Evaluation of Reactive Technologies Inertia Measurement and Techno-economic Modelling

Technical Knowledge Sharing Report

Report prepared for Reactive Technologies, System Inertia Measurement Demonstration Project

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Abbreviations

Term	Definition
AEC	Economic Regulation Authority
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BESS	Battery Energy Storage System
DEECA	Department of Energy, Environment, and Climate Action
ERCOT	Electric Reliability Council Of Texas
ESO	Electricity System Operator
FAT	Factory Acceptance Test
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
GWs	Gigawatt Second
ISP	Integrated System Plan
LAN	Local Area Network
MEI	Melbourne Energy Institute, University of Melbourne
MQTT	Message Queuing Telemetry Transport
MWs	Megawatt Second
NEM	National Electricity Market
Neoen	Owner/Operator of VBB
NSW	New South Whales
OEM	Original Equipment Manufacturer
PFR	Primary Frequency Control
PMU	Phasor Measurement Unit
PV	Photovoltaics
QLD	Queensland
QSS	Quasi-Steady-State
REZ	Renewable Energy Zone
RoCoF	Rate Of Change of Frequency
RTAC	Real-Time Automation Controller
SA	South Australia
SATs	Site Acceptance Tests
SFC	Secondary Frequency Control
TNSPs	Transmission Network Service Providers
UI	User Interface
UoA	University of Adelaide
UoM	University of Melbourne
VBB	Victorian Big Battery
VIC	Victoria
WEM	Wholesale Electricity Market
XMU	Extensible Measurement Units

Nomenclature

Term	Definition
R_{pfr}	PFR
R_{ffr}	FFR
$Lr_{\Delta f}$	Load Relief
D	Damping Factor
P_D	System Demand
Δf	Frequency Deviation
ΔP_{loss}	Generation Unit Output
H_{sys}	System Inertia
H_{aws}	Inertia Awareness Factor
H_g	Inertia Constant of Generator g
G_{sys}	Set of generators
pf_g	Power Factor of Generator g
$\bar{P}_g$	Maximum power output of generator g
$\Delta ROCOF_{max}$	Maximum ROCOF
T_{ROCOF}	Time to measure RoCoF
T_{ffr}	Time to provide FFR
f	Frequency of the system
Δf_{DB}	Frequency deadband
Δf_{nadir}	Frequency Nadir

Executive summary

The transition to a fully decarbonised power system presents significant challenges for system operators due to new operating conditions, particularly declining system inertia due to the retirement of conventional generators and increased inverter-based resources. This issue is expected to become more common and more extreme in the future.

To address this, system operators are exploring the roles of Frequency Control Ancillary Services (FCAS) and inertia to maintain stability. Various countries have implemented measures to monitor and manage inertia. For instance, the Electric Reliability Council of Texas (ERCOT) has established minimum inertia requirements and real-time monitoring inertia, while the UK is analysing the development of new FCAS and inertia markets. In Australia, inertia and FCAS concerns led to the implementation of an inertia market in the Wholesale Electricity Market (WEM) and a very Fast FCAS market in the National Electricity Market (NEM). The Australian Energy Market Operator (AEMO) projects a potential inertia deficit in Queensland (QLD) by 2027, highlighting the need for additional measures.

In this context, Reactive Technologies partnered with the University of Melbourne (UoM), and AEMO to carry out a pilot demonstration project for real-time inertia measurements in the NEM, using its GridMetrix® technology to provide accurate inertia data. This project received funding from ARENA and DEECA. Thus, this report focuses on two main aspects: analysing real-time inertia measurements from June to September 2023 to understand the difference between theoretical and actual inertia; and quantifying the potential value of the residual inertia (attributed to the demand-side inertia) for both operational and planning purposes.

The data analysis revealed a strong positive correlation between high demand and system inertia. The analysis also found an inverse relationship between high renewable penetration and system inertia, indicating a potential rise in low-inertia periods as inverter-based resources become more prominent. Moreover, discrepancies between theoretical and measured inertia values suggest inaccuracies in generator data and the presence of demand-side inertia. The effectiveness of measuring inertia using Reactive's technology was validated through an event-based approach, confirming its improved accuracy compared to AEMO's theoretical calculations.

The operational value of demand-side inertia was quantified by calculating potential operational dispatch cost savings. This model was tested on the NEM and an isolated Queensland (QLD) system, as well as a future scenario without coal generation. The results suggest potential annual savings of approximately $1.5 million for the current system. Besides, annual savings are projected to increase in the year 2037, ranging from $26 million to $87 million.

Moreover, potential savings from lower inertia source procurement were assessed for QLD and South Australia (SA), since these regions have a declared inertia shortfall that needs to be addressed in the short term. The findings highlight very significant potential economic benefits from deferring future investments in synchronous condensers. The rapid deployment of the inertia measurement technology complements these benefits by providing an advantage over the lengthy construction of alternative assets. The analysis suggests that delaying or avoiding these investments could save the system a total of between $99 million and $145 million[1]. Besides, reducing inertia payments associated with contracting additional FFR providers could potentially save a total of $2 million to the system in the short-term.

[1] It should be noted that these savings are based on reduced need for synchronous condensers for frequency security, based on higher levels of available inertia as from measurements. Investment in synchronous condensers might still be required for other purposes, for example for system strength reasons.

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1 Introduction and Overview

The transition to a fully decarbonised system presents challenges for system operators given by new operating conditions. One key challenge is the declining system inertia due to the active retirement of conventional generators and the increasing penetration of inverter-based resources. These conditions are projected to become both more common and more extreme in future scenarios.

To address this challenge, system operators are actively exploring the role of both Frequency Control Ancillary Services (FCAS) and inertia to maintain stability in systems in future power systems. For instance, Japan was advised by its energy institute to deploy inertia monitoring and to set a minimum inertia requirement per area [1].

Similarly, since 2016 the Electric Reliability Council of Texas (ERCOT) monitors the inertia and enforces an hourly minimum inertia [2]. This level of inertia is monitored in real-time by calculating the inertia of the online generators. This inertia must be greater or equal to 100 GWs to ensure an adequate Rate of Change of Frequency (RoCoF) limit. If system inertia drops below 120 GWs, the ERCOT closely monitors the situation and acts if it falls below 105 GWs. These actions are usually the deployment of offline resources with a quick start to increase the inertia level [3].

In the UK, National Grid ESO has defined the inertia as a system-wide stability constraint [4]. In this context, National Grid is exploring new markets and the role of both generators and demand-side inertia [5]. In academia, there are some efforts to develop adequate inertia markets in the UK system by assigning shadow prices to inertia [6] [7]. However, in the midterm, the market will be focused on procuring inertia only as a primary product, with a target inertia requirement for the first year set at an indicative value of 7 GWs. This requirement is technology agnostic, and the volume could be adjusted based on bids received [8].

In Australia, concerns about inertia and FCAS are not recent. In 2017, the University of Melbourne (UoM) performed the system security studies commissioned by the Chief Scientist for his 'Finkel Review' [9]. The UoM's work highlighted the importance of co-optimization of system inertia and multiple frequency control ancillary services to maintain frequency stability, including challenges for islanded regions [10].

More recently, a report published by the Global Power System Transformation identifies the inclusion of inertia as a service, primary frequency control (PFR), and secondary frequency control (SFC) as key areas for research [11]. The report also emphasized the need for a market capable of accommodating various FCAS to secure minimum response during potential islanding operations in the NEM.

To address the evolving needs in Australia, the Australian authorities have implemented different mechanisms. In October 2023, the Wholesale Electricity Market (WEM) implemented an inertia market to control the system's RoCoF. This service is offered in MWs and has 2 functions: (1) to ensure that the RoCoF is restricted below a certain maximum level and (2) to ensure that minimum frequency requirements are maintained in accordance with the frequency standards and potentially reducing raise FCAS requirements [12]. The inertia has an upper limit calculated as the minimum between 3 GWs and the forecast minimum inertia available in the next 12 months [13]. Besides, the price ceiling of this service is 300 $/MWs/h.

On the other hand, the evolving needs were addressed in the National Electricity Market (NEM) by implementing a 1-second market called very Fast FCAS market in October 2023 [14]. However, with the retirement of conventional generators and new operating conditions with very deep penetration of renewable generators, inertia response services are expected to play a more critical role in the upcoming years. The Australian Energy Market Operator (AEMO) projections suggest a potential inertia deficit of 1.6 GWs in Queensland (QLD) during islanding operation by 2027 [15]. The current regulation requires transmission network service providers (TNSPs) to ensure sufficient inertia for islanding events through either procuring inertia from market participants or by asset investment (e.g., in synchronous condensers). As a result, inertia has become a critical focus for many stakeholders in the NEM [15].

The AEMC is studying the impact of developing a new inertia market additional to the existing FCAS market [16]. The creation of an inertia market would need to understand any potential hidden inertia coming from inaccurate theoretical calculations or additional inertia coming from the demand side.

In this context, Reactive Technologies partnered with AEMO and ARENA to carry out a pilot demonstration project for real-time inertia measurement in the mainland NEM [17]. These measurements were performed using a new technology developed by Reactive, which consists of a modulator and several Extensible Measurement Units (XMU) along with an algorithm to analyse the data [18] [19]. Using this technology, the system is capable of measuring inertia with a confidence range of approximately 10%. Besides, [20] suggests that inertia measurement using this technology might be more accurate than other methods to calculate inertia (event-based approaches or theoretical calculation) in systems with low inertia and a high penetration of fast-acting controllers (commonly known as Fast Frequency Response (FFR) service).

The value of inertia has been shown in the UK in [21] and [22]. Particularly, [22] has studied the value of demand-side inertia to the system. In this study a 5s inertia constant was used to study the inertia from the demand side and the savings were proved to be around 360 - 9800 £/hour with 2% of the demand providing inertia (with a 10% error in the measures) in 2030.

This report delves into two critical aspects of inertia within the NEM. First, we analyse inertia measurements captured by Reactive's GridMetrix® technology between June and September 2023. This analysis aims to bridge the gap between theoretical calculations and the actual inertia to estimate the residual inertia attributed to the demand-side inertia. Besides, this analysis helps to understand under what conditions the system presents low and high inertia.

Second, we quantify the operational and planning value of considering demand-side inertia. Firstly, we developed a model that incorporates RoCoF, Quasi-steady-state (QSS), and nadir requirements. This model helps us understand the relationship between online inertia, FFR, and PFR, ultimately quantifying how demand-side inertia contributes to optimal resource allocation for system stability. Besides, we evaluate the value of demand-side inertia beyond unit commitment models by quantifying potential cost savings from deferring investments or avoiding additional inertia payments.

Thus, this report sheds light on the potential benefits of incorporating measured inertia data into NEM operations, providing insights into potential cost savings from operational optimisations, deferred investments, and reduced inertia payments.

2 Installation and Setup of Project Components for Inertia Measurement Demonstration Project in NEM

2.1 Installation and Configuration of XMUs

Reactive's XMU devices were built into an industrial panel for ease of installation and commissioning. The XMU panels manufactured at a local panel builder facility in Vic Australia, were pre-configured and ready to be plugged into a domestic 230V wall socket. As soon as the panels are plugged in and turned ON, they automatically start to report frequency measurements from each installation location to Reactive's secure cloud platform GridMetrix®. For the Inertia Measurement Demonstration project, a total of 15 XMU panels were installed at DEECA offices across 15 VIC state government offices. Later, during the project testing phase, ElectraNet SA and Powerlink QLD also showed interest in becoming part of the demonstration project, and 5 XMU panels each were installed in SA and QLD and 3 XMU panels were installed in NSW to enable Reactive Technologies to measure changes in frequency in these regions to allow measurement of Inertia in the NEM and regional Inertia. It was demonstrated during the demonstration project that the XMU panels can be deployed easily without the need for complex installations at substations thus avoiding any shutdowns or interruptions to operations of the Grid.

Figure 1 XMU locations across NEM

2.2 Implementation of Modulator Controls at VBB

Early in the project phase, Reactive Technologies shared the technical specification of the modulator requirement for NEM with AEMO. AEMO performed modeling and assessment to ensure that the operation of the modulator with the suggested signal parameters would not have any adverse impacts on the grid or nearby generators. After confirmations from AEMO and UoA (who performed small signals studies) that there would be no impacts during the operation of the Modulator, the Modulator requirements were shared with Tesla (Supplier and OEM of VBB) and Neoen. This helped Tesla to understand and implement the modulator controls on an inverter in their lab and then conducted comprehensive lab tests to validate and confirm that the BESS could indeed fulfill the specified modulator functionality. This comprehensive validation ensured that the modulator would perform as required for the success of the demonstration project. Tesla implemented the modulator controls at VBB to enable the modulator functionality.

2.3 Description of Testing Period

The demonstration project involved 250 hours of Modulation operation for Inertia measurement. During this phase Neoen's VBB was utilised as a modulator to inject a power signal into the NEM, resulting in a very small but measurable change in the grid frequency. This change in frequency was measured by Reactive Technologies XMUs installed across the NEM and reported back to Reactive's GridMetrix® platform. Together with these frequency measurements and the modulation power data from VBB, Reactive Technologies was able to measure the total NEM Inertia for the periods when modulation was carried out. Also, during the project testing period, high-speed boundary flow power data was made available by AEMO for the VIC region and ElectraNet for the SA region which enabled the Reactive Technologies to calculate the regional Inertia for VIC, SA, and QLD+NSW regions.

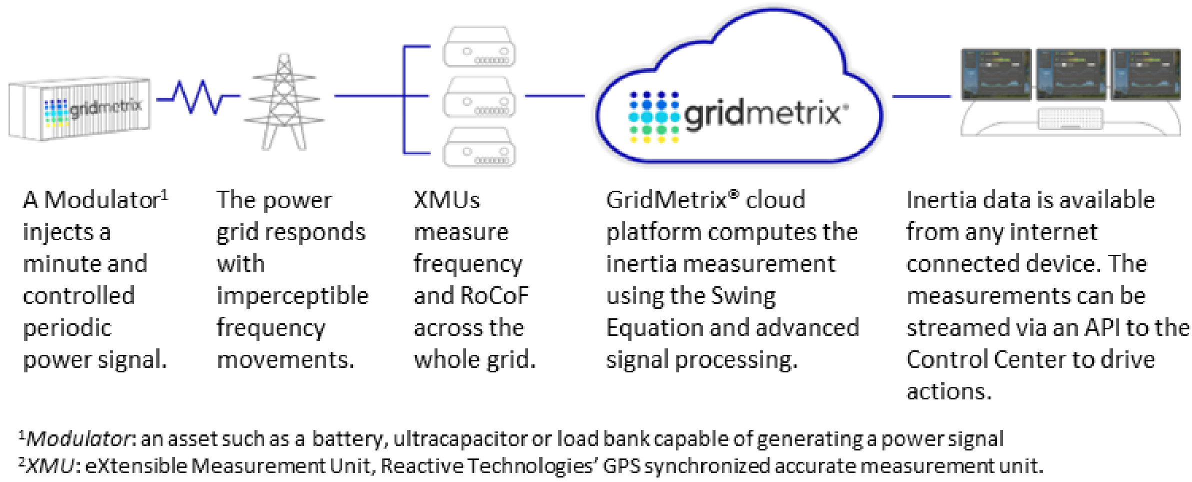

Figure 2 GridMetrix® Inertia Measurement High-level Schematic

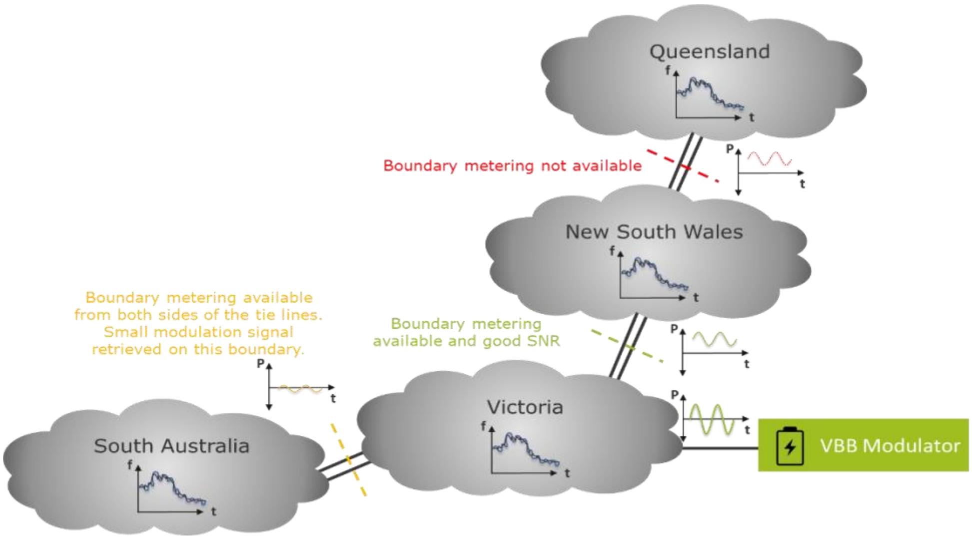

Figure 3 GridMetrix® Regional Inertia Measurement High-level Schematic

The testing period was carried out from 5th June 2023 to 28th Sep 2023. During this period modulation activities were systematically carried out to encompass a wide range of grid conditions, ensuring comprehensive testing and measurement of the system's inertia under various scenarios provided by the AEMO test coordinator. These included:

1. **High Demand with High VRE:** Testing was conducted during periods of high electricity demand, coupled with high levels of variable renewable energy generation from sources like solar and wind.

2. **Low Demand with Low VRE:** Testing under conditions of low electricity demand and minimal variable renewable energy generation.

3. **Low Demand with High VRE:** Evaluating system behaviour during low demand periods while experiencing substantial variable renewable energy contributions.

4. **High Demand with Low VRE:** Assessing the system's response when demand is high but variable renewable energy generation is relatively low.

5. **High Export from VIC:** Focusing on situations where Victoria experiences high electricity exports to neighbouring regions.

6. **High Wind and Solar Generation:** Testing under conditions of significant wind and solar energy production at a general range of demand levels.

7. **Low Wind and Solar Generation:** Evaluating system performance when wind and solar energy generation is minimal at a general range of demand levels.

8. **Weekday/Weekend Coverage:** Analysing the system's behaviour on both weekdays and weekends to account for variations in demand and grid activity.

9. **Different Times of the Day:** Testing was conducted at various times of the day to assess how system behaviour varies with diurnal patterns.

3 Overview of System Reserve Requirements

3.1 System Requirements

The swing equation (1) describes how the system's frequency behaves over time [23]. In this equation, Δf is the change in frequency in Hz, H_{sys} is the system inertia measured in MWs, D $[\frac{\%\,\Delta MW}{\%\,\Delta\text{Hz}}]$ represents the damping factor, P_D is the system demand in MW, $|\Delta P_{loss}|$ represents the highest generation unit output in MW, R_{pfr} and R_{ffr} refer to PFR and FFR reserves in MW. To ensure a secure response and prevent the activation of system protection mechanisms, the reserve requirements have been historically set based on QSS needs, ensuring the system has at least sufficient resources to supply the contingency size.

As system inertia decreases, the importance of RoCoF and frequency nadir increases. The RoCoF refers to the initial slope of the frequency immediately after a contingency event. Meanwhile, nadir is the lowest point the frequency reaches after a disturbance. This trend has caused a growing concern for system operators in recent years. To address this, our model incorporates the nadir as a non-linear constraint, helping to prevent under-frequency load-shedding events.

$$2H_{sys}\frac{\delta \Delta f(t)}{\delta t} + D \cdot P_D \cdot \Delta f(t) = \sum_{g}\left(R_{pfr}(t) + R_{ffr}(t)\right) - |\Delta P_{loss}| \quad (1)$$

3.1.1 RoCoF Requirements

By solving the differential equation (1) considering as an initial condition $\Delta f(0) = 0$, we can obtain the minimum system inertia required to meet the RoCoF limits and prevent the activation of RoCoF protection schemes. This constraint considers only the contribution from FFR reserves due to its fast response time. This equation is obtained from [24] and it is shown in (2). In this equation, T_{ROCOF} is the time (in seconds) to measure the RoCoF, T_{ffr} is the time (in seconds) to provide FFR, $\Delta ROCOF_{max}$ is the maximum RoCoF measured in Hz/s and f is the frequency in Hz.

$$H_{sys} \geq \frac{\left(2 \cdot |\Delta P_{loss}| \cdot T_{ROCOF} \cdot T_{ffr} - T_{ROCOF}^2 \cdot R_{ffr}\right) \cdot f}{4 \cdot \Delta ROCOF_{max} \cdot T_{ROCOF} \cdot T_{ffr}} \quad (2)$$

3.1.2 QSS Requirements

The QSS requirement guarantees the minimum amount of reserve capacity (PFR plus FFR) needed after a contingency. This reserve capacity must be greater than or equal to the difference between the largest credible contingency and the load relief ($Lr_{\Delta f}$) measured in MW. This constraint is given in the equation (3), while the load relief is defined in (4). The load relief is calculated with the damping factor, the system demand and the target frequency deviation from the normal operation.

$$R_{pfr} + R_{ffr} \geq |\Delta P_{loss}| - Lr_{\Delta f} \quad (3)$$

$$Lr_{\Delta f} = D \cdot P_D \cdot \Delta f \quad (4)$$

3.1.3 Nadir Requirements

The Nadir requirement is also derived from the swing equation and defines a non-linear relationship between the required PFR, FFR, contingency size and the online inertia. Other factors influencing the nadir requirement include system demand, load damping factor and the response times of FFR and PFR.

The nadir requirement utilized in the model is shown in (5) (see [25] for more details about how to derive this constraint), and it is based [23] and [26]. In this equation Δf_{DB} is the frequency deadband, T_{ffr} and T_{pfr} are the times to deliver FFR and PFR, respectively. Additionally, $D^{'}$ and $\Delta P_L^{'}$ are defined in (6) and (7), respectively.

$$|\Delta f_{nadir}| = \Delta f_{DB} + \frac{R_{ffr} \cdot T_{ffr} \cdot R_{pfr} + T_{pfr} \cdot \left(\Delta P_L^{'} - R_{ffr}\right)^2}{4 \cdot R_{pfr} \cdot H_{sys} + T_{pfr} \cdot D^{'} \cdot (\Delta P_L^{'} - R_{ffr})} \tag{5}$$

$$D^{'} = D \cdot P_D \tag{6}$$

$$\Delta P_L^{'} = \Delta P_L - \Delta f_{DB} \cdot D \cdot P_D \tag{7}$$

To illustrate the relationships between these parameters, we consider a fixed nadir requirement of 49.2 Hz[2], T_{ffr} and T_{pfr} are equal to 1 and 6 seconds, aligning with the Australian market FCAS (FFR = 1 second and PFR = 6 seconds), and a typical load damping factor of 0.5 % [27]. Additionally, we assume a demand level of 30 GW.

Figure 4 shows the impact of increasing the FFR provision in the PFR and inertia requirement. It is possible to see how when the FFR provision is higher, the PFR and inertia requirements decrease. Similarly, Figure 5 illustrates the impact of the contingency size, showing how a larger contingency size increases both the required PFR and inertia.

Figure 6 shows the influence of load damping factor in the PFR and inertia requirement. By reducing the damping factor from 0.5% to 0.1% increases the PFR requirement by approximately 150 MW for a system inertia of 40 GWs.

Finally, an overview of the RoCoF, QSS and nadir requirement can be seen in the Figure 7. This figure shows how the nadir requirement is a bounding constraint when the inertia decreases. Therefore, this constraint gets more important as system inertia decreases.

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[2] The containment band for frequency deviations is 49.5 Hz for generation events and is extended down to 49 Hz for network or separation events. Protection systems are activated when frequency drops to 49 Hz or below. For nadir constraint calculations, using a higher frequency (like 49.5 Hz) would yield more conservative results as it requires greater resources to prevent frequency from reaching this level. To balance this conservative approach with the need to avoid proximity to the protection system threshold, we've set a nadir requirement of 49.2 Hz. This value was chosen because it takes 200 ms (time to activate a protection) to reach 49 Hz considering maximum rate of change of frequency (RoCoF) of 0.5 Hz/s.

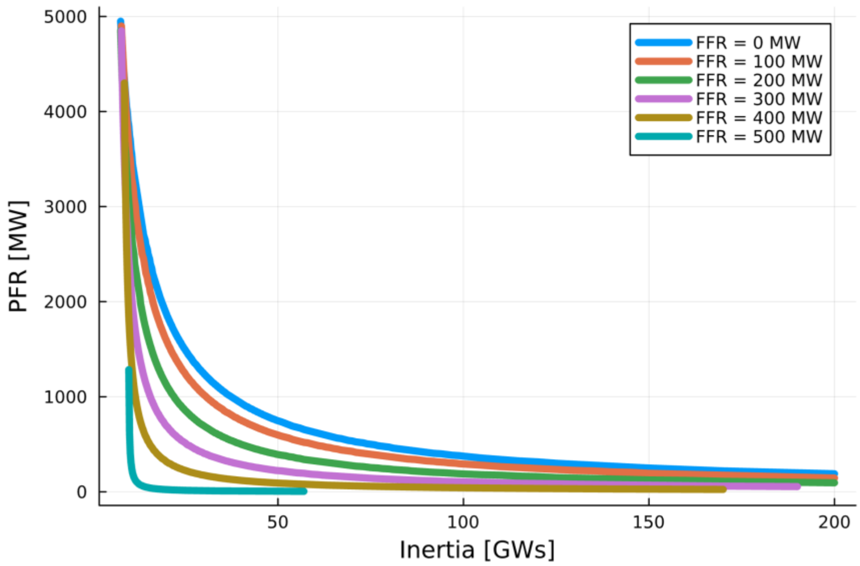

Figure 4 PFR requirement for different levels of inertia considering different FFR availability.

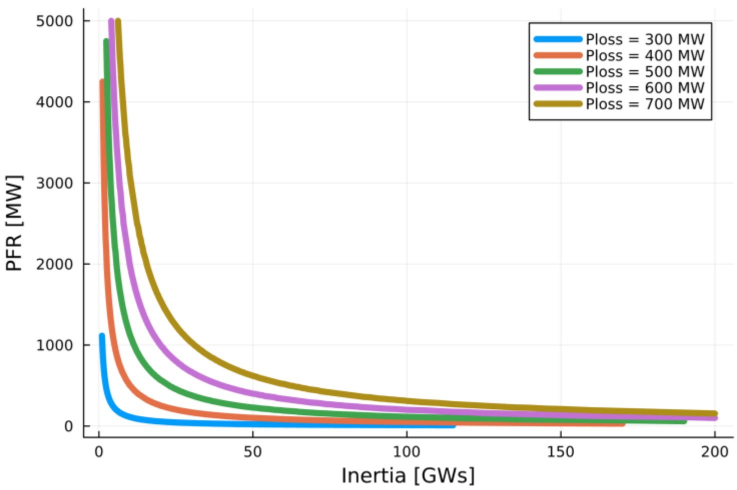

Figure 5 PFR requirement for different levels of inertia considering different contingency sizes.

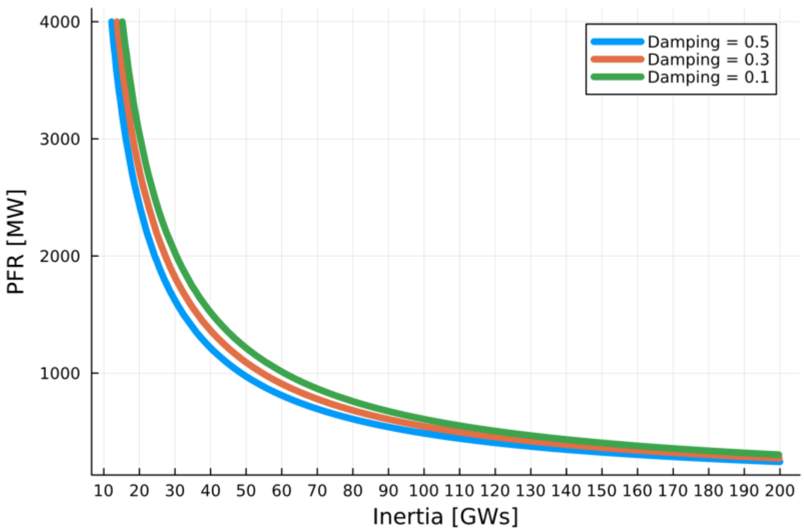

Figure 6 PFR requirement for different level of damping

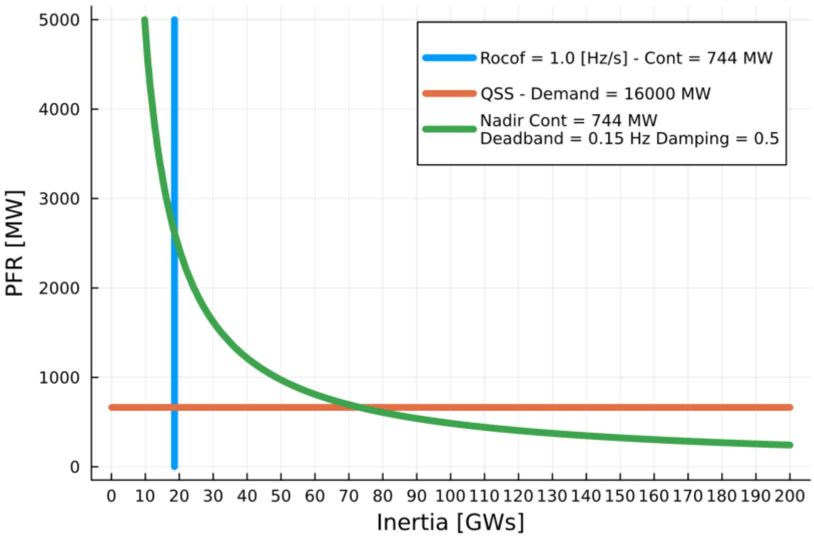

Figure 7 QSS, RoCoF and Nadir requirements

3.2 NEM FCAS Requirements

The NEM leverages FCAS for grid contingency management through 10 dedicated markets, each catering to different response time requirements. The existing FCAS offerings include both raise and lower frequency control services across various timeframes: 1-second, 6-second, 60-second, 5-minute, and regulation FCAS.

The 1-second service considers RoCoF requirements, while the other services are based on QSS requirements. Appendix 11.1 provides more details about the calculation of these services.

4 Technical validation

4.1 Theoretical Inertia

The total theoretical inertia of the system (H_{sys}) is calculated as the sum of the inertia of the online generators, this expression is shown in equation (8). In this expression, H_g is the inertia constant of the generator g in seconds, $\bar{P}_g$ is its maximum power output in MW and pf_g is the power factor. Typical inertia constant values for different technologies can be found in the Figure 8 [28].

$$H_{sys} = \sum_{g\ in\ G_{sys}} H_g \cdot \frac{\bar{P}_g}{pf_g} \tag{8}$$

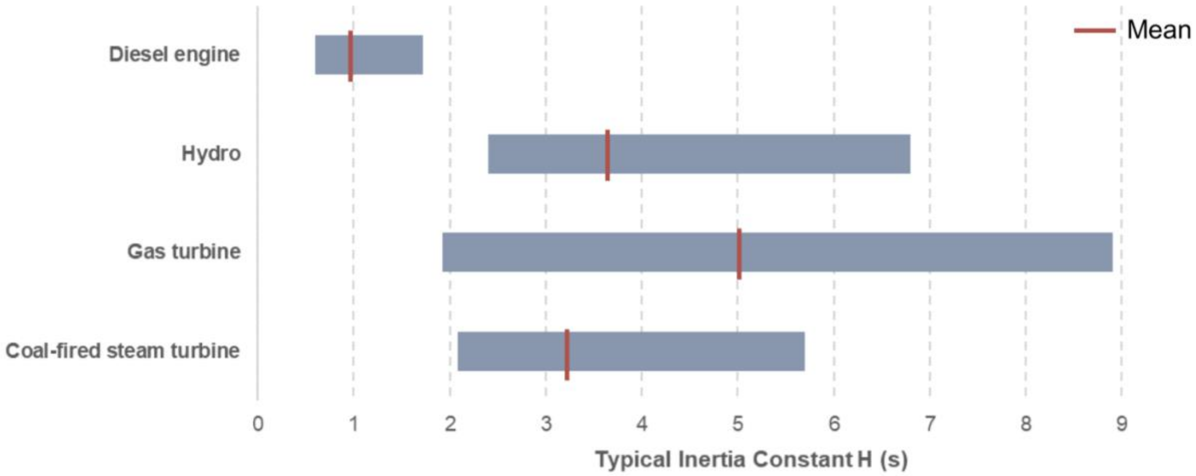

Figure 8 Inertia distribution per technologies [28]

In the last few years, the online theoretical inertia is decreasing. Figure 9 shows the average online inertia per year in the NEM and Figure 10 shows the average inertia per region. The inertia in these figures was calculated using average inertia values shown in the Figure 8.

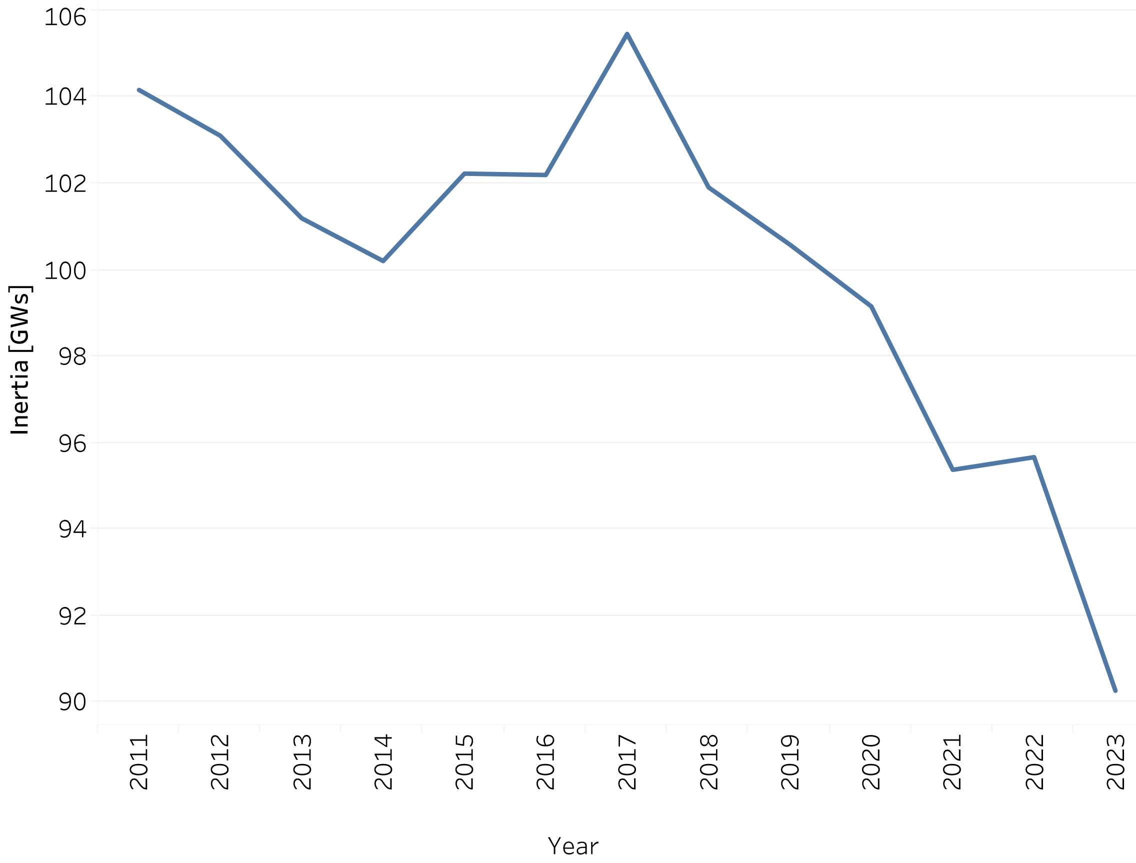

Figure 9 Inertia in the NEM per year

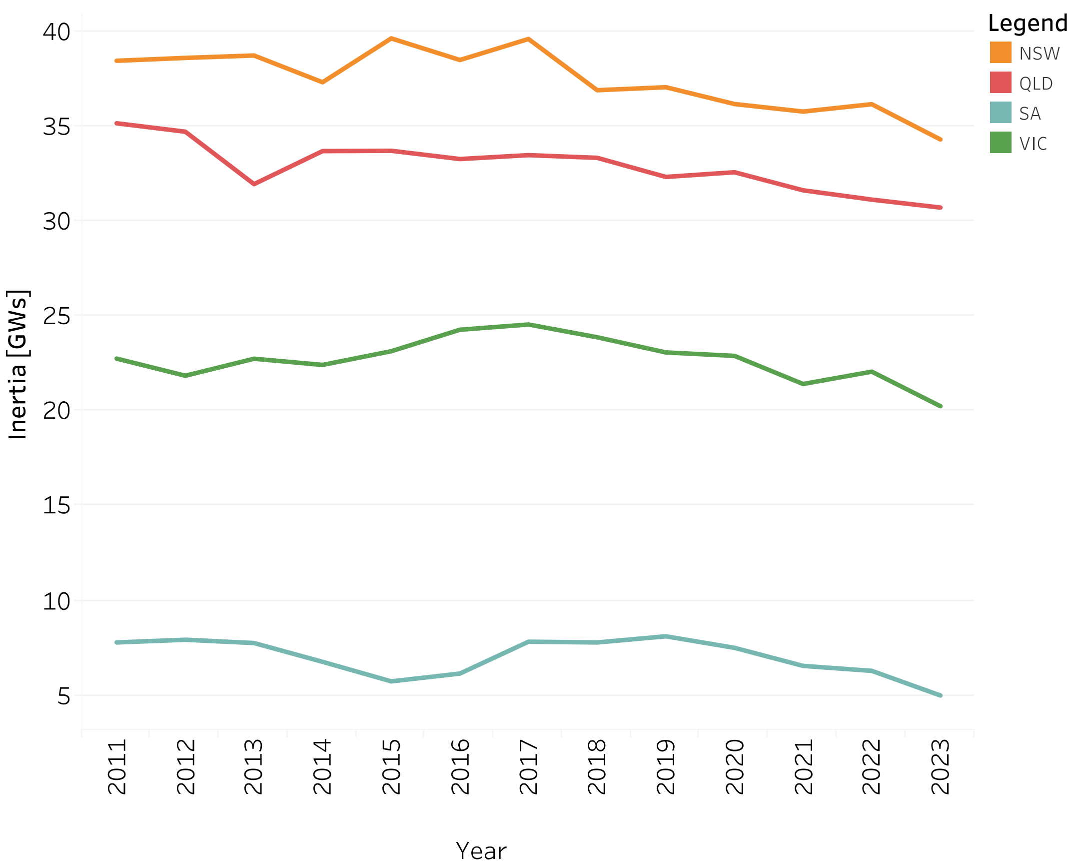

Figure 10 Inertia per region and year

4.2 Summary of inertia results-Reactive Technologies Inertia Measurement in NEM

Reactive collected 1078 5-minute inertia measurements over a span of 41 days between June and September 2023. AEMO selected these periods to capture system conditions during times of greater interest. Figure 11, Figure 12, and Figure 13 show the distribution of these measurements by month, day of the week, and hour of the day, respectively. Notably, September has the highest number of measurements collected. The day with the lowest number of recorded data was Friday. The data indicates that inertia measurements were not collected during hours 1,5, 19,20, and 21.

The inertia measurements are bounded by an upper and a lower value. The upper bound is on average 14.2% higher than the measurement, with a standard deviation of 4.2%. Conversely, the lower bound is on average 10.9% lower than the measurement, with a standard deviation of 2%.

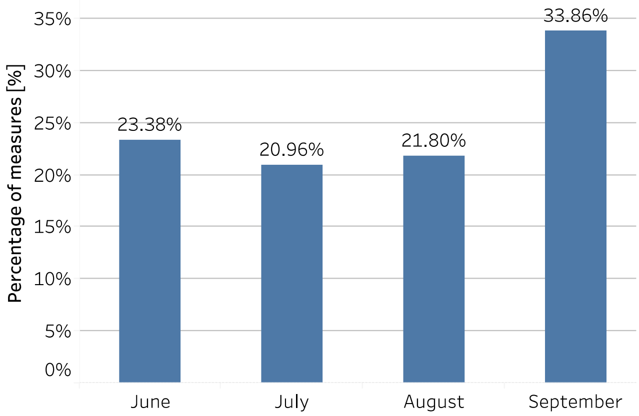

Figure 11 Distribution of inertia measurements by month

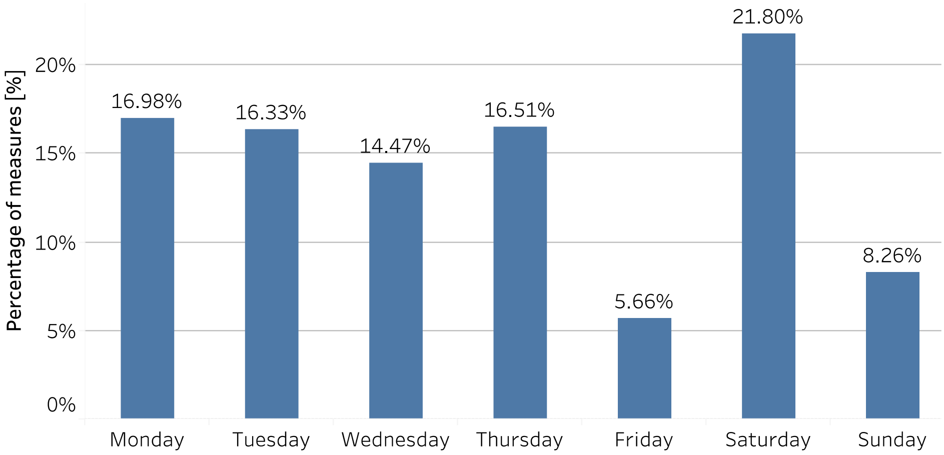

Figure 12 Distribution of inertia measurements by day of the week

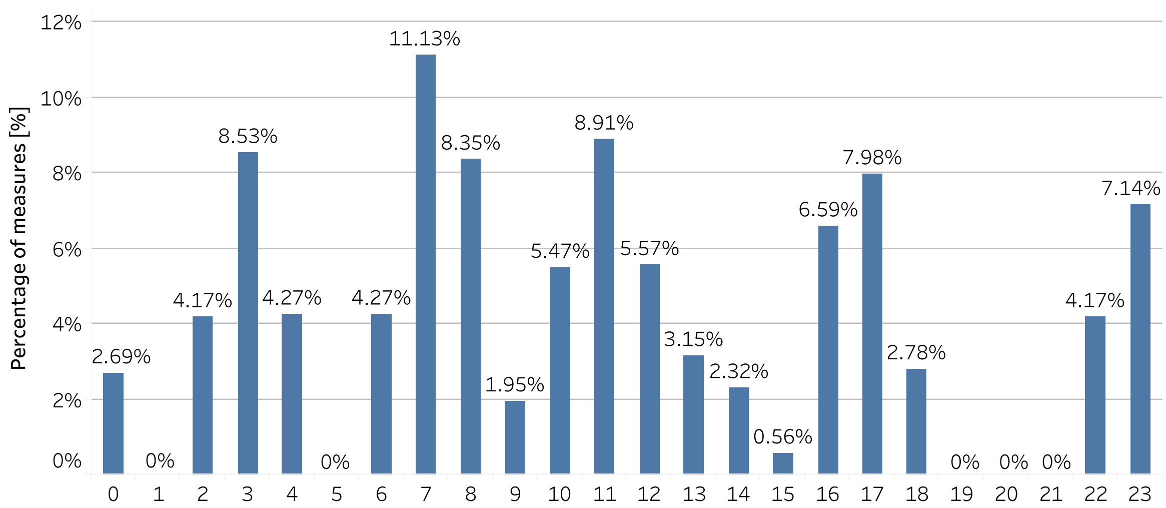

Figure 13 Distribution of inertia measurements by Hour of the day

4.2.1 Inertia by Demand Level

Figure 14 shows a bimodal distribution with a long tail for high inertia measures. The figure also shows the average demand for each inertia level, revealing a positive correlation, where higher demand coincides with higher inertia.

This behaviour is explained by two key factors. First, during periods of higher demand, more generators are online to meet demand requirement. The combined inertia of these additional generators naturally contributes to a higher overall system inertia. Second, beyond generator inertia, there is also a hidden inertia attributed to the demand-side. Certain loads, like large industrial motors, contribute to the system inertia. Therefore, periods of higher demand can be correlated to the presence of these loads, leading to increased demand-side inertia and contributing to the observed correlation.

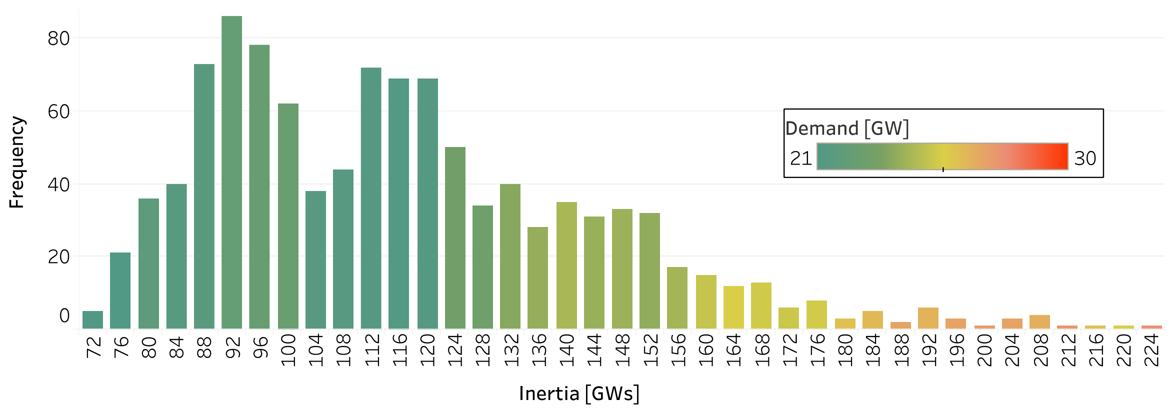

Figure 14 Inertia histogram per demand level

4.2.2 Inertia by Renewable Penetration Levels

Figure 15 explore the relationship between the distribution of the inertia measurements and the renewable penetration. In the figure, the colour gradient represents renewable penetration, which is calculated using 5-minute SCADA data for solar and wind generators [29], along with a 5-minute rooftop PV penetration derived from the 30-minute AEMO data [29] through linear approximation (refer to Appendix 0 for details about the linear approximation).

The figure reveals a tendency for high inertia measurements to coincide with low renewable penetration. However, the values of 72 GWs and 76 GWs describe a zone with low inertia and low renewable penetration. These conditions typically occur during low-demand hours when fewer generators are online, resulting in lower overall system inertia.

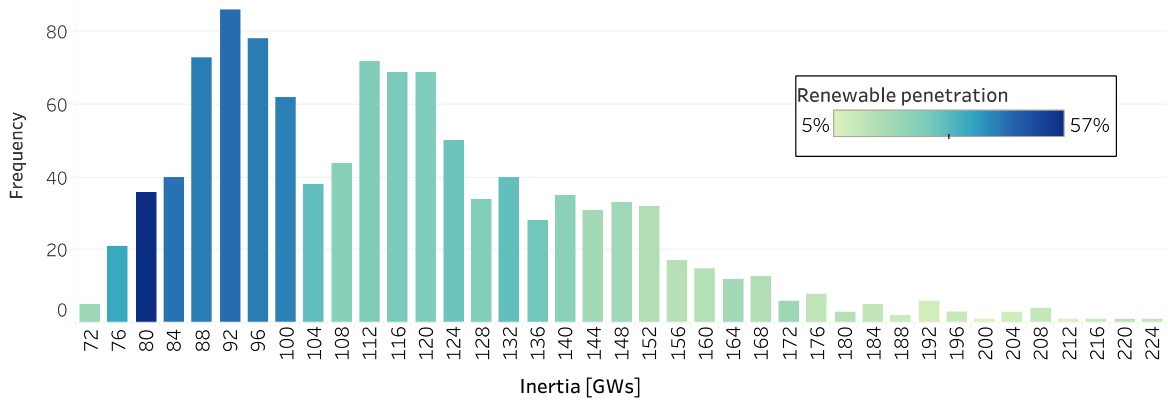

Figure 15 Inertia histogram per renewable penetration level

Figure 16 depicts the relationship between inertia and demand level for the measurement data, including colour variations to indicate different renewable penetration levels. Notably, inertia tends to be higher for measurements associated with high demand and low renewable penetration.

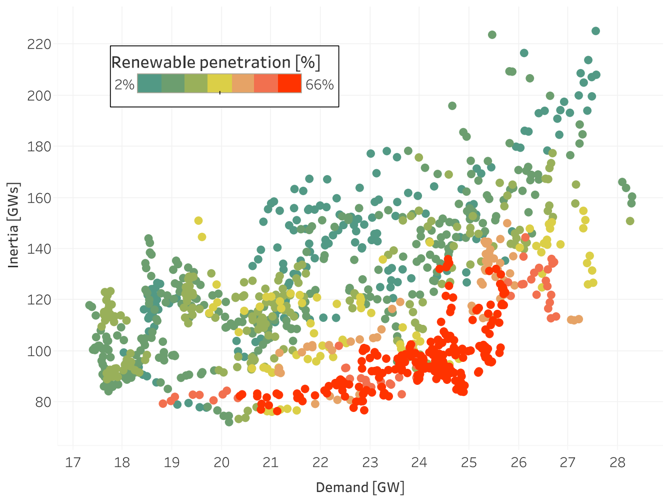

Figure 16 inertia per demand level considering renewable penetration

Figure 17 reinforces the trend observed in Figure 16. It depicts the relationship between renewable penetration and demand, using colour variations to represent different inertia levels. This figure shows different inertia zones, making the correlation between high demand, low renewable penetration, and high inertia even clearer.

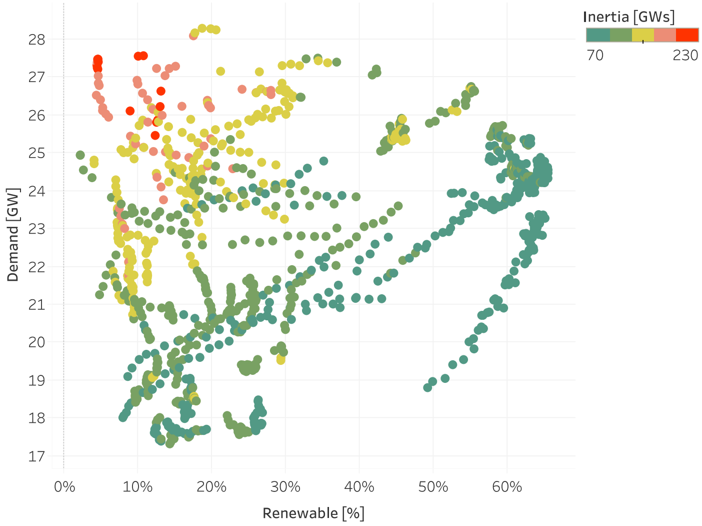

Figure 17 Inertia by renewable penetration and demand level

4.3 Comparison against AEMO's current calculation methodology

AEMO shared their theoretical estimation of online inertia with the UoM at a 5-minute resolution. These estimates data align in time with 893 inertia measurements obtained by Reactive.

Figure 18 shows a difference between measured and theoretical inertia for the analysed hours. Measured inertia values consistently exceed theoretical values and exhibit significant dispersion, while theoretical inertia values tend to be clustered around a central point. On average, the measured inertia is 38% higher compared to AEMO's estimate.

This difference arises from the limitations of theoretical calculations. The theoretical inertia calculations rely on reported inertia constants for generators, which might not capture the actual contribution of individual generators.

In contrast, measured inertia captures a more precise contribution of all operating conditions. This includes not only generator inertia but also any other additional hidden inertia.

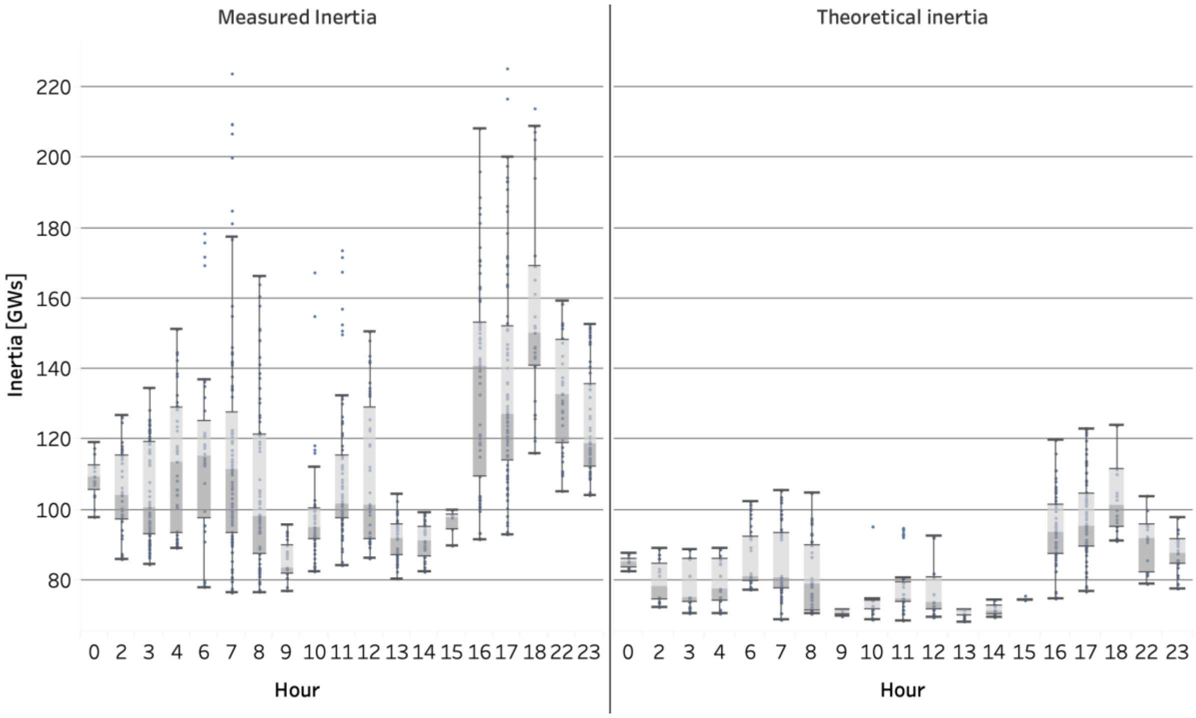

Figure 18 Distribution per hour of measured inertia and theoretical inertia in the NEM

Figures 19 and 20 help to understand the relation between inertia and system demand. Figure 19 shows the average measured and theoretical inertia of the NEM. Figure 20 shows the average demand and net demand of the NEM, where the net demand refers to the demand met by conventional generators, which are the generators providing inertia. By comparing these figures, it can be seen how the inertia tends to follow the behaviour of the net demand. This is because conventional generators are the main contributors to system inertia. Therefore, as net demand increases, more conventional generators come online, leading to a rise in overall system inertia.

Besides, it can also be seen how the estimated theoretical inertia is lower than the measured inertia. Moreover, the hours with high demand levels tend to have higher measured inertia.

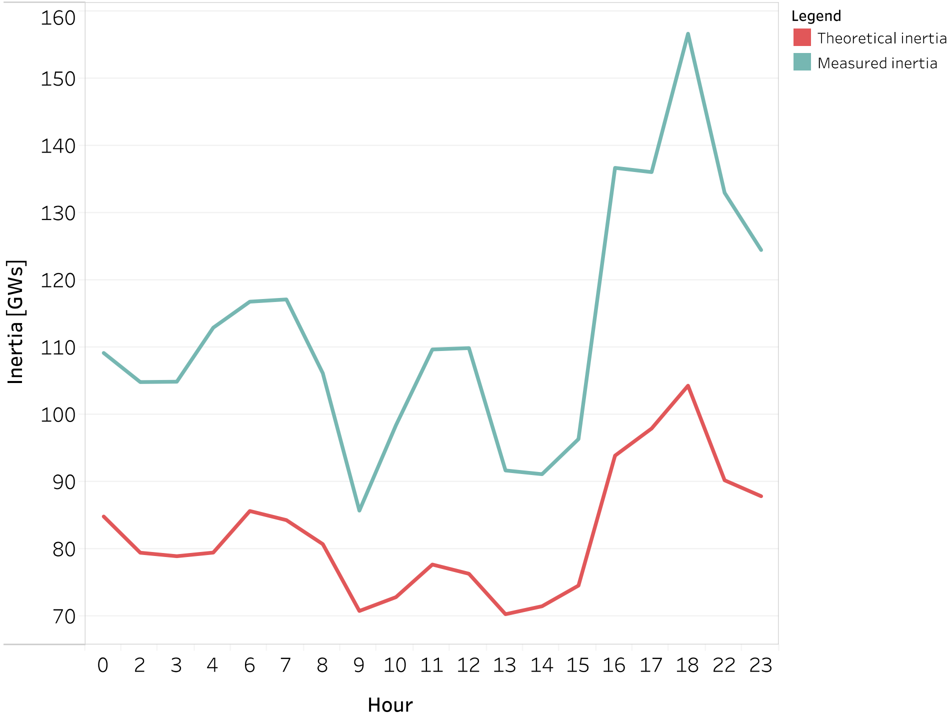

Figure 19 Average measured and theoretical inertia

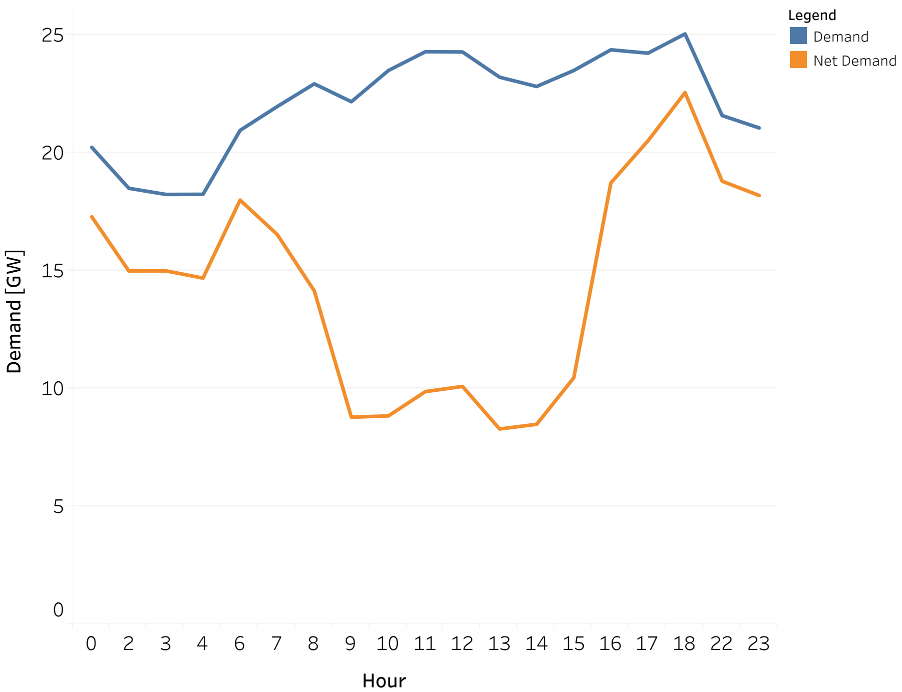

Figure 20 Average demand and net demand

4.4 Calculations of demand-side inertia contributions

The difference between the measured and the theoretical inertia is called residual inertia[3] [30]. The residual inertia can be divided by the demand to calculate an inertia constant for the residual inertia (this is attributed to the demand-side inertia). The average residual inertia and the average demand inertia constant are shown in the Figure 21 and Figure 22, respectively.

Figure 21 shows residual inertia peaking near 52 GWs during high-demand hours, while dropping to a minimum of 14 GWs in the morning. Figure 22 shows a similar behaviour for the residual inertia constant, with a maximum value of 2.05 s, a minimum of 0.6 s and an average value of 1.4 s.

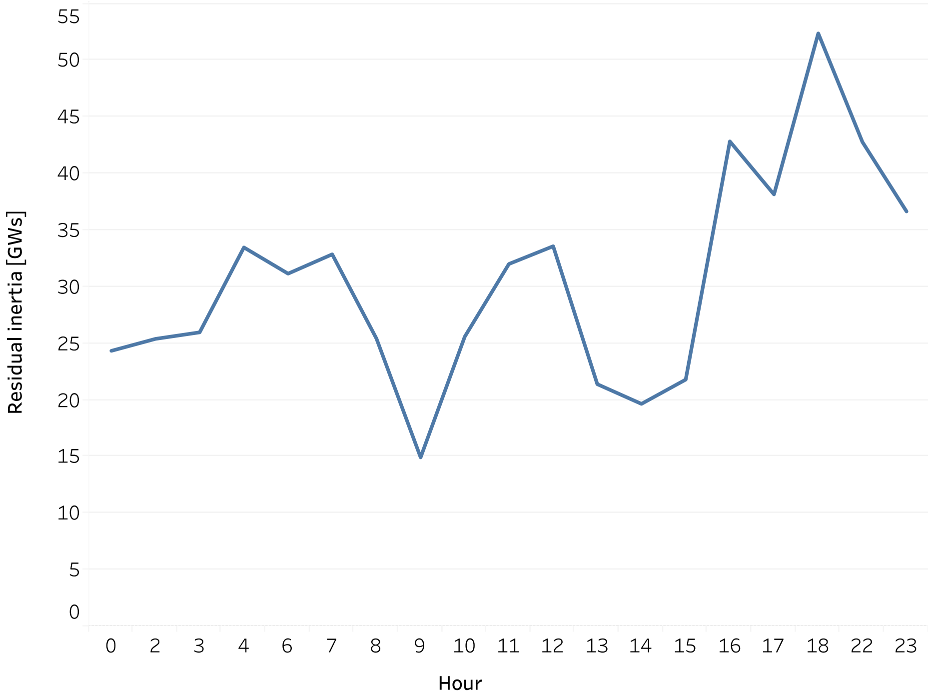

Figure 21 Average residual inertia per hour in the NEM

[3] For simplicity, this report attributes residual inertia to demand-side inertia. However, it's important to highlight that other factors might contribute to residual inertia, such as: Inaccurate data for on online generators or synchronous condensers, incorrect inertia constants for generators or other reasons.

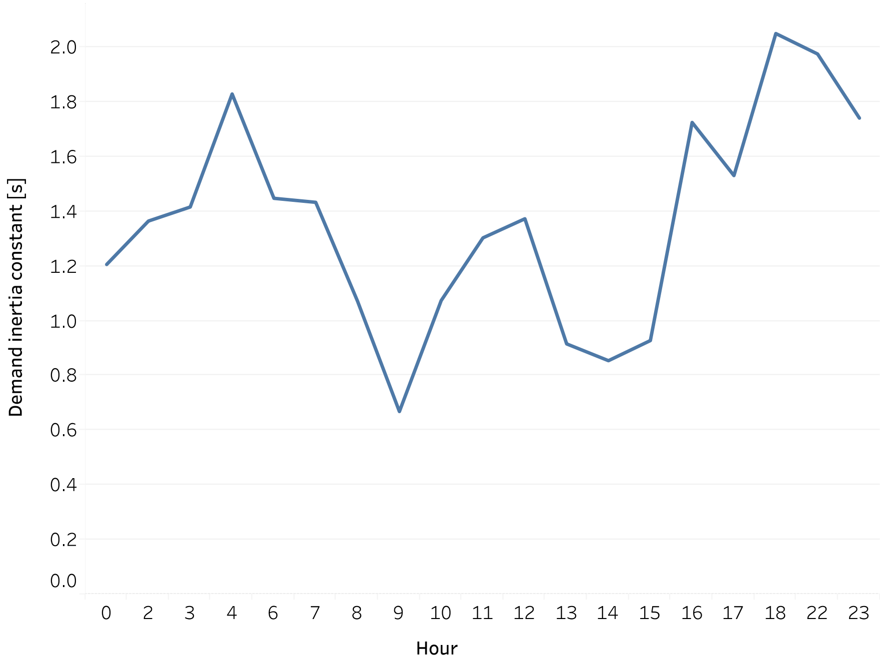

Figure 22 Average residual inertia constant (or demand inertia constant) per hour in the NEM

4.5 Reactive Technologies Regional Inertia Measurement

Several factors limited the availability of regional inertia data. Firstly, Reactive captured a reduced dataset due to the limited number of modulation hours, and secondly, AEMO provided fewer inertia theoretical calculations for the different regions. This combination resulted in a smaller dataset for analysis. Additionally, the boundary power flow data between NSW and QLD during the modulation was unavailable, resulting in a combined inertia measurement for QLD and NSW.

The number of inertia measurements collected in different regions of the NEM varies significantly. Due to an earlier measurement start date, VIC collected the most extensive dataset, with 205 data points recorded with a 5-minute resolution. In contrast, SA and a combined of QLD and NSW (denoted as QLD+NSW) have a substantially smaller dataset, with only 67 measurements each.

Figure 23 shows a comparison of the distribution of measured and theoretical inertia in VIC. This figure reveals a significant difference between measured inertia and theoretical estimates in Victoria. The measured inertia values exhibit a wide dispersion, being on average 38% higher than AEMO's estimate.

Due to the reduced dataset in SA and QLD + NSW, it is not possible to display the data dispersion for these regions. However, average hourly measurements are shown in Figure 24 for SA and Figure 25 for QLD + NSW. The measured inertia in SA is on average 38% higher than AEMO's estimate. Similarly, the measured inertia in QLD + NSW is 26% higher than AEMO’s estimate.

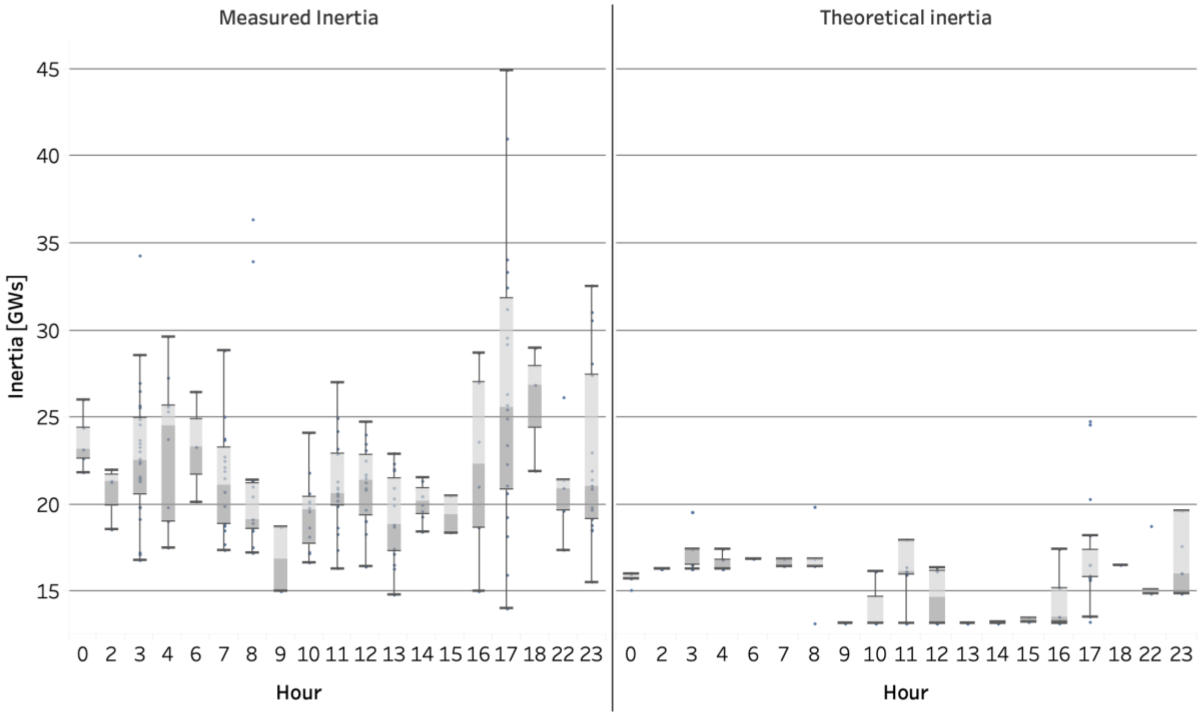

Figure 23 Distribution per hour of measured inertia and theoretical inertia in VIC

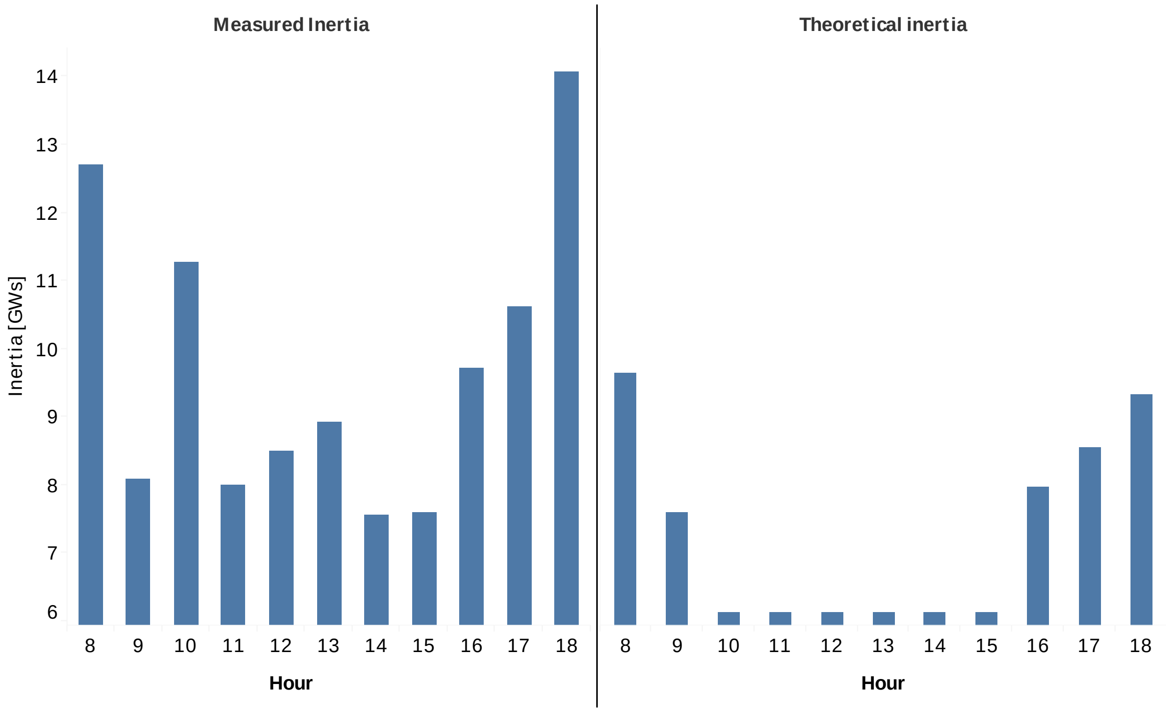

Figure 24 Average measured inertia and theoretical inertia in SA

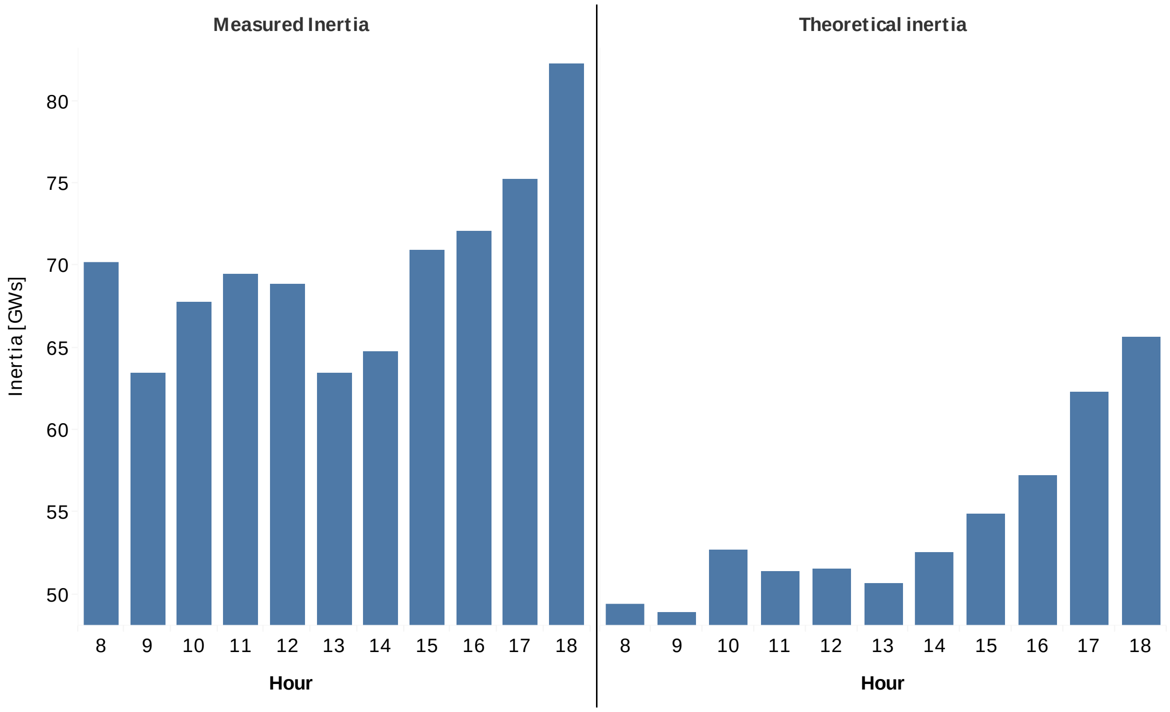

Figure 25 Average measured inertia and theoretical inertia in NSW + QLD

Finally, Table 1 summarizes the average residual inertia, demand, and the average and minimum inertia constant for VIC, SA and QLD + NSW. The table additionally presents the average residual inertia and average inertia constant for the NEM, based on the reduced dataset available for each region. Since the data for QLD and NSW is combined, the residual inertia of each region can be calculated proportionally to the average demand of each region. NSW has an average demand of 8501 MW, while QLD is 7662 MW. Using this demand data, the estimated average residual inertia in QLD is 6875 MWs, and in NSW it is 7629 MWs.

Table 1 Residual inertia, demand and inertia constant data for VIC, SA, QLD + NSW and NEM

	Average residual inertia [MWs]	Average demand [MW]	Average inertia constant [s]	Minimum inertia constant [s]	Average NEM residual inertia [MWs]	Average NEM inertia constant [s]
VIC	6,127	5,286	1.16	0.05	28,722	1.33
SA	2,642	1,664	1.58	0.14	23,672	1.02
QLD + NSW	14,505	16,164	0.90	0.46	23,672	1.02

4.6 Event-based verification

AEMO publishes quarterly reports detailing system contingencies, including their time of occurrence and the RoCoF. One such event occurred in QLD, involving the disconnection of a generator at 7:36 AM on September 26th [31]. The report indicates a recorded RoCoF of -0.11 Hz/s, and the associated event was the tripping of Kogan Creek Power Station while producing 517 MW. Data from Reactive

Technologies GridMetrix® platform [32] indicates the minimum system frequency during this event was 49.8085 Hz.

To calculate system inertia from contingency data, reference [33] suggests equation (9). AEMO calculates the RoCoF using a 500-millisecond rolling window [31]. However, for accurate inertia calculation, it is required the RoCoF value before any automatic response activation.

To achieve this, we calculated the instantaneous RoCoF using high-resolution frequency data (measured every 20 ms) obtained from [32]. This calculation yielded an instantaneous RoCoF value of 0.13 Hz/s. The calculated system inertia using this value is approximately 99.4 GWs.

Figure 26 shows the system frequency during the event in blue. The figure also displays the measured inertia (red) with its upper (green) and lower (yellow) bounds. Additionally, the calculated inertia based on contingency size and RoCoF (named event inertia in the figure) is shown in purple. Finally, AEMO's theoretical inertia is shown in black. By comparing these values, we observe that the calculated inertia falls within the range of the measured inertia, providing confidence in the results from the technology used to measure inertia. Besides, during the event, it was observed a difference between AEMO's theoretical inertia and the actual system inertia. AEMO's theoretical inertia was 77 GWs, which is roughly 22 GWs lower than the event inertia, which was approximately 99 GWs. On the other hand, the measured inertia was closer at approximately 92 GWs, deviating from the event inertia by only 7 GWs.

$$H_{sys} = \frac{\Delta P}{2\frac{df}{dt}} \cdot f_0 \quad (9)$$

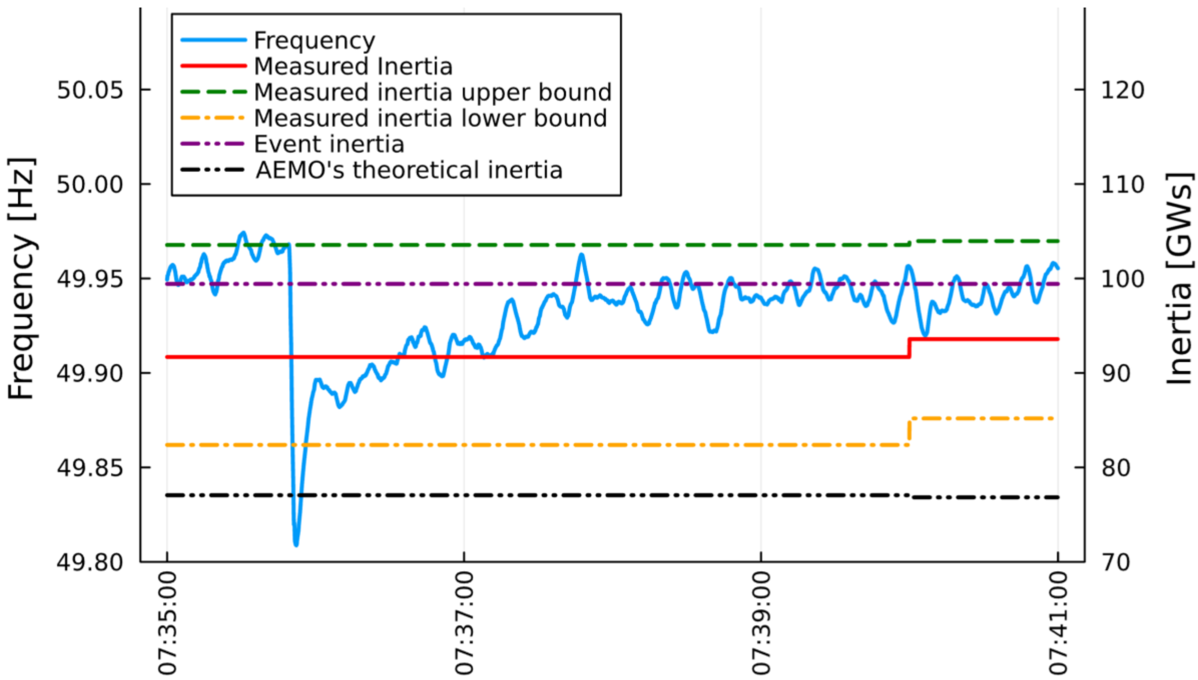

Figure 26 Frequency, measured inertia and calculated inertia

5 Economic assessment

This Chapter analyses how residual inertia could contribute to potential operational savings, reduced inertia payments, and investment savings. The Chapter details the methodology employed and the results.

The operational savings are studied through two case studies using a simplified single-area model for the NEM and for the isolated operation of QLD. The cases explore different contingency sizes and include a variable demand-side inertia for the NEM and QLD. The residual inertia is estimated as demand-side inertia by using a 1.4 s inertia constant for the demand in the NEM, while the demand-side inertia constant used for QLD is 0.9 s. These values are in line with the average values found in the Chapters 4.2 and 4.5.

The first case investigates the potential benefit of residual inertia that is assumed to come from the demand-side in the current NEM conditions, utilising real system data from 2023. Notably, the model incorporates the total available renewable energy, actual hydro generation profiles, and coal generator availability (further information provided in Appendix 11.3). In this case, the contingency size is the maximum power output given by Kogan Creek (744 MW).

The second case explores the impact of isolated operation of QLD. This case is studied because AEMO identified the isolated operation of QLD as a credible event in [15]. This report also projects insufficient inertia in the region by 2027. Therefore, this case study is crucial to understand the potential value of demand-side inertia in the short and medium term. Since this system is isolated, the regional contingency size is co-optimised with the dispatch, and it is given by the maximum power output of any online generator in Queensland. Due to the uncertainty surrounding the inertia constant of QLD (as detailed in Chapter 4.5), we analysed a sensitivity including the minimum inertia constant obtained with the measurements, which is equal to 0.46 s.

The dispatch model incorporates the existing FCAS services (described in section 3.2) to capture the current system behaviour. The inclusion of these services ensures the QSS requirements. However, the RoCoF and nadir requirements are not included in the existing services, and they are implemented as defined in chapter 3.1. The RoCoF limit is set to 1 Hz/s based on the current regulation [34]. The nadir requirement considers the under-frequency load shedding activation frequency. These protections operate from 49 Hz and require 100-200 milliseconds to operate [35]. Thus, to ensure the nadir limit is higher than the frequency that triggers load shedding, we have set the nadir limit at a slightly higher value of 49.2 Hz (which could drop to 49 Hz with a RoCoF of 1 Hz/s over 200 milliseconds).

Finally, we also analysed the savings coming from reduced inertia payments and deferred/reduced investments. These cases were studied for QLD working isolated, which have a declared inertia shortfall of 1.6 GWs from 2027 [15] and also for SA, which has an inertia shortfall of 0.5 GWs [15] the second half of 2024 and it will last for at least 6 months.

5.1 Methodology to Assess the Potential Benefits of Inertia Measurements

As illustrated in the previous sections, inertia measurements may highlight the presence of 'hidden' residual inertia (which we have for simplicity entirely associated with the demand side). Residual inertia might mean that less inertia than otherwise anticipated could be needed to maintain system security, in turn potential leading to both operational and investment savings. This section discusses the methodology adopted by UoM to assess such potential savings under different scenarios and considering both the entire NEM and regional instances.

5.1.1 System Operational Cost Savings

Residual inertia (which again we will associate with the demand-side) identified via inertia measurements could bring operational savings to the system that may generally arise from lower FCAS procurement cost, avoided commitment and operational cost of additional units required to provide inertia and FCAS, and associated reduced renewable energy curtailment. To quantify these potential cost savings associated with residual inertia, we developed a unit commitment model including variable costs, start-up/shut-down costs, and FCAS costs[4]. Additionally, the model considers key generator limitations that impact dispatch decisions, including minimum/maximum power output and start-up/shut-down times.

The system operational cost savings are calculated based on two dispatch cases:

- Base case: This scenario represents the total system operating cost without the inclusion of demand-side inertia.
- Demand-side Inertia included: This case incorporates the demand-side inertia in the economic dispatch.

The difference in total system operating cost between these two cases quantifies the potential economic benefit of including demand-side inertia into the dispatch. The operational savings are calculated using weekly profiles for different renewable penetrations (See Chapter 5.1.3 for more details).

5.1.2 Other Savings from Avoided Investment in Inertia Sources to Maintain Regional Security

Further benefits from inertia measurements, associated for example with avoiding additional payments to inertia sources or deferring/reducing inertia-related infrastructure investments could also importantly emerge which might not be captured by the operational cost savings analysis illustrated above. For simplicity, the savings discussed in this section will be referred to as "investment savings”.

In the NEM, in particular, these savings may be driven by minimum *regional* inertia requirements imposed by AEMO to ensure safe operation after a contingency, especially in those cases when specific regions might have to operate islanded for a period of time. These minimum requirements and the declining system inertia from retiring synchronous generators may lead to forecasting potential inertia shortfall in specific regions. By revealing the presence of residual inertia, inertia measurements might help address, or even completely compensate for, these shortfalls, and the system might potentially achieve additional cost savings through:

[4] The development of the evolving energy market, including potential future markets for inertia and other services, is uncertain. Given the scope of this report, we focused on the current FCAS markets and values to understand the impact of inertia and we have not made any assumption about cost projections.

- *Reduced inertia or FFR procurement payments*: There might be two kinds of payments to address the inertia shortfall. Firstly, there might be some side payments (as capacity payments or other incentives) to keep generators (which otherwise might leave the market) available to avoid inertia shortfalls. The second option is the current mechanism, where the TNSPs may contract FFR equivalent to the inertia shortfall [15]. By including demand-side inertia the required amount of FFR services to be hired under this mechanism could be reduced or completely avoided.
- *Deferred/Reduced investment in synchronous condensers*: The investment in synchronous condensers is an alternative to address potential inertia shortfall. However, by considering demand-side inertia, the need of investing in these devices could be reduced in size or in the best case completely deferred.

5.1.2.1 Reduced Inertia Payments

To estimate the potential savings from reduced inertia payments, we used the inertia shortfall declared by AEMO, which can be met by contracting inertia or FFR. According to AEMO, this shortfall, measured in MWs, directly reflects an amount of FFR capacity in MW that TNSPs need to contract depending on the region and the 1-second market; the equivalent amount of FFR can be obtained from inertia vs contracted FFR for each region as in [15]. Thus, we have estimated potential inertia payments as cost of contracting FFR using the current average cost of the 1-second market[5].

The demand-side inertia has the potential to reduce the inertia payments by reducing the amount of FFR contracted to address inertia shortfalls. To estimate these potential savings, we calculate the minimum contribution of demand-side inertia. This is determined by multiplying the minimum demand by the minimum demand inertia constant.

The new FFR requirement is calculated by subtracting the minimum contribution of demand-side inertia from the original requirement. It's important to note that real-time contributions from demand-side inertia may be higher. However, these savings are based on a conservative estimate of the "firm" inertia available from the demand side. Considering the new FFR requirement, two situations might occur:

1. Full shortfall addressed by demand-side inertia: If demand-side inertia can fully address the shortfall, the savings are given by the total cost associated with contracted FFR by the TNSPs.
2. Partial support from demand-side inertia: If demand-side inertia provides partial support, the savings are determined by average cost of FFR, and the new reduced FFR requirement, including the support given by the demand-side inertia during the shortfall.

5.1.2.2 Deferred/Reduced Investment

Inertia payments can address short-term and medium-term inertia shortfalls, especially for situations lasting few months. However, investing in synchronous condensers is a more cost-effective solution for anticipated longer shortfalls.

[5] This cost might decrease as energy storage penetration grows. However, this methodology is used to assess a current situation (South Australia 2024), and the utilisation of current costs is needed.

To evaluate investment needs, a combination of synchronous condensers with varying capacities (80, 125, 200, and 250 MVA) could be considered to select the investment portfolio [36]. These synchronous condensers can be equipped with flywheels to achieve an inertia constant of up to 16 s [37].

To calculate the capacity of demand-side inertia to defer or complement investment decisions we calculate its contribution using the same methodology from Chapter 5.1.2.1. This consists in multiplying the minimum demand by the minimum demand inertia constant. This approach provides a conservative estimate to capture the "firm" contribution of demand-side inertia in the assessment of new investment.

Then, depending on the calculated demand-side inertia, two situations might occur:

1. Full shortfall addressed by demand-side inertia: If demand-side inertia can fully address the shortfall, the planning savings are equivalent to the minimum investment cost among the different portfolios of synchronous condensers.
2. Partial support from demand-side inertia: If demand-side inertia can partially address the shortfall, the cost savings are equal to the difference between the original investment required for synchronous condensers/flywheels and the new investment needed to address the reduced inertia shortfall. The new shortfall is calculated by subtracting the minimum contribution of demand-side inertia from the original inertia shortfall.

5.1.3 Week Selection

To reduce the computational burden, the operational savings were assessed using weekly profiles. The selection of the operating conditions is crucial for understanding both the current inertia state of the NEM and its potential evolution by 2037, when it is expected the full retirement of coal generators. Additionally, it's necessary to select conditions for QLD because AEMO defined the island operation of QLD as a likely event and AEMO projects a potential 1.6 GWs inertia shortfall during isolated operation by 2027 [15].

To identify an operational year to select the operating conditions, we focused on identifying "low inertia events". These events are defined as any 5-minute period where the online inertia falls below the 10th percentile, which is 85 GWs for the NEM and 29 GWs for QLD.

Figure 27 show the number of low inertia events in the NEM over the past 14 years (calculated with a 5-minutes resolution using the average values of theoretical inertia shown in Chapter 4.1). The data reveals a trend of increasing annual occurrences that coincides with the growing penetration of solar and wind generators in the last few years. In fact, the number of events recorded in just 2 months of 2024 is already comparable to the total observed in 2015. Given this significant rise, the year 2023 was chosen as the base year to assess the value of demand-side inertia through case studies.

Figure 28 provides a more granular view of low inertia events in 2023, showing the weekly total alongside the average and minimum system theoretical inertia. Figure 29 shows the average weekly renewable penetration (including wind, large scale, and rooftop PV) along with the total available generation (including curtailed capacity). Comparing Figure 28 and Figure 29 reveals a correlation between higher low inertia events and increased renewable penetration. Therefore, renewable energy penetration is a major factor contributing to low inertia conditions in the system. Thus, to calculate annual savings, we selected operating conditions with varying levels of renewable penetration across different weeks.

Then, we calculated system savings by running these weeks with and without inertia from the demand side. Finally, a polynomial regression was performed using the average weekly renewable penetration to estimate the weekly savings for every week of the year, and then the annual saving is obtained as the sum of the savings per week.

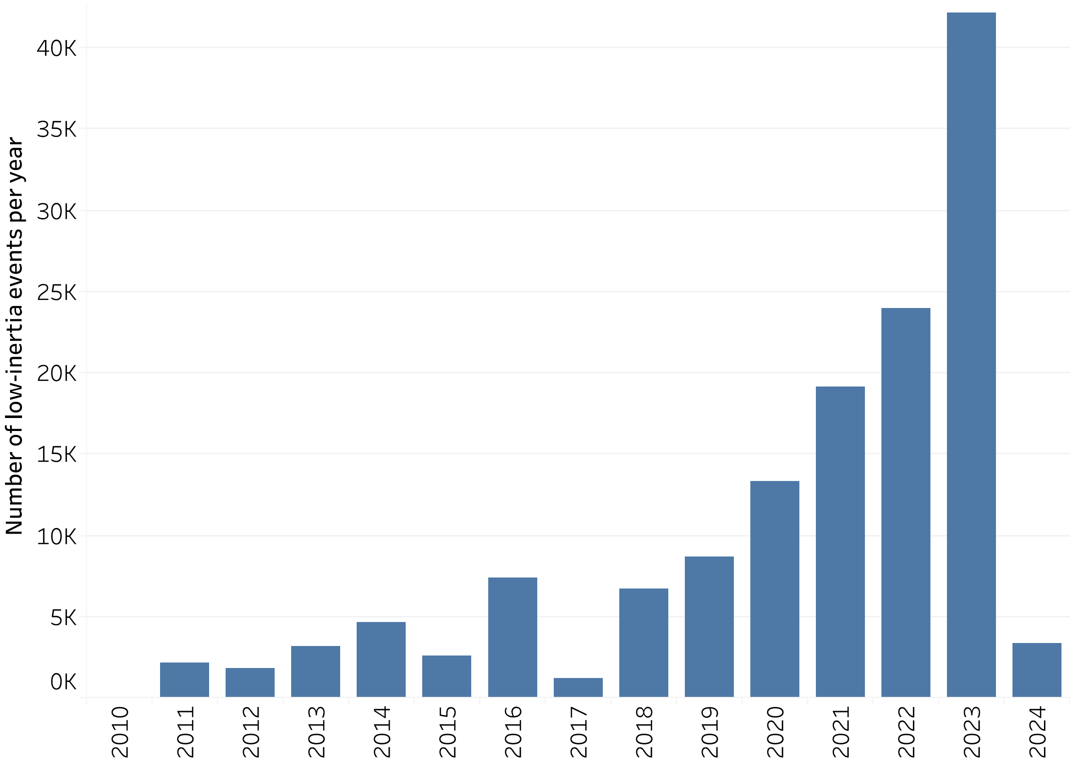

Figure 27 Number of low-inertia events per year (inertia below 85 GWs)

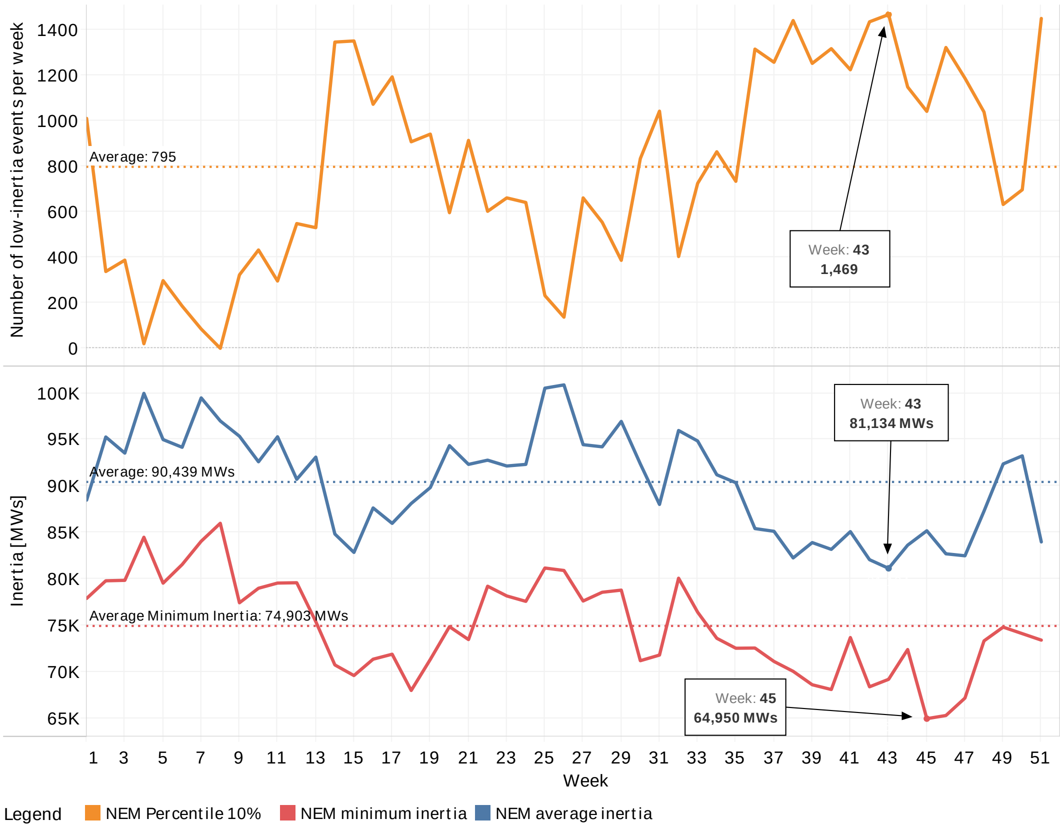

Figure 28 Number of low-inertia events per week, average inertia and minimum theoretical inertia for the NEM in 2023

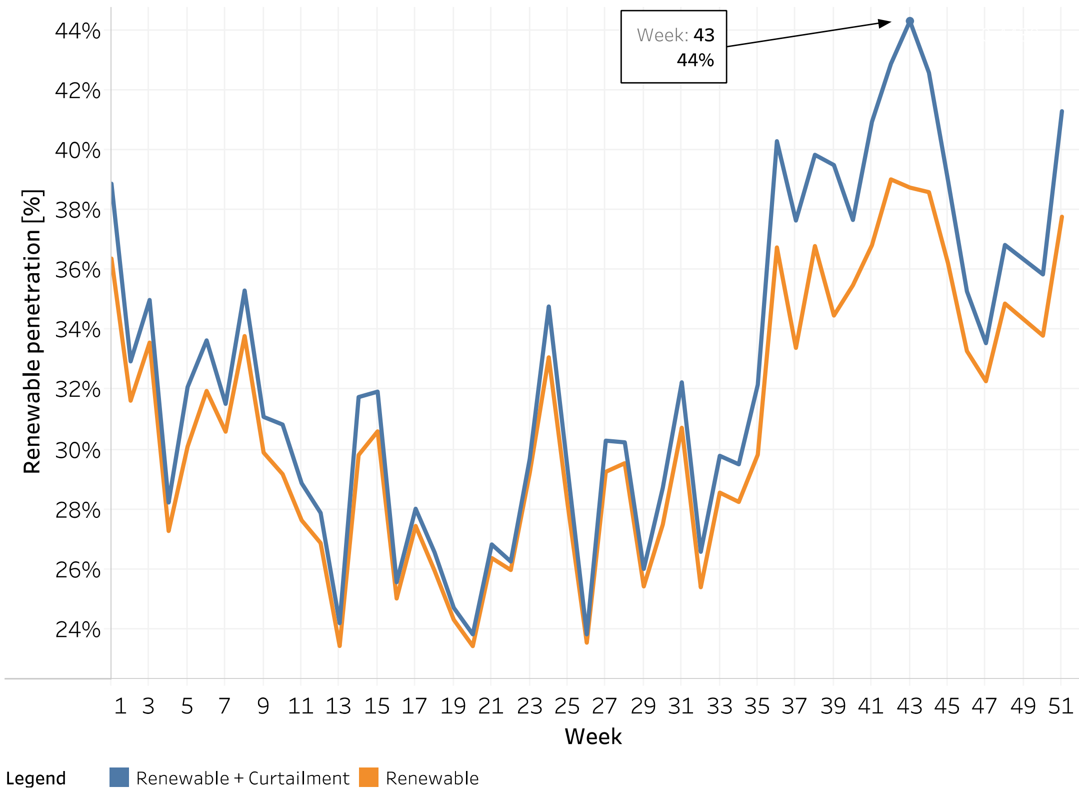

Figure 29 Average renewable penetration and maximum availability of renewable penetration per week for the NEM

Since AEMO has identified the isolated operation of QLD as a likely event [15], understanding the economic impact of demand-side inertia under these conditions becomes crucial. This analysis should focus on potential weeks with minimal inertia to establish an upper limit on the cost savings achievable by incorporating the demand-side inertia into the operation. For this reason, the selection process prioritizes operating conditions where the system might have low inertia, including:

- High frequency of low inertia events: Weeks with a high frequency of events where the calculated 5-minute online inertia falls below the 10^{th} percentile, which is 29 GWs for QLD.
- Minimum system inertia conditions: Weeks exhibiting the lowest recorded system theoretical inertia value.
- Maximum renewable penetration: Weeks with the combined highest potential for renewable energy contribution, considering both actual generation and curtailed generation.

Figure 30 shows the weekly low inertia events in QLD, alongside the average and minimum system theoretical inertia. Figure 31 illustrates the average weekly renewable penetration (including wind, large-scale, and rooftop PV) along with the total available generation (including curtailed capacity). Based on these figures, the following weeks were selected to study the value of additional inertia in the isolated operation of QLD:

- Week 16: This week exhibits the highest number of low-inertia events.
- Week 40: This week has the lowest average inertia observed throughout the year.
- Week 41: This week experiences the highest level of renewable penetration.

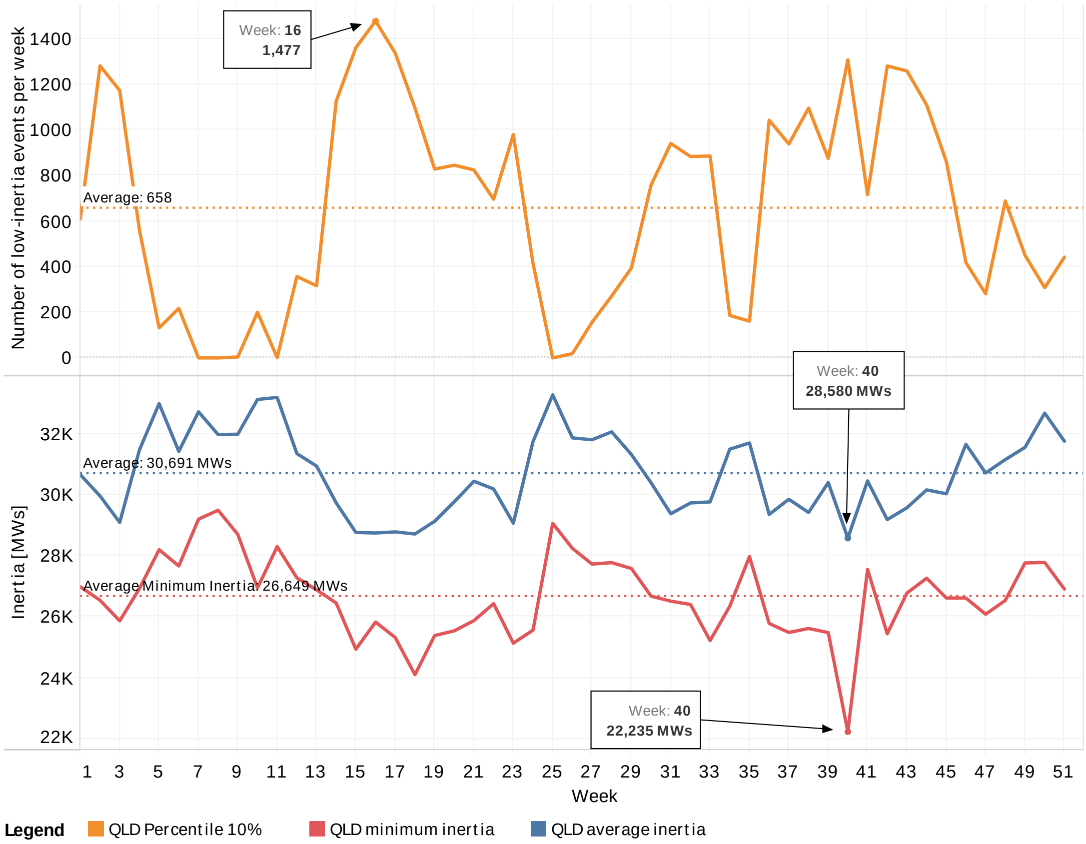

Figure 30 Number of low-inertia events per week, average inertia and minimum theoretical inertia for QLD in 2023

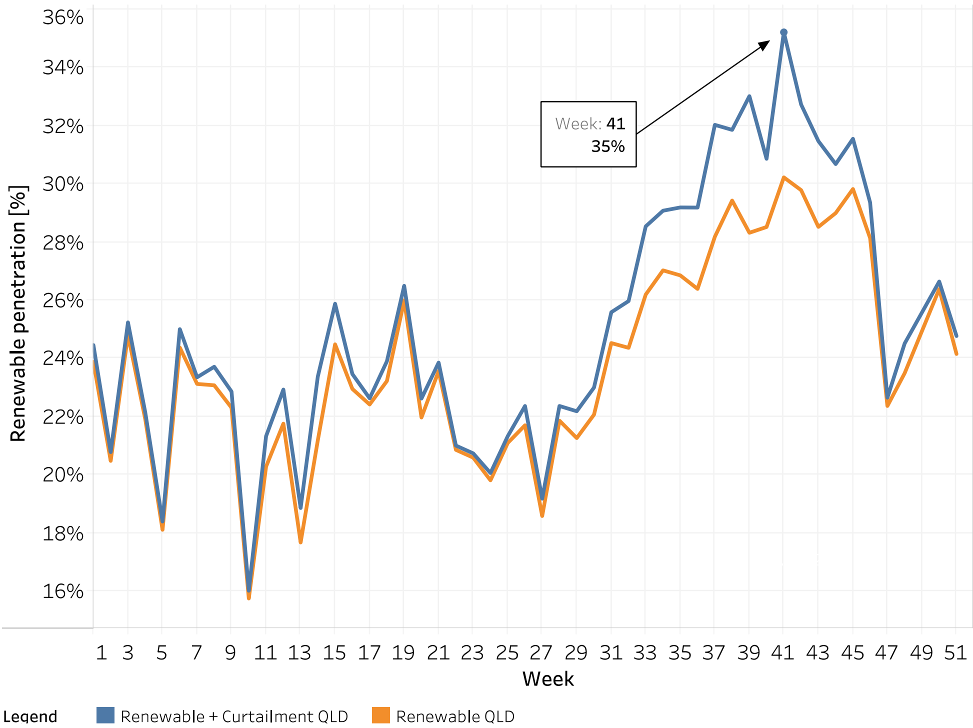

Figure 31 Average renewable penetration and maximum availability of renewable penetration per week for QLD

5.2 Operational Savings

5.2.1 NEM 2023

This case analyses the impact of additional inertia in the current market, assuming a fixed contingency size of 744 MW, equivalent to the maximum power output of the Kogan Creek generator. However, historical data reveals instances where this generator has exceeded this capacity. In fact, the largest contingency in 2023 was a trip of Kogan Creek power station unit 1 on 12/06/2023 at 12:33, resulting in the loss of 759 MW [38].

5.2.1.1 Installed Capacity

Table 2 shows the installed capacity, the minimum power output of the generators (as a percentage of maximum capacity) [39] and their start-up and shutdown times [40]. The variable cost and the start-up cost are obtained from [41] and [40], respectively. The cost of proving reserves for the different markets is obtain as the average price from historical data from [29][6]. The value of lost load is 16,600 $/MWh, based on the market price cap in [42].

[6] The average raise prices (from January 2023 to March 2024) are 24.06 $/MW/h and 5.74 $/MW/h for the 1-second and 6-second markets, respectively.

Conventional generators are assumed to provide up to 10% of their capacity for the 6-second and 60-second markets, while the 5-minutes market is limited by the ramp-up capabilities of the generators detailed in [41]. Additionally, PS can provide PFR, while BESS can provide both FFR and PFR.

Table 2 Characteristic of power generators NEM 2023

	Coal	Gas	Other thermal	Hydro	PS	BESS	VPP	Large-scale PV	Rooftop PV[7]	Wind
Installed capacity [GW]	23	10	1	5	0.8	2	0	9	12	11
Pmin [% of Pmax]	50	40	5	0	0	0	0	0	0	0
Start-up/shut down time [h]	8	4	0	0	0	0	0	0	0	0

5.2.1.2 Results

Figure 32, 33 and 34 show the online inertia, FFR requirements and PFR requirements, respectively, for the week with the maximum renewable penetration and an inertia constant of 1.4 s. An analysis of these figures together reveals interactions between these 3 services.

A critical factor influencing the allocation of both, PFR and FFR is the system's nadir constraint, which depends on the system inertia and is described in Chapter 3.1.3. As shown in Figure 32, during low-inertia periods (e.g., hour 132), the FFR requirement is higher in the case without additional inertia for the same amount of PFR reserves, as shown in figures 33 and 34. This highlights the role of inertia in the FCAS markets modelled including the nadir constraint, where a higher system inertia reduces the need for expensive FFR services.

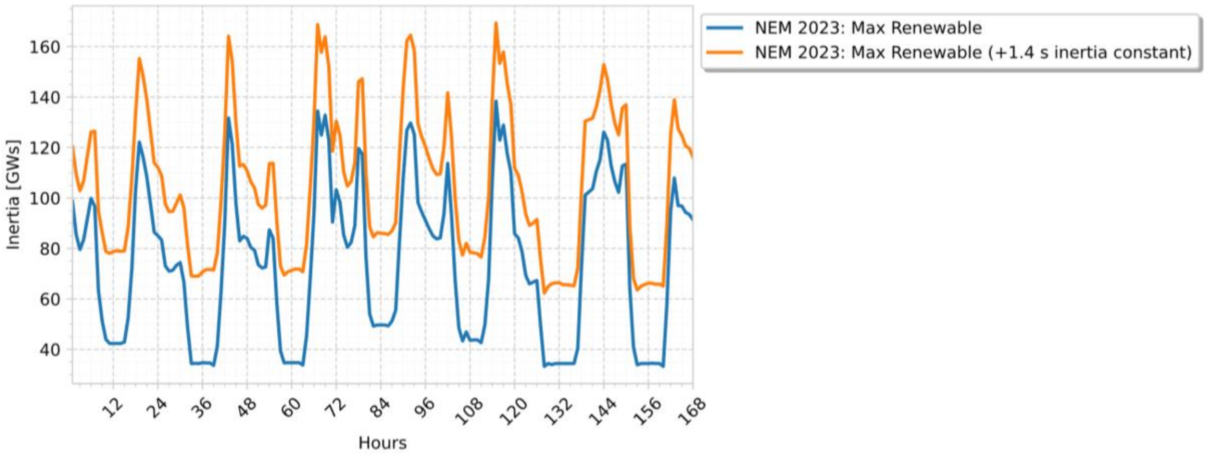

Figure 32 Online inertia in NEM 2023 case for Max renewable week

[7] The installed rooftop capacity shows the maximum power output

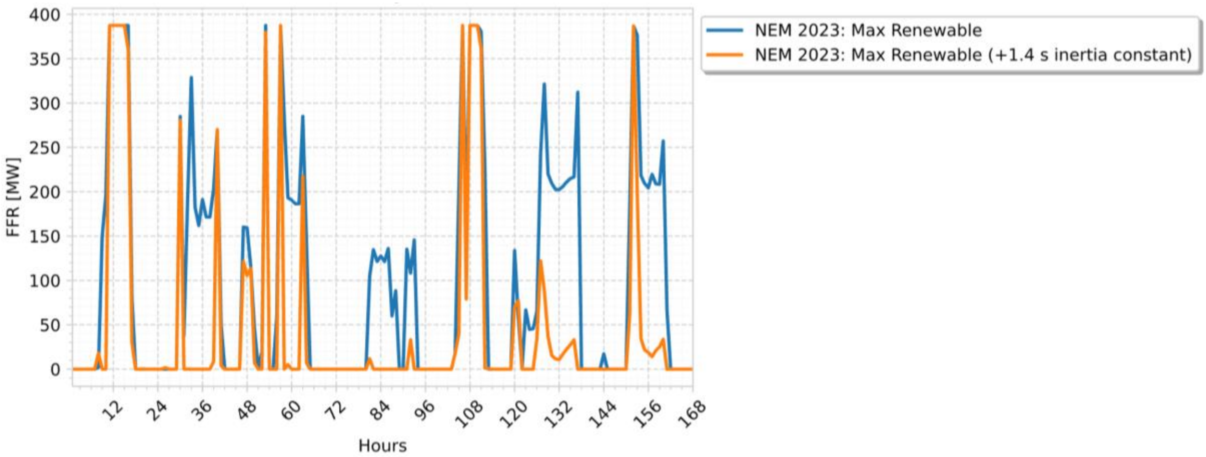

Figure 33 FFR requirements in the NEM 2023 case for Max renewable week

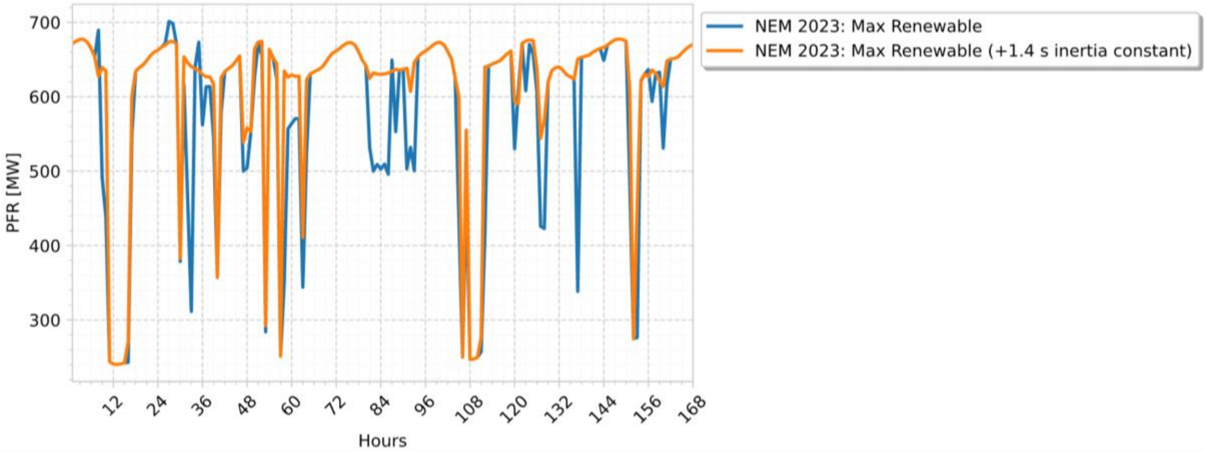

Figure 34 PFR requirements in the NEM 2023 case for Max renewable week

Figure 35 shows the potential cost savings in the NEM 2023 case for different levels of renewable penetration by adding demand-side inertia (with an inertia constant of 1.4 s). The figure analyses five weeks with varying levels of renewable penetration in the NEM, ranging from the minimum of 24% to the maximum of 44%, with increments of around 5%. As the figure illustrates, weekly operational savings increase as the penetration of renewable sources rises.

The figure also includes a dashed line representing a polynomial curve that approximates the original data points. This curve is used to estimate the annual savings achievable by including additional demand-side inertia. The analysis reveals that annual savings of including additional demand-side inertia may be estimated as $1.56 million. The primary factor behind these cost savings is the reduced need for FFR and PFR requirements, which translates into a cheaper dispatch/commitment of generators.

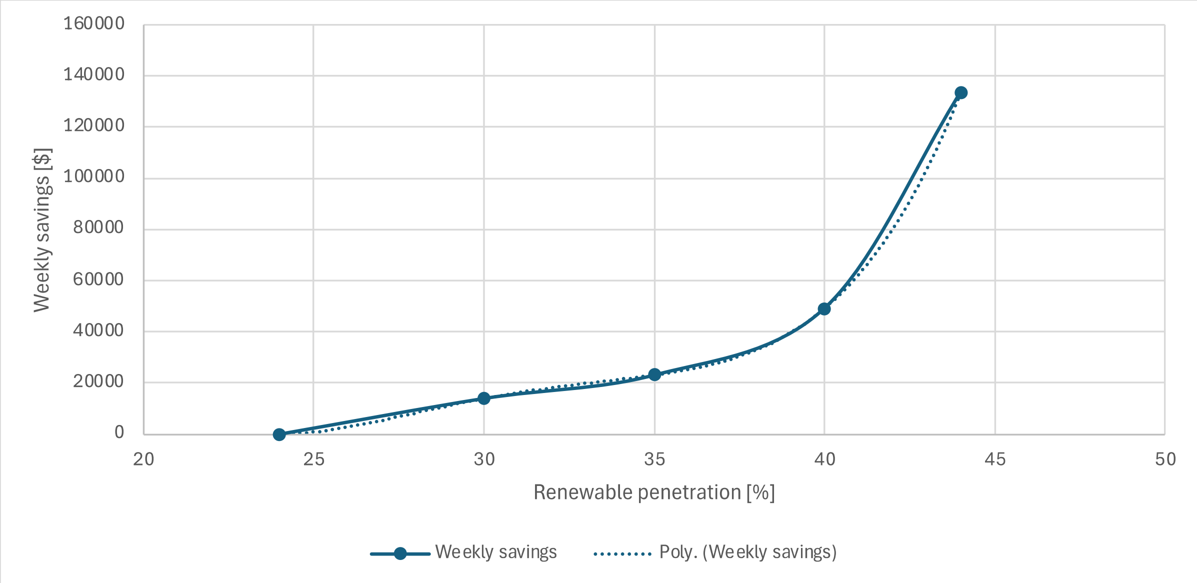

Figure 35 Savings in NEM 2023 for different levels of renewable penetration by including an inertia constant of 1.4 s in the demand side

5.2.2 Islanded Queensland

This case study is crucial to understand the potential value of demand-side inertia the region of QLD. In this case, the contingency size is co-optimized with the dispatch, and it is given by the maximum power output of the online generators.

5.2.2.1 Installed Capacity

Table 3 shows the installed capacity, the minimum power output of the generators [39] and their start-up and shutdown times in QLD. This case study considers the same assumptions about the conventional generators as in the NEM 2023 case mentioned in 5.2.1.1.

Table 3 Characteristic of power generators QLD

	Coal	Gas	Other thermal	Hydro	PS	BESS	VPP	Large-scale PV	Rooftop PV[8]	Wind
Installed capacity [GW]	8	3	0	0	0.6	0.25	0	4	4	1
Pmin [% of Pmax]	50	40	5	0	0	0	0	0	0	0
Start-up/shut down time [h]	8	4	0	0	0	0	0	0	0	0

5.2.2.2 Results

Figures 36, 37 and 38 show the online inertia, FFR requirements and PFR requirements, respectively, for the islanded operation of QLD during the week with the highest renewable penetration. The relation between the three requirements can be observed in the hour 120. The figure shows the same provision of FFR across all cases (see Figure 37). However, the PFR requirements differ between the

[8] The installed rooftop capacity shows the maximum power output

different cases, with the case without additional inertia exhibiting the highest PFR requirement (Figure 38). This highlights the role of inertia because additional inertia can potentially lead to operational cost savings by reducing PFR requirements.

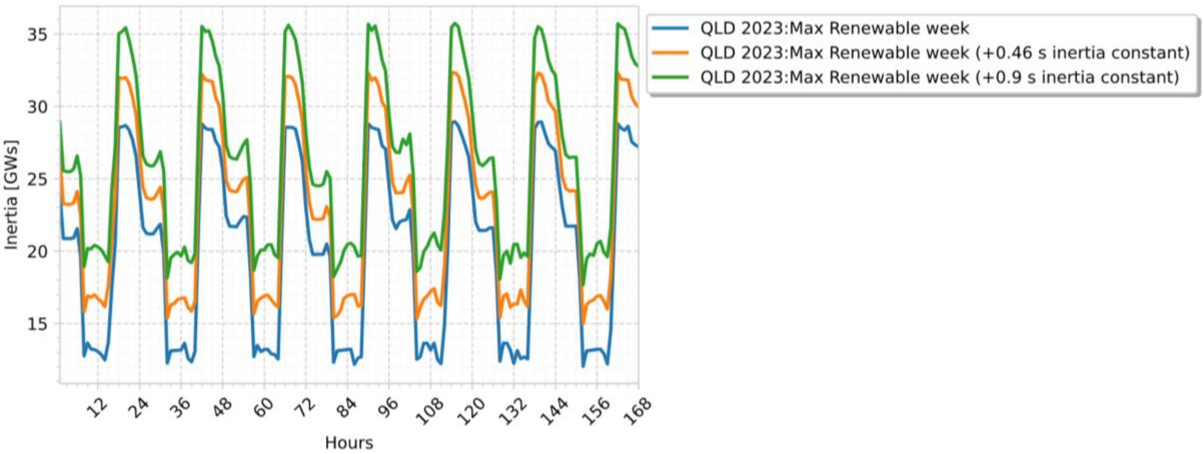

Figure 36 Online inertia for islanded QLD case for Max renewable week

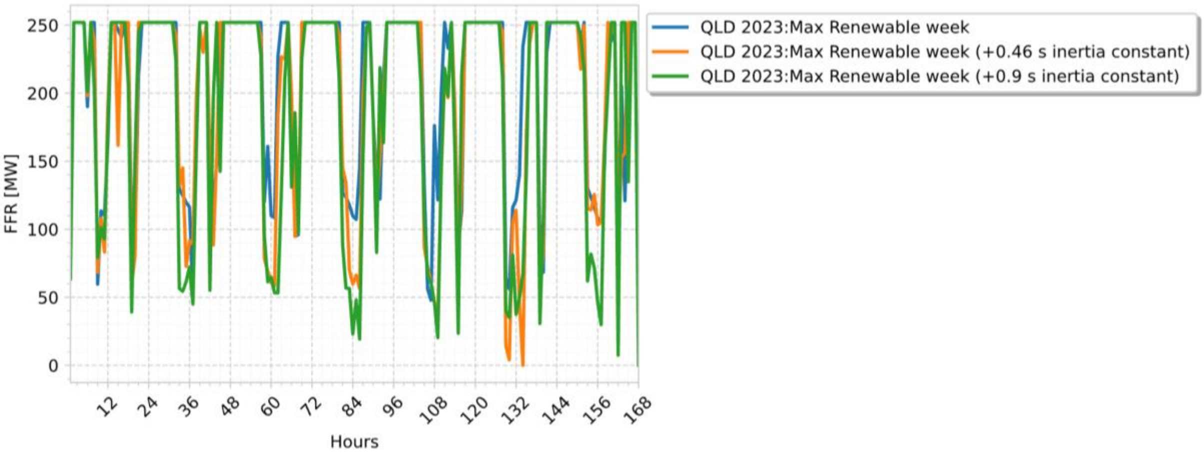

Figure 37 FFR requirements for islanded QLD case for Max renewable week

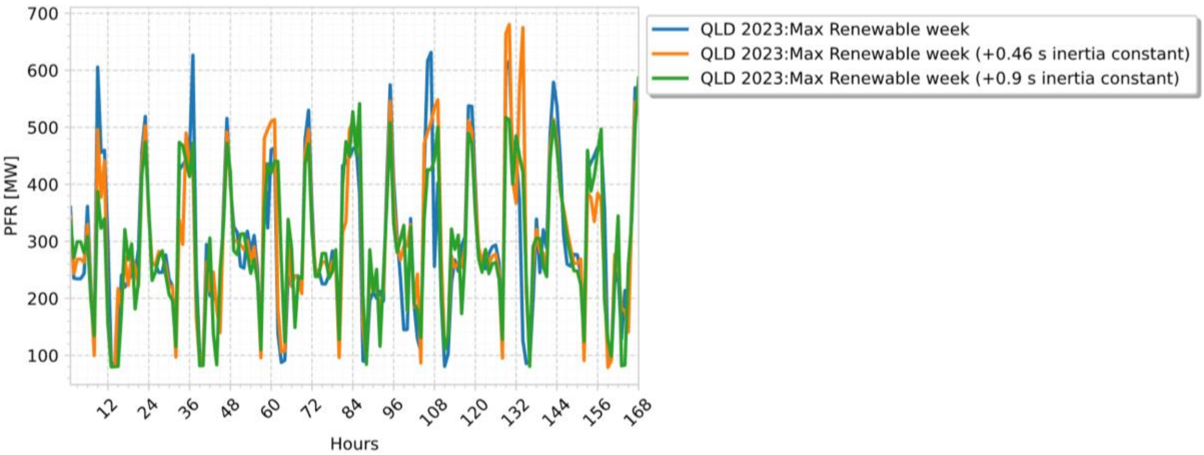

Figure 38 PFR requirements for islanded QLD case for Max renewable week

Table 4 presents the potential weekly savings of the islanded QLD case by including an inertia constant of 0.6 s and 0.9 s for the three selected weeks: minimum inertia, maximum number of low inertia events (called just 'low inertia') and Max renewable weeks. The maximum benefits are observed during the max renewable week, while the lowest savings occur during the low inertia week.

By comparing these savings with the savings coming from the NEM 2023 case in Figure 35, it can be seen how the operational savings are higher in the islanded conditions. The factors behind the higher cost savings are two. Firstly, including demand-side inertia decreases the PFR requirements (nadir constraints less restrictive) while allows for higher maximum power output from cheaper generators (RoCoF constraints less restrictive). The second source of savings is given by avoided renewable energy curtailment. The renewable curtailment is reduced by 1.02 GWh with a demand inertia constant of 0.46 s. This reduction increases to 2.18 GWh when the inertia constant is 0.9 s.

Although this analysis highlights potential cost savings during isolated QLD operation, these savings cannot be directly extrapolated to annual figures without performing risk analysis to consider the probability and duration of islanded operation.

Table 4 Savings in QLD isolated case

Case	Weekly savings (+0.46 s Inertia constant) ($)	Weekly savings (+0.9 s Inertia constant) ($)
QLD 2023 Min inertia	152,686	273,443
QLD 2023 Low inertia	91,778	155,610
QLD 2023 Max renewable	190,050	383,958

5.3 Other Savings

5.3.1 Islanded Queensland

Demand-side inertia offers additional benefits, which cannot be addressed by dispatch models. One of these benefits is helping to meet inertia security requirements in the short and medium term. The region of QLD has a projected inertia shortfall of 1.6 GWs by 2027, requiring a short-term solution from TNSPs.

To address this inertia shortfall, it might be necessary to invest in synchronous condensers. The procurement and installation of these devices could take 2.5 years [43]; therefore, to meet the 2027 inertia requirements, investment decisions must be made in advance.

There are two potential investment solutions to address the shortfall, which are summarized in Table 5. The first option is to build two synchronous condensers of 80 MVA each with a 10 s inertia constant (investment cost for synchronous condenser are available in [44]). Besides, an additional $2.9 million (investment cost per $/MWs is available in [45]) would be needed for flywheels to fully address the shortfall. Thus, the total cost of this option is $144.9 million.

The second option consists of a single, larger synchronous condenser of 125 MVA (costing $96 million) paired with a flywheel with a 13 s inertia constant, costing $2.95 million. Thus, the total cost of this option is $98.95 million[9].

An alternative approach could involve implementing inertia measurement in QLD. To analyse the potential of the residual inertia to address the shortfall, we observe the minimum residual inertia measured in QLD. The minimum observed combined inertia in NSW and QLD was 6,863 MWs at a demand of 14,938 MW. Under such conditions, the minimum inertia constant would be 0.46 seconds. In 2023, the minimum demand in QLD was 4,880 MW. Using these values, the minimum contribution of demand-side inertia is estimated at 2,242 MWs. This suggests that demand-side inertia has the potential to address inertia shortfalls of 1,600 MWs even considering its minimum contribution.

Therefore, demand-side inertia in QLD might have the potential to at least delay investments in synchronous condensers, leading to potential cost savings of $98.95 million. However, more inertia measurements throughout the year are necessary to confirm this potential and ensure there are no situations where demand-side inertia cannot meet the shortfall.

Table 5 Projects to supply inertia shortfall in QLD isolated

Case	Project 1	Project 2
Synchronous condensers size [MVA]	80	125
Number of synchronous condensers	2	1
Synchronous condenser cost [$ million]	142	96
Flywheel inertia constant [s]	10	13
Flywheel cost [$ million]	2.9	2.95
Total inertia [MWs]	1,600	1,625
Total cost [$ million]	144.9	98.95

5.3.2 South Australia

AEMO's report [15] identifies a temporary inertia shortfall of 500 MWs in SA, which would need 50 MW of FFR to be met. This temporary inertia shortfall is expected from July 2024, until early 2025. This six-month gap coincides with the commissioning of a critical transmission line and related infrastructure.

Given the temporary inertia shortfall and the fact that islanding operation of SA is unlikely according to [15], the analysis for SA focuses on potential cost savings achievable by reducing inertia payments associated to the extra FFR services required to supply the period of the inertia shortfall.

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[9] It should be noted that synchronous condensers are installed in networks to provide system strength to weak areas, and that with the inclusion of flywheels can also provide inertia. Whilst higher inertia measurement (indicating greater inertia than expected) could result in savings by reducing the number of synchronous condensers, it may not displace a synchronous condenser all together. Potentially there is the possibility to save or delay the implementation of synchronous condensers, and/or flywheels, but this will be based upon conditions in the network and the use of synchronous condensers for system strength

The average cost of the 1-second FFR service between October 2023 and March 2024 was $24/MW/h. Assuming the inertia shortfall needs to be procured every hour, the total cost of contracting 50 MW of FFR from July 2024 to January 2025 would be approximately $5.3 million.

To estimate the minimum contribution of demand-side inertia, we calculated it using the minimum demand of 1010 MW and a minimum inertia constant of 0.14 s. Using these values, we estimate that the demand-side inertia could provide an additional 141 MWs of inertia, reducing the inertia shortfall to 359 MWs. By incorporating this estimate and using the inertia-FFR curves for SA [15], we determined a potential reduction of approximately 20 MW in contracted FFR capacity. This reduction might lead to potential cost savings of approximately $2 million based on the current FFR market prices.

6 Future use case: Discussions of future use cases for inertia management

This section explores the potential cost savings driven by demand-side inertia in a future NEM scenario. The NEM is represented by a simplified single-area model, incorporating existing FCAS requirements along with RoCoF and nadir limits. The limits used in this study are 1 Hz/s for RoCoF and 49.2 Hz for nadir, which are the same values used for the 2023 case.

The future scenario analysed in this section is based on AEMO's 2037 projections for the "Step Change" scenario [46]. The Step scenario is defined in the Integrated System Plan (ISP) 2024 [47] and it is the most likely to occur, being assigned a 43% probability by the Delphi panel [48]. This is a scenario with a high decarbonization and penetration of renewable technologies. In fact, the Step change scenario anticipates the complete retirement of coal generators by 2037 [46].

Coal generators contribute significantly to the system inertia due to their constant operation. Hence, it is important to understand the absence of coal generation in the overall system inertia, helping to understand the long-term value of demand-side inertia.

The retirement of coal-fired generators makes selecting the right contingency for assessment more challenging. To address this challenge, we will analyse the loss of a renewable energy zone (REZ). Figure 39 shows the REZ considered by AEMO in the ISP. V7 is an offshore wind farm connected to Victoria. This zone has a projected installed capacity of 4,913 MW in 2037 with a capacity factor of 0.46. While specific projects are not yet finalised, the Victorian government and AEMO are currently studying the zone's development [49].

We assume the construction of four separate wind farms within REZ V7. Our contingency size will be based on the fault of a single wind farm generating at maximum capacity, resulting in a loss of 1,230 MW[10]. This scenario reflects real-world events, such as the August 9th incident, that occurred in the UK in 2020 where an entire offshore wind farm was lost [50].

Additionally, to assess the long-term value of demand-side inertia, it is important to analyse potential reductions in both the load-damping factor and demand-side inertia itself[11]. Two sensitivity analyses are conducted to assess these potential impacts.

The first sensitivity analysis investigates the impact of the reduced damping factor. To base this analysis on realistic numbers, we considered historical reductions. In 2019, the damping factor in the NEM observed a drop from 1.5% to 0.5%, representing a 66% decrease [51]. Due to the uncertainty in predicting future load-damping reductions, a hypothetical decrease of 80% (from 0.5% to 0.1%) was chosen to try representing a potential worst-case scenario. This selection builds upon the historical trend, extending the previously observed 66% reduction to a more extreme 80% decrease.

[10] Losing approximately 1,230 MW is similar to assuming the loss of half of the installed capacity in REZ V7 operating at its capacity factor (2,260 MW / 2 = 1,130 MW). This alternative approach yields a contingency size of 1,130 MW, which closely aligns with the chosen value.

[11] A higher penetration of inverter-based technologies might reduce load damping and residual inertia.

A second sensitivity analysis explores the reduction in both damping factor and demand-side inertia. Here, the inertia constant is reduced from its current value of 1.4 s to 0.28 s, following the same logic applied to the damping factor (a reduction of 80%).

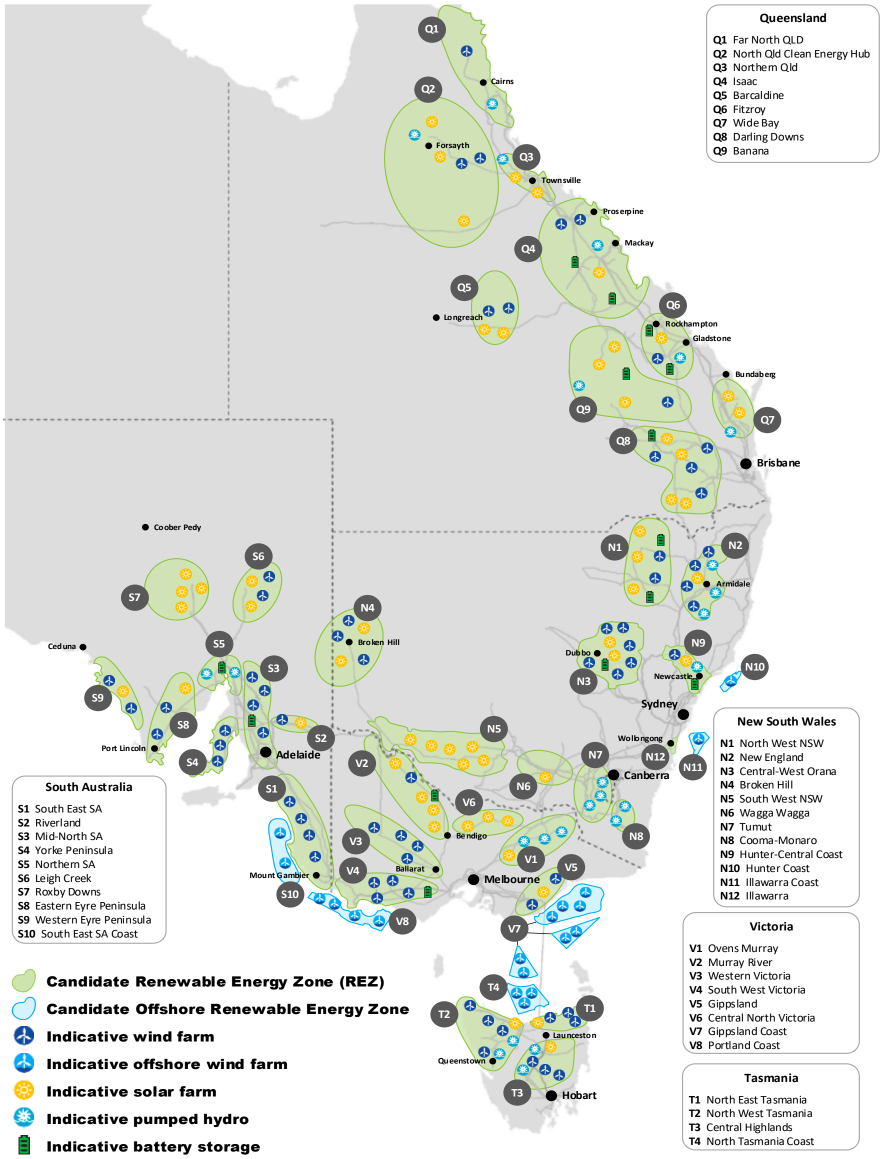

Figure 39 Renewable energy zones [41]

6.1 Installed Capacity

Table 6 shows the installed capacity [46], the minimum power output of the generators, and their start-up and shutdown times. This scenario assumes improved generator flexibility, resulting in a decreased minimum power output and faster start-up and shutdown times. However, the cost of proving reserves for the different markets is obtained as the average price from historical data from [29]. The value of lost load is projected to increase to 20,000 $/MWh, based on the market price cap trend of increasing every couple of years [42]. Additionally, the demand growth rate for 2037 is projected to be 42% [52].

In this scenario, conventional generators are assumed to provide up to 10% of their capacity for the 6-second and 60-second markets, while the 5-minutes market is limited by the ramp-up capabilities of the generators detailed in [41]. Additionally, PS can provide PFR, and BESS can participate in all the FCAS markets, including the 1-second, 6-second, 60-second and 5-minutes markets.

Table 6 Characteristic of power generators NEM 2037

	Coal	Gas	Other thermal	Hydro	PS	BESS	VPP	Large-scale PV	Rooftop PV[12]	Wind
Installed capacity [GW]	0	13	1	5	0.8	19	14	30	28	53
Pmin [% of Pmax]	-	15	5	0	0	0	0	0	0	0
Start-up/shut down time [h]	-	2	0	0	0	0	0	0	0	0

6.2 Results

6.2.1 Damping 0.5 %

Figures 40, 41, and 42 show the online inertia along with the number of online units, FFR requirements, and PFR requirements, respectively, for the case NEM 2037 with a damping of 0.5% and an extra demand-side inertia in the week with the highest renewable penetration. The higher contingency size of this case with respect to the other case studies, makes the requirement of all these services higher. Besides, the relation between inertia, PFR, and FFR can be seen between hours 36 and 48. In this time window, the system without additional inertia from the demand side needs to turn on additional generators to obtain more inertia and at the same time to provide more reserves.

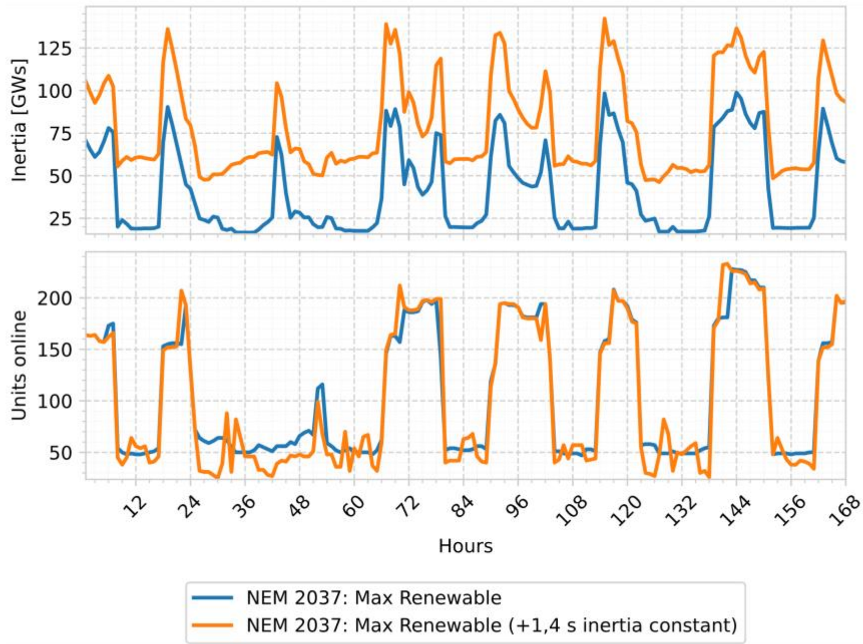

Figure 40 Online inertia and units in NEM 2037 case for Max renewable week

[12] The installed rooftop capacity shows the maximum power output

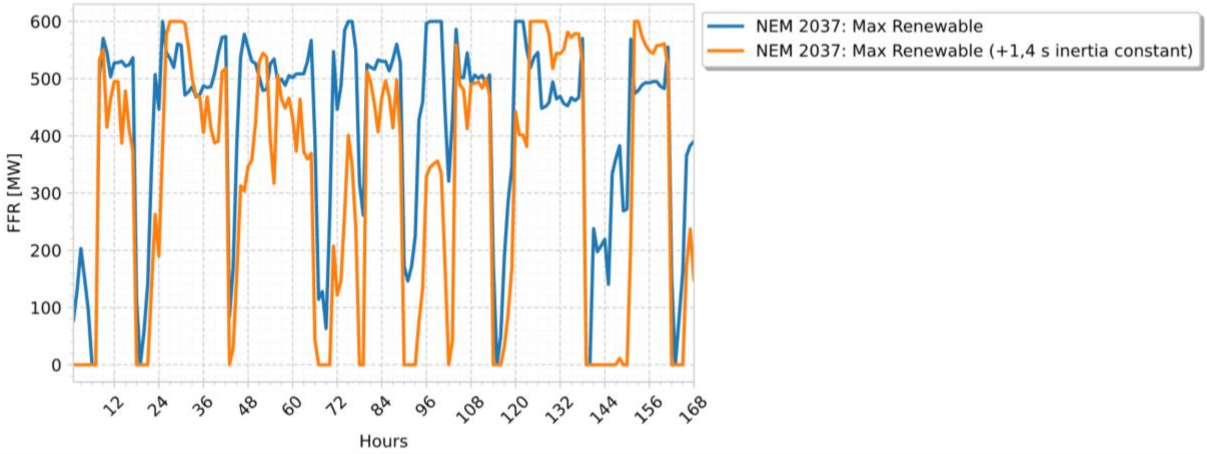

Figure 41 FFR requirements in NEM 2037 case for Max renewable week

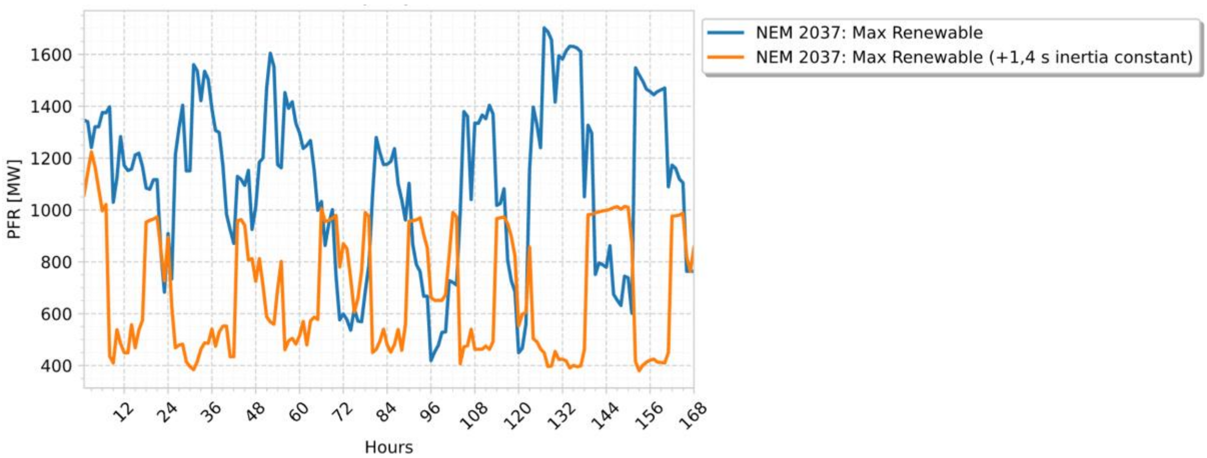

Figure 42 PFR requirements in NEM 2037 case for Max renewable week

Figure 43 shows the potential operational cost savings achievable in the NEM 2037 for different levels of renewable penetration by adding demand-side inertia (with an inertia constant of 1.4 s). This figure analyses four weeks with varying levels of renewable penetration in the NEM, ranging from a minimum of 33% to a maximum of 61%. As the figure illustrates, weekly savings increase linearly as the penetration of renewable sources rises.

Moreover, the annual operational savings are around $60 million. Compared to the yearly savings in the NEM 2023, the expected yearly savings in this future scenario (NEM 2037) are significantly higher. This increase in savings is explained by the contingency size and inertia levels. Figure 5 shows how larger contingencies increase the PFR and inertia requirements substantially (due to nadir constraint). Moreover, a larger contingency size requires either a higher online inertia or a greater allocation of FFR (due to RoCoF constraint).

As a result, inertia becomes more valuable to reduce these requirements. Therefore, in a future system characterised by high renewable penetration and low inertia, the need for FFR and PFR services rises significantly due to stricter requirements. Demand-side inertia helps to reduce both FFR and PFR services, leading to cost savings.

Furthermore, demand-side inertia could significantly reduce renewable energy curtailment in a future scenario. In this case, with a demand inertia constant of 1.4 s during the week with the highest renewable penetration, curtailment could be reduced by up to 31 GWh.

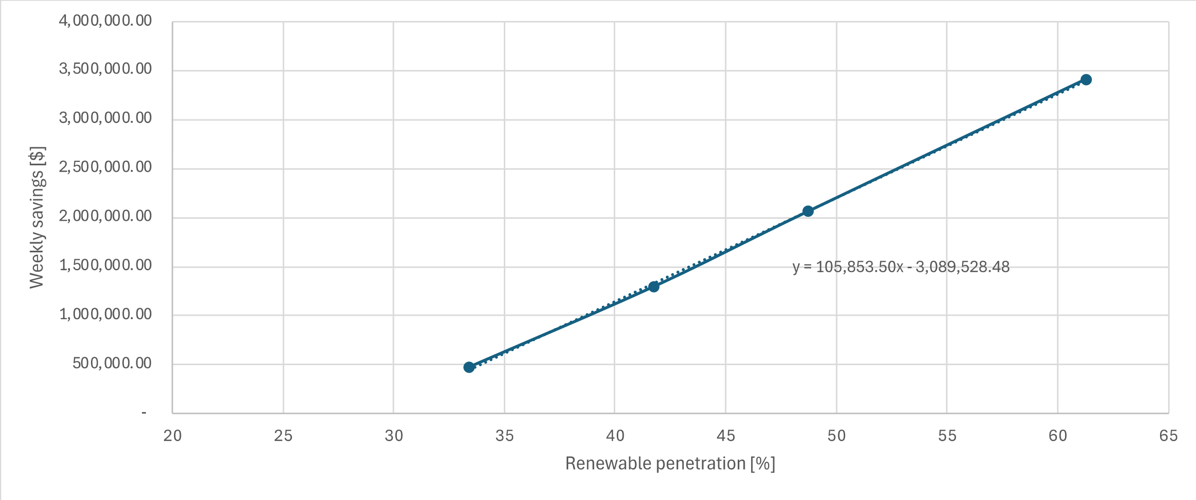

Figure 43 Savings in NEM 2023 for different levels of renewable penetration by including an inertia constant of 1.4 s in the demand side

6.2.2 Damping 0.1 %

Figures 44, 45, and 46 display the key metrics for the NEM 2037 scenario including different damping factors during the week with the highest renewable penetration. Figure 44 presents the online inertia along with the number of online units. Figures 45 and 46 show FFR requirements and PFR requirements, respectively.

These figures show the relation between inertia, FFR, and PFR requirements with a reduced damping factor. A lower damping factor leads to dispatching more generators due to the higher PFR requirements. This can be seen in the solar hours, when the PFR requirements are higher for the case with a reduced damping while the levels of inertia and FFR are similar in both cases.

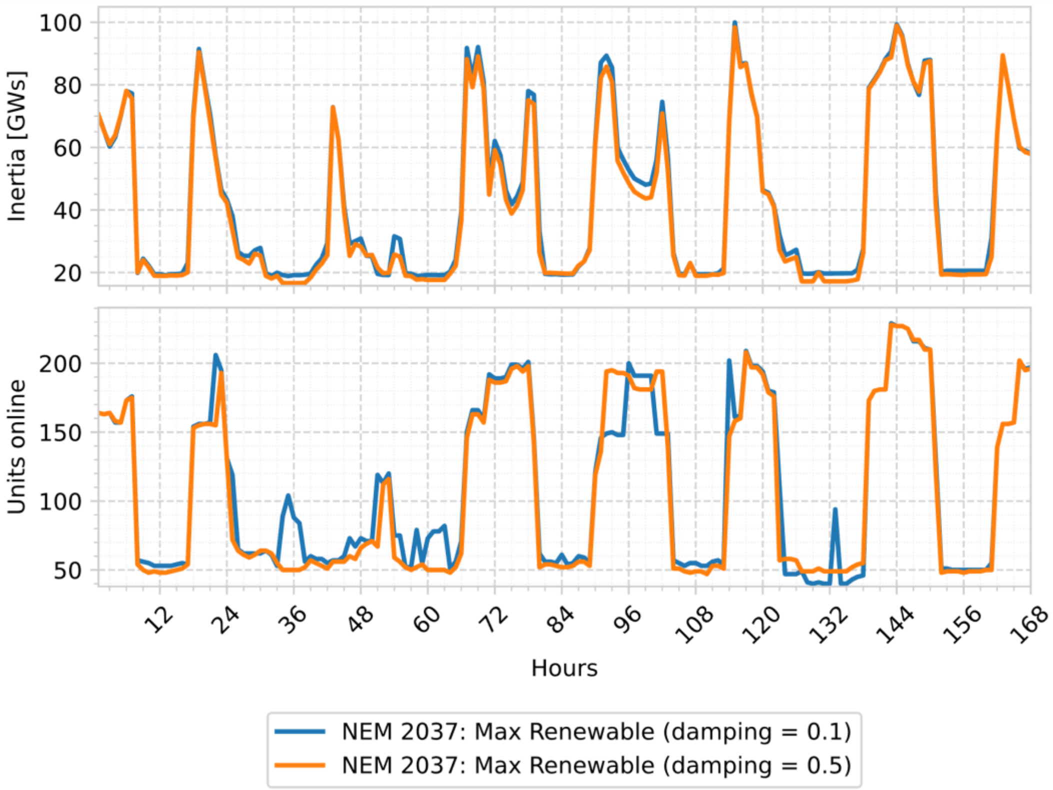

Figure 44 Online inertia and units in NEM 2037 with different damping factors in the Max renewable week

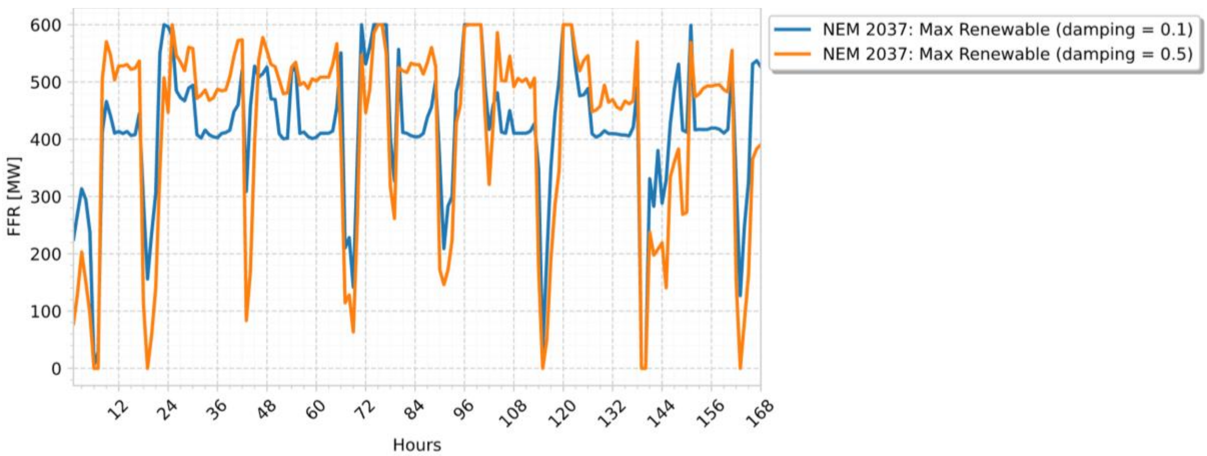

Figure 45 FFR requirements in NEM 2037 with different damping factors in the Max renewable week

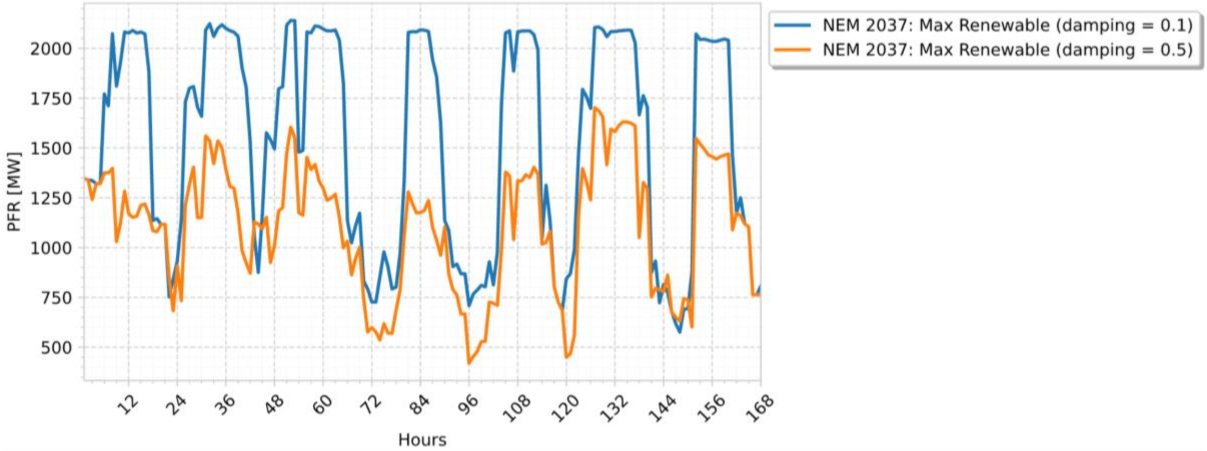

Figure 46 FFR requirements in NEM 2037 with different damping factors in the Max renewable week

Figures 47, 48, and 49 display the key metrics for the NEM 2037 scenario including sensitivities with a reduced damping factor and inertia constant during the week with the highest renewable penetration. Figures 47 presents the online inertia along with the number of online units. Figures, 48 and 49 shows FFR requirements and PFR requirements, respectively.

These figures show the relation between inertia, FFR, and PFR requirements, and the reduced damping factor and inertia constant. A lower damping factor calls for dispatching more generators to meet the increased PFR/FFR needs during solar hours. Similarly, a reduced inertia constant for demand also increases PFR/FFR requirements, resulting in more generators online in that sensitivity.

Reducing the damping factor in the 2037 scenario with a 1.4 s inertia constant and a damping factor of 0.1% yields annual savings of $87 million. These savings decrease to $26 million when the inertia constant is reduced to 0.28s but are still very substantial.

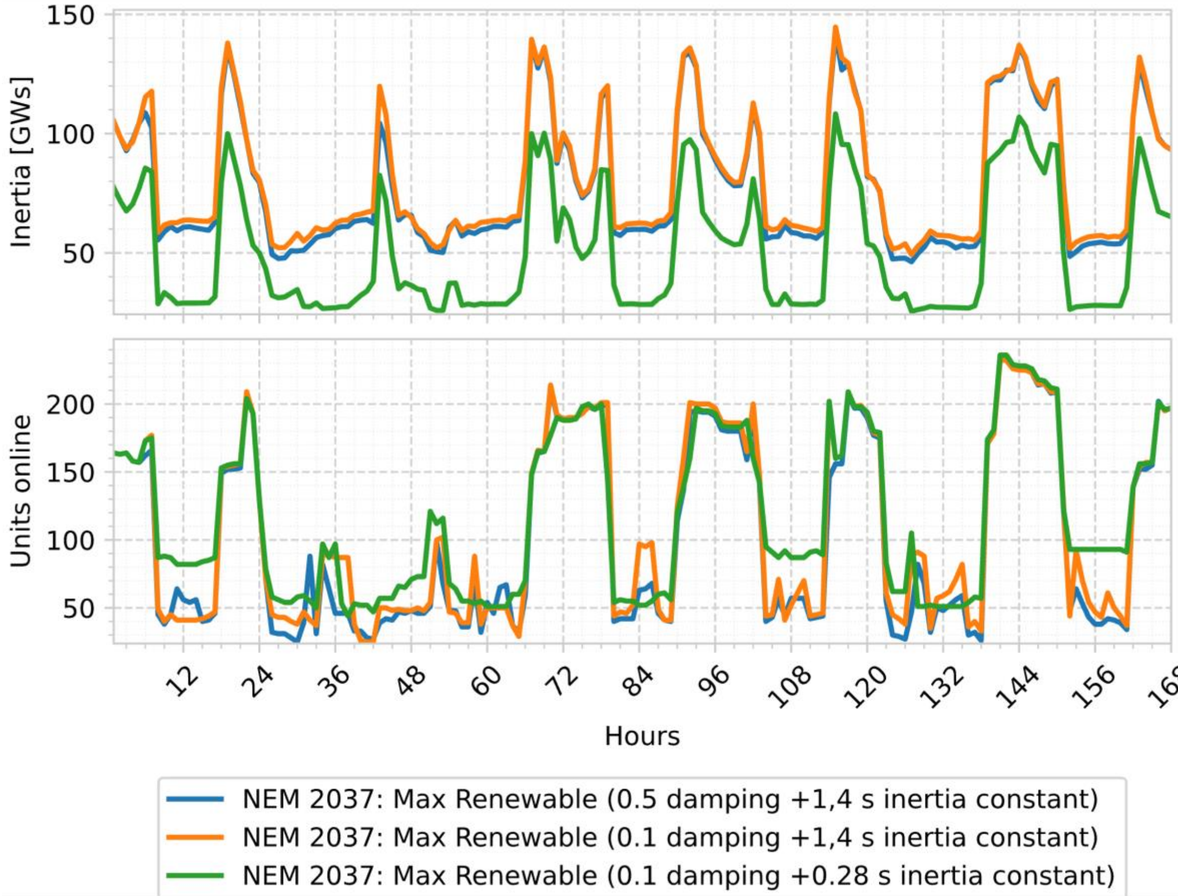

Figure 47 Online inertia and units in NEM 2037 with different damping factors and inertia constants in the Max renewable week

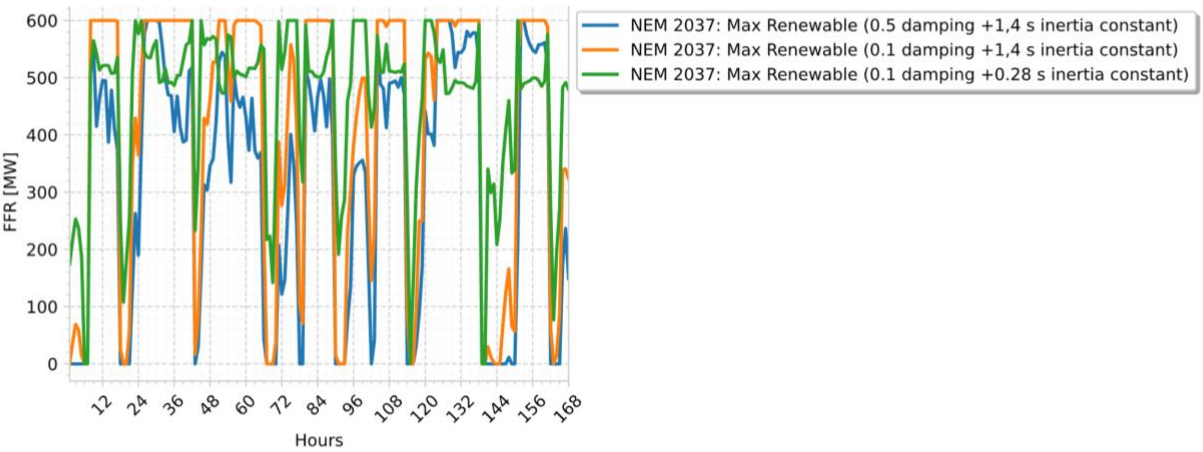

Figure 48 FFR requirements in NEM 2037 with different damping factors and inertia constants in the Max renewable week

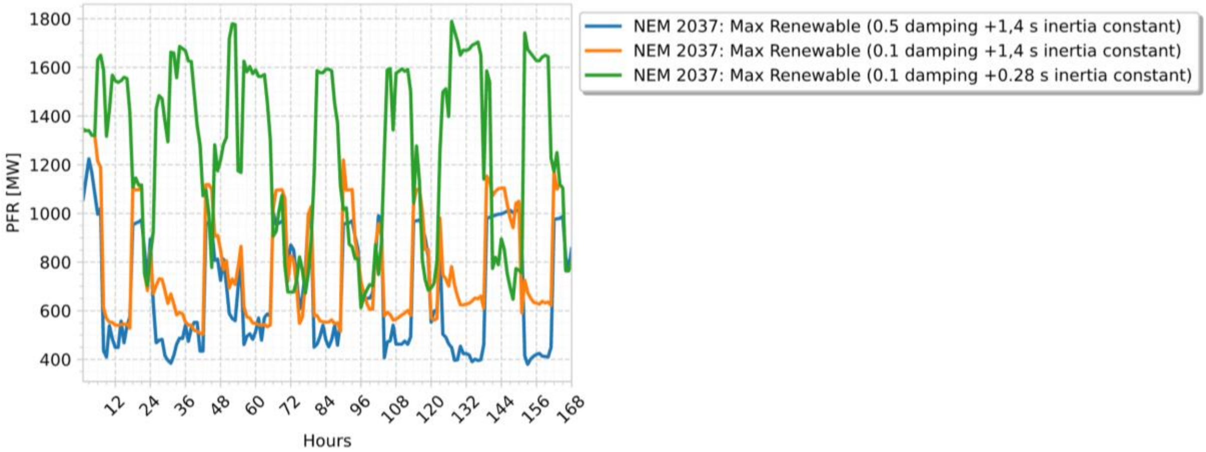

Figure 49 FFR requirements in NEM 2037 with different damping factors and inertia constants in the Max renewable week

7 Summary of potential savings[13]

Table 7 summarizes the potential cost savings achievable through demand-side inertia. As the table shows, planning savings in QLD offer the higher benefits in the short and medium term. These savings stem from the avoided investment in QLD, where the estimated contribution of demand-side inertia could potentially fully address the region's declared inertia shortfall. Beyond potential economic benefits, the rapid deployment of an inertia measurement scheme is a critical advantage. In contrast, the procurement and installation of a new synchronous condenser might take some 2.5 years or more [43].

Furthermore, with declining system inertia, the operational savings projected for 2037 become increasingly important, highlighting the growing value of residual inertia in the future.

Table 7 System savings

	Case	Damping factor [%]	Residual inertia constant [s]	Operational annual cost savings [$ million]	Total “Planning” cost savings [$ million]
Current system	NEM 2023	0.5	1.4	1.56	-
	QLD	0.5	0.46	0.09 - 0.19[14]	100 – 145
	SA	-	0.14	-	2
Future system	NEM 2037	0.5	1.4	60	-
	NEM 2037: Reduced damping	0.1	1.4	87	-
	NEM 2037: Reduced damping + Reduce demand-side inertia	0.1	0.28	26	-

In addition to the savings above, we have not costed the benefits in the following areas:

- Reduced carbon emissions, which AEMO price at $70/tonne [53]
- Reduced costs of retaining coal plant for regional system security as a result of reduced inertia requirements.

[13] The University of Melbourne team do not have access to the cost details of the scheme to measure inertia; therefore, the cost-benefit analysis does not include these costs. However, Reactive has reported that several variables impact the implementation cost such as network size, the technology used for the modulator (e.g., BESS, capacitors, others), and the size and location of this element.

[14] Potential savings per week in case of islanded operation.

8 Regulatory Consideration and Pathway to Commercialisation

Integrating inertia measurements into the NEM has the potential to help optimising FCAS markets, decrease unnecessary costs associated with side-payments, and optimise investment decisions. However, to unlock these benefits, a review of the existing regulatory framework and its requirements is crucial.

The current NEM regulation requires the TNSPs to procure sufficient inertia within their sub-networks to prevent any potential inertia shortfall [15]. In the short term, this can be addressed by contracting with existing third-party inertia providers or acquiring an equivalent amount of FFR service. In the long term, this regulation might incentivise new investments in network assets to meet inertia requirements [54].

In this context, the demand-side inertia (potentially obtained through inertia measurements) would help procure the optimal amount of inertia or FFR to prevent excessive contracting of these resources, potentially leading to cost reduction. Besides, a better understanding of the regional demand-side inertia would defer or drive investments (transmission, synchronous condenser or other) according to the actual inertia requirements.

Another key consideration lies in the existing FCAS markets within the NEM. Currently, most markets only focus on QSS requirements, delivered in different timeframes (6-second, 60-second, and 5-minute services). The exception is the 1-second market, which depends on system inertia to limit the RoCoF (refer to Appendix 11.1 for details on NEM FCAS service calculations).

However, as Chapter 3.1.3 highlights, with declining inertia, the nadir requirement becomes the binding constraint for system operation. This constraint adjusts the PFR requirement based on inertia levels, FFR availability, and contingency size. Therefore, current RoCoF-based requirements might be insufficient to guarantee system security. Thus, the system could be exposed to under-frequency load shedding in low inertia conditions if nadir constraints are not included in the operation.

This report does not study the impact of the potential creation of an inertia market [16]. However, it is important to highlight that the implementation of inertia measurement would play an important role in this market. Recent research highlights the importance of co-optimising regional inertia and FCAS allocation, managing contingency size, and considering interconnector flows [10]. Additionally, recent works suggest potential transient instability risks due to unbalanced regional inertia and FFR location (see [55] and [56]).

Therefore, designing a future inertia market for a multi-area system requires careful consideration of several factors beyond just balancing FCAS and inertia. These factors include incorporating additional risk assessments to mitigate transient instability risks, and strategically placing both FCAS and inertia resources to optimise system security. In this context, having a more accurate measure of inertia would provide valuable insights for ensuring secure system operation.

9 Conclusions and Recommendations

Key findings on data analysis of inertia and system conditions

The data analysis explored the relation between inertia and system conditions. As expected, a strong positive correlation exists between high demand and high inertia. This is because more online generators contribute to greater inertia during periods of high energy consumption. However, the existence of residual inertia (the difference between measured and theoretical inertia) is noticeable in the comparison of theoretical and measured inertia. The residual inertia could be attributed to several factors, including inaccuracies in generator data (inertia constant and MVA capacity), which are generally expected to be relatively small, as well as, more importantly, the presence of significant demand-side inertia due to the presence of synchronously connected generators and motors embedded in the distribution network and generally the demand side. For simplicity, in the studies performed here all the residual inertia is attributed to the demand-side inertia.

Furthermore, the analysis revealed an inverse relation between high renewable penetration and system inertia. This suggests a potential increase in low-inertia events as inverter-based resources become more prominent in the future.

Key findings on validating inertia measurement with real-world events

The inertia measured were validated through an event-based approach. In this context, it was analysed from the disconnection of a generator in Queensland at 7:36 AM on September 26th. The analysis employed instantaneous RoCoF calculations using frequency data from Reactive's GridMetrix® platform and contingency size information published by AEMO. The results from this event gave confidence in the effectiveness of using Reactive's technology to measure real-time inertia.

Furthermore, the event highlighted a significant discrepancy between theoretical and actual system inertia. AEMO's pre-calculated inertia for this moment was 77 GWs, a 22 GWs difference from the actual inertia observed during the event (approximately 99 GWs). In contrast, Reactive's technology yielded measured inertia of 92 GWs, deviating from the actual event inertia by only 7 GWs.

These results highlight the limitations of relying on theoretical calculations for inertia estimation. By incorporating real-time measurements, the accuracy of the inertia estimation can be significantly improved, allowing for better decision-making in real-time situations.

Key findings on the value of inertia

This study investigated the integration of demand-side inertia into power system dispatch. We implemented a state-of-the-art model encompassing the existing FCAS markets along with the RoCoF and nadir requirements. We applied the model to assess a single-area NEM and an isolated QLD system. Additionally, we analysed a future scenario (2037) simulating the NEM's first year without coal generation. This analysis included sensitivity analyses to assess potential reductions in system damping and demand-side inertia contribution.

Furthermore, we also analysed the economic benefits of demand-side inertia beyond traditional dispatch models. The performed analysis assessed the value of avoiding additional inertia stand-by payments and deferring/reducing infrastructure investments.

The results underscore the importance of considering low inertia conditions when designing FCAS requirements. We found that demand-side inertia may hold significant value in the current system, especially under the isolated operation of some regions. Besides, in a high renewable scenario with reduced online inertia, demand-side inertia might play an even more crucial role, potentially lowering overall system costs and FCAS requirements. The sensitivity analyses indicate that the potential value of demand-side inertia persists in the future, even with a reduced contribution from these resources.

Furthermore, incorporating demand-side inertia might defer or reduce the need for critical infrastructure investments, such as synchronous condensers, which currently require a deployment time of at least 2.5 years. Thus, this rapid deployment capability of inertia measurement technology significantly enhances its overall value.

Additionally, demand-side inertia can directly lead to cost savings through lower inertia payments, which are currently used to compensate for inertia shortfalls by contracting additional generators or FFR services. These translate to cost savings across both short-term and long-term operations in scenarios and regions where an inertia shortfall has been identified.

Future Considerations: Inertia Markets

The current regulation requires the TNSPs to procure inertia or FFR under inertia shortfall periods. In this context, the demand-side inertia (potentially obtained by the inertia measurement) would help to procure the optimal amount of inertia or FFR. Moreover, a better understanding of the actual system inertia would defer or drive investments according to the actual system requirements.

In the future, it is expected an inertia ancillary services market, which could address potential inertia shortfalls while improving efficiency in procuring inertia. However, current RoCoF-based requirements might be insufficient if nadir constraints are not considered, leading to the potential activation of under-frequency load shedding. Therefore, to capture the value of inertia and in particular demand-side inertia, it is important to consider nadir requirements, at least at a national level.

While this study focused on a single-area model, the specific design of an inertia market requires further evaluation. Previous research highlights the importance of co-optimising regional inertia and FCAS allocation, managing contingency size, and considering interconnector flows. Additionally, recent works suggest potential transient instability risks due to unbalanced regional inertia and FFR location. Therefore, the development of a future inertia market needs to consider not only a careful balance between FCAS and inertia but also the location of these services in a multi-area system.

As such, our results show a potential benefit in the adoption of inertia measurement as follows:

- Adoption of inertia measurement across the NEM would support more efficient operation today with significant growth in value as renewable energy penetration increases;
- Inertia measurement data would offer improvements to planning and modelling to support future system investment;
- Measurements of inertia would support effective developments of inertia markets and regional inertia allocation to avoid potential imbalances and instability which could lead to system-wides disturbances.

10 References

[1] Renewable Energy Institute, Agora Energiewende, “Integrating renewables into the Japanese power grid by 2030,” 2018.

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11 Appendix

11.1 FCAS Markets in Australia

There are currently 10 markets to provide FCAS services in Australia. The name of these markets from the fastest operation to the slowest are as follow:

- 1-second market (Raise and Lower)
- 6-second market (Raise and Lower)
- 60-second market (Raise and Lower)
- 5-minute market (Raise and Lower)
- Regulation market (Raise and Lower)

The requirement for the fastest service, the 1-second market (also known as FFR) is determined using equation (10). In this equation, the load relief is calculated considering a frequency deviation of 0.5 Hz, and H_{aws} is the inertia awareness factor, which is a number between 0 and 1 as described in [31] and [57]. This factor is calculated as the minimum of 3 linear equations incorporating the peak RoCoF risk, defined in defined in equation (11), where H_{sys} is the total inertia in the mainland NEM. By incorporating the peak RoCoF risk, the inertia directly impacts the FFR requirement by increasing the requirement of this service when the inertia decreases.

$$\left(|\Delta P_{loss}| - Lr_{\Delta f=0.5Hz}\right) \cdot H_{aws} \tag{10}$$

$$Peak_{ROCOF\_risk} = 25 \cdot \frac{|\Delta P_{loss}|}{H_{sys}} \tag{11}$$

For the 6-second and 60-seconds markets, the requirements are calculated using a simpler equation defined in (12). This equation only considers the contingency size and a load relief calculated with a frequency deviation of 0.5 Hz.

$$|\Delta P_{loss}| - Lr_{\Delta f=0.5Hz} \tag{12}$$

The calculation for the 5-minute service is given by (13). In this equation the frequency deviation consider is 0.15 Hz to reach the deadband of frequency deviation. This service is co-optimized with the regulation FCAS, which must be at least 220 MW [57] for the whole NEM and 170 MW for the mainland NEM. The requirement for this service increases as the cumulative frequency deviation grows.

$$|\Delta P_{loss}| - Lr_{\Delta f=0.15\,Hz} \tag{13}$$

11.2 5-minutes Rooftop PV

The rooftop PV profiles are available with a 30-minute resolution. We applied a linear approximation to obtain the 5-minutes resolution. Figure 50 shows the measured distributed PV and the approximation to obtain the 5-minutes resolution. The result of implementing this methodology is plot in the Figure 51. This figure shows the results for the different regions for the 16 and 17 of June of 2023.

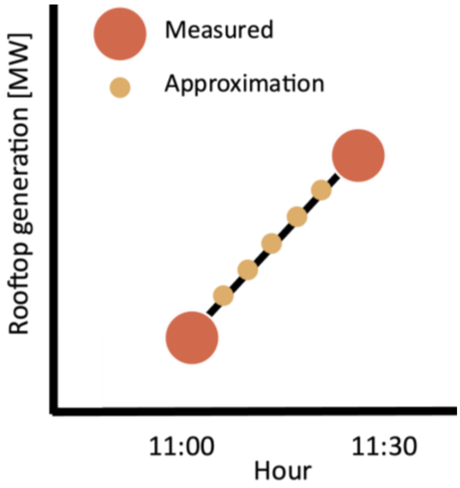

Figure 50 Example of linear approximation to obtain 5-minutes resolution for rooftop PV

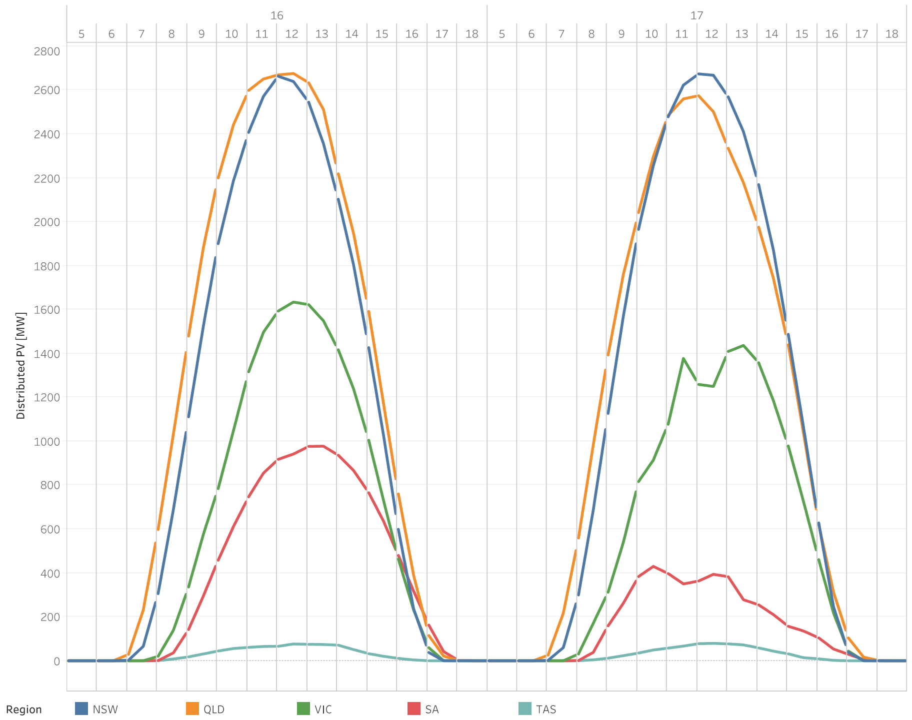

Figure 51 5-minutes resolution for rooftop PV per region

11.3 Availability of Coal Generators

A coal generator is considered unavailable if it experiences an outage lasting 5 or more days in a week. The weekly average unavailable capacity for coal generators per year are shown in Figure 52. Figure 53 shows more details about the weekly unavailability for the year 2023.

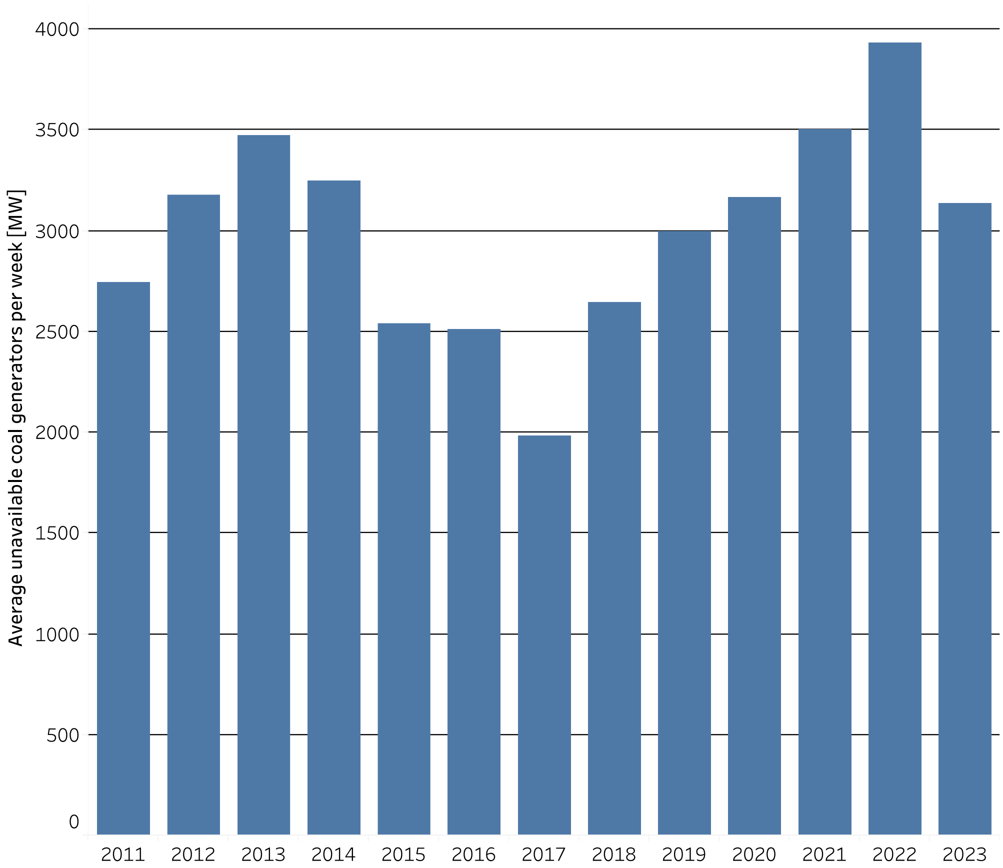

Figure 52 Weekly average of coal generators unavailable per year in the NEM

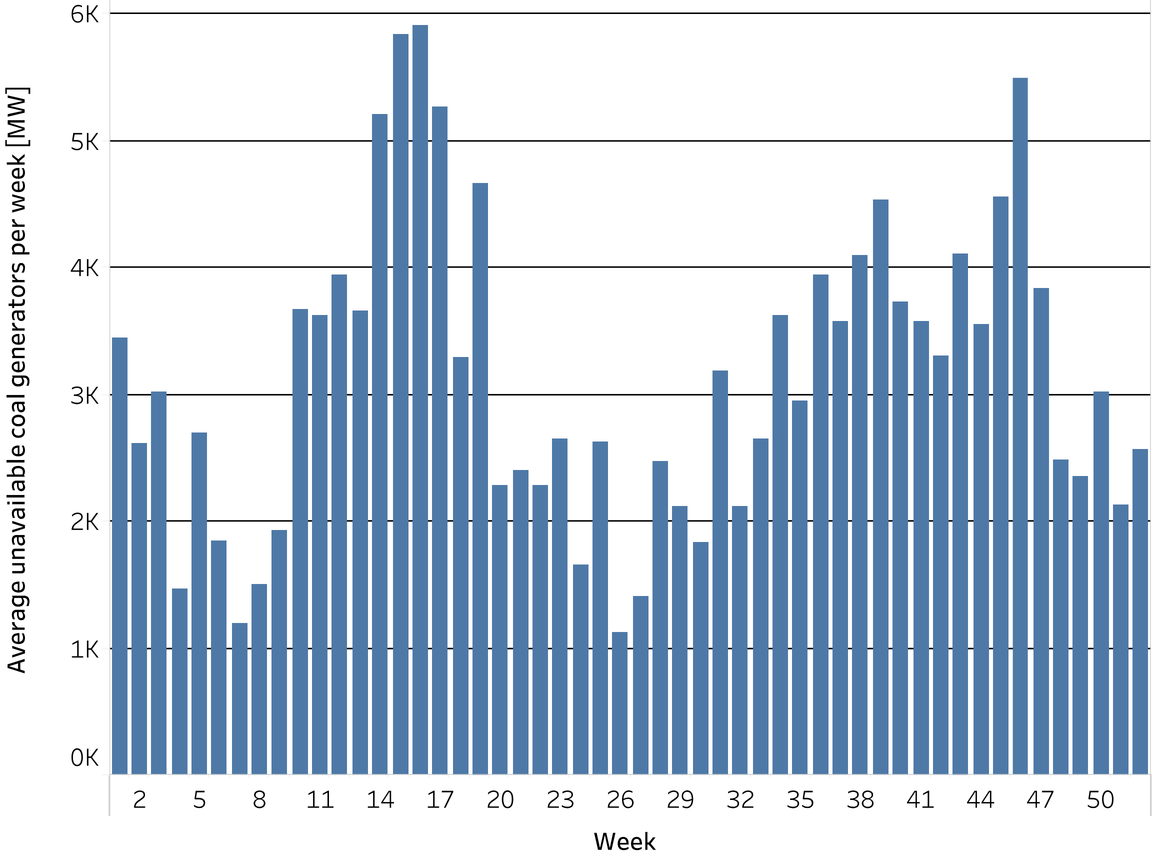

Figure 53 Number of coal generators unavailable per week in 2023 for the NEM