A DOUBLE-SIDED CAUSER PAYS IMPLEMENTATION OF FREQUENCY DEVIATION PRICING

A Project Sponsored by the Australian Energy Council

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FINAL REPORT

IES
Intelligent Energy Systems

Disclaimer

The views expressed herein are not necessarily the views of the Australian Government. The Australian Government does not accept responsibility for any information or advice contained within this document.

This Project received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program.

Executive Summary

Background

The Australian Energy Council (AEC) with ARENA support has sponsored this Project to examine a specific option for pricing and promoting a market for Primary Frequency Response (PFR) in the National Electricity Market (NEM). PFR is a service required to keep system frequency within an acceptable limit (as defined by the Reliability Panel) under normal operating conditions.

The work is motivated by a desire to see a market for PFR maintain good frequency control in normal conditions in the NEM when the current mandatory approach to provision sunsets in 2023. AEC sponsorship does not imply a commitment to the approach by itself.

The aim of the current Project is to outline the basis for Frequency Deviation Pricing (FDP) specifically applied to PFR, but potentially also to related services required to maintain frequency control. There is an existing mechanism known as Causer Pays that is used to recover the costs of regulation. One possible approach is to improve and extend this approach by making it apply more widely; such a concept, known as Double-Sided Causer Pays (DSCP) was the starting point and headline title for the current Project.

This Project is carried out in four stages, each concluding with a stage report:

1 Inception Report[1]

2 Pricing and Theory Report[2]

3 Analysis Report[3]

4 Final Report

The Project also provides for a knowledge-sharing workshop after publication of the Pricing and Theory Report and at the end of the Project.

This is the Final Report of the Project which summarises all work done to date. We conclude with a recommended approach to a system design as well as an implementation strategy.

The IES Project Team would like to thank the AEC and the other industry sponsors who supported this ARENA-funded Project and who provided valuable guidance. The first knowledge sharing workshop and subsequent industry discussions have also provided valuable input.

The 'Deviation' Approach to Frequency Control

We first outline the intuitive concept of measuring and processing deviations to assess frequency control performance and to make payments.

[1] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing, Inception Report*, 16 April 2021
[2] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing, Control and Pricing Theory Report,* July 2021
[3] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing, Analysis Report*, January 2022

To operate the electricity system the Australian Energy Market Operator (AEMO) first produces a schedule, which is a plan for the operation of the system over the next Dispatch Interval (DI).

Generation units are expected to follow a straight-line trajectory (in MW) from where they are at the start of the DI to their scheduled position at the end, except for plant that is scheduled directly for control. If actual MW output is measured using **SCADA** data (at 4 second intervals on the mainland), we observe that the energy market trajectory is generally not followed exactly. This is considered 'bad' if that deviation acts to worsen frequency and control and 'good' if it acts to improve it.

If we can find a system-wide metric whose deviation is a measure of departure from the ideal (zero frequency and time deviation), the sign and magnitude of the product of the two deviations at each measured point provides an intuitively sensible performance measure. If we add these measures over a full DI, we get a DI-level 'performance factor' that can be used for settlement. This is the basis for the current Causer Pays system for recovering the cost of **AGC** regulation. This system is now perceived to have significant shortcomings and is to be replaced.

But what sort of system should replace it? Should it be similar to the current Causer Pays with some improvements and additions, or should one return to basics for a bottom-up design? That was the subject of this Project.

Inception Report

In the Inception Report we:

- review the international experience on frequency control;
- set out our proposed approach for each of the proposed Project reports; and,
- confirm the Project administrative arrangements.

We reviewed the current status of frequency control in the NEM market entities, AEMO, the Australian Energy Market Commission (AEMC) and the Energy Security Board (ESB). In summary, all these entities agree on the need for reform although the form that reform should take is not settled nor even proposed in any detail at the time of Project start.

The international experience canvassed was:

- California Independent System Operator (CAISO) – USA;
- Nordic Market – Europe;
- Ireland – Europe; and,
- New Zealand.

These markets operate a variety of arrangements, none identifiably similar to the current or proposed extensions to the Causer Pays arrangements. All are grappling with the challenges of a much more uncertain and low inertia future system and associated control challenges. Australia is well advanced down this path, without the extent of hydro backup of New Zealand or the Nordic market.

Control Theory and Pricing Report

The aim of the Control and Pricing Theory work was to provide a solid foundation for a system design. The intuition for deviation pricing is a useful motivator, but to extend its application we need to ask:

- What is the engineering and economic basis for the FDP approach?
- Does this theory suggest some system design features that may not be intuitive?
- Does the theory support the design for a simulation system to test the design details?

Our theoretical development proceeded in stages:

- Review and analysis of a robust control system tool, the Linear-Quadratic Regulator (LQR).
  - this system uses system deviations to minimise a control function (a frequency deviation measure)
- Review of this tool to extract deviation prices.
- Extension to Linear-Quadratic Gaussian Control (LQGC) when there are disturbances and only limited measurement options available (e.g. frequency and time deviations).

This approach yields a control schema that:

- is optimal and linear (i.e. relatively simple);
- capable of being implemented locally by responding to price components
  - even though it may be settled centrally;
- under reasonable assumptions, produces outputs that are normally distributed; and,
- is balanced, both physically and financially.

The theoretical results need to be simplified in a number of respects:

- to reduce the number of price components to a manageable but still effective level;
- to make the price components separable and thus easily implementable; and,
- to take account of changing system structure and costs over time, which would be too difficult to model in detail.

The report also examined a range of practical implementation issues, some of which aim to simplify the system. Various studies to examine the nature of outcomes under a range of situations were deferred pending the development of a viable system model. Progress with model development was reported in Appendix A the Analysis Report. The studies on specific situations using an upgraded model are in Appendix D of this report.

Knowledge Sharing Workshop

A Knowledge Sharing Workshop on the control and pricing theory work was held on 27 May 2021. It was attended by people from industry bodies, industry participants and

external parties. The main points emerging from the workshop were summarised in an Appendix to the Control and Pricing Theory Report.

Analysis Report

The Analysis Report documents a set of studies that have been performed on some key issues relevant to FDP/DSCP implementation. These include:

- Studies on historical plant performance on frequency control and the scope for improvement. It was concluded from these studies that the mandatory PFR has been successful in improving frequency performance but the cost of achieving that has not been accounted for. While the costs may not be large for the moment as existing frequency control units have been tuned to perform better, this cannot be guaranteed as such plant faces retirement in the future. For this reason, improved processes need to be in place before the retirements occur.
- Studies on the impact of potential AGC metering errors.

We conclude that lags in the transmission of data are likely to be the most significant source of error. This error is focussed on the PFR measure; slower-moving metrics are less affected. Errors would be kept to within 5% if communication standards are observed. This is likely an overestimate in most cases as all units are likely to suffer similar lags.

We outline a high-resolution meter design (mainly firmware) that would improve accuracy and not require real time communications.

The metering work also highlighted some design issues:

- FDP/DSCP should continue to operate after a generator contingency as most of the measurement of deviations and associated benefit of FDP/DSCP is in the recovery phase;
- units that suffer bad or missing data during a DI should be treated as part of the Residual for that DI; and,
- Development of FDP/DSCP analytical tools.

During this analytical work the AEMC released its Draft Determination on enduring arrangements for PFR. This prompted the Project to re-orient priorities to address some of the issues raised. In particular, the Project decided to focus on development of a back-casting methodology to compare and contrast FDP/DSCP approaches using historical data. In the appendices of this Report we describe:

- a FDP/DSCP control and pricing model at its current stage of development; and,
- back-casting tools, including some indicative results.

The AEMC Draft Determination and Some Key Design Issues

Appendix B of this Final Repot summarises and comments on the proposed arrangements for DSCP in the AEMC Draft Determination. Prompted by the release of the Draft Rule and

what we learned from industry consultation, this Section reviews a number of core design issues which are potentially contentious. These are:

- distinguishing primary and secondary control and pricing;
- characterising the Residual;
- relationship between AEMC Draft Rule and FDP;
- treatment of the AGC regulation enablement trajectory;
- AGC payment options
  - paying the FDP to AGC units based on the energy market trajectory;
  - including AGC-enabled units in FDP but not paying them;
  - operational issue and assessment; and,
- separating Raise and Lower and DI level weighting.

This analysis has led in some cases to modification of our initial design. In other cases, we acknowledge that some preferences previously expressed are really choices requiring practical justification, preferably based on system trials. These choices include:

- the weights to be applied to each DI to reflect different system conditions; and,
- whether or not a distinction between Raise and Lower services is necessary for an FDP, given the added complication.

Proposed FDP Design

With the theoretical work, analytical studies, and our review of the AEMC Draft Rule as background, we outline a specific form of the FDP arrangement to support PFR and decentralised regulation. In some cases we identify where some choices have yet to be made, hopefully following system trials. The design elements covered are:

- Participation in FDP trading
- Separation of Raise and Lower
- Pricing and settlement
- Performance metrics
- Unit deviations
- Performance factors
- Weighting of MPFs for settlement
- Settlement of the Residual and AGC enablement costs
- Metering
- Treatment of regions and network separation
- Operational constraints
- Information flows

We also provide a comparative evaluation of the Draft AEMC Rule and the proposed design, based on AEMO and AEMC assessment criteria. Relative simplicity is the major advantage of the approach proposed.

Implementation Strategy

Some form of prototyping to resolve complex issues has clear advantages. The implementation process should contain the following elements:

- further consultation;
- meter development;
- concept trial;
- DER rule change; and,
- follow-up reviews.

Conclusions

When we worked through the theory of control and the pricing logic that emerges from it (in precisely the same way that pricing emerges from a linear programming model of the electricity system), we derive a readily identifiable FDP model. We concluded that DSCP, when implemented efficiently, is FDP in reality.

An important outcome of the theoretical work is that the FDP, and hence the performance metric, should have more than one price component. This can include tight dead band (15mS) PFR as well as decentralised secondary control or regulation. These components are readily calculated from real time frequency measurements. We have proposed options and a strategy for ensuring that AGC enablement gets paid for on a DI basis.

The AEMC Draft Determination took a somewhat different approach. It took the Causer Pays logic to pay for regulation enablement as a given, fixing some of the more obvious shortcomings. It then adds additional features to expand the scope of the system. This new scope would make payments to parties helping to control frequency but not otherwise paid to do so. However, we conclude that adherence to the Causer Pays model, while a useful starting point because of its familiarity, would deliver a system design more complex that it needs to be.

The key to simplifying the logic is to recognise that double-siding can deliver an efficient and financially balanced system without additional scaling (and opportunities for portfolios not available to others) if an FDP philosophy is followed. We note some important characteristics of the FDP approach as proposed in this report:

- the approach avoids assigning any costs (outside of an FDP) to scheduled units, thereby avoiding the risk of distorting behaviour;
- being a balanced approach (apart from the specific arrangements for AGC enabled units), there is no potential advantage in settling at a portfolio level;
- settlement payments are complete and free-standing within each DI; and,
- the level of pricing can be adjusted to reflect unit responses while maintaining a financially balanced system

Other areas where further simplification or at least clarity should be explored include:

- whether positive and negative performance measures need to be maintained separately or combined, noting that the only purpose of separating them is

targeting some level of FDP turnover. Using the relative size of FDP payment to enablement allocated to the Residual seems like a perfectly adequate proxy;

- whether a distinction between Raise and Lower needs to be maintained in practice; and,
- the best *Weighting Price* to be applied to the factors measured at each DI.

If these simplifications are made, the implementation of an effective DSCP via a relatively simple FDP appears possible. However, we see implementation being phased in, beginning with a trial involving a relatively few units.

While this Project has focussed on and FDP approach that supports PFR and secondary, regulation-type responses, FDP as proposed has wider application in two directions:

- with improved metering and new FDP components defined, FDP could be used to support Fast Frequency Response (FFR) and even synthetic inertia (response proportional to RoCoF); and,
- with existing metering and possibly with a new, 5-minute FDP component defined (requiring no new system infrastructure), support for an operational reserve requirement and for ramping could be provided. Options for operational reserve and ramping arrangements are already under consideration as AEMC Rule Change ERC0295. FDP could provide sufficient flexibility to defer or indefinitely avoid the need for such additional arrangements. For this reason, we propose that this element be included in a trial programme.

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List of Equation Variables and Parameters

Note: Only non-descriptive parameters and variables used in this report are included.

Name	Description
Constant0	dimensionless constant of order 1, but is subject to adjustment to get a desired outcome
dt	The measurement interval (4 seconds on mainland for SCADA)
Metric (j,t)	The value of metric j and measurement time within DI of t
MPF	Mean Performance Factor
MPFM	Mean Performance Factor of all Metered units
MPFR	Mean Performance Factor of the Residual
SigmaF	The targeted standard deviation of system frequency
SigmaX	The standard deviation of the Aggregate Dispatch Deviations
SX, SX-Old	A generalised metric (signal)
TC	Time Constant
TDI	Dispatch Interval duration
x(m,t)	Deviation power of unit m at time t within a dispatch interval

Glossary

Term	Description
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
ARENA	Australian Renewable Energy Agency
CAISO	California Independent System Operator
Causer Pays	A NEM system designed to recover the cost of AGC regulation enablement
Covariance (Matrix)	A statistical concept describing the behaviour of related random variables
Damping	The tendency for a system to resist change rate change in proportion to the rate of change
DER	Distributed Energy Resources
DI	Dispatch Interval – the period over which units are scheduled for dispatch in the NEM
DSCP	Double-Sided Causer Pays
ESB	Energy Security Board
FCAS	Frequency Control Ancillary Services
FDP	Frequency Deviation Pricing (or Price)
FDP/DSCP	A DSCP system that is based on FDP concepts
FFR	Fast Frequency Response
FI	Frequency Indicator (an output of the AGC)
FOS	Frequency Operating Standard
Hz	Hertz (the unit of frequency)
IES	Intelligent Energy Systems
Inertia	The tendency for a system to resist change rate change in proportion to the system acceleration
LQGC	Linear Quadratic Gaussian Control
LQR	Linear Quadratic Regulator
mHz	milliHertz

Term	Description
MPF	Mean Performance Factor
MPFM	Mean Performance Factor of all metered units
MPFR	Mean Performance Factor of the Residual
MW	MegaWatts
NEM	National Electricity Market
NFOB	Normal Frequency Operating Band
Normally Distributed	Randomly distributed in the shape of a bell curve
Performance Factor	The product of Performance Metric and a deviation
Performance Metric	A system-wide calculation based on measurement used to assess system performance
PFR	Primary Frequency Response – equivalent to damping
POR	Primary Operating Reserve
Raise and Lower	Distinct system services to provide more power input (Raise) or less (Lower)
Regulation	The system service designed to correct for longer term system deviations such as forecast error
Reliability Panel	The NEM Panel designated the task of defining and monitoring the reliability requirements of the NEM
Residual	The block of power, usually load, that is not metered at a level sufficient to take part in FDP/DSCP
RoCoF	Rate of Change of Frequency
SCADA	System Control and Data Acquisition
VPP	Virtual Power Plant

1 Introduction

1.1 Project and Report Objective

The Australian Energy Council (AEC) with ARENA support has sponsored this Project to examine a specific option for pricing and promoting a market for Primary Frequency Response (PFR) in the National Electricity Market (NEM). PFR is a service required to keep system frequency within acceptable limits (as defined by the Reliability Panel) under normal operating conditions. In the NEM, PFR is defined as response (e.g. additional generation relative to schedule) in direct proportion to the negative of frequency deviations with a tight dead band of 15 mHz. This means that PFR is active well within the Normal Frequency Operating Band (NFOB) of150mHz.

The work is motivated by a desire to see a market for PFR maintain good frequency control in normal conditions in the NEM when the current mandatory approach to provision sunsets in 2023. AEC sponsorship does not imply a commitment to the approach by itself or by its members; only a desire to see the option fully examined.

In its Frequency Control Frameworks Review and subsequent discussion papers, the AEMC has identified some modification of the existing Causer Pays system for regulation as a candidate for pricing PFR[4]. Subsequently, CS Energy commissioned a small Project from IES to demonstrate how such an approach might work; the approach was called Double-Sided Causer Pays (DSCP)[5]. On 16 September 2021 the AEMC released a Draft Determination on a proposed rule change on how to provide PFR to the NEM, specifically ruling on whether the current mandatory rule on PFR capability ought to endure.[6]

The aim of the current Project is to outline the basis for Frequency Deviation Pricing (FDP) specifically applied to PFR in the form that can be seen as implementing a variation of a DSCP arrangement. It could, when extended, potentially also apply to centralised AGC regulation and similar decentralised services, and even to other faster or slower acting services.

This Project is carried out in four stages, each concluding with a stage report.

1 Inception Report[7]

2 Pricing and Theory Report[8]

3 Analysis Report[9]

4 Final Report

Intermediate and final knowledge sharing workshops are also included within the Project scope.

[4] AEMC, *Frequency Control Frameworks Review*, *Final Report*, July 2018
[5] IES, *Costing of Primary Frequency Control, A Report to CS Energy*, August 2019
[6] AEMC, *Draft Rule Determination National Electricity Amendment (Primary Frequency Response Incentive Arrangements),* 16 September 2021
[7] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing, Inception Report*, 16 April 2021
[8] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing, Control and Pricing Theory Report,* July 2021
[9] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing, Analysis Report*, January 2022

The current document reports on the fourth stage, which aims to draw together the conclusions from the previous work undertaken. As work has progressed, we have also sought to refine our earlier results and conclusions and we report that additional work here. Further, we now have the benefit of a Draft Determination from the AEMC to work on. As we will demonstrate, there is enough commonality in the approach taken by the AEMC to take it as a starting point. However, we seek to improve the Draft Rule, using some of the insights we have gained from this Project. This approach will guide the remainder of this report.

