across loads based on demand or consumption. In Europe, however, much attention has been given to FCS market pricing, scoring (the order in which offers are selected) and cost-allocation. Specifically, literature on European FCS markets has explored whether pay-as-bid or uniform pricing better facilitates suppliers revealing their true costs (**Musgens2014?**; **Hirth2015?**; **Ocker2018?**), the particular offers scoring should consider (**Musgens2014?**; **Ehrhart2021?**) and the design of imbalance prices to suffi-

[2]The terms *virtual, emulated and synthetic* inertia have been used in the literature to refer to a proportional active power response to RoCoF. However, these terms do not distinguish whether the inverter control scheme provides an inherent response (i.e. from inverters operated as a voltage source which are commonly referred to as *grid-forming inverters* (**Lin2020a?**; **Cherevatskiy2020?**)) or a controlled response following frequency measurement (**Tielens2016?**; **Eriksson2018?**).

ciently incentivise short-term balancing (**Vandezande2010?**; **Hirth2015?**; **Papavasiliou2020?**). Regardless, both European and North American literature suggest that increased competition in FCS markets is a priority. This could be facilitated by enabling distributed and utility-scale VRE and IBR to qualify for FCS provision, reducing minimum offer quantities, separating raise and lower (positive and negative) products and increasing market clearing frequency and the time resolution of FCS products (**Hirth2015?**; **Poplavskaya2019?**; **Lago2021?**; **Frew2021?**). Despite the typically "shallow" nature of FCS markets (i.e. additional supply can significantly reduce prices (**Riesz2015a?**)), dynamic efficiency has received considerably less attention. Notable exceptions include (**Papavasiliou2020?**) and (**Frew2021?**), who briefly discuss the potential for FCS scarcity pricing to better reflect the true value of system reliability and support investment in FCS.

An additional challenge in implementing efficient FCS markets involves the trade-offs that must be considered. As outlined in Section 1, some mechanisms that improve efficiency may come at the expense of visibility, control and redundancy afforded to the SO, which typically does not own any FCS-capable assets. The former is typically achieved using market-based mechanisms and the latter through regulatory mechanisms. (**Ela2012b?**), (**Billimoria2020?**), (**Mancarella2021a?**) and (**Lal2021a?**) discuss several prerequisites for implementing market-based mechanisms and stress that balance between market-based and regulatory mechanisms may be required. However, achieving this balance can be challenging due to the asymmetry between the risk of an event and its consequences, and that between the benefits of market efficiency and the cost of resilient and robust mitigation measures (**Mancarella2021a?**; **Lal2021a?**). Another trade-off is the arbitrary definition of FCS products. Market-based mechanisms will work best when FCS are "discrete" commodities and fungible. However, this ignores the wide "spectrum" of resource technical capabilities. Favouring fungibility may obscure physical and control interdependencies between FCS and restrict or fail to incentivise higher quality provision, thereby leading to an inefficient overall outcome (**Gimon2020?**; **MacGill2020?**).

Chapter 10

Frequency control arrangements in the Australian National Electricity Market

10.1 Overview of the NEM

The NEM consists of five regions corresponding to the eastern and southern Australian states of New South Wales (NSW), Queensland (QLD), Victoria (VIC), South Australia (SA) and Tasmania (TAS) (Figure [fig:nem]). In 2020, the NEM serviced a total electricity consumption of approximately 190 TWh/year and a peak demand of approximately 35 GW across a 'stringy' network over 5000 kilometres long with relatively weak interconnection between regions through interconnectors (**AustralianEnergyRegulator2021a?**; **MacGill2020?**). As high voltage DC transmission connects the island of Tasmania to the mainland state of Victoria, the NEM consists of two synchronous areas operated at a nominal frequency of 50 Hz: the mainland states and Tasmania. Due to the large distances involved, the NEM is not electrically connected to other markets.

image

Figure 10.1: image

The NEM is a single platform (real-time) energy-only market with no explicit capacity mechanisms. Unit commitment is managed by market participants, who must submit resource-specific offers for energy and Frequency Control Ancillary Services (FCAS) capacity in price-quantity pairs the day before delivery. These offers are subsequently used in a pre-dispatch process, which provides forecasted market information (e.g. generation and demand, interconnector flows, prices, etc.) to market participants. While prices in submitted offers are fixed, participants may change the energy volumes in their offer up to a few minutes before the delivery dispatch interval commences. As the NEM is single-sided, security-constrained economic dispatch is run every five minute to meet forecast demand at least cost, subject to network and security constraints. Much like ISO/RTO markets, energy and FCAS markets are co-optimised with respect to technical feasibility and cost (**AustralianEnergyMarketOperator2017?**; **AustralianEner-**

gyMarketOperator2019i?). Real-time dispatch produces zonal marginal prices for energy and FCAS, which form the basis for market settlement in each of the NEM's regions.

10.2 FCAS markets

The NEM's competitive FCAS markets consist of eight separate raise and lower FCAS products that can be classed as regulation FCAS or contingency FCAS, with the former responsible for control when frequency is within the normal operating frequency band (NOFB) and the latter for when frequency deviates outside the NOFB after an event (see Table [tab:nem_fcas]). This is similar to arrangements in many ISO/RTO markets, where FCS are divided into event and non-event reserves (**Ela2011?**).

Security-constrained economic dispatch includes system-wide and regional FCAS requirement constraints. Regulation and contingency FCAS are typically procured for and from all regions of the NEM in the absence of binding local constraints. Local requirements for FCAS procurement apply to Tasmania and to the other regions of the NEM if they experience network constraints, are at risk of separation or when islanded[1] (**AustralianEnergyMarketOperator2010?**; **AustralianEnergyMarketOperator2015?**). Prices are calculated for each region of the NEM based on the sum of the shadow prices of local and system-wide constraints and FCAS costs are allocated to market participants based on a "Causer Pays" principle, which bears similarities to imbalance penalties in European markets (**AustralianEnergyMarketOperator2015a?**). FCAS providers are paid for enablement (capacity provision) regardless of whether their capacity is activated (**Thorncraft2007?**; **Riesz2015b?**; **AustralianEnergyMarketOperator2015a?**).

For a resource to provide FCAS, it must meet pre-qualification criteria and undergo a registration process. Historically, FCAS was provided by thermal generation (predominantly coal and some gas), hydropower generation and some large loads, such as hydropower pumps and an aluminium smelter, as only resources associated with wholesale energy market participants were permitted to offer FCAS. In 2017, the first battery energy storage system (BESS) in the NEM began to offer FCAS and market reform enabled demand response (DR) aggregators to offer contingency FCAS without participating in the energy market (**AustralianEnergyMarketCommission2016?**; **Aurecon2019a?**). In recent years, new FCAS market entrants have included several DR aggregators, new BESS, distributed PV-battery virtual power plants and wind farms (the latter two through trials) (**Aurecon2019a?**; **AustralianEnergyMarketOperator2021b?**; **AustralianEnergyRegulator2021a?**). However, these new entrants tend to offer smaller volumes and there are still relatively few FCAS providers in the NEM, with no single FCAS product having more than 30 providers across the system or 8 providers in any one region (**AustralianEnergyRegulator2021a?**).

=**Product**	= **Control Action**
=Regulation (raise & lower)	= Centralised control through AEMO Automatic Generation Control (
=-second Contingency (fast raise & lower)	=
=-second Contingency (slow raise & lower)	=

[1] From 2015-2019, the Tasmanian and mainland contingency FCAS markets were separated on average for 40% of the time due to the technical limitations of the high voltage DC interconnector (**GHDAdvisory2019?**). However, if the interconnector flow is within the appropriate operating envelope, NEM-wide FCAS procurement is possible as the interconnector's frequency controller enables FCAS transfer between the mainland and Tasmania (**AEMO2017e?**).

=Product	= Control Action
=-minute Contingency (delayed raise & lower)	= Response pre-configured by AEMO but triggered in response to loca

10.3 NEM operation and governance

The Australian Energy Market Operator (AEMO) is responsible for the operation of the market and power system in the NEM in accordance with the National Electricity Rules (NER). They act as a single buyer of dynamically-determined volumes of FCS. The Australian Energy Market Commission (AEMC) is responsible for making or amending rules for the NEM. Both AEMO and the AEMC provide operational and strategic advice to the Energy Security Board (ESB), which is responsible for coordinating market oversight and longer-term reform such as the ongoing post-2025 NEM market design framework. As the market regulator, the Australian Energy Regulator (AER) monitors compliance with and enforces the NER.

10.4 Challenges to frequency control posed by VRE and IBR

The rapid pace at which IBR have entered the NEM was preceded by the exit of FCAS-capable synchronous generation (Figure 1). Many of these IBR do not currently offer FCAS or any meaningful frequency response to deviations other than the most extreme. Furthermore, though updated equipment standards require distributed IBR to ride-through and/or respond to certain frequency deviations, some inverter models have been found to be non-compliant and there is still a significant number of legacy systems in the NEM (**Stringer2020?**; **AustralianEnergyMarketOperator2021k?**).

Entry (of IBR) and exit (of synchronous generation) capacity in the NEM between Australian financial years 2013/14 and 2019/20. Data source: (**AustralianEnergyMarketCommission2020d?**).

Figure 10.2: Entry (of IBR) and exit (of synchronous generation) capacity in the NEM between Australian financial years 2013/14 and 2019/20. Data source: (**AustralianEnergyMarketCommission2020d?**).

The challenges that VRE and other IBR pose to frequency control have been exacerbated by the NEM's network topology. Limited interconnection between regions reduces the NEM's cross-regional balancing capabilities and increases the likelihood of synchronous area separation following power system events, a consequence of which is that local requirements for FCAS may apply (**AustralianEnergyMarketOperator2019?**). Furthermore, correlated variability and uncertainty can arise from intensive development of similar utility-scale VRE in areas with good wind or solar resources (as might occur in the Renewable Energy Zones identified by AEMO's least-regrets transmission planning study (**AustralianEnergyMarketOperator2020h?**)). This is also an issue at the distribution level given the significant installed capacities of rooftop solar PV located within proximity of one another in suburban areas (**AustralianEnergyMarketOperator2021g?**).

10.5 Features of NEM frequency control arrangements

Below, we highlight some noteworthy features of the NEM's frequency control arrangements that complement or contrast previous analyses in (**Thorncraft2007?**), (**Riesz2015b?**) and (**Thorncraft2008?**).

10.5.1 Control mechanisms:

- There is no explicit TFR FCS in the NEM. Security-constrained economic dispatch is run every five minutes and is expected to relieve PFR and SFR and address supply-demand imbalances (**AustralianEnergyMarketOperator2020l?**).
- PFR from contingency FCAS is only required to respond to frequency deviations outside the NOFB (50 $\pm$ 0.15 Hz). When FCAS markets were implemented in the NEM in 2001, mandatory PFR around a tight deadband of $\pm$50 mHz was removed from the NER (**AustralianEnergyMarketOperator2019e?**). Since then and prior to 2020, there was no explicit procurement or requirement for tight-deadband PFR provision within the NOFB. The decline in the provision of tight-deadband PFR in the NEM is discussed further in Section 4.1.
- The mainland synchronous area is controlled as one balancing area by AEMO's AGC (i.e. no tie-line biased SFR) despite limited interconnection between adjacent regions (**AustralianEnergyMarketOperator2018c?**). AGC control performance is discussed further in Section 4.2.

10.5.2 Market-based mechanisms:

- There are relatively few limits imposed on FCAS participation. FCAS can be provided by any technology through variable, switched or hybrid controllers (**AustralianEnergyMarketOperator2020g?**). Furthermore, regulation and contingency FCAS products are unbundled into raise and lower services, and contingency FCAS products are unbundled based on response time. All of these features improve the potential for participation and competition in FCAS markets, though market participants can and often are enabled to provide multiple FCAS.
- FCAS unbundling has enabled a 'Causer Pays' cost allocation framework. Raise contingency FCAS costs, which are incurred as insurance for the failure of a generator, are distributed amongst generators in proportion to their generation in the trading interval. Similarly, lower contingency FCAS costs are distributed amongst loads based on their consumption in a trading interval. A complex methodology is used to calculate monthly, portfolio-wide Causer Pays contribution factors (outlined in (**AustralianEnergyMarketOperator2018b?**) and summarised in (**Riesz2015b?**)) that determine how regulation FCAS costs are allocated to market participants. We discuss the issues associated with this methodology in Section 4.2.
- The NEM co-optimises FCAS that respond within similar timeframes. In the absence of constraints, the volume of 5-minute delayed contingency FCAS procured is reduced by the volume of regulation FCAS enabled (**AustralianEnergyMarketOperator2010?**).

10.5.3 Regulatory mechanisms:

- Connecting utility-scale generators negotiate the frequency response capability of their plant between a minimum access standard and an automatic access standard, the latter guaranteeing network access to the applicant. A suite of generator standards for frequency response were added to the NER in October 2018 and apply to any newly-connecting generation. These standards include minimum frequency disturbance ride-through times, automatic generation output reduction following extreme over-frequency events and the capability to operate in a frequency response mode with a proportional response[2] (**AustralianEnergyMarketCommission2018?**).
- Transmission Network Service Providers (TNSPs) are required to address any inertia shortfalls identified by AEMO within the NEM region in which they build, maintain, plan and operate the transmission network. AEMO's assessment considers whether an islanded region can be securely operated following a contingency event. Shortfalls can be reduced by special protection schemes (e.g. disconnection of load following interconnector trip) and the provision of FFR, but they must ultimately be met by providers of inertial response (**AustralianEnergyMarketOperator2018?**; **AustralianEnergyMarketOperator2020o?**).

[2] In addition to these standards, newly-connected generation may install a synchronous condenser under the 'do no harm' requirements outlined in the NER if they are determined to have an adverse impact on system strength. Particularly when fitted with a rotating mass or flywheel, these synchronous condensers can also provide inertial response (**AustralianEnergyMarketOperator2020e?**).

Chapter 11

Insights from the National Electricity Market

In light of existing challenges and those posed by energy transition, effective and efficient frequency control arrangements should enable sufficient FCS to be procured across timeframes and strike the appropriate balance between efficiency and robustness. In the following sections, we review issues associated with two core elements of the NEM's frequency control hierarchy (i.e. PFR and SFR), assess their physical and economic performance and outline reform underway. Drawing on developments in the NEM and our review of arrangements in North America and Europe, we then discuss the merits and flaws of regulatory and market-based mechanisms with respect to sufficiency and efficiency. We conclude by offering insights that could serve as design principles for jurisdictions revisiting their frequency control arrangements during energy transition.

11.1 Declining tight-deadband primary frequency response

When FCAS markets were implemented in 2001, mandatory tight-deadband PFR was superseded by two types of PFR: voluntary PFR within the NOFB and competitive procurement for PFR outside the NOFB in the form of contingency FCAS (**AustralianEnergyMarketOperator2019e?**).

As such, the NEM's frequency control scheme deviated from what has been argued to be international best practice as it only explicitly specified and procured wide-deadband PFR (i.e. deadband of $\pm$150 mHz) (**AustralianEnergyMarketOperator2019e?**). In contrast, ENTSO-E specifies that PFR providers have a deadband no greater than $\pm$10-15 mHz depending on the control area (**EuropeanNetworkofTransmissionSystemOperatorsforElectricityENTSO-E2013?**) and FERC Order 842 mandates all newly-connecting generation in US interconnections to operate frequency-responsive control equipment with maximum deadbands of $\pm$36 mHz (**FederalEnergyRegulatoryCommissionFERC2018?**).

In recent years in the NEM, the lack of an incentive or requirement for tight-deadband PFR and perceived disincentives to its provision (through Causer Pays contribution factors discussed further in Section 4.2) has led to many synchronous generators that once provided tight-deadband

PFR to widen deadbands or install control systems that block or dampen PFR from the speed governor within the NOFB (**AustralianEnergyMarketCommission2020?**). Furthermore, many VRE generators were deployed in the NEM and connected with inverter control systems that were unresponsive to any frequency deviations other than the most serious.

The extent to which tight-deadband PFR provision had declined in the NEM and the consequences of this became clear to AEMO following a major power system incident on the 25th of August 2018 (**AustralianEnergyMarketOperator2019n?**). Prior to the event, the QLD region was exporting ∼900 MW to the rest of the NEM. Around 13:11:41, lightning strikes at the QLD-NSW interconnector resulted in the QLD region being separated from the rest of the NEM with excess supply. The SA region was exporting ∼200 MW prior to the event and following QLD's separation, this increased by more than 200 MW in response to under-frequency. The sudden increase in active power flow triggered an emergency scheme that disconnected SA from the NSW-VIC synchronous area, resulting in local over-frequency.

There were diverse responses from various generators following the double separation event. While many synchronous generators provided some form of PFR though not enabled for FCAS, their response was withdrawn by their load controllers in several cases so that the unit could return to its dispatch target (e.g. green and pink lines in top frame of Figure 2). Wind and solar farms were either unresponsive, tripped due to protection settings in their inverters, or reduced their active power output in line with performance standards negotiated in their connection agreements (middle and bottom frames in Figure 2). AEMO attributed slow frequency recovery and under-frequency load shedding in NSW and VIC to insufficient PFR from generators and a lack of appropriate contingency FCAS within the islanded regions. Over 50% of fast and slow raise contingency FCAS needed in NSW-VIC was enabled in SA and QLD, whilst QLD had no lower FCAS enabled to respond to over-frequency[1] (**AustralianEnergyMarketOperator2019n?**).

Active power output of QLD super-critical coal generators (top), SA solar PV farms (middle) and SA wind farms (bottom). The response of an individual generator is denoted by solid lines (obtained from 4-second AEMO SCADA data using NEMOSIS (**Gorman2018?**)). None of these generators are enabled for FCAS. The red dashed line in each frame is the regional frequency as measured by high-speed (1-second) phasor measurement units.

Figure 11.1: Active power output of QLD super-critical coal generators (top), SA solar PV farms (middle) and SA wind farms (bottom). The response of an individual generator is denoted by solid lines (obtained from 4-second AEMO SCADA data using NEMOSIS (**Gorman2018?**)). None of these generators are enabled for FCAS. The red dashed line in each frame is the regional frequency as measured by high-speed (1-second) phasor measurement units.

Prior to this incident, deteriorating control of frequency within the NOFB was of concern to AEMO and the AEMC, and trials and investigations were recommended to inform the design of an incentive for tight-deadband PFR provision (**AustralianEnergyMarketCommission2018a?**). However, this separation event demonstrated the "urgent need for regulatory changes to arrest the ongoing decline in frequency performance in the NEM" and to enhance "the resilience of the NEM to similar major disturbances", with AEMO submitting a rule change proposal for all capa-

[1] AEMO is currently investigating appropriate regional requirements for FCAS, particularly for contingency FCAS in the terminal regions of QLD and SA (**AustralianEnergyMarketOperator2019m?**; **AustralianEnergyMarketOperator2020b?**)

ble generators in the NEM to provide mandatory PFR with a maximum deadband of ± 0.015 Hz (i.e. 10% of the NOFB) (**AustralianEnergyMarketOperator2019e?**).

This rule was initially incorporated into the NER in 2020 as a temporary arrangement through the addition of a "sunset" after three years to demonstrate the AEMC's commitment to investigating incentives or market-based mechanisms for tight-deadband PFR (**AustralianEnergyMarketCommission2020?**; **AustralianEnergyMarketCommission2020b?**). AEMO has specified PFR settings, including maximum droop and response time, but is unable to require generation to reserve headroom for PFR (**AEMO2020a?**).

11.2 Performance and efficiency issues of regulation services

For SFR provided by regulation FCAS within the NOFB to be effective, the dynamics of the system need to accommodate slower SFR control action and the centralised secondary controller (in the NEM, AEMO's AGC) needs to be properly configured. Prior to the introduction of mandatory PFR in the NEM, AEMO observed no significant improvement in NOFB frequency stability despite several increases in the minimum volumes procured for regulation FCAS in 2019 (**AustralianEnergyMarketOperator2019e?**). This is likely due to:

- A lack of fast and decentralised tight-deadband PFR supporting slower SFR;
- Inappropriate control signals being calculated within the AGC due to the use of rate limiters to account for ramping constraints, signal filtering and generator controller models that do not accurately reflect a unit's frequency response (**DIgSILENT2017?**). The latter is the consequence of an absence of control coordination between market participants and AEMO; and
- Variable communication delays between individual unit controllers and AEMO's AGC system, and disparate response times from generators.

Furthermore, the control of all mainland regions as one balancing area can be problematic in the event of separation. AGC control of regulation FCAS enabled in islanded regions may exacerbate local frequency deviations when responding to the AGC frequency reference. This was the case during the double separation event on the 25^{th} of August 2018, in which the AGC instructed raise regulation FCAS generators in QLD and SA to respond to under-frequency in the AGC frequency reference despite local over-frequency (Figure 3). Such incorrect control action can occur until AEMO is able to manually reconfigure the AGC to treat each island as a control area - a process which can take up to 15 minutes (**AustralianEnergyMarketOperator2019n?**).

Regional phasor measurement unit frequency data and AGC reference frequency data from AEMO's NSW control centre (obtained using NEMOSIS (**Gorman2018?**)) during the power system event on the 25th of August, 2018. Note that the AGC reference frequency deviates in the opposite direction to local frequency in QLD and SA.

Figure 11.2: Regional phasor measurement unit frequency data and AGC reference frequency data from AEMO's NSW control centre (obtained using NEMOSIS (**Gorman2018?**)) during the power system event on the 25th of August, 2018. Note that the AGC reference frequency deviates in the opposite direction to local frequency in QLD and SA.

Over time, inefficiencies in regulation FCAS procurement and cost-allocation have also become apparent. Regulation FCAS procurement in the NEM is dynamic beyond a minimum volume, but the dynamic component is based on the system time error (**AustralianEnergyMarketOperator2015?**). Time error control is largely unnecessary as modern clocks no longer rely on power system frequency to keep the time (**Rebours2007b?**). Furthermore, whilst AEMO is required to control the NEM within certain time error limits, these have been relaxed in recent years (**AEMCReliabilityPanel2017?**). Given that time error is no longer prioritised as a control objective, dynamic regulation FCAS procurement based on better measures of sustained frequency deviation (e.g. mean absolute error as suggested by (**Riesz2015b?**)) and/or a modelled distribution of potential intra-dispatch ramp uncertainty may be more suitable.

Regulation FCAS costs are allocated to market participants based on their contribution factor, a calculation which represents the extent to which the participant has contributed to the need for regulation FCAS through a deviation from a dispatch trajectory. Though the calculation methodology assigns weights to a generator or load's dispatch trajectory deviation based on the AGC regulation direction and mileage requirement every 4 seconds, the disincentive for dispatch deviation suffers from a disconnect to causation. This is because the contribution factors of a generator or load are averaged over a 5-minute dispatch interval, summed over a 28-day period and then within a market participant's portfolio (**AustralianEnergyMarketOperator2018b?**; **AustralianEnergyMarketCommission2018a?**; **AustralianEnergyRegulator2020?**).

Much like portfolio-based balancing in Europe, the aggregation of contribution factors enables a market participant to offset antagonistic deviations with assisting deviations (from the provision of tight-deadband PFR) across its resources and time. However, the complexity and opacity of the methodology and cost-allocation process has contributed to the withdrawal of tight-deadband PFR in the NEM. Several generators disabled governor response in the NOFB in the belief that dispatch adherence alone will minimise Causer Pays liabilities (**DIgSILENT2017?**).

11.3 NEM assessment and outlook

Though the introduction of competitive FCAS markets in 2001 initially resulted in significantly lower FCAS prices in the NEM (**Thorncraft2007?**; **Riesz2015b?**), volume-weighted average FCAS prices, particularly those for raise regulation and contingency services, have increased relative to the volume-weighted average energy price since 2016 (Figure 4). Furthermore, the increases in minimum regulation FCAS volumes and reductions in assumed load relief in 2019 have raised the procured volumes of regulation and contingency FCAS, respectively. Together, these factors have contributed to higher NEM-wide FCAS costs (**AustralianEnergyMarketOperator2019l?**). While quarterly FCAS costs were less than 1% of quarterly total NEM costs in 2015, 50% of all quarters from 2017 to 2020 had FCAS costs that were between 1-2% of total NEM costs (**AustralianEnergyRegulator2021a?**).

Events and volume-weighted NEM-wide average quarterly prices for energy, raise regulation FCAS and raise contingency FCAS in the NEM. The entry of new albeit smaller FCAS providers in 2017 was preceded by the retirement of several large thermal generation. Q1 2020 FCAS prices were high due to local procurement in the SA region, which was islanded for approximately two weeks. Note that while average energy prices fell in Q2-Q4 in 2020 to levels previously seen in 2014-2015 (due to lower demand during COVID-19 lockdowns), FCAS prices remained relatively high. Five-minute price and volume data obtained using NEMOSIS (**Gorman2018?**).

Figure 11.3: Events and volume-weighted NEM-wide average quarterly prices for energy, raise regulation FCAS and raise contingency FCAS in the NEM. The entry of new albeit smaller FCAS providers in 2017 was preceded by the retirement of several large thermal generation. Q1 2020 FCAS prices were high due to local procurement in the SA region, which was islanded for approximately two weeks. Note that while average energy prices fell in Q2-Q4 in 2020 to levels previously seen in 2014-2015 (due to lower demand during COVID-19 lockdowns), FCAS prices remained relatively high. Five-minute price and volume data obtained using NEMOSIS (**Gorman2018?**).

Prior to the implementation of mandatory PFR, higher NEM FCAS costs were arguably not accompanied by an improvement in frequency control performance. Alongside deteriorating frequency control performance within the NOFB (Figure 5), AEMO has expressed a loss of confidence in the NEM's resilience to complex power system events, such as the double separation incident on the 25th of August 2018 (**AustralianEnergyMarketOperator2019e?**). These events are typically more severe than the 'credible' contingency events (i.e. N-1 contingency) that dictate the volume of contingency FCAS procured.

Normalised distribution of mainland frequency within the NOFB in 2005 and 2018. Reproduced from (**AustralianEnergyMarketOperator2019m?**)

Figure 11.4: Normalised distribution of mainland frequency within the NOFB in 2005 and 2018. Reproduced from (**AustralianEnergyMarketOperator2019m?**)

Since the implementation of the mandatory PFR, settings specified by AEMO have been applied to a majority of large synchronous generators (>200MW) and some smaller synchronous generators. Despite the absence of requirements for maintaining headroom and/or footroom, preliminary analysis by AEMO[2] suggests that mandatory PFR has delivered better control of frequency within the NOFB (see Figure 6) and reduced excursions beyond the NOFB (**AustralianEnergyMarketOperator2021g?**). As a result of this initial success and further technical advice provided by AEMO, the AEMC has indicated that it intends to retain mandatory PFR at a tight-deadband following the "sunset" of the initial rule (**AustralianEnergyMarketCommission2020e?**).

[2]We note that AEMO has yet to complete mandatory PFR implementation. In particular, settings have yet to be changed for many VRE plant as inverter control system software changes are being trialled.

Standard deviation of mainland frequency grouped by each day, week, month or quarter from 2009 to 2021. Some initial PFR setting changes were made in late September 2020 and many generators moved to final settings in late October 2020. Source: (**AustralianEnergyMarketOperator2021g?**).

Figure 11.5: Standard deviation of mainland frequency grouped by each day, week, month or quarter from 2009 to 2021. Some initial PFR setting changes were made in late September 2020 and many generators moved to final settings in late October 2020. Source: (**AustralianEnergyMarketOperator2021g?**).

However, this initial success may be a result of the headroom maintained by these generators for risk management purposes (e.g. defending contract positions) and any headroom made available to the system through the displacement of more expensive synchronous capacity by VRE. Given that several large synchronous generators are expected to retire in the coming decades (**AustralianEnergyMarketOperator2020h?**), continuing to rely on this "free" headroom (and any available footroom) into the future may reduce the potential resilience benefits of widespread, tight-deadband PFR and place a greater burden on generators that do reserve headroom and hence respond. The AEMC is proposing to address this issue by paying resources that provide assisting tight-deadband PFR ("double-siding") (**AustralianEnergyMarketCommission2020e?**).

Presently, several other operational and market changes are being considered or implemented with the goal of improving the effectiveness of arrangements in the NEM. AEMO is investigating the use of dispatch constraints to (**AustralianEnergyMarketOperator2021e?**):

- Procure contingency FCAS volumes based on system inertia;
- Apply regional contingency and regulation FCAS requirements; and
- To limit the amount of switched contingency FCAS procured. Switched FCAS has a number of limitations compared to governor-like control (**AustralianEnergyMarketOperator2020c?**).

These additional constraints will likely improve the effectiveness of frequency control arrangements but may lead to higher FCAS costs. In addition to these procurement changes, the AEMC has made a rule to introduce raise and lower contingency markets for FFR by October 2023, each with a likely response time of 1 second (**AustralianEnergyMarketCommission2021d?**; **AustralianEnergyMarketOperator2021c?**). Whilst AEMO has highlighted that potential stability issues and interconnector maloperation will need to be managed (e.g. through delivery caps or provision constraints) (**AustralianEnergyMarketOperator2021?**), these FFR markets, along with the ESB's proposals for short-term scheduling and/or procurement of inertial response (**EnergySecurityBoard2021a?**), will likely improve AEMO's operational toolbox for managing a low-inertia NEM.

11.4 Reactive regulatory requirements

Despite a broad set of FCS markets, there is a high degree of reliance on regulatory mechanisms in the NEM. Performance standards and mandatory PFR enforced by connection requirements in the NEM have recently been aligned with international grid-codes (**Roberts2018?**). As argued by TNSPs and AEMO during the mandatory PFR rule change process, near-universal widespread provision of frequency control should lead to relatively low costs for individual participants and be outweighed by greater visibility and certainty for AEMO alongside the system-wide benefits of improved physical frequency control performance (**ChantalHopw2019?**; **Dillon2019?**; **AustralianEnergyMarketOperator2019e?**).

Regulatory mechanisms are ideal for mandating basic FCS capabilities as a condition for access, which may reduce the need to procure more specialised FCS, or where FCS faces significant barriers to efficient price formation or unbundled procurement. The latter reasons are particularly pertinent in the NEM. Current FCAS prices do not appear to be incentivising FCS provision from the vast majority of VRE generators, which have business models centred around energy provision (**AustralianEnergyMarketCommission2021?**; **Meegahapola2021?**). Furthermore, procuring inertial response is challenging due to its inseparability from system strength provision and unit commitment costs (**Billimoria2020?**). With respect to these challenges, regulatory mechanisms in the NEM have assisted in ensuring some level of frequency response from most power system resources (e.g. mandatory PFR) and improving the ability of AEMO and TNSPs to coordinate the procurement of essential but "lumpy" FCS (e.g. inertia shortfall mechanism).

While mechanisms such as mandatory PFR are likely to improve the robustness of frequency control arrangements, it may be difficult for other regulatory mechanisms to keep in step with changing physical performance requirements in systems rapidly facing higher penetrations of VRE and IBR. Regulatory mechanisms are often only updated after a number of years to reduce the burden placed on connecting resources. As such, they are slow to respond to changing capabilities and requirements. This delay often makes new standards and requirements reactive rather than proactive. For example, AEMO can only review utility-scale generator technical performance standards every 5 years (**AustralianEnergyMarketCommission2018?**), a timeframe in which the solar PV capacity installed in the NEM has more than quadrupled (2015-2020) (**AustralianPVInstitute?**).

Additional concerns with regulatory mechanisms include poor dynamic efficiency and opaque costs (**Riesz2015a?**). In the absence of remuneration or incentives, particularly those that are linked to the quality of frequency response, there is no incentive to innovate or invest in higher-quality frequency control capabilities (**Meegahapola2021?**). Furthermore, cost opacity may lead to FCS provision costs being internalised within other prices (e.g. energy) by participants and prevent the implementation of imbalance or dispatch non-conformance disincentives through cost-allocation mechanisms.

11.5 Preference for market-based arrangements

Since the establishment of the NEM, a competition norm has been established, with markets being viewed as a key driver for delivering the National Electricity Objective of "efficient investment in, and efficient operation and use of electricity services" (**Haines2016?**; **MacGill2020a?**). This norm has pervaded all levels of participation and governance in the NEM. Generator owners opposed the mandatory nature of the mandatory PFR rule change on the basis that a lack of remuneration was against market principles and that it would lead to economically inefficient outcomes (**Skinner2019?**; **Rolfe2019?**; **Scott2019?**). AEMO did not include a headroom requirement in its proposal, making the mandatory PFR rule change more palatable to market bodies and participants. The AEMC, who have expressed a clear preference for market-based approaches (**AustralianEnergyMarketCommission2018a?**), included a "sunset" clause in their initial decision to implement mandatory PFR. Furthermore, and the scope of the ESB's post-2025 market design process (**EnergySecurityBoard2020c?**; **EnergySecurityBoard2021a?**), a market for FFR will be implemented in 2023 and the ESB's post-2025 market design process is considering new system services markets for inertial response and TFR (**EnergySecurityBoard2021a?**).

If incentives or remuneration are designed correctly, markets can drive short-run efficiency. Where required, they can also support investment in FCS capability and assist a power system in achieving dynamically efficient frequency control arrangements. However, in some cases, simply introducing new FCS markets may serve as 'patchwork' solutions to existing control deficiencies and market failures. These deficiencies and failures could be partially addressed by improving FCS cost allocation processes, verifying FCS performance and linking incentives to higher quality provision.

As discussed in Section 2, efficient Causer Pays cost-allocation mechanisms in FCS markets could provide suitable disincentives for dispatch non-conformance or imbalances. In the NEM, the aggregation of regulation FCAS Causer Pays contribution factors over time and a portfolio has resulted in a blunt frequency performance market signal. The solution to this problem may not be as simple as strengthening disincentives (e.g. as proposed by (**Hirth2015?**) and (**Papavasiliou2020?**)) for resource-based cost-allocation processes as potential exposure to high instantaneous FCS costs may lead to participants curtailing or decommitting flexible resources rather than providing an assisting frequency response. This has been observed in the NEM when local constraints have resulted in regulation FCAS (**AustralianEnergyMarketCommission2018a?**) and contingency FCAS (**AustralianEnergyMarketOperator2020?**) price spikes. The AEMC has proposed a compromise to this problem by shortening the settlement period for regulation FCAS Causer Pays to 5 minutes but only allocating the costs of regulation FCAS capacity that is activated by AEMO (i.e. the cost of any unactivated capacity is socialised across power system users) (**AustralianEnergyMarketCommission2020e?**).

An alternative to Causer Pays is to allocate costs based on needs ('User Pays'), such that connected equipment imposing RoCoF or frequency constraints pay for FCS. 'Users' of frequency control currently include synchronous machines and IBR that have not been configured to ride-through higher RoCoFs and greater frequency deviations. Following more extreme frequency deviations, the former may suffer equipment damage whereas both have the potential to trip (**DGAConsulting2016?**; **Miller2017c?**). A User Pays approach to cost-allocation could encourage resources to be more resilient to frequency deviations and thereby reduce system FCS costs (**Lal2021a?**), particularly if a significant proportion of connected equipment are IBR that can be configured to ride-through such disturbances.

Beyond choosing who costs should be allocated to and what an appropriate granularity for cost-allocation might be, market designers should ensure that the chosen methodology is transparent, can be understood by participants and that any calculations can be replicated using accessible data. If appropriate design choices are made, efficient cost-allocation could create counter-parties for financial instruments that hedge price risk (**Thorncraft2007?**; **Skinner2020?**). FCS derivatives may drive investment in FCS capabilities by supporting business models in which FCS is a major revenue stream (this is currently the case for utility-scale BESS, DR aggregators and virtual power plants in the NEM) and assist in FCS price formation (**Pollitt2019a?**; **Billimoria2020?**).

As in ISO/RTO Regulation markets, aligning FCS procurement and/or remuneration with performance essentially recognises that there is a spectrum of FCS capabilities. This recognition is lacking in the NEM, where battery energy storage systems are responding precisely and rapidly to AGC regulation signals but are being paid the same as thermal plant that provide lower quality regulation FCAS (**AustralianEnergyMarketOperator2018i?**). However, implementing performance-based design is contingent on the SO verifying FCS provision. While AEMO has outlined FCAS delivery measurement standards and verification principles (**AustralianEnergyMarketOperator2020g?**), delivery verification appears to be restricted to confirming contingency FCAS delivery following a power system event (to the authors' best knowledge). While a regular verification process does not appear to be in place for regulation FCAS, AEMO is proposing to specify minimum control requirements (e.g. response delay and ramp rate) and implement a regular testing cycle for resources registered for regulation FCAS (**AustralianEnergyMarketOperator2021l?**).

Market designers may also need to consider price formation in FCS markets to ensure that arrangements are at least capable of supporting investment during energy transition. As discussed by (**Hirth2015?**), VRE have low to no short-term energy market opportunity-costs when providing lower/negative FCS but can incur significant short-term energy market opportunity-costs when providing raise/positive FCS. The raise/positive opportunity-cost may be even higher if the SO requires additional curtailment to better ensure that FCS capacity is firm, which AEMO has required, or if the resource has entered into an energy off-take agreement, which is common in the NEM (**AEMO2018d?**). While co-optimised FCS markets mean that such opportunity-costs can be accounted for, FCS prices can be suppressed if large conventional generators with low to no opportunity-costs offer large volumes of FCS. Low prices can limit the incentive for high capital, low operating cost IBR to provide and invest in FCS capabilities. This may lead to a dynamically inefficient outcome as additional conventional generators are retired and limited FCS capabilities are offered by VRE and other IBR (**Ela2019?**; **Meegahapola2021?**). As discussed in Section 2.3.2, one potential solution to this issue is to strengthen scarcity pricing in FCS markets. The AEMC and ESB have discussed implementing system demand curves with scarcity pricing for all existing and proposed FCAS (**EnergySecurityBoard2020c?**; **AustralianEnergyMarketCommission2020b?**). However, the shape of these system demand curves and how they account for interdependent or interchangeable FCAS will ultimately dictate their success.

Chapter 12

Conclusion

Whilst recent years have seen increasing participation from demand response and IBR, energy transition and a pervasive competition norm have exposed design issues in the NEM's frequency control arrangements. As such, considerable attention and effort have been devoted to reforming the NEM's arrangements in the past two years.

From our review of North American and European frequency control arrangements and our analysis of the NEM's, we share four key insights below that could serve as design principles for operators, regulators and market-bodies attempting to design effective and efficient frequency control arrangements in restructured electricity industries during energy transition:

1. Control deficiencies may not be addressable through introducing new FCS. While this solution may address emerging needs (e.g. low-inertia operation), SOs and market bodies need to better understand the interdependency, interoperability and interchangeability between FCS and the interactions with other technical attributes of the power system (e.g. system strength) to ensure that frequency control is first and foremost effective. Once this has been achieved, the short-run efficiency of arrangements can be improved through mechanisms such as dynamic and probabilistic dimensioning and co-optimising the procurement of interchangeable FCS.
2. Given the pace and scale of energy transition, a dynamically efficient outcome in some power systems may require additional investments in FCS capability. FCS prices can be strengthened through scarcity pricing, which may better reflect the system's preference for security and reliability. Such pricing mechanisms are complementary to appropriate and efficient cost-allocation based on causation or needs. Both efficient price formation and cost-allocation will improve the potential for FCS derivatives, which may assist in providing price signals for investment.
3. SOs should systematically and frequently verify FCS delivery, where relevant, and withhold or penalise remuneration when delivery is deemed to be insufficient. If such monitoring is in place, FCS remuneration can be performance-based to drive the provision of high quality FCS. Performance monitoring would also enable the SO to assess FCS arrangements and identify any deficiencies in control action or procurement.
4. During energy transition, a suitable set of frequency control arrangements will most likely involve a combination of market-based and regulatory mechanisms. Frequency control is

a power system public good and achieving frequency stability requires a degree of coordination and cooperation between resources. These characteristics make it difficult to establish complete markets for FCS, and an emphasis on market solutions may obscure these characteristics to market participants and undermine effective control. In contrast, regulatory mechanisms may prove to be more robust and resilient in the face of uncertainties, particularly those that are exogenous to the power system (e.g. climate risk). Regardless of whether arrangements are skewed towards market-based mechanisms or regulatory mechanisms, designers should be more forward-looking and avoid assumptions regarding the provision of FCS capability over time, particularly when there is a pervasive competition norm and effective frequency control relies on sequential and hierarchical control actions.

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