1.2 Assessment Criteria

Both AEMO and the AEMC have provided assessment criteria which they propose should guide the development of new arrangements for frequency control. These are summarised briefly below and repeated in full as Appendix A. While they share some common features, AEMO's are more technical and AEMC's are more economic, as would be expected.

1.2.1 AEMO's Assessment Criteria

In its Technical White Paper produced for the AEMC[10], AEMO has set out five criteria that it believes a frequency control regime should satisfy. In summary, they are:

- Decentralised.
- Distributed.
- Simple.
- Predictable.
- Flexible.

Suitably interpreted, these criteria seem appropriate for evaluating the AEMC Draft Rule Change against the proposed arrangement developed earlier in this Project. This analysis will provide the basis for proposing amendments to the rule change, or to a specific approach to design issues during the AEMO consultation process.

1.2.2 AEMC's Assessment Criteria

The Commission developed the following principles to assess whether the preferred rule change is likely to support and improve the security of the power system, as well as improve the effectiveness and efficiency of frequency control frameworks. In summary, they are:

- Promoting power system security and reliability.
- Appropriate risk allocation.
- Technology neutral.
- Flexible.
- Transparent, predictable, and simple.
- (Proportionate) implementation costs.

[10] AEMO, *Technical White Paper: Enduring primary frequency response requirements for the NEM*, August 2021,page 17, Extracted from UNSW submission to the AEMC.

1.3 Outline of this Report

- Section 2 presents a brief overview of the system design that was proposed and analysed in the earlier stages of this Project. Further detail is provided in the Section 4 comparison with the AEMC proposal and again in Section 5 which sets out a proposed design that builds on the AEMC draft rule change.
- Section 3 outlines the main elements AEMC Draft Rule Change. The Draft Rule Change does not specify a compete system design; critical elements would be deferred to a consultation to be conducted by AEMO.
- Section 4 provides a detailed analysis of the strengths, weaknesses and alternatives for both the AEMC design elements and for certain key elements not yet determined.
- Section 5 presents the key design elements of the proposed system. It also highlights which elements differ from or fill in detail from the AEMC Draft Determination. This section also sets out an implementation strategy.
- Section 6 draws conclusions for the Project as a whole.

The report includes the following appendices:

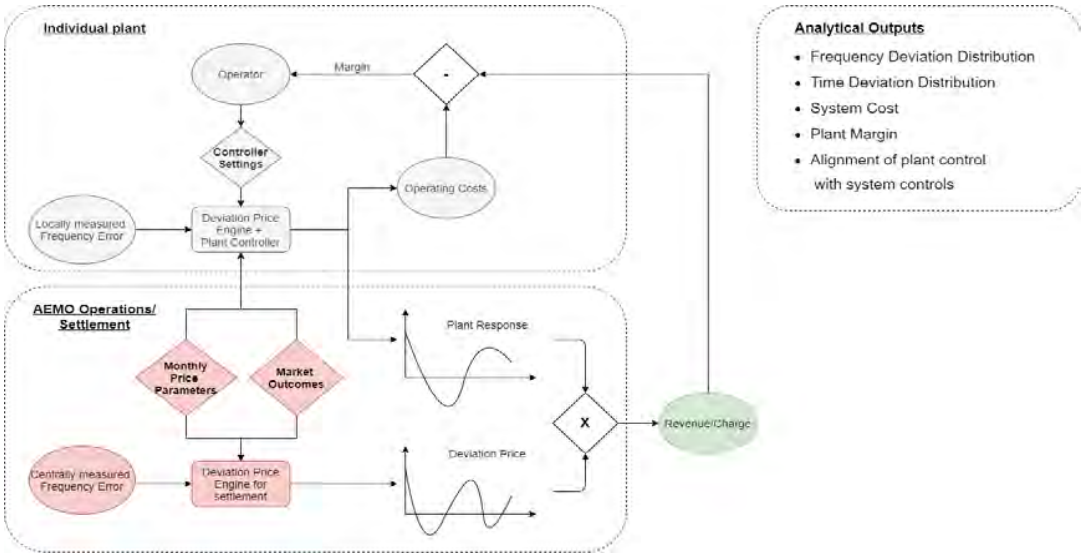
- Appendix A - Assessment Criteria
- Appendix B - AEMC Draft Determination
- Appendix C - FDP Settlement Formulae
- Appendix D - Modelling of Specific Cases
- Appendix E - Results of Back-casting Studies

2 The "Deviation" Approach to Frequency Control

2.1 Overview

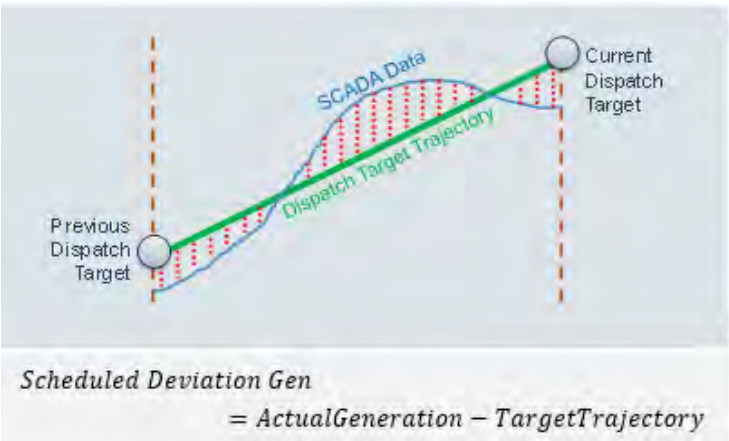
Any system of payments for frequency control would broadly operate according to the diagram in Figure 1 below.

Figure 1: Power and information flows for an FDP/DSCP system



- Focussing on the bottom right in the AEMO box, AEMO first determines the deviations (labelled 'Plant Response') of each unit from a reference trajectory set in the energy market. The figure below illustrates how this is done using SCADA data gathered and maintained centrally. On the mainland, the measurement interval is just 4 seconds.

Figure 2 Causer Pays Deviation Quantities



Source: AEMO Causer Pays Procedure[11]

[11] [11] AEMO, Regulation FCAS Contribution Factor Procedure, December 2018

- The unit deviation (in MW) is a measure of how much it is causing the need for or assisting with the control of frequency. However, we need a measure of system imbalance, there is a range of possible choices, but the simplest is some constant multiplied by the deviation of frequency from its reference value of 50 Hz. This is marked as 'Deviation Price' in the Figure.
- To get a measure of when and how much a unit is causing and when it is helping, it makes intuitive sense to take the product of these two measures to produce a single 4-second value. In words:

Performance_Measure = - Frequency Deviation x Unit Deviation (1)

Note the negative sign. The table below shows where this formula indicates situations where a unit deviation is causing or assisting frequency control (injections and frequency increases are positive). The formula also provides an indication of strength as well as sign.

Table 1: Cases of cause and assist

		Unit Deviation	
		-	**+**
Frequency Deviation	**-**	**Cause**	**Assist**
	+	**Assist**	**Cause**

- We can derive this intuitive formula as the outcome of a system of payments based on performance. Define:

Frequency_Deviation_Price = Constant x Frequency_Deviation (2)

From the frequency deviation price and the unit deviation energy *Unit_Deviation x dt* where dt is the measurement interval, we get a payment due over a single measurement interval:

Payment_Measurement_Interval = Frequency Deviation Price x Unit Deviation x dt (3)

Note that this payment formula includes the product of *Frequency_Deviation* and *Unit_Deviation* and so is consistent with the Table 1 and also formula (1). We can summarise these payments in values for each Dispatch Interval (DI)

Payment_DI =
Sum_over_DI (Frequency Deviation Price x Unit Deviation x Constant x dt)
= Sum_over_DI (Frequency Deviation x Unit Deviation) x Constant x dt
= Performance_Factor x Constant x dt)

where

Performance_Factor = Sum_over_DI (Frequency Deviation x Unit Deviation) (4)

This is AEMO's 'Revenue Charge' (positive or negative) as shown in Figure 1.

- The other activities in the AEMO section of Figure 1 relate to the determination and publication of energy market data which are used to weight the individual DI-level performance factors.
- The participant section in the figure is intended to describe how performance can be measured locally and the unit's control system adjusted to maximise returns to the unit operator. AEMO settlement data confirms and formalises the payments as a result of good or bad performance.

2.2 The Existing Causer Pays System

The current system to allocate the cost of AGC regulation (known as Causer Pays[12]) is based on the formula (1) but implemented as follows:

- only negative ('bad') Factors are used as the system is designed to pay for AGC regulation;
- the performance metric used, called FI, is produced by the AGC and is difficult to understand and reproduce;
- the factors are pro-rated over a settlement period to precisely pay for the cost of regulation, not at the time of measurement but for a period two weeks later (check);
- there is no DI-specific weighting; performance when regulation is plentiful is valued in the same way as performance when the system is constrained;
- settlement is based on portfolio rather than unit performance, so that 'good' performers in a portfolio can offset 'bad' performers; and,
- measurements for a DI are dropped whenever the FI measure used as a performance metric is counter to frequency.

The existing system does not recognise the link to FDP outlined in equations (2)-(4) because the single-sided nature of the approach renders the FDP interpretation unhelpful.

2.3 DSCP and FDP

The AEMC has recognised significant problems with the current system for recovering the cost of AGC regulation. These include the specific features listed in the previous sub-section. It further identifies likely future requirements including a faster-acting service called Fast Frequency Response (FFR) which could potentially operate in the sub-second range.

In its Frequency Control Frameworks Review, the AEMC's longer term approaches were listed as:

- fixing up the problems with the current Causer Pays system and also add a feature to make payments to 'good' performers who are not enabled for AGC regulation. This is Double-sided Causer Pays (DSCP); and,
- implement Frequency Deviation Pricing (FDP), p a (nearly) balanced system of payments to good performers funded by payments from bad performers.

[12] AEMO, *Causer Pays Procedure, Version 5*, July 2018

In 2019 CS Energy commissioned IES to develop the details and a calculation system for DSCP[13] . Some of the concepts in that report have found their way into the AEMC Draft Determination published in September[14] when the current Project was well advanced. We will review some features of the Draft Rule later in this report.

2.4 Scope of the Current Project

The scope of the current Project is laid out in the Project Inception Report[15] and is summarised below:

2.4.1 Inception Report

1. Review the literature on frequency control and, specifically, on implementation approaches in selected international systems.

2.4.2 Control and Pricing Theory Report

2. Is there a robust control and pricing theory that support the general FDP/DSCP approach?
3. If so, what insights does it offer on the details of implementation?
4. How are some practical implementation issues resolved?
5. What services could FDP/DSCP support?

2.4.3 Analysis Report

6. What is the current level of performance for PFR and AGC regulation?
7. What scope is there for improvement in this performance?
8. Is SCADA metering adequate for measuring PFR?
9. What alternative metering could improve the accuracy of measurement of FDP/DSCP and what additional services might be covered by such metering?

2.4.4 Final Report

10. Project Summary and Conclusions, including updated analysis and a proposed design of an FDP/DSCP system.

2.4.5 Modifications and Additions

As the Project progressed, some priorities were adjusted. Specifically:

- we spent time and effort analysing the AEMC Draft Determination to understand the reason for any points of difference with our proposed design;
- we decided to undertake a significant back-casting effort to allow us to compare outcomes under different approaches based on historical data; and,
- as a result, our physical and cost model was developed and is operating, but at a simplified level relative to the original ambition.

[13] IES, *Costing of Primary Frequency Control, A Report to CS Energy*, August 2019
[14] AEMC, *Draft Rule Determination National Electricity Amendment (Primary Frequency Response Incentive Arrangements)*, 16 September 2021
[15] IES, *A Double-Sided Causer Pays Implementation of Frequency Deviation Pricing, Inception Report*, 16 April 2021

3 Project Reporting

3.1 Overview

In this section we summarise the key content, findings, and conclusions from earlier reporting under the Project.

3.2 Literature Review (Inception Report Appendix D)

3.2.1 Overview

In this section we reviewed the status of the work programs being undertaken locally by:

- AEMO;
- AEMC; and,
- ESB

Also summarised is the stated position of the AEC, the sponsors of the current Project.

The Appendix also summarises the frequency control arrangements in selected international systems.

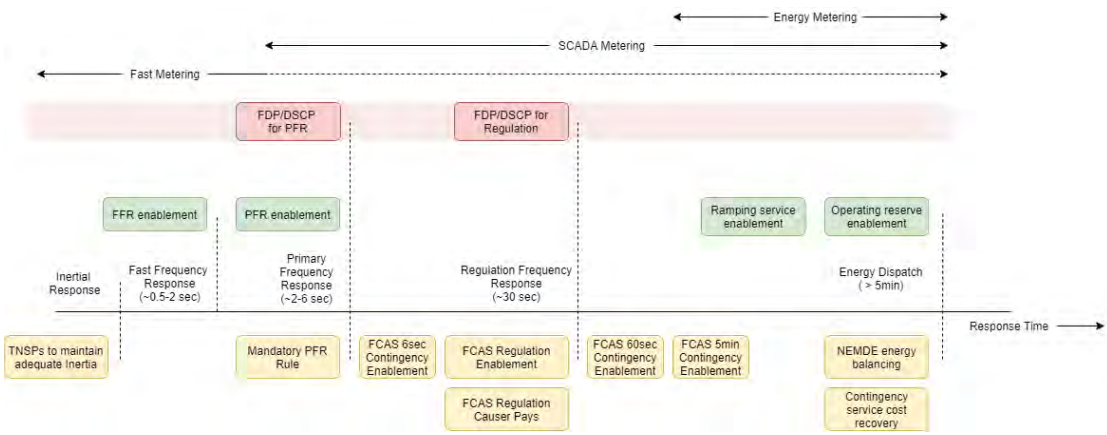
3.2.2 Australia

Current frequency control arrangements include:

- a mandated PFR capability requirement on scheduled and semi-scheduled generation (originally scheduled to sunset in 2023);
- Raise and Lower AGC regulation services;
- Three Raise contingency services at 6, 60 and 300 second timescales; and,
- Three Lower contingency services at 6, 60 and 300 second timescales.

Figure 3 below shows the current arrangements in yellow, new arrangements postulated by AEMO. AEMC and/or the ESB in green, and the possible role of FDP/DSCP shown in pink. We will justify the two roles in the sections following.

Figure 3: Current and proposed frequency control arrangements in the EM



Source: IES presentation to Industry participants, May 2021

AEMO's work program recognises the need to tune existing services and possibly to develop new, faster acting services such as PFR and FFR to deal with the expected loss of system inertia as thermal plant retires. Its work programme includes an improved modelling capability but its planning at Project start had no identified commitment to the development of new pricing mechanisms. AEMO has been assisting the AEMC in its work with technical advice but has not engaged actively with the current Project.

In its Discussion Paper on PFR[16], the AEMC identified three broad approaches for delivering PFR:

- maintain the existing mandatory PFR (MPFR) arrangements with improved PFR pricing,
- revise the MPFR by widening the frequency response dead band and develop new FCAS arrangements for the provision of PFR during normal operation; or,
- remove the MPFR and replace it with alternative market arrangements to procure PFR during normal operation.

In its Discussion Paper, the AEMC expressed a preference for the second approach. However, its Draft Determination would make MPFR enduring and so it is now following the first approach.

Three ESB priorities identified in its Directions Paper[17] are relevant. The future NEM should deliver:

- Resource adequacy mechanisms thermal plant ages and retires – ensuring the right mix of resources is available through the transition.
- Essential system services and scheduling and ahead mechanisms – ensuring those resources and services required to manage the complexity of the power system are available.
- Demand side participation – progressively unlock the potential of consumers to compete in the wholesale market.

The second of these in particular would represent a major shift in NEM philosophy.

3.2.3 AEC Position

The AEC represents a wide range of industry participants and is a sponsor of the current Project.

The AEC considers that mandatory narrow-band PFR is inconsistent with the valuation of 'missing markets' philosophy and distorts existing markets and incentives. AEMO desires that all existing frequency control capability be made available to protect the system from extreme non-credible contingency events (e.g. 25 Aug 2018). The AEC believes this objective can be accomplished with mandatory wide-band PFR and a market arrangement to procure narrow-band PFR.

The AEC argues that the current data shows that only a few units enabling narrow-band PFR will result in a more favourable frequency performance as stated by AEMO. This is highly conducive to a competitive market arrangement – only a small number of providers

[16] *AEMC Consultation Paper Primary Frequency Response Rule*, September 2019
[17] ESB, *Directions Paper*, January 2021

are needed to deliver strong performance. As the performance was largely due to tightening the dead bands of the ageing thermal fleet, there is a need to create a new value stream to ensure investment in adequate PFR replaces the ones that withdraw from the market.

The AEC has recognised the value of exploring in DSCP in detail as one option that may be consistent with its preferred approach. It has sponsored this ARENA research Project to that end.

The AEC has recommended that the Reliability Panel review the FOS to determine whether it is still relevant to the current power system as it is clearly inconsistent with AEMO's views on frequency performance.

3.2.4 International Experience

We reviewed the frequency control arrangements in the following systems:

- CAISO – USA;
- Nordic Market – Europe;
- Ireland – Europe; and,
- New Zealand.

The system that is most comparable to the Australian NEM in terms of size (in MW) as well as progress towards accommodating a future with a high level of renewables and limited inertia is Ireland. Schedules for 14 system services have been developed including:[18]

- Synchronous Inertial Response (SIR) to deliver stored kinetic energy;
- Fast Frequency Response (FFR) to deliver MW between 0.15 and 10 seconds;
- Primary Operating Reserve (POR) to deliver MW 5 and 15 seconds; and,
- Secondary Operating Reserve (SOR) to deliver MW between 15 and 90 seconds.

Figure 4 provides a categorisation of the 14 services from the perspective of performance monitoring.

Figure 4: Categorisation of the 14 DS3 System Services for Performance Monitoring

Source: DS3 System Services Protocol – Regulated Arrangements, 1May 2019, Version 2.0

The rules allow wind and solar generators to participate in some services (such as FFR, POR and SOR) provided sufficient headroom is provisioned. Storage is also eligible subject

[18] Refer to *DS3 System Services Protocol – Regulated Arrangements*, 1May 2019, Version 2.0

to recharge limitations and a requirement to provide a real-time signal confirming its remaining charge available. Responses for these services are based on Reserve Triggers and not on Rate of Change of Frequency (RoCoF). Notable is the range of timescales required for delivery, similar to the NEM's contingency definitions (but adding FFR and inertia) and apparently intended for broad use.

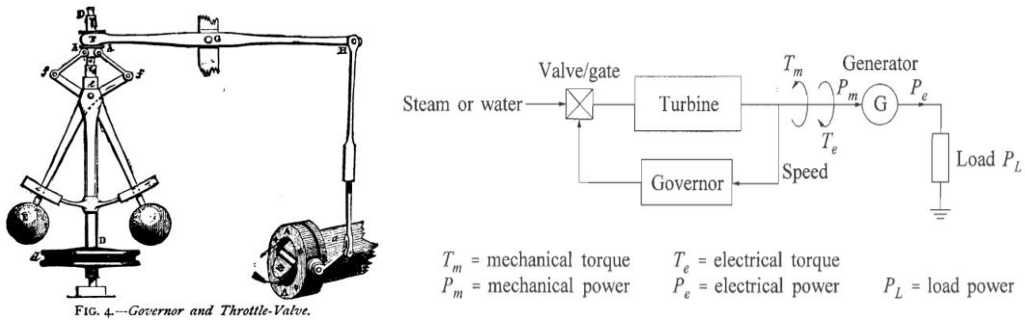
The NEM's Causer Pays system and a proposed extension to FDP/DSCP appears to be relatively novel in this company. A degree of novelty is likely needed to deal with the unprecedented conditions that the NEM is facing.

3.3 Control and Pricing Theory Report and Presentation

3.3.1 Frequency Control and the Energy Market

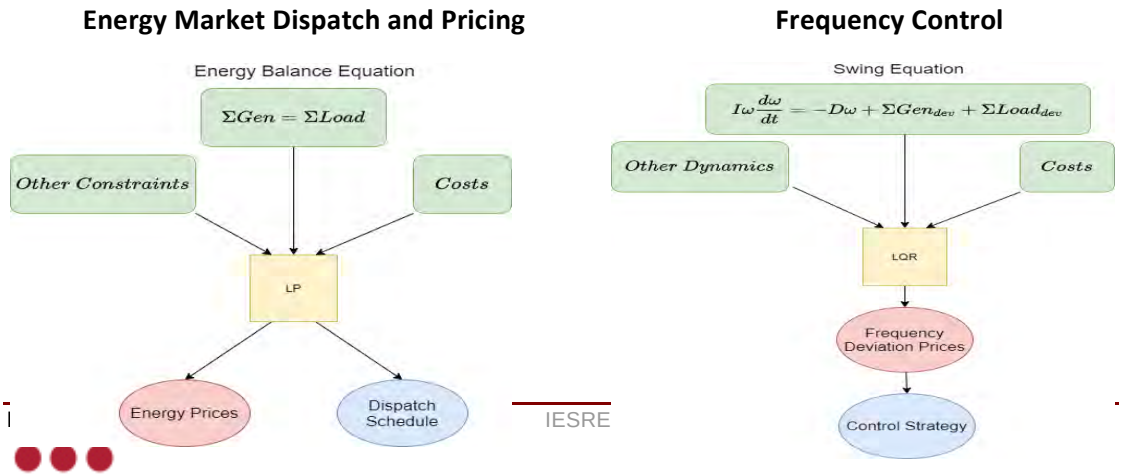
Within a 5-minute DI, the system can no longer be managed using the simple sequence of static models that drive the energy and FCAS enablement markets. Generators and loads have inertia, damping and lags from various sources, including from boilers. The governor is an early example of a feedback control system that aims to stabilise the system speed; a simple version is illustrated in Figure 5 below.

Figure 5: Example of a simple control system: the James Watt governor



Control is normally regarded as a purely engineering problem, but there is an implicit economic perspective. To see this, we examine a basic solution approach to the physical control problem; the Linear-Quadratic Regulator (LQR). The LQR is analogous to the scheduling and pricing engine used in the energy market, as highlighted in Figure 6 below.

Figure 6: Comparison between Energy Market and Frequency Control



3.3.2 The Linear Quadratic Regulator

The basic equation driving the energy market dispatch and pricing model is a simple static energy balance. For frequency control, we need to account also for inertia, damping and multiple lags in the system. The energy balance is static rather than dynamic.

Frequency control can be considered as a *variation* or *deviation* around an initial energy market solution:

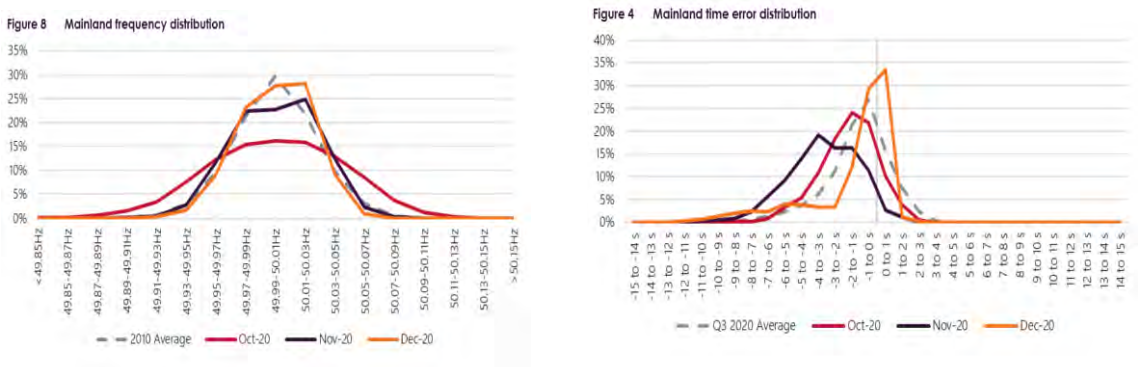
- The variables in the problem are the system state (e.g. frequency deviation, generation level) and the system controls (e.g. generator ramp rates). The system can be of any complexity subject to the limits set out below.
- The objective is to meet a frequency standard at least cost.
- Therefore, the system dynamics are well approximated by linear relationships around the initial point (unless against a hard limit, to be addressed later).
- Linear costs are accounted for in the energy market, so the costs of control are quadratic variations around the initial linear cost curve.
- In addition, the LQR approach can deal with random disturbances in the system as modelled by a covariance matrix.

The LQR solution produces two outputs (mathematically, these outputs are matrices). These matrices describe:

- a control strategy, where the control (e.g. a ramp rate) is a linear function of the system state;
- specifically, the resulting linear control is stable and optimal; and,
- an optimal cost function which is quadratic in the current system state, with recurring constant term if there are system disturbances present.

Further, the outputs from this (optimal) control can be described by a multivariate normal distribution. This implies that frequency and time error, two important variables defining the state of system, are both normally distributed. We can see this holds to a good approximation for frequency in the NEM data plotted in Figure 7 below.

Figure 7: Historical Frequency and Time Error in the NEM



Source: AEMO - Frequency and Time Error Monitoring –Quarter 4 2020

We observe that the frequency distribution is symmetric and approximately normal while the time error distribution is skewed. This skewness in the time deviation can be explained by the cumulative effect of larger scale disturbances to the system from contingencies, and possibly a cost bias on the raise side. In such a case LQR is guaranteed to yield an optimal *linear* controller. However, there may be a better non-linear one and the resulting distributions may be non-normal. In the case of frequency deviations, the requirement to keep time deviations within bounds provides a correction that compensates for other non-linearities.

The LQR solution is driven by an objective to minimise costs, such as:

Objective = Constant1 x (Frequency_Deviation + Constant2 x Time_Deviation)^2 +

Other_Costs^2 *(5)*

Where *Other_Costs* is representative of the quadratic costs of state deviations and control.

Note in the above formula we do not directly constrain the frequency and time deviations to be a specific value as this logic is not supported directly by LQR. Instead, we iterate by:

- choosing an initial value of value of *Constant1*.
- solving the LQR and extracting the frequency standard deviation from the solution;
- determine a revised *Constant1* based on the error between the LQR standard, deviation and the target standard deviation; and,
- return to second step and iterate until convergence.

We take this approach in our modelling and a similar approach is likely to be required in practical implementation.

3.3.3 Extracting a Price from the LQR Solution

At face value, the LQR appears to deliver a purely physical solution. However, it is a cost minimisation solution, and it delivers function (in the form of a matrix) and a constant which is the cost incurred in the system from the current state.

- From this function the marginal cost from the current state is easily derived.
- Specifically, we can determine the marginal cost of a variation of the stored energy (inertia) in the system. This marginal cost is a linear function in the variables describing current system state.
- Using a straightforward algebraic trick, we can transform the system state variables to cost components, with the result that the optimal control strategy for each unit can be expressed in terms of some set of weights applied to these price components.

The last result above justifies the FDP approach. If participants are given, or can calculate themselves, a set of price components, they can control their units to give an optimal outcome for the system. Further, such an outcome is optimal for each unit individually under conditions of adequate competition.

3.3.4 Basing Control Strategy on Readily Available Measurements

The basic LQR model and its solution, including the pricing interpretation of the optimal control strategy, assumes knowledge of the complete state of the system. However, units providing decentralised responses must instead rely on more limited, readily available measurements.

There is an extension to the LQR which assumes that only a limited set of measurements is available. This limited data can be used to estimate the state of the system, which in turn allows the optimal control strategy and the corresponding pricing rules to be determined. This control model is called linear Quadratic Gaussian Control (LQGC). As with LQR, it also has a pricing interpretation.

Variables that are easily measured locally are frequency and time deviations and the state of a unit's plant. A conservative information set would be frequency and time deviations only. Working through the algebra we can show that, in the absence of disturbances, the vector of price components decays over time according to a recursive formula of the form

New_Price_Components = Function1(Old_Price_Components) (6)

Because the system can be shown to be stable, the size of the *Price_Components* decays over time.

System disturbances are reflected in ongoing measurements of frequency and time deviations. They drive the system away from its tendency to remove all deviations. The evolution of the price components then becomes:

New_Price_Components = Function2(Old_Price_Components, Measurements) (7)

By making some useful simplifications (such as discarding oscillatory components in the solution), the theory provides a specific form for a near-optimal pricing function - a FDP:

- The FDP consists of the sum of separable price components.
- Each price component can be modelled as constant (which is a weighting price in $/MWh) multiplied by a smoothed function of a measurement (frequency or time deviation), scaled by a constant. So, for the jth component we have at time t within the kth DI:

FDP_Component(j,t) = Weighting_Pricet(k) x Metric(j,t) x Constant

where

*Metric(j,t) = Metric(j,t-1) x (1 – dt/TC(j) – (Measurement(j) * dt/TC(j))*

where

TC(j) is a time constant associated with component j; and

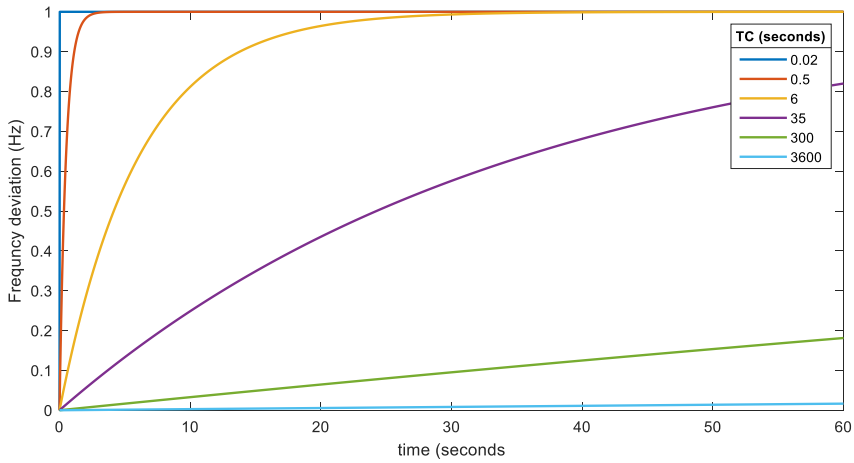
Measurement(j) is either measured frequency or measured time deviation associated with component j. (8)

The equation (8) above for *Metric* is simply a low pass filter applied to the sequence of measurements. It has the effect of smoothing and lagging the original measurement as illustrated in Figure 8 following. The chart shows the response of a step disturbance of 1 unit. The smoothing and lagging effect for each time constant is clearly evident

for this simple step change. In practice, of course, disturbances are typically more random in nature. The chart assumes that high-resolution frequency measurements are available. A raw 4-second SCADA metric would be approximated by the 4 second time constant case.

Pricing of this form is suggestive of the NEM frequency control services, which for contingency have time constants of the order of 6, 60 and 300 seconds. AGC regulation has an estimated time constant of around 35 seconds (although AGC regulation uses a highly non-linear control function at present) while PFR would be measured according to response to raw 4 second SCADA measurements, with a time constant of 4 seconds. With improved metering, time constants down to sub-second values could be handled as additional, to support FFR for example. Time deviation pricing would have a much longer time constant of, say, one hour, which would have the effect of adding a small, slow moving trim to frequency-based pricing.

Figure 8: Step response of price component metrics for different Time Constants



Note also that the theory would apply these price components to all units in the system, regardless of whether they can respond to some components or not; all units would see the same price unless some external weighting separates them. The concept is that units can adjust their controls to respond to the price components that are most beneficial to them.

3.3.5 Setting Parameters for the FDP Depending on System Conditions

The basic theory presented in the Control and Pricing Theory Report does not take account of how the system might change over the course of the day and year and as technology and responses evolve; it's focus is the very short term - within a DI. To reflect conditions in the system as it evolves over time, the weights and time constants applied to the price components will need to evolve with the state of the system in some way. We make the following observations

- The time constants in the system are broadly reflective of the mix of technologies in the system and are not likely to change quickly. Further, some approximation

is acceptable as a single practical time constant is really an amalgam of many slightly different theoretical time constants.

- On the other hand, the weights can potentially change for each DI and change even on a regional or finer basis as well.
- The weights should also be scaled by a common scaling factor, not to balance the system (which is guaranteed or at least managed by the FDP logic), but to allow control of the relative turnover in FDP and enablement services.

Our thinking on these matters has developed as the Project has progressed. Our final analysis is presented in Section 4 of this report.

3.3.6 Other Practical Implementation Issues

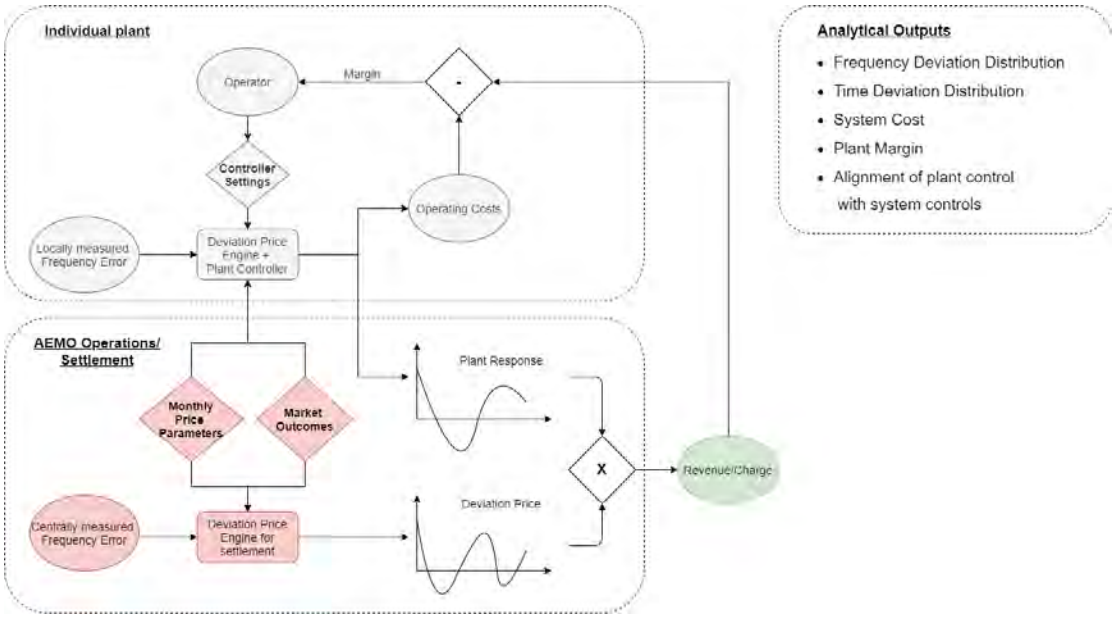
The Project Inception Report outlined a range of other issues intend to be considered in our Analysis Report. Our full consideration of some of them had to await further development of our simple system model and we have also reviewed our thinking based on industry comment received. Most of the issues below are dealt with in Section 5.3, although the Analysis Report contains detailed studies on metering accuracy.

- Adequacy of metering
- Determining Time Constants
- Dealing with system non-linearities
- Interface with other frequency control services
- Stability of the system with more renewables as well as lower inertia
- Stability of the system with more batteries
- Impact of potential 'rogue' behaviour
- Fixing DSCP pricing discontinuities between dispatch intervals

3.3.7 An Initial Design for a DSCP/FDP System

Bearing in mind the above discussion, our initial 'straw man' design for a DSCP system is outlined below. It is a slightly more detailed and extended version of the basic DSCP system outlined at the start of this section. The main elements of the system including the general flow of control and data are illustrated in the figure below.

Figure 9: Proposed DSCP/FDP Implementation



Note that the system has decentralised control but centralised settlement. Inputs to the decentralised control are:

- FDP components easily calculated from local measurements of frequency and time deviations;
- dispatch interval weightings based on energy market dispatch local pricing outcomes, available in advance of each DI (or seconds after start); and,
- additional global weightings applied by AEMO, also known in advance, before the start of a settlement period.

More details are set out below.

- The DSCP system will target PFR and regulation, as two distinct but closely related services.
- The system will initially use AGC metering for settlement. Participants can track their own performance locally.
- The FDP components will be based on:
  - a raw 4 second frequency deviation metric, or frequency deviation filtered with a 4 second (say) time constant, supporting PFR;
  - a frequency deviation metric filtered through a 35 second (say) time constant, supporting performance under AGC and decentralised regulation;
  - a time deviation metric with a one-hour (say) time constant, to provide a small price offset designed to help correct time deviations; and,
- Within a DI, FDP signals would be weighted by a price ramp between the previous local energy price (including loss factors) and the next local energy price.

- The FDPs within each DI should be accumulated and averaged into 5-minute factors. Because of the ramping there will be two factors per interval.
- A global weighting will be set to target some fraction of a corresponding or neighbouring enablement income stream.
- As not all participants are metered, there will be a residual to be allocated on some basis, likely in proportion to energy. The residual is defined and justified as the negative sum of the metered units (assuming all positive deviations have the same sign)
- Some additional rules may assist confidence, especially initially and during a transition.
  - Another might be to make the arrangement opt-in for all participants. SCADA-metered parties could choose to abstain from DSCP (but be charged a share of residual costs based on energy), while embedded and non-SCADA metered parties could choose to opt-in with suitable metering, not necessarily SCADA.
  - Some limits on the droop settings of individual units may also be desirable, at least initially.
- Initially, all existing or proposed services could be kept in place and the FDP logic phased in, possibly initially on a trial basis to help firm up the design.
  - However, the regulation Causer Pays cost stream should reduce in size over time and support a simplified cost recovery option in line with that used for contingency.

This design and variations on it were stress tested with an LQR-type model in later stages of the Project and industry comment on the work to date also noted. As a result, our final recommended design varies in some details from that outlined above.

3.4 Analysis Report

3.4.1 Overview

In this document we report on a set of studies we have performed on some key issues relevant to an FDP/DSCP implementation. These include:

- Studies on historical plant performance on frequency control and the scope for improvement.
- Studies on the impact of potential AGC metering errors.
- Development of DSCP analytical tools:
  - FDP/DSCP Control and Pricing Model
  - Back-casting tools.

Our focus for the latter items in the report was adjusted after the release of the AEMC Draft Determination. We decided to focus on developing a back-casting capability that would use historical 4 second data to allow different designed options to be compared. This is a useful although incomplete form of analysis. Progress on the control and pricing model was made but studies using it were deferred to a later Project stage.

3.4.2 Recent Frequency Control Performance and Scope for Improvement

After demonstrating how frequency control has improved since AEMO introduced mandatory PFR, we carried out a comprehensive set of studies using two metrics.

- 4 second (raw SCADA data) metric which corresponds to the response required of PFR-enabled units
- A filter frequency metric with a time constant of 35 seconds, approximating a regulation or secondary control function.

In both cases we calculated an approximate covariance measure[19], which corresponds to the performance factors used in DCSP calculations. We also calculated normalised versions to get a sense of performance independent of size. A useful chart plots these measures with units arrayed along the X axis in descending order of performance measure. This can be done for different time periods; we have chosen two-month periods from January 2020 to June 2021, covering the time when AEMO was implementing mandatory PFR. We constructed charts of 4 and 35 second metrics like this for:

- All units;
- AGC-enabled units; and,
- Non AGC- enabled units.

Following is a brief summary of the main observations. As shown in Figure 10, frequency control has noticeably improved, with the standard deviation much reduced as the early tranches of the mandatory PFR were implemented prior to November 2020.

[19] The measure id only an approximate covariance because we do not take account of the mean. It should ideally converge to a mean of zero but over short intervals it may not.

Figure 10: Bimonthly standard deviation of frequency

Performance of individual units has improved at both 4 and 35 seconds as illustrated in Figure 11 and Figure 12 following.

Figure 11 Performance of all units using the 4sec_freq performance metric against cumulative capacity

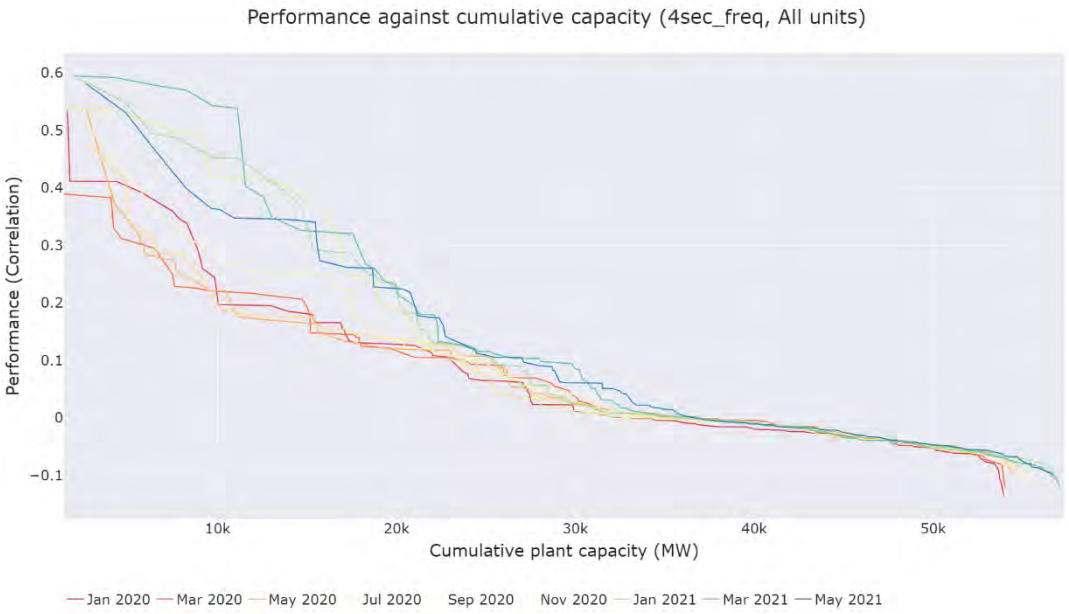
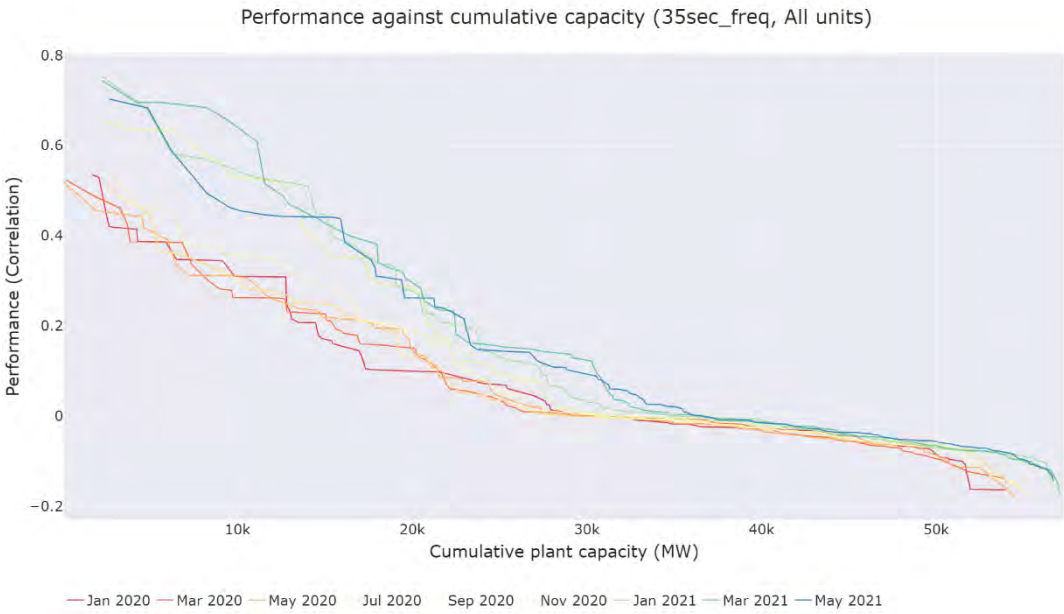


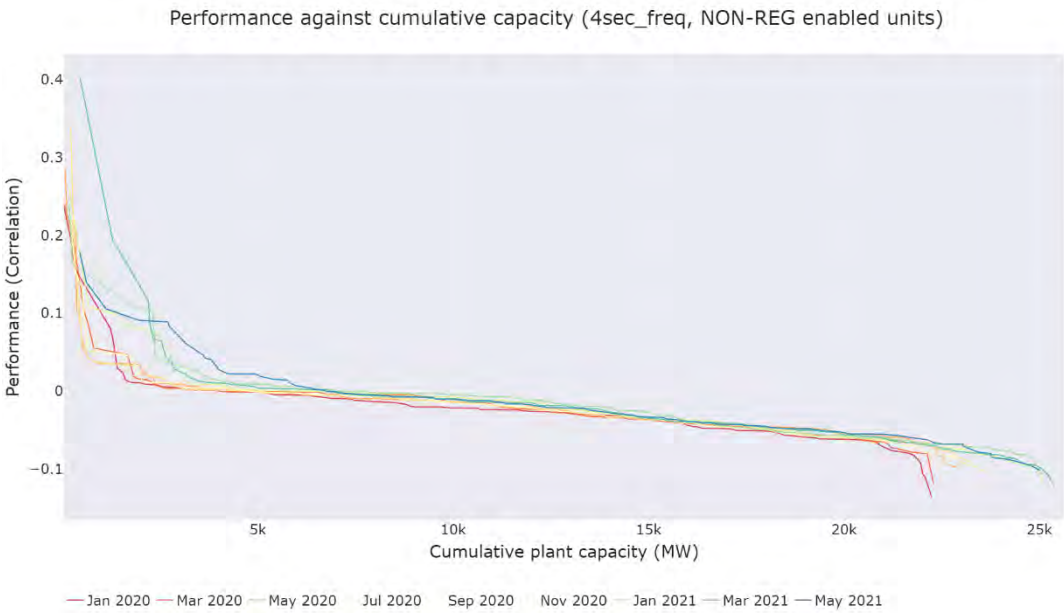
Figure 12 Performance of all units using the 35sec_freq performance metric against cumulative capacity



However, both these charts show that the improved performance is concentrated in about half the fleet and, Figure 13 with the remainder doing show little or no improvement.

Figure 13 following shows the chart for all units not on AGC regulation. We can infer the improvement is mostly with units that are already performing a control function.

Figure 13 Performance of non AGC-Regulation enabled units using the 4sec_freq performance metric against cumulative capacity



We conclude from these studies that the mandatory PFR has been successful in improving frequency performance but the cost of achieving that has not been accounted for. While the costs may not be large for the moment as existing frequency control plant have been tuned up to perform better, this cannot be guaranteed as such plant faces retirement in the future. For this reason, improved processes need to be in place before the retirements occur.

The conclusion above is widely recognised already. Not yet settled is what these arrangements should look like.

3.4.3 Impact on DSCP of Potential Metering Errors

SCADA metering is a natural choice to use for a DSCP/FDP implementation because:

- it is universally installed and used already for scheduled plant;
- it is already used for system control including AGC regulation;
- it is already used for AGC regulation Causer Pays settlement; and,
- at 4 second resolution, it would appear useable although not ideal for PFR and decentralised regulation settlement.

Recognising that the adequacy of AGC metering for real-time PFR duty is not self-evident, we have conducted studies to examine the nature of AGC errors that could occur and their potential significance, to do this we initially classified the sources of error as follows:

- Scaling error
- Offset error
- Time delay error
- Discretisation error
- Outage error
- Time resolution error
- Random error

From this analysis we draw some conclusions on SCADA metering and then proceed to consider the following:

- Other metering options
- Standard fast metering
- Fast metering dedicated to Frequency Deviation Pricing (FDP) service

Looking at these one-by-one we have concluded that the following are likely the most significant.

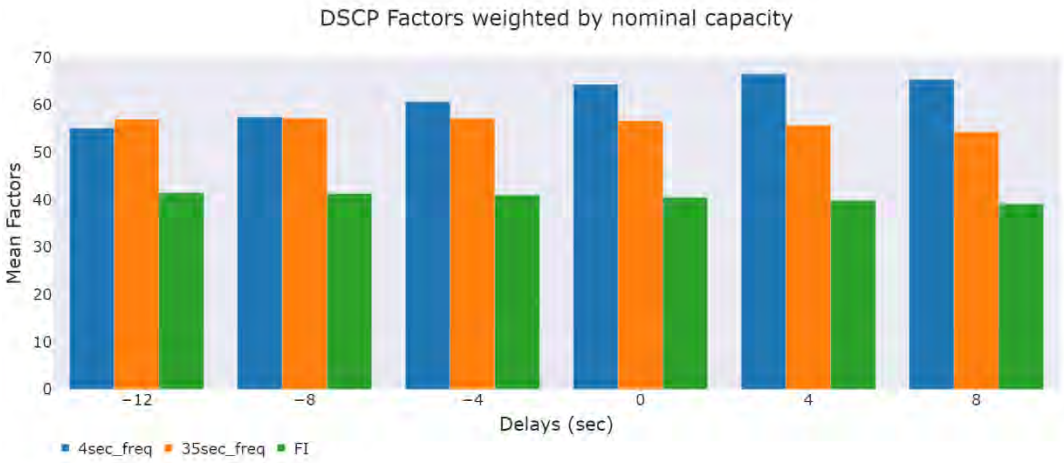
- Time Delay Error; and
- Outage error

Time Delay Error

For the time delay error, our method was to shift the frequency measure recorded by the AGC at AEMO with the generation and load profiles also recorded there, and to examine performance factors cases with the generation shifted forward and back in 4 second blocks. The metrics used were 4 and 35 second lagged frequency measures as well as

AEMO's AGC Frequency Indicator (FI) measure. The results averaged over all units are shown in Figure 14 following.

Figure 14 Average of DSCP factors for each delay and each performance metric weighted by capacity



- When interpreting these charts, note that the measurements recorded at AEMO already have a lag which may vary with the unit and may vary also with the unit at different times. Therefore, to correct for that lag we need to shift the load forward – in the positive direction in the chart. However, in general, we don't know the lag.
- The figure shows that for the 35-second and FI metrics there are no significant differences for positive or negative lags up to 12 seconds. The difference between the two lagged measures is of no significance.
- There is a significant trend evident for the 4-second measurement. The slope is quite steep on the negative side but flattens out in the positive direction. This cannot be surprising. We would expect tight PFR to be delivering a close relationship between deviations and frequency, so we would assume the performance metric would be at a maximum when the metrics are properly aligned.
- From the chart, this suggests that 'true' generation values are around 4 seconds ahead, so the average error is the difference between the 4 second ahead and zero second blue bar heights. This error is about 5% on the low side. As a sanity check, we note that the AEMO communication standard specifies a maximum transmission time delay of 6 seconds, so a 4 second average time delay is well within bounds.
- One interesting observation is that there would be an incentive to work to reduce any transmission delays, to maximise a unit's metered PFR factors.
- Another observation is that the use of factors in a 'sharing' mode, or with an adjustable pricing gain could ameliorate the effect of uniform transmission delays. However, these delays could vary at the bad end. The best solution in that case would be to stay within the standard.

Outage Error

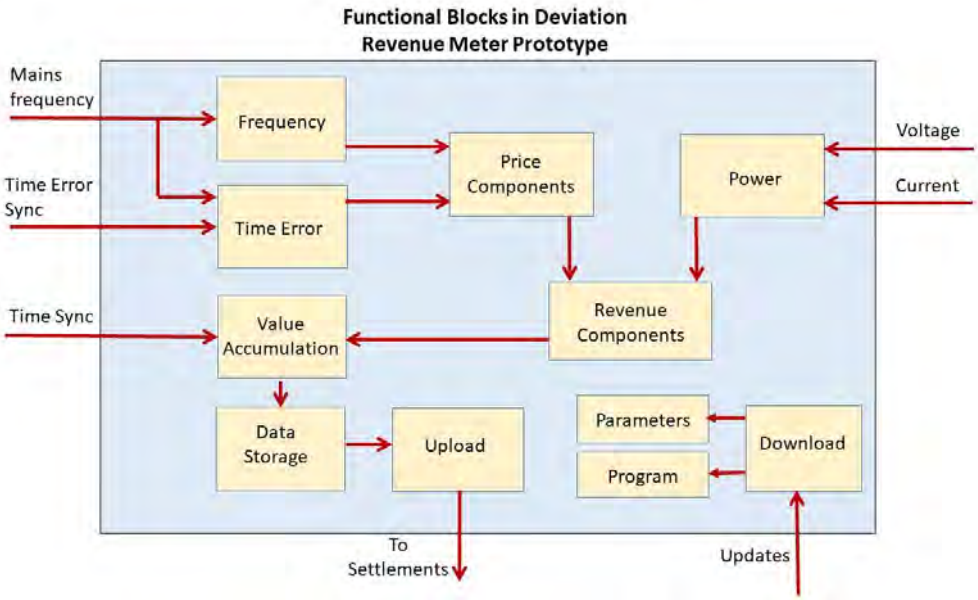
SCADA metering outages occur from time to time and some procedure is required to deal with them. For revenue metering a range of estimation methods can be used but for PFR/DSCP we suggest a clean and simple solution.

- If metering affecting a unit at some DI is deemed unreliable or not available, that unit should be deemed 'unmetered' and treated as part of the residual for the affected intervals.

Oher Metering Issues

- FDP/DSCP should continue to operate, even during generator contingencies. Even though there will be some initial error, the DSCP logic will be valid and greatly assist during the recovery phase. The initial error will be relatively small, even when considered only over the duration of the incident.
- In the event of network separation, the FDP/DSCP system can continue to operate with the same global parameters but local frequency measurements and market weights. Some additional adjustment may also be applied in time. Regional frequency data should be available to SCADA at all times.
- The different SCADA standard in Tasmania (8 second resolution) presents no issues. In implementation, we calculate mean performance factors rather than totals and compensate at settlement time. No data interpolation is required. Naturally, resolution will be less but adequate for Tasmania.
- Local metering dedicated to FDP or perhaps upgraded revenue metering with an FDP capability should be researched. Such metering would support the participation in DSCP/FDP of smaller scale embedded options where centralised SCAD might be impractical. In case local metering is likely to be superior because there are no transmission lags. A functional diagram of such a mater is show in Figure 15 below.

Figure 15: Functional diagram for a dedicated DSCP/FDP meter



3.4.4 FDP/DSCP Model Development

- Our initial planning provided for the development of a comprehensive control and pricing model to test issues around a FDP/DSCP implementation. This model is operating but at a basic level, sufficient to demonstrate concepts (which we will use later in this Report). However, it needs further reporting to allow a more comprehensive system to be modelled and understood. The details of the modelling system is outlined in Appendix A of the Analysis Report
- After the release of the AEMC Draft Determination, the Project adjusted its priorities to develop a back-casting capability. We have demonstrated this by undertaking a preliminary comparative analysis of the Draft AEMC Rule and the proposed system design that this Project has proposed (although not at the time a final version). This is presented as Appendix B of the Analysis Report.

3.4.5 Modelling and Testing of Specific Situations

- We reviewed some DSCP/FDP implementation issues in the Control and Pricing Theory Report. However, most of those nominated in the Inception Report for completion in the Analysis phase have been deferred to this Final Report as outlined in the previous sub-section. They are summarised in Appendix D to this (Final) Report.

3.4.6 Conclusions from the Analysis Report

The conclusions from the Analysis Report are briefly summarised as follows.

- The mandatory PFR rule introduced by the AEMC and implemented by AEMO with effect from 4 June 2020 has been successful in improving system frequency performance. However, this has been achieved substantially from plant that is expected to be phased out over the next decade or two. There remains the

challenge of how to muster resources efficiently to achieve adequate frequency performance.

- SCADA metering is subject to a range of error sources, more so than dedicated revenue metering. The likely largest source of error is the potential delay between measurement at a site and its receipt by AEMO. Some DSCP measures, including raw frequency, are more sensitive to delays than is a smoothed measure such as the FI from the AGC system or a smoothed frequency measure. For compliant units with data delays less than 6 seconds, the error is bounded but there are likely to be pathological cases. A program to develop and roll out dedicated FDP/DSCP meters would certainly resolve this issue but should not be required for an initial implementation. The possible need for upgrade of some communication facilities and the associated cost needs consideration at the design stage.
- This analysis also highlighted some likely design choices related to metering, including:
  - units with missing or poor-quality data should be treated as part of the residual for affected dispatch intervals; and,
  - the FDP/DSCP system should continue to operate during a contingency event.
- We have developed code which can process SCADA data for notional DSCP settlement using various design parameters. This will be used to further tune and stress test our final recommendations, along with the operational modelling foreshadowed in our Inception Report.

4 Review of Critical Design Elements

4.1 Overview

This Project has canvased the theoretical basis for FDP/DSCP and performed a number of analytical studies on elements relevant to the approach. During that time the study team has received feedback from the Project Steering Committee, AEMC and AEMO and the industry generally, though a number of workshops.

In September 2021, the AEMC released is Draft Determination of the issue[20]. In Appendix B we summarise and critique the proposed arrangements. We conclude that, while the arrangements would represent clear improvements to the current arrangements, they appear more complex than they need to be. Further, there is much left unspecified. While leaving the technical details open for AEMO specification is appropriate, the latitude given is so wide that the stated objective of the arrangements could be compromised.

These developments have given us the opportunity to revise some of the detail in our proposed arrangements. In this Section we review some of the elements of the design that have evolved since our initial work or have provoked most debate. We will compare and contrast the proposed approach with that in the AEMC Draft Determination when appropriate.

4.2 Distinguishing Primary and Secondary Control and Pricing

One of the debating points in the industry is the form of the metric to be used to assess performance. For a single DI we have, we have:

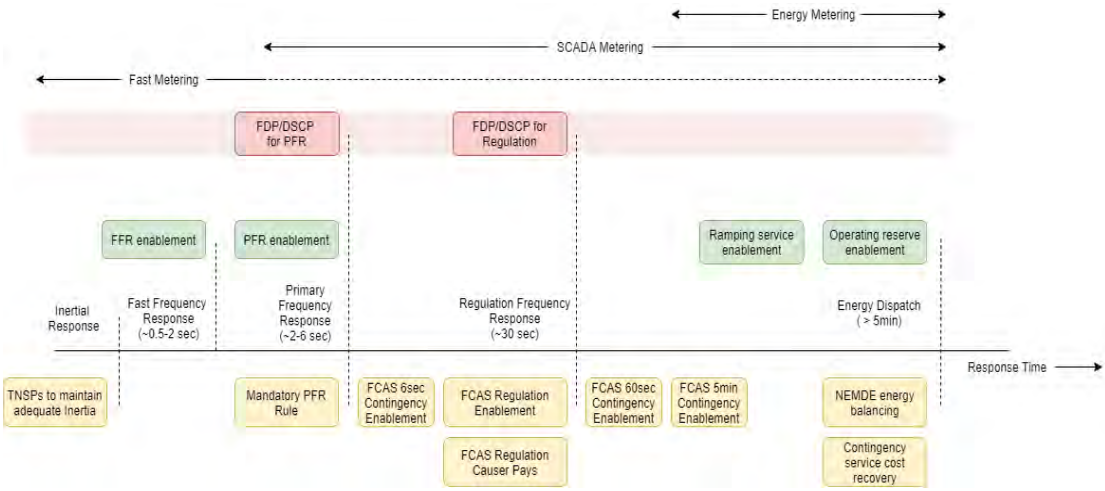
Performance_Factor = Sum_over_DI (Metric x Deviation-from-Scheduled Trajectory (9)

A key result from the theoretical work is that an optimal control and pricing strategy is well approximated by the sum of distinct, or separable, components based on the readily available measurements of frequency deviation and time deviation. Each component is characterised by time constant, indicating how much the raw measurement is 'smoothed', and a gain, indicating the component's relative importance.

For both a system model as well as a real system the number of different price components is potentially very large. However, a practical implementation requires identification of a set of components with time constants separated by, say, an order of magnitude. Figure 16 following shows the different existing and potential services, highlighting distinct FDP/DSCP services for PFR and for regulation

[20] AEMC, *Draft Rule Determination National Electricity Amendment (Primary Frequency Response Incentive Arrangements)*, 16 September 2021

Figure 16: Existing and potential frequency control services in the NEM



To illustrate the basis for distinguishing these services, which mirror currently mandated PFR capability and AGC regulation, we have constructed a simple system model and the present a specific simulated outcome illustrated in Figure 17 following.

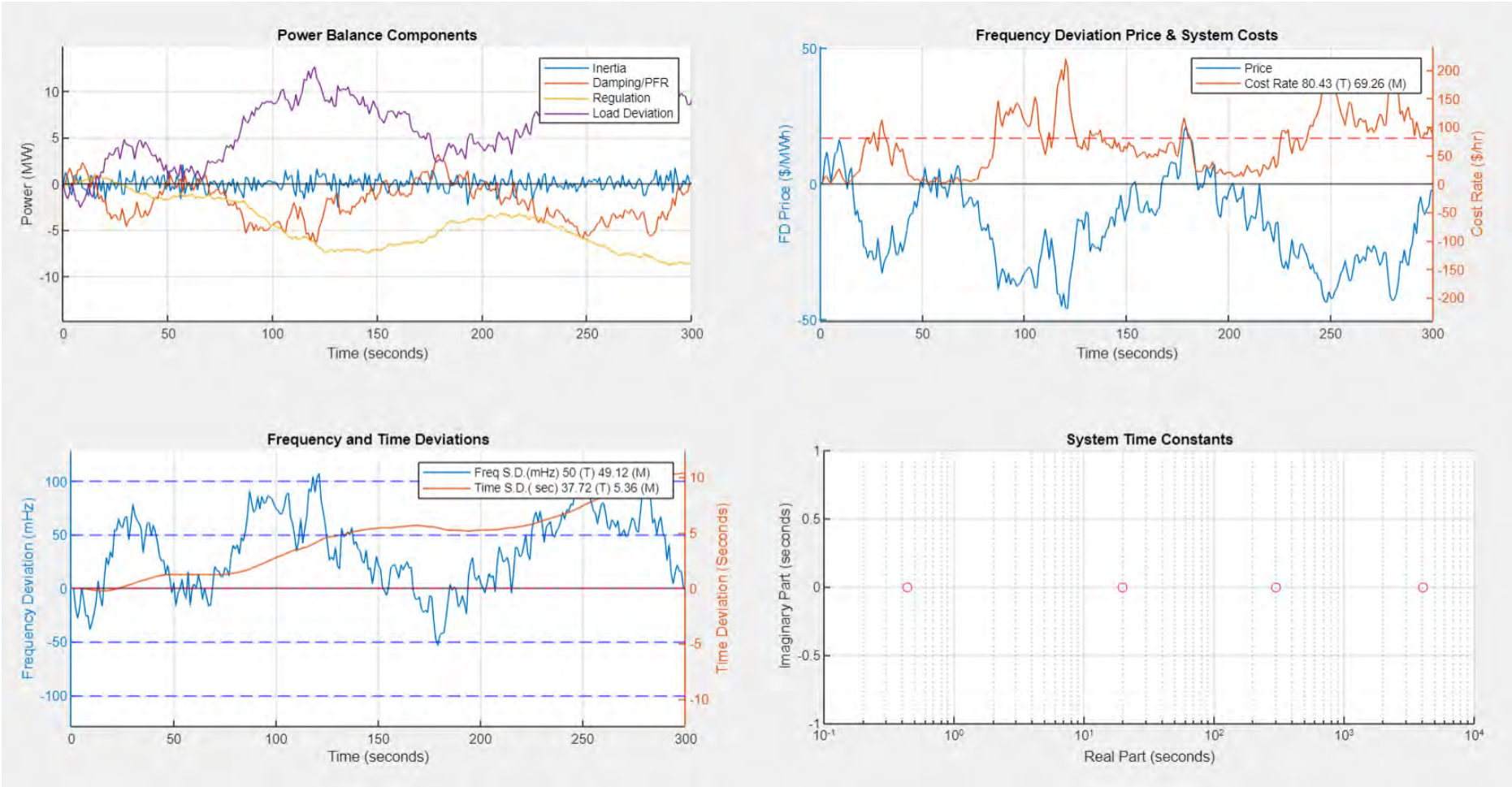
The system is a single generator and single load subject to random disturbances similar to a real load. System parameters are reasonably realistic but are intended for illustration only. The generator has a PFR capability and costlier, slow moving control capability. The objective is to achieve a target standard deviation (variance) of frequency at least cost. Note that all deviations that involve a net injection that increases frequency are treated as positive, regardless of whether they are caused by the generator or the load.

- The top left chart shows the evolution of key power components in the system over the 300 seconds of the simulation.
- The bottom left chart shows the frequency deviation behaviour (In blue) and the slow-moving time deviation.
- The top right chart shows the total system costs (in red) and the system frequency deviation price (in blue).
- The bottom right chart shows the system time constants on a log scale, to be described later.

Focussing on the top left power balance, the purple trace is the load, which shows a drift upwards (causing frequency increases, which means the load is dropping). This is balance by three components. The blue is inertia, or stored energy which absorbs the very rapid load fluctuations. The second (red) component is PFR or damping. It varies somewhat more than inertia. The last and balancing component id the regulation (yellow). These three components, in sum, balance the load.

We can see a period here (between 150 and 200 seconds) where the frequency has been controlled and PFR is small or zero, yet a significant regulation (yellow) element is required to maintain that frequency. It follows that a price based solely on raw frequency deviation would fail to support the secondary service needed to maintain frequency control.

Figure 17: Simulation illustrating the distinct roles of PFR and regulation



On the other hand, pricing the smoothed secondary service without pricing PFR would lead to many situations where secondary pricing alone would run contra to the need of the system for a PFR response. The price spike at about 180 seconds is an example. This PFR component is necessary to avoid contrary behaviour of secondary pricing alone, even separate from considerations of compensating or rewarding the performance of PFR. The existing Causer Pays has a problematic arrangement whereby DIs containing such contrary periods are simply dropped from consideration in settlement. Adding a PFR price component would have been simpler and more robust.

The system time constants shown in the bottom right chart are instructive. These values are derived by analysing the dynamic characteristics of the modelled system. The system is simple, so there are relatively few such time constants. However, they illustrate a range of possible situations that are worth reviewing. Time constants are plotted on a log scale:

- at 0.5 seconds, this reflects the near instantaneous PFR or FFR response;
- at 11 seconds, this would represent the slower response/regulation (relatively fast!);
- at 200 seconds, this reflects the slow 'mean reversion' behaviour of the load; and,
- at 1300 seconds, this represents the time constant that would be applied to time deviation component.

We note that

- the energy market is intended to maintain energy balance over the period beyond 5 minutes from a disturbance; and,
- SCADA metering cannot accurately measure performance acting more quickly than PFR.

If we are restricted to SCADA metering, the price components we can support are:

- a raw 4 second component;
- a component corresponding to regulation with a time constant of around 35 seconds (matching centralised AGC); and,
- a time error correction component with a time constant of the order of one hour.

4.3 Characterising the Residual

We review some properties of the Residual that simplify any implementation of FDP/DSCP.

We can think of the Residual as the loads and generators in the system that are not metered to capture dynamic performance. However, this is a mischaracterisation. If we include losses in this definition (which do not have direct metering), we can in fact meter the Residual because its interfaces with the rest of the system are all metered. So, the residual by this definition is the negative sum of all the participating unit meter readings a corresponding definition applies at the time of scheduling.

To further justify this, consider a boundary drawn around a region through measured points of entry and exit. Those points can be generators, loads or interconnector boundaries. We then note the following:

- The scheduling process defines a set of MW targets which are required to sum to zero for equilibrium, setting aside modelling error.
- The physical realisation of power injections and offtakes also sum to zero by the laws of physics, noting that losses are including in demand forecasts.
- The sum of deviations is the difference between actual and scheduled summations and so must also be zero.
- It follows that, when weights are uniform throughout the region or regions being settled, positive payments must equal negative payments at all times, including at each sampled point in time, whether the system is requiring Raise or Lower or whether the sampled measure is a raw measurement or summed over a DI.
- A slight adjustment is required if there is price separation between regions for any reason. In this case, interconnectors and even a regional network could generate a surplus or deficit, as in the energy market. This would need to be allocated in some way. However, if regional residuals are to be spread around evenly on equity grounds, or regional settlement not performed at all unless physically required, we do not normally need to calculate regional residuals; we can settle the whole interconnected system as a single entity.

Given that the residual can be metered implicitly, we should in principle be able treat it in an FDP manner, just like other units in the system. It will have:

- a baseline trajectory (the forecast together with scheduled losses);
- a response proportional to frequency deviation (called load relief, which is proportional to frequency deviation);
- possibly some smoothed responses; and,
- possibly also some controlled responses.

A difference is that demand general loads are not currently bid into the market (a forecast is the substitute) and that settlement amounts must be distributed to the various commercial entities that make up the residual according to some rule.

The existing Causer Pays system has a complex treatment of the residual. It includes within the procedure analyses of how demand-side deviations are incurred, through demand forecast errors, deviations within 5 minutes and in interconnector losses. Such analyses are useful to do after the event but contribute little to the FDP/DSCP outcome. The simplification proposed above is worthwhile.

4.4 Relationship Between AEMC Draft Rule and FDP

This sub-section examines how the relatively complex implementation rules set out in Clause 3.15.6A of the draft rule can align with the logic proposed in the Pricing and Theory Report prepared for this Project. The rule change clause defines 7 types of transactions to apply at each trading interval for various classes of participants and levels of performance:

1. An allocation of the AGC regulation enablement cost ‘used’, based on a measure of the degree of cause where such a measurement can be made.
    - differs from current Causer Pays which allocates all of this cost, not just the ‘used’ part.

2. A similar allocation to the residual, pro-rated to parties by energy at each DI.
3. A separate allocation of the remaining 'unused' FCAS enablement cost to scheduled and unscheduled parties, pro-rated by energy in the DI.
4. A payment to units with positive performance factors, paid in a similar way and rate as in (1) above.
5. A payment similar to (3) to unmetered parties who, as a group, also have positive factors.
6. A charge to recover the costs of (3) and (4) allocated to metered bad performers in proportion to their performance factors.
7. A charge to recover the costs of (4) and (5) allocated to non-metered bad performers allocated in proportion to energy in the DI.

There are elements of this approach that are problematic, such as the proposal (3) to spread the cost of unused regulation enablement to scheduled units, whose behaviour can be distorted by such payments.

However, an over-riding observation is the complexity of the approach. Part of this complexity is driven by the sequencing of the tasks: first, to recover the cost of enablement; next, to pay something to positive non-enabled performers; next, to recover the cost of these payments, next to spread the cost of unused enablement and, finally to allocate costs to elements of the Residual.

Further, the settlement formulae themselves appear complex. For example, the cases above typically implement variations of the following formula:

$$TA = \text{the aggregate of}\left(TSFCAS \times \frac{PMPF}{NAMPF} \times \frac{RR}{EA}\right) \tag{10}$$

where

TA is the trading amount for the DI for a unit

TSFCAS is the cost of enablement for the interval

PMPF is the positive performance factor of the unit

NAMPF is the aggregate of negative performance factors

RR is the regulation requirement for the DI (in MW)

EA is the enabled amount (in MW)

The aggregation function refers to the distinct raise and lower services and the possibility of local and global services. We can ignore this for discussion purposes and focus on the DI-level terms inside the brackets.

From Appendix C, the corresponding settlement formula for the FDP approach is simpler. Adopting a similar notation to equation (10) above we have:

TA = the aggregate of (MPF x Weighting_Price x Constant)

Where *Constant = Constant0 * TDI / SigmaF*

MPF is the Mean Performance Factor

Weighting_Price is a price (energy or AGC enablement) expressed as $/MWh

TDI is the DI duration

SigmaF is the targeted standard deviation of the performance metric (11)

However, we can recognise that the Draft Rule settlement formula and FDP settlement formula are slightly different variations of the same thing by noting the alternative FDP settlement formula from (29) in Appendix C.2. Adjusting the notation again to be relatable to the Draft Rule, the re-formulated FDP settlement formula is:

TA = The aggregate of (FDP_COST x MPF/MPFM x Ratio)

Where *FDP_COST = SigmaX x Weighting_Price(k) x TDI x Constant0*

Ratio = MPF/(SigmaF x SigmaX) (12)

We compare and contrast the Draft Rule formula (10) with the FDP formula (11):

- The costs *TSFCAS* and *FDP_COST* would likely be very similar but not identical. *TSFCAS* could be more variable. The FDP option through the constant *C0* provides a facility to tune the level of the FDP price to recognise performance relative to need. This feature is absent from the draft Rule approach but could be added.
- The ratio *PMPF/NAMPF* in the case of the Draft Rule and *-MPFM/MPFR for* the FDP are both shares that sum to 1 if the Residual is calculated as the negative sum of the metered units. However, for the Draft Rule the denominator is the sum of all negative performers while for the FDP the denominator is the residual only. The use of mean factors in the FDP case rather than totals is a convenience but not critical. More critical is that the FDP ratio can be interpreted as the fractional contribution of the unit to the variance of frequency (or equivalent MW) over the interval. The Draft Rule version allows no such interpretation.
- Finally, the ratio RR/EA in the Draft Rule and *Ratio* in the FDP case above are adjustments that recognise the system performance in the DI relative to a longer run expectation or target. Again, the relative measure in the FDP case is based on a form of correlation - in the Draft Rule it's based on a MW calculation. The outcomes would be similar but not identical.

While these are interesting comparisons and highlight the genetic compatibility of the Draft Rule and FDP approaches, the FDP settlement formula below (repeating equation (11)) seems far more direct:

TA = the aggregate of (MPF x Weighting_Price) x Constant) (13)

An FDP yields a self-balancing settlement, but leaves open the question of how regulation enablement should be paid for. Some options compatible with the FDP approach are analysed in the next sub-section.

4.5 Treatment of Regulation Enablement Trajectory and Costs

The Draft Determination leaves it to AEMO's consultation process to determine an appropriate rule for setting trajectories, including whether or not the AGC regulation trajectory should be a component of the deviation measure[21].

We see merit in including AGC-enabled units in a regime that pays for good performance as performance under AGC seems very uneven. If this is done the FDP/DSCP regime could be regarded complementing and improving the performance of a range of existing services including:

- AGC regulation
- Decentralised regulation
- PFR
- Ramping
- Operating reserve
- Contingency recovery

Our starting point is that AGC enablement should be paid for by the Residual. Our argument is that non-AGC-enabled and metered units will be actively priced by a balanced FDP arrangement and there should be no additional cost allocations to them to distort outcomes.

However, there are several ways to include AGC regulation into an FDP system. Each in turn will affect how much revenue is generated to help the Residual to pay for AGC regulation enablement.

- Assess the performance of AGC-enabled units (and pay them) according to their performance relative to a trajectory which includes their dynamic AGC trajectories.
- Assess the performance AGC-enabled units (and pay them) according to their performance relative to an energy market trajectory, as for all other units.
- Assess the performance of AGC-enabled units (but do NOT pay them) according to their performance relative to an energy market trajectory. The earned amount instead goes directly to the Residual.

The last two are similar except that the income (usually) earned by the AGC-enabled units in the first case goes to the units and in the second case goes directly to the Residual. We will argue that competitive pressures should tend to drive the outcomes of each of these cases together.

4.5.1 AGC Trajectory Option

Using a unit's AGC trajectory for any form of performance evaluation of the unit is problematic. The reason is that this trajectory is the result of a dynamic re-adjustment within the AGC every 4 seconds that accounts for and tracks a unit's actual performance. Thus, it cannot be used to measure AGC performance or even PFR performance. While it has been moderately useful in the past to encourage less use of AGC when aggregated

[21] See Clause 3.15.6A(k3) of the Draft Rule

over all enabled units to form the FI measure, we reject using it in any updated FDP/DSCP system.

4.5.2 Paying the FDP to AGC Units Based on the Energy Market Trajectory

Under this option, AGC-enabled units are treated exactly the same as other units and are paid an FDP according to their performance relative to the standard (non-AGC) metrics and their energy market trajectories.

- An attraction of this approach is simplicity and consistency in incentivising performance, while maintaining the inherent financial balance in the system.
- A potential disadvantage is the scope and perception of 'double payment'; payment for both enablement and performance.
- A practical issue for review is whether the FDP metrics are sufficiently consistent with the AGC trajectories which are centrally controlled, even though the response is very much at the unit level.

To consider the double payment issue, we examine how a notional system might evolve. **Error! Reference source not found.** below shows and indicative cost allocation to broad groups in the NEM under a series of potentially evolving situations.

- The existing allocation is shown in the first column, showing regulation enablement cost at 100%. Of this roughly 50% is currently allocated to poor-performing generators and 50% to the Residual. Non-enabled good performers get nothing.
- Under Phase 1 of the new arrangement, all regulation enablement costs allocated to the Residual. The FDP cost to the Residual is tuned to 50% of enablement cost. This leaves the cost allocated to poorly performing units unchanged, an FDP amount available to enabled units and an amount available to good-performing non-enabled units. In Phase 1 this allocates 150% of AGC regulation costs to the Residual (relative to the present) when it was only 50% previously. The changes are shown in yellow.

Table 2: Indicative evolution of payment and cost allocations under Project proposal Case: 50% FDP relative to residual enablement allocation

Payer/payee Groups	Existing	New - Phase 1			New - Phase 2			New - Phase 3		
	Reg	Reg	FDP	Total	Reg	FDP	Total	Reg	FDP	Total
Reg units	100	100	50	150	50	50	100	0	50	50
Good non-reg units	0	0	50	50	0	50	50	0	50	50
Poor non-reg units	-50	0	-50	-50	0	-50	-50	0	-50	-50
Residual	-50	-100	-50	-150	-50	-50	-100	0	-50	-50
Total	0	0	0	0	0	0	0	0	0	0

These figures are indicative only. Note that the initial target of 50% FDP relative to enablement cost allocated to the residual is not maintained though this evolution. In Phase 2 the ratio has moved to 100% and in Phase 3 to a very large value. As a result, it would be prudent to ramp up the target ratio gradually to avoid the use of enabled units falling faster than AEMO can prudently adjust the requirement. Driving a large gap between regulation enablement and its use could be costly.

Phase 3 is not the end of it. Heavier reliance on FDP is likely to lead to improved performance all around and, importantly, scope for wider participation by embedded loads and generation.

4.5.3 Including AGC-enabled Units in FDP But Not Paying Them

This option is the same as the previous one except the payments that would otherwise go to enabled units go directly to the Residual.

- The advantage of this approach relative to the previous is that the funds generated would be a substantial contribution to enablement costs that would not relay on competitive behaviour from enabled units.
- The obvious disadvantage is that enabled units would be completely removed from the competitive incentives provided by an FDP system, offering little incentive for improved performance.

One way to phase in the participation of AGC regulation in FDP is to add a system parameter to define the proportion of AGC income from FDP to be paid directly to the Residual. This could start at 100% and be ramped down over time toward zero. However, if the FDP were to be ramped up gradually, this phasing in may not provide any useful additional flexibility

4.5.4 Operational Issue and Assessment

If AGC-enabled units are to be paid under FDP as well as be controlled by AEMO, there needs to be reasonable consistency between the controls and the FDP Metrics, lest potential AGC units don't see it to their advantage to become AGC-enabled.

Figure 18: Relationship between FI and smoothed frequency with TC = 35 secs

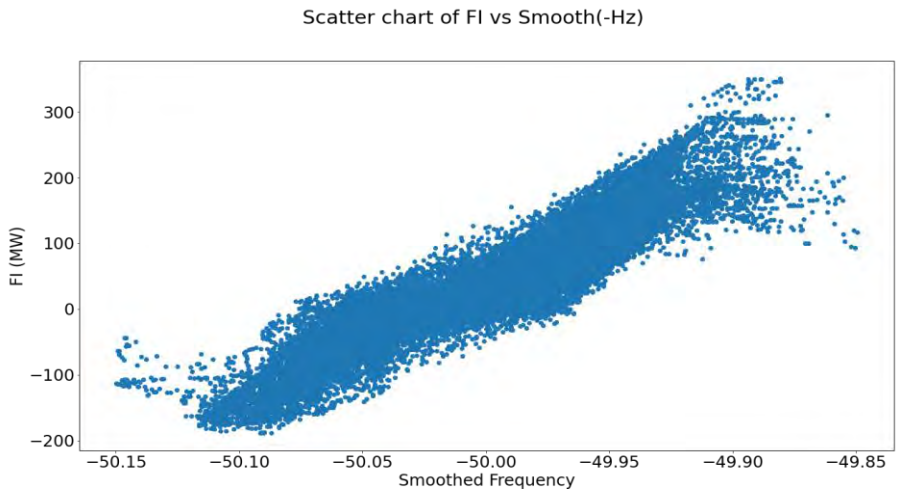
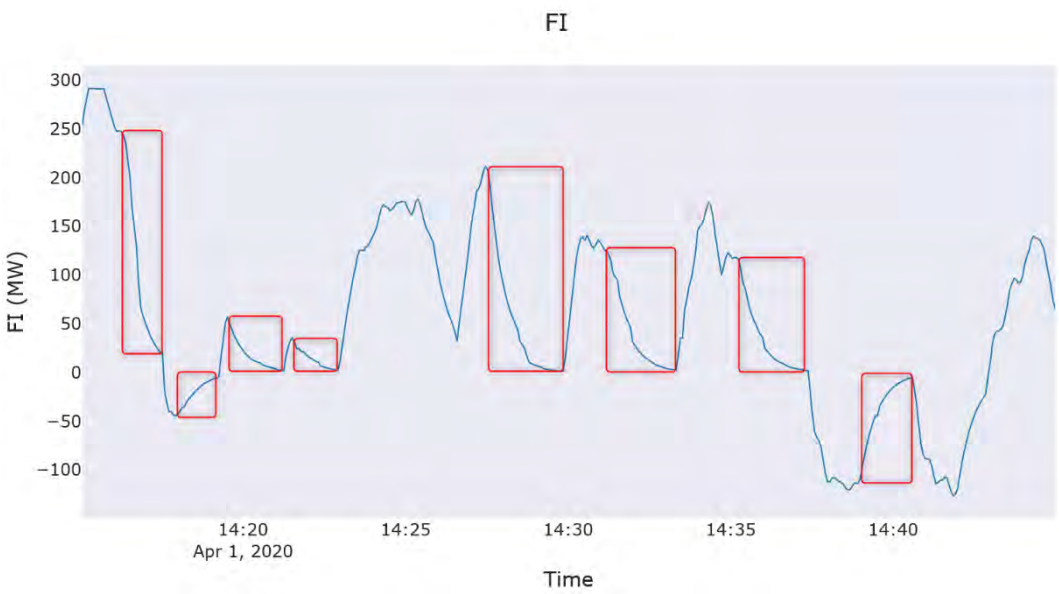


Figure 18 plots FI, which is indicative of the shape of most AGC trajectories, against an FDP smoothed metric with a time constant of 35 seconds. The relationship seems clear although further studies would be helpful.

On the other hand, if we review the actual FI trajectories from the AGC we observe highly non-linear behaviour. In Figure 19 below, the red boxed areas show frequent asymptotic behaviour toward zero. Clearly, the system at these times is operating within its dead bands (which do not yield zero signals because of the operation of the AGC's low-pass filter; the signals will approach zero asymptotically in those cases). It may be that the frequency is well controlled and frequently within the AGC dead band at these times. It may also be that the AGC dead bands are currently set too wide; the AGC might benefit from being set up in a more linear mode, with smaller dead-bands, now that mandatory primary response has improved frequency performance.

Figure 19: AGC control signals



4.6 Separating Raise and Lower and DI Level Weighting

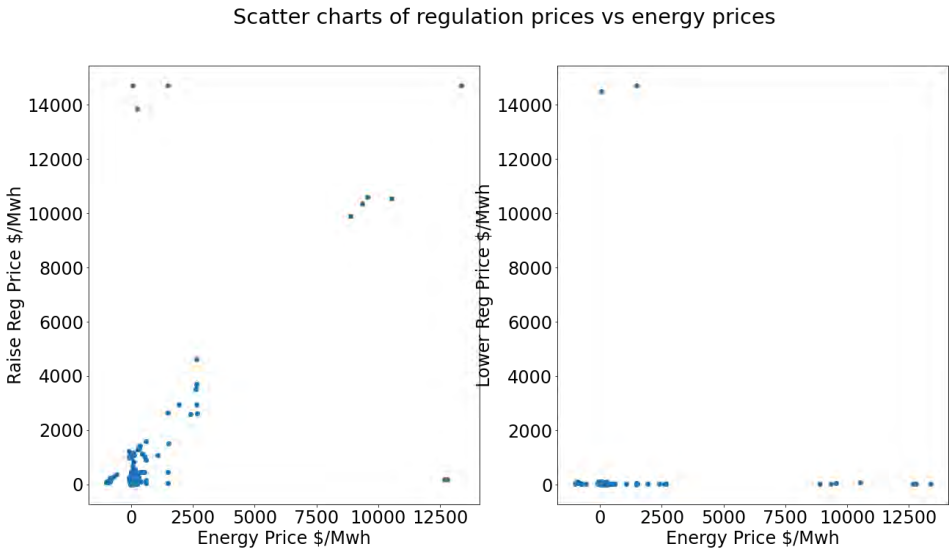
The Draft Rule would require Raise and Lower to be separated. This can be done by maintaining two sets of factors; one set for raise and one for lower. If we maintain negative and positive values also (as required by the formulae in the Draft Rule), that increases to 4 factors to be calculated and stored for each unit and each DI. In any one DI a unit can be subject to raise or lower, and be a causer or helper, to varying degrees. While such calculations are not particularly difficult, these distinctions tend to make interpretation and operations less transparent than they might otherwise be.

Another consideration is the weights to be applied at each DI while some weighting appears necessary to account for different system conditions, the most appropriate to use is unclear. In our Control and Pricing Theory Report we argued for the energy price as a natural benchmark, but this must be modified to account for near zero and negative

values. If Raise and Lower are to be distinct services, the enablement price seems like a more natural weighting.

In Figure 20 following we show a scatter plot of the energy price against the enablement price expressed in equivalent terms. There is a close relationship at the high end for Raise but not for Lower. At the low end, the energy price seems consistently above the enablement price. The reasons for this behaviour are well known to the industry but how that translates to an FDP/DSCP environment is not immediately clear. Preliminary examination suggest that behaviour is likely to be driven by a range of complex factors

Figure 20: Scatter Chart of energy price v. enablement price for Raise and Lower



The need to separate Raise and Lower, and the best weightings to apply at the DI level are, in our view, decisions and parameters that would benefit from trials or at least flexibility in implementation. It would seem relatively straightforward to provide for weightings to come from a variety of sources, as long as they are knowable ahead of time. Separate Raise and Lower services may well be found to mergeable if their optimal parameters are found to be sufficiently close.

We note that there appear to be no compelling arguments to have separate FDP-type payments for Raise and Lower in the case of PFR.

5 Proposed FDP/DSCP Design and Assessment

5.1 Proposed Design Elements

We are now in a position to outline an FDP/DSCP arrangement that takes account of the theoretical and analytical work we have done, and which simplifies and makes more specific the AEMC Draft Determination.

5.1.1 Scope

1. Mandatory PFR and AGC enablement markets should be maintained.
2. A new FDP/DSCP service should be introduced, intended to support:
   - AGC regulation
   - Decentralised regulation
   - PFR
   - Ramping
   - Operating reserve
   - Contingency recovery
3. The existing Causer Pays system should be terminated and replaced with a new arrangement as set out below.

5.1.2 Participation in FDP Trading

The new FDP/DSCP service will be based initially on the performance of scheduled units and interconnectors based on measurements at short sampling intervals, initially at the 4 seconds (mainland) and 8 seconds (Tasmania) available from the system SCADA. Participation of scheduled units will be compulsory, except possibly for an initial trial stage.

The set of elements (mostly loads but also including system losses) whose members are not metered at 4 second intervals or less is called the Residual. This can be specified at a regional level or an interconnected system level. The Residual will be a passive participant in the FDP/DSCP system.

Longer term, embedded generation and DER facilities may participate in the FDP arrangements. Doing this this will require:

- improved high resolution metering that does not require real time communication;
- arrangements to operate through an aggregators as required;
- arrangements for AEMO to have visibility of performance from metering data;
- arrangements to define reference trajectory for use in AEMO scheduling and in settlement; and,
- a new NEM rule defining the above arrangements.

5.1.3 Separation of Raise and Lower

Provision will be made for separate Raise and Lower services. These are distinguished for each metric (price component) in the system by the sign of the metric, positive implying raise and negative implying lower.

Further trials may indicate that Raise and Lower Services can and should be merged.

5.1.4 Pricing and Settlement

The system will support separate price components which are settled independently. They can be viewed by participants as separate prices or as a single combined price or FDP.

The pricing formula for FDP component j is defined for a specific short (SCADA) time interval t This leads to the following settlement formula for the DI as:

FDP_Component(j,t) = Metric(j,t) x Weighting_Price x Constant (14)

This leads to the following settlement formula for an FDP component and unit over a DI:

Settlement = MPF x Weighting_Price x Constant0 x TDI / SigmaF

Where

Settlement is the settlement amount in $

MPF(k) is the unit's Mean Performance Factor over the DI (see next sub-section)

Weighting_Price is the weight to be applied to MPFs in the DI

Constant0 is a dimensionless tuning constant (expected to be of order 1)

TDI is the DI duration

SigmaF is the target standard deviation for the metric. In the case of PFR it is set by the frequency standard and will be around 25mS for PFR and a similar number for a smoothed metric. (15)

Note that as the target standard deviation increases (is relaxed) the settlement amount will decrease, as expected.

The final settlement for AGC enabled units and the Residual will also account for enablement payments, as outlined in Section 4.5.

5.1.5 Performance Metrics

The system or region-wide measurements available locally are frequency deviation and time deviation. The FDP IT arrangements should provide for generic requirements, but the following are proposed for initial implementation:

- a smoothed 4-second time constant frequency deviation *Metric_SPFR* to support PFR, if desired; and,
- a smoothed 35-second time constant frequency deviation *Metric_SREG* to support both centralised AGC regulation and decentralised regulation.

Each Metric or signal SX is calculated with the following recursive formula (a low-pass filter):

*SX = (1 – dt/TCX) * SX_Old + (dt/TCX) * Freq_Deviation_Measure*

where

SX_Old is the SX value at the previous sample point

dt is the sampling interval (4 seconds on the mainland)

TCX is the component's time constant

Freq_Deviation_Measure is the measured frequency deviation (16)

Note that if *TC = dt* (both 4 seconds, say), then *SX = Freq_Deviation_Measure*

- Note also that the measurements take no account of the 15mS dead band implemented for mandatory PFR. The current standard deviation of frequency is about 25 mS which is lower than it strictly needs to be, so that units must operate well outside this dead band. So, the proposed measure would be capable of capturing performance outside the dead band which is critical to achieve a 25mS standard deviation. Some practical calculations of recent historical data should settle this issue.
- It would be possible and desirable to add a time deviation correction component to provide a slight pricing bias to correct for time deviation. This can be justified in several ways but all lead to a small, separable price component. The time constant to correct time deviation is currently one hour and is designed to correct time deviations with minimal impact on frequency control. This integral component is *not* the same as the component supporting secondary control, which has a much shorter time constant of 35 seconds.

5.1.6 Unit Deviations

Unit deviations are measured at SCADA intervals relative to a target-to-target energy market trajectory. This reference trajectory will apply to all metered units including those under AGC regulation, although final settlement for AGC regulation and the Residual will also account for the cost of AGC enablement; see sub-section 5.1.9.

The deviation of the Residual Including losses) is the negative sum of all the metered deviations.

5.1.7 Performance Factors

The measure of performance aggregated at the DI level is the Mean Performance Factor, or *MPF*, defined for each Metric for a participant and a DI as

$$MPF = Mean\_0ver\_DI\ (\ Metric \times Unit\_Deviation) \tag{17}$$

Note the that this measure is the same performance factor as used in the current Causer Pays system and proposed in the AEMC Draft Determination, except that we use the mean rather than the total. This is a modest implementation change but has the advantage of:

- being independent of the measurement interval; and,
- avoiding the need for data interpolation in the case of Tasmanian data.

5.1.8 Weighting of MPFs for Settlement

The *Weighting_Price* parameter is a multiplier to the DI performance factors to reflect the way incentives need to change as system market and technical conditions change during a normal day and in unusual situations.

If there is no distinction between Raise and Lower Services, as would be appropriate in the case of the PFR component and possible also for the secondary price component, a suitable weighting could be the local energy price (ideally including the local MLF) modified to deal with zero and negative values:

$$Weighting\_Price = Maximum(\ Floor,\ abs(Energy\_Price)\ ) \tag{18}$$

If the secondary price component is to be separated into Raise and Lower, the Raise and Lower enablement prices may be more suitable:

Weighting_Price = Enablement Price (Raise or Lower) (19)

In our settlement formula we assume the price is expressed in equivalent $/MWh rather than $/MW.

Our work to date has provided no quantitative evidence for whether one weighting approach is better than the other, or whether both could be improved upon in some way. We see advantages in using the energy price at is consistent with ease of hedging. However, the choice is likely empirical, along with whether or not separate services are really required for secondary FDP pricing

5.1.9 Settlement of the Residual and AGC Enablement Costs

FDP costs or payments are initially allocated to the Residual on an interconnected, synchronised system basis or regionally in the same way as to other units, based on the calculated MPF for the Residual. Regional Residual MPFs if needed or desired must use AGC interconnector scheduled flows and AGC measurements to bound the Region.

Define a parameter *AGC_FDP_Share*, which may be revised from time to time, as the share of assessed AGC FDP income (which will generally be positive and significant) which is actually paid to AGC-enabled units. For a particular DI it follows that the Settlement amount paid to an AGC participant is:

Settlement_AGC = AGC_Enablement_Payment + AGC_FDP_Share x AGC_FDP_Payment

which is a payment TO the AGC-enabled units (20)

For the Residual:

Settlement_Residual = Residual_FDP_Payment + AGC_Enablement_Cost +

(1 - AGC_FDP_Share) x AGC_ FDP_Cost

where the terms are self-descriptive, except

AGC-FDP_Cost = sum_over_all_AGC_units (AGC_FDP_Payments) (21)

The second is a payment BY the Residual. The Residual pays its share of FDP and all of the AGC enablement cost, but the enablement cost is offset by a share of the FDP earnings of all of the AGC units.

If AGC_FDP_Share is 100%, all the AGC FDP income would be retained by the AGC units. However, some or all could be returned to the Residual through the action of competition.

The settlement cost allocated to the regional Residuals will be allocated to Residual participants pro rate to metered energy in the interval. AEMO through its consultation process may choose to equalise residual payments across regions in most cases

5.1.10 Metering

Metering for settlement will be use SCADA measurements in the first instance:

- To minimise errors, data transmission delays should be kept within the standard.
- FDP based on SCADA metering should be used at all times when good data are produced and the market is operating, including during and immediately following contingencies.

- In the event that SCADA readings are assessed to be in error or unavailable for part or all of a DI, the unit for that DI should be treated as part of the residual.
- As the pricing formula contains a function of frequency which can be measured and calculated locally, only market data on energy and/or regulation enablement prices need be made available to participants ahead of (or slightly later than the start of) each DI.
- As concluded in our simple system studies reported in Appendix D, a future FDP/DSCP system is likely to require higher resolution metering. This requirement will be driven by the loss of system inertia as thermal plant retired and the likely prominence of fast-acting battery technology that can be a good substitute.

5.1.11 Treatment of Regions and Network Separation

- All settlement will take place on a regional basis, even though *Weighting_Price* may not have a regional basis on many occasions.
- When there is price separation between regions for any reason, a financial surplus or deficit may be produced by an interconnector. Any such surplus should be amalgamated into the regional residual pool.
- The FDP arrangements for the mainland, Tasmania and any other asynchronous but connected sub-region should be operated independently. DC interconnectors embedded in the AC network should be treated as scheduled units at their input and output points, although we would not expect them to respond to FDP signals.
- When there is physical separation in the network, the same pricing formula (but with different, regional weighting prices and frequency measurements) could apply if local frequency measurements are available. However, we would expect the market to be suspended in the smaller region until reconnection is established, so this possibility may not be relevant.

5.1.12 Operational Constraints

From time-to-time, AEMO may define additional operating constraints.

- An example may be to limit concentration of provision by defining rules on droop settings, although this may not be necessary.
- Such rules should be subject to industry consultation processes unless implemented as an emergency measure.

5.1.13 Information Flows

It is important for AEMO to be fully informed of the performance of units so it can monitor and assure the security of the power system.

- The components of the performance metric (PFR at 4-seconds and AGC and decentralised regulation at 35 seconds are proposed initially) are very direct performance measures.
- In addition, data from aggregators and VPNs can be combined in a specific way, for example, separately into discrete local networks, for TNSP, DNSP and AEMO analysis.

5.2 Indicative Outcomes Based on Historical Data

The Project team has developed a flexible back-casting model to evaluate FDP/DSCP options and their interactions with other services, mainly AGC regulation. This is presented in Appendix E. Three cases are presented:

1. One interpretation of the AEMC model from its Draft Determination.
2. The initial outcome of the final proposal from this Project.
3. The Projected settlement outcome after some competitive adjustments have modified settlement amounts.

It is important to recognise that these results do not show all the outcomes after behaviour has been modified in response to the change in incentives.

5.3 Studies of System Behaviour Under a Range of Future Conditions

In Appendix D we present the results of modelling that addresses some operational issues identified in Section 3.3 of the Project Inception Report. Rearranged for convenience and supplemented, the modelled cases are:

- System in 2021 – Base Case;
- System with high battery presentation;
- System with low inertia;
- System with more variability in forecasting and dispatch;
- System with bad behaviour by some units; and,
- System circa 2021.

In Appendix A of the Project Analysis Report we outlined a model that implements key elements of an FDP system. With some additional enhancements, we use that model in the studies. An important addition from the model described in the Analysis Report is the ability to target a specific standard deviation of frequency performance. This supports direct comparison of different situations because the y performance is maintained the same in all cases, by tuning the control and pricing parameters.

The physical model remains simple but captures most of the key elements that might affect system performance. It consists of a generator and a load of the same size. The generator and load both have properties of inertia, damping (PFR) and control (regulation). Data for the base case following is shown in Figure 21.

The data used are indicative only with no pretence at precision. The cases studied will generally be variations on the base case with a single parameter changed, except for the final case when multiple changes are made. Thus, the studies will indicate potential trends rather than absolute outcomes.

In all cases the target standard deviation for frequency is 30mHz, slightly more than the rather tight control of around 25mHz currently maintained by the 15mHz dead band of the mandatory PFR requirement.

The key conclusion from these studies is that, with all these changes to the system, stable control at some likely reasonable cost appears achievable with this FDP approach. However, higher resolution metering suitable for FDP settlement would be required.

5.4 Evaluation Against Assessment Criteria

5.4.1 AEMO's Assessment Criteria

The AEMO criteria, presented in detail in Appendix A.1, appear to have been written with PFR in mind but could apply also to decentralised secondary control supported by FDP/DSCP. The AEMC proposal and our Project proposal (slightly changed from out earlier report) are assessed against each in Table 3 below:

Table 3: Assessment of AEMC and Project proposals against AEMO criteria

Criteria	AEMC Proposal	Project Proposal
Decentralised	Decentralised control, centrally transmitted metering and centralised settlement. Would apparently leave current centralised AGC untouched but this is not fully specified	Provides for decentralised PFR and secondary control and a clear path to fully decentralise metering and embedded customer settlement though an aggregator.
Distributed	Yes, though mandatory rule	Mandatory rule maintained but with programmable level of financial support that may focus provision more narrowly unless controlled in some way. Weighting strategy could encourage geographical diversity
Simple	Complicated by keeping Causer Pays and adding a separate payment and cost recovery measure (double siding). Some backward-looking settlement elements. Performance metrics and reference trajectories not specified.	Simple, balanced FDP market. Performance measure has several components including PFR but all are readily understood and easily measured locally.
Predictable	Maintains 'predictable' AGC, External provision and causer performance metrics are unspecified, but likely stabilising	AGC would be reduced and FDP increased, but stabilising
Flexible	The design fixes a pricing relationship between centralised AGC and external control action, which is some as yet unspecified	Pricing parameters tuneable: PFR relative to decentralised regulation and decentralised and

	mixture of PFR and secondary control headroom is notionally supported through pricing.	decentralised FDP relative to AGC. Extendable to DER

5.4.2 AEMC's Assessment Criteria

AEMC's criteria are similar to AEMO's in many respects but, understandably, have a more economic focus. For example, they refer to cost the of implementation, a cost benefit analysis and appropriate risk allocation in addition to a set of technical and other criteria similar to AEMO's.

Table 4: Assessment of AEMC and Project proposals against AEMC criteria

Criteria	AEMC Proposal	Project Proposal
Promote power system security and reliability. Includes cost/benefit.	Yes, but no detailed cost/benefit done	Yes, but likely a little easier and quicker to implement at AEMO and by customers, because simpler
Appropriate risk allocation	Allocates some of the cost of unused enablement to dispatchable units when it would be better smeared to inelastic elements	Allocates enablement cost to inelastic elements (i.e. the Residual).
Technology neutral	Much is unspecified, but some options would make technology assumptions (e.g. dead bands in price formulae). Not easily extended to DER	Largely neutral. Time constants and gains in pricing formulae need tuning depending on system behaviour. Easily extended to DER.
Flexible	Not fully specified but weighting of decentralised v. centralised appears locked in. No pathway to DER identified.	Absolute and relative weights of pricing for PFR and regulation are tuneable. Readily extendable to DER with high-resolution metering.
Transparent, predictable and simple	DSCP arrangements appear complex although not fully specified. They appear to have some backward -looking elements dependant on opaque AGC parameters	Simple, tuneable, AGC cost allocation to residual coupled with simple and balanced FDP arrangement applying to all other parties, separately tuneable for both PFR and secondary control. Performance is locally measurable in real time

Implementation costs	Relatively high cost for relative complexity – 4 values per unit per DI to be calculated and used for settlement	Low cost and faster implementation because of relative simplicity. One or two values per unit per DI to be calculated and used for settlement

5.4.3 Assessment Summary

The AEMC proposal has taken the long-standing Causer Pays process and improved it in several ways, including making measurement and payment/charging apply to each DI and applying different weights at different times depending on system need. It then adds a payment outside AGC for good performance and then seeks a mechanism to charge for it. It leaves open for AEMO to decide whether AGC will be affected or not. Other critical design parameters such as the performance metric remain unresolved. In summary:

- The AEMC system design is more complex than the simplified Project design.
- The AEMC leaves many important design details to later industry consultations. Some of these choices could completely change how the system works.
- Some allocation of costs (to dispatchable units) in the AEMC design provide poor incentives.
- The Project design is more easily extended to DER and is therefore more technology-neutral.
- The implementation cost and timeline of the AEMC proposal is likely to be higher than the Project proposal.

6 Implementation Strategy

6.1 Overview

The arrangements under consideration in this report are novel. The initial one-sided implementation, known as Causer Pays, was a one-sided arrangement that had some initial success, but failed on its own to maintain good frequency control because it had no focus on primary frequency control. A further challenge of the Causer Pays system is its one-sided nature, which introduces elements of arbitrariness. For example, one-sidedness makes aggregation into portfolios an attractive option, which is inherently anti competitive. Double-siding the arrangement does reward good performers but the system remains inherently unbalanced.

This Project has returned to fist principles and has come up with an alternative arrangement based on a frequency deviation pricing framework. We show that this framework can be made consistent with efficient, stable control if implemented correctly, with separable price components.

There are some elements of the design that cannot readily be resolved theoretically or by a direct appeal to experience. These elements can be regarded as tuning parameters rather than fundamental design features. For this reason, a phased implementation approach will likely yield the best outcomes.

The AEMC Draft Determination on enduring arrangements for frequency control was published part way through this Project. The Project team has taken account of the AEMC approach in our ongoing work.

This section sets out how an enduring FDP arrangement could be rolled out, with the Same DSCP functionality that the AEMC and industry is seeking, but simpler and more robust in operation and implementation.

6.2 Further Consultation

The AEMC Draft Determination implements a complex arrangement and also leaves critical design choices unspecified. These unspecified choices go beyond being technical details and could redirect the intent of the proposed new arrangements. A further 6 months of study and consultation should resolve these outstanding critical issues.

6.3 Meter Development

As soon as possible as the broad framework is agreed, work should commence on developing a high resolution, commercial revenue meter suitable for FDP operations. Again, a prototype design should be built and tested as soon as possible.

6.4 Concept Trial

Some issues may not be easily resolved without a trial. Such a trial could commence immediately after the consultation period; planning for the trial could be done before the end of that period. Ideally a trial should use real money and involve as many units as

possible, but a smaller trial using only notional money might be feasible, all else failing. The supporting system software should not be difficult to implement if it's just for a trial.

It may be that an early trial could continue while production software is developed and rolled out. The design proposed for this Project should not require complex software. A phased rollout should be possible by implementing the FDP at a low level and gradually ramping up the target percentage. Dollar turnover could be kept small and perhaps the current Causer Pays retained for a period. This would allow participants time and an operating platform to adjust their thinking and their systems. When any issues and software hiccups have been ironed out, one could 'flip the switch', reallocate enablement costs entirely to the residual and ramp up the FDP turnover.

Particular issues that could be explored at this stage include:

- whether positive and negative performance measures need to be maintained separately or combined, noting that the only purpose of separating them is targeting some level of FDP turnover. Using the relative size of FDP payment to enablement allocated to the residual seems like a perfectly adequate proxy;
- whether a distinction between raise and lower needs to be maintained in practice; and,
- the best form of the *Weighting_Price* to be applied to the factors measured at each DI.

Ongoing trials could be undertaken to:

- test the practicality of monitoring and pricing FFR with a high resolution protype meter; and,
- test whether FDP might be used, with or without t extensions, to defer or remove the need for separate operational reserve and ramping services in the NEM.

6.5 DER Rule Change

Once the wholesale FDP system is bedded down, consideration could be given to a rule change that would define how FDP can be extended to DER including VPNs and to individual sites via aggregators.

6.6 Reviews

The AEMC should track the development of FDP arrangements through a series of statutory FDP reviews.

- The first review (a revised and Final Determination) should conclude within in six months of the publication of this report and set the parameters for a trial and/or the system design in sufficient detail to define its capability.
- Another review and final determination might follow at the end of any trial period.
- In, say, two years the AEMC could receive a rule change to extend FDP to DER, VPP and other non-scheduled operation such as customer loads.

- A review after 3-5 years could examine historical performance and prospects for extension to, say, faster acting services such as FFR and even inertia. Conceptual work and trials on these options could begin earlier.

7 Conclusions

At the start of this Project, we had no precise definition of Double-Sided Causer Pays (DSCP). From earlier AEMC reports we knew it was envisaged as an improvement and extension of the current Causer Pays mechanism used to allocate the cost of AGC regulation. Compared with the 'ultimate' mechanism of Frequency Deviation Pricing (FDP), its merit was presumed to be relative simplicity in implementation as well as retaining the comfort of familiarity.

When we worked through the theory of control and the pricing logic that emerges from it (in precisely the same way that pricing emerges from a linear programming model of the electricity system), we derive a readily identifiable FDP model. A modest surprise from the theoretical work was the optimised form of the performance metric. Instead of being some function of 4-second frequency, it should also have one or more smoothed components added, filtered at different time constants, but still easily measurable and calculable in real time. Indeed, the raw 4 second signal can be regarded as an approximation to a frequency measured at high-resolution, filtered with a 4-second time constant. Thus, we concluded that DSCP, when implemented efficiently, is FDP in reality.

We can relate this result to the existence and need to support existing frequency control services. These include tight dead band (15mS) PFR and secondary control or regulation at present and, potentially, faster acting services such as FFR and synthetic inertia as well as slower ones such as operational reserves and ramping.

The AEMC Draft Determination took a somewhat different approach. It took the Causer Pays logic to pay for regulation enablement as a given, fixing some of the more obvious shortcomings such as:

- the broken connection between performance measurement and financial outcome; and,
- and the lack of weighting or indexing of DI performance factors.

It then added some separate logic to provide a payment for good performance outside of AGC regulation, and a means to pay for it. However, many critical design features were unspecified and several that were seem problematic. These include:

- the implied rigid relationship between the cost of AGC enablement, which depends on AEMO's requirement settings and FDP/DSCP payments in a more competitive environment;
- the cost recovery mechanism proposed for 'unused' enablement can distort behaviour;
- the lack of specification on the inclusion or exclusion of the AGC regulation trajectory, a critical design choice;
- there is no clear path to extend the system distributed and embedded assets, and possibly also to support fast-acting services such as FFR and Inertia; and,
- the settlement formulae, based on Causer Pays with extensions, seems complicated, with 7 separate settlement logics.

In short, adherence to the DSCP model, while a useful starting point because of its familiarity, has delivered a design more complex that it needs to be.

The key to simplifying the logic is to recognise that double-siding can deliver an efficient and financially balanced system without additional scaling (and opportunities for portfolios not available to others) if an FDP philosophy is followed. Such an FDP-based system cannot by itself pay for enablement because it is inherently balanced. However, we can expect AGC regulation performance to improve and to be more competitive if AGC enabled units can receive FDP payments. Further, FDP payments to units not enabled will also improve performance and reduce the need for the AGC-enabled service. By easing the pressure on enablement, cost recovery can be simplified by assigning it directly to the Residual. At present, it goes substantially to the residual by a more complicated route. We can ease the transition initially by allocating some fraction of the FDP earnings of AGC units to the Residual.

We note some important characteristics of the FDP approach as proposed in this report:

- the approach avoids assigning any costs (outside of an FDP) to scheduled units, thereby avoiding the risk of distorting behaviour;
- being a balanced approach (apart from the specific arrangements for AGC enabled units), there is no potential advantage in settling at a portfolio level;
- settlement payments are complete and free-standing within each DI; and,
- the level of pricing can be adjusted to reflect unit responses while maintaining a financially balanced system

Other areas where further simplification or at least clarity should be explored include:

- whether positive and negative performance measures need to be maintained separately or combined, noting that the only purpose of separating them is targeting some level of FDP turnover. Using the relative size of FDP payment to enablement allocated to the Residual seems like a perfectly adequate proxy;
- whether a distinction between Raise and Lower needs to be maintained in practice; and,
- the best *Weighting_Price* to be applied to the factors measured at each DI.

If these simplifications are made, the implementation of an effective DSCP via a relatively simple FDP appears possible. However, we see implementation being phased in, beginning with a trial involving a relatively few units. While prototyping was used as an effective tool in the early stages of the NEM, current rulemaking appears to avoid this approach. Some form of prototyping to resolve complex issues has clear advantages. The Implementation process should contain the following elements:

- further consultation;
- meter development;
- concept trial;
- DER rule change; and,
- follow-up reviews.

While this Project has focussed on and FDP approach that supports PFR and secondary, regulation-type responses, FDP as proposed has wider application in two directions:

- with improved metering and new FDP components defined, FDP could be used to support FFR and even synthetic inertia (response proportional to RoCoF); and,
- with existing metering and possibly with a new, 5-minute FDP component defined (requiring no new system infrastructure), support for an operational reserve requirement and for ramping could be provided. Options for operational reserve and ramping arrangements are already under consideration as AEMC Rule Change ERC0295. FDP could provide sufficient flexibility to defer or indefinitely avoid the need for such additional arrangements. For this reason, we propose that this element be included in a trial programme.

Appendix A Assessment Criteria

A.1 AEMO's Assessment Criteria

In its Technical White Paper produced for the AEMC[22], AEMO has set out five criteria that it believes a frequency control regime should satisfy. They are quoted below in full for completeness:

- Decentralised – based on local detection and response, not impacted by communications unavailability, providing a dependable, robust, and proportionate response.
- Distributed – with a large number of contributors over a geographically disperse area, enabling responsiveness physically close to the disturbance, reducing dependence on individual providers and prevailing network conditions, and reducing duty on individual unit.
- Simple – reduceable to a sequence of actions that can be handled within the control hierarchy of unit, and, at the system level, provide a stable base level of narrowband frequency responsiveness for other frequency control reforms be progressively overlaid.
- Predictable – establishes a level of consistent responsiveness to frequency deviations, reducing uncertainty in power system behaviour, system adequacy and frequency control need assessment.
- Flexible – can scale over time as the technology mix changes and can be potentially extended to include new PFR sources and overlaid with a headroom management mechanism in the future (if needed).

Suitably interpreted, these criteria seem appropriate for evaluating the AEMC Draft Rule Change against the proposed arrangement developed earlier in this Project. This analysis will provide the basis for proposing amendments to the rule change, or to a specific approach to design issues during the AEMO consultation process.

A.2 AEMC's Assessment Criteria

The Commission developed the following principles to assess whether the preferred rule change is likely to support and improve the security of the power system, as well as improve the effectiveness and efficiency of frequency control frameworks. Unsurprisingly, these principles are largely consistent with the AEMO criteria but include some economic criteria, including appropriate risk allocation and technology neutrality. They are fully listed below for completeness:

- Promoting power system security and reliability: The operational security of the power system relates to the maintenance of the system within predefined limits for technical parameters such as voltage and frequency. System security, including frequency, underpins the operation of the energy market and the supply of electricity to consumers. Reliability refers to having sufficient capacity to meet

[22] AEMO, Technical White Paper: Enduring primary frequency response requirements for the NEM, August 2021,page 17, Extracted from UNSW submission to the AEMC.

consumer needs. It is therefore necessary to have regard to the potential benefits associated with improvements to system security and reliability brought about by the proposed rule change, weighed against the likely costs. These costs are likely to be minimised through workably competitive markets; where this is not the case, that is where providers of these services lack viable competition resulting in inefficient prices that exceed the marginal cost of providing these services, regulatory arrangements will be required to limit the exercise of market power.

- Appropriate risk allocation: The allocation of risks and the accountability for investment and operational decisions should rest with those parties best placed to manage them. The arrangements that relate to frequency control should recognise the technical and economic characteristics and capabilities of different types of market participants to engage with the system services planning, procurement, pricing, and payment. Where practical, operational and investment risks should be borne by market participants, such as businesses, who are better able to manage them. Risks, where allocated to market participants, are often managed through contracts. The impact of regulatory changes on the contract market, and the resulting ability of market participants to manage risk, is an important consideration.
- Technology neutral: Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology or be designed with a particular set of technologies in mind. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.
- Flexibility: Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment. Where practical, regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating security outcomes where required, while not imposing undue market or compliance costs.
- Transparent, predictable, and simple: The market and regulatory arrangements for frequency control should promote transparency and be predictable, so that market participants can make informed and efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to administer and participate in.
- Implementation costs: Regulatory change typically comes with some implementation costs for regulators, the market operator and/or market participants. These costs are ultimately borne by consumers. The cost of implementation should be factored into the overall assessment of any change.

Appendix B AEMC Draft Determination

B.1 Overview

Following is a brief overview of the main elements of the AEMC Draft Determination.

B.1.1 Coverage

The proposed system would operate in parallel with and support more efficient operation of MPFR as well as centralised AGC regulation. MPFR capability will endure.

B.1.2 Option to Distinguish Raise and Lower

The system will distinguish raise and lower services operating at different pricing levels.

B.1.3 Measurement and Settlement

Unlike regulation Causer Pays, settlement would be based on performance at the time of measurement. The intent is to use 4 second SCADA data but there is no detailed consideration of other metering options.

B.1.4 Performance Measure

The draft rule is not specific about the performance factor; this is something for AEMO to determine after consultation. However, it should be based on the product of

- some measure of "the need for regulation services"; and
- the deviation of each scheduled unit.

The residual is not regarded as a participant in this process, but rather a (collective) party to whom costs are allocated.

B.1.5 Double Siding of Causer Pays

A key element of the rule change is to make Causer Pays 'double-sided' i.e. to have an arrangement that pays 'good' performers in addition to penalising bad ones. At the moment the only way to be paid is to participate in the regulation enablement dispatch market.

The Draft Determination does not go back to first principles of FDP to define what double-siding means. Instead, it takes the implementation logic of regulation Causer Pays, which is based on 5-minute accumulated 'performance factors', settles them at the 5-minute level based on what proportion of reserved regulation capability is used (which in turn raises issues of what is to be done with the cost of unused enablement and how much enablement is required). It then defines an additional set of arrangements, linked to the first through a pricing rule, to implement and also recover the costs of positive performance payments. This approach yields an arrangement that appears more complex than it needs to be.

B.1.6 Deviations of Units and Residual

The measure of unit deviation is to be defined during AEMO's consultation process. The reference trajectory is expected to be a linear ramp either from the current measured position or the previous dispatch target to the next dispatch target. These are detailed design decisions that offer no scope to change the intent of the draft rule.

However, also left open is whether to include the regulation AGC trajectory into the reference level for DSCP settlement. We will argue that this is a major design decision and propose a preferred approach in Section 4.5.

B.1.7 Performance Metric

AEMC has attempted to use broad such as "reflecting the need for frequency control" to define the intent of its measure, but we will show that this can be widely interpreted. Some technical flexibility in the rule is necessary and desirable, but not differences that take the system in an unexpected direction.

The AEMC leaves the definition of the performance metric that would reflect the need for frequency control to be determined by AEMO through a separate consultation process. However, the options for this are very wide and imply more than differences in detail; some would completely re-define the purpose of the new rule. Examples of measures that could reflect the system requirement include:

- Raw 4 second frequency and time deviation measurements.
- Smoothed (low pass filtered) versions of the above.
- MW values derived from the above.
- Some combination of 1 and 2 or 3.
- Regulation requirement as defined the AGC.
- The system residual deviation.

The frequency-based measurements may be linear or perhaps some smooth, non-linear function such as a cubic. A dead band in the pricing/performance measure has also been proposed, introducing a pricing discontinuity as well as a non-linearity in an attempt to mimic the dead band settings of participating units. And distinguishing raise and lower services adds another layer of complication.

B.1.8 Accumulating Factors into DI-level Performance Factors for Weighting and Settlement

For practical implementation, factors are accumulated into DI-level (5-minute) values. The AEMC draft then links these values very tightly to the cost of that part of the enablement (raise or lower) that is 'used' in that DI. The cost of enablement is then allocated to assessed 'causers' according to their performance factors.

To implement double siding, a separate set of transactions pays parties with helpful factors and allocates costs to those with harmful ones, at a rate consistent with that used to allocate the costs of enablement.

Under this logic, the cost of 'unused' enablement must be allocated in some other way. AEMC proposes that this be spread to all participants, both scheduled and unscheduled (mostly the residual) in the same period where the unused amount is incurred.

B.1.9 Option to Extend Applicability to Parties with High-res Revenue Metering Rather than Real Time SCADA Metering

The Draft Rule says little about metering accuracy or the expansion of participation so that currently unscheduled parties including embedded generation and loads could provide

PFR and regulation services. Yet AEMO's technical paper does envisage greater demand-side participation by some means.

While the current rule should not be burdened with the detail how such expansion of participation might work, a vision of such an arrangement could highlight helpful adjustments to the current draft rule and its implementation.

B.2 Commentary

The proposed rule goes a long way towards fixing the weaknesses and distortions and inadequate coverage of the current AGC regulation Causer Pays process.

Key elements of the Draft Determination are:

- The rule mandating a tight 15 mHz dead band for all units should be enduring; and,
- there should be no enablement market for PFR.

Clear improvements are:

- settlement based on performance when needed as distinct from performance measured at an earlier time unrelated to a specific need;
- an attempt to weight the performance measure according to the cost of frequency control at the time (as indicated by the cost of enablement taken each 5 minutes from the dispatch process); and,
- inclusion of a regime for paying non-enabled parties for good performance (double siding of Causer Pays).

On the downside, the proposed rule fails to recognise or even rejects the FDP logic behind DSCP and appears not to recognise some useful characteristics of the residual. The result is unnecessary complexity in implementation and operation.

We note that AEMO's published advice to AEMC rejects the idea of a market for PFR. It argues that tight dead band MPFR is needed to deliver widespread primary response. Efforts to improve market arrangements should focus on secondary control. Perhaps this explains why a cost allocation logic more related to Causer Pays than FDP is proposed (although Causer Pays is simply a one-sided version of FDP). However, AEMO does support payment to tight dead band PFR providers. FDP is such a payment mechanism; it can be regarded as an administrative arrangement; not a market. One way or the other, this characterisation does not seem critical.

Appendix C FDP Settlement Formulae

C.1 Settlement amount for a Unit over a DI

For metered units, the FDP approach implements a formula of the following form for a DI at time period k[23]:

FDP_Component(j,t) = Weighting_Pricet(k) x Metric(j,t) x Constant (22)

The FDP components are separable so we can also settle them separately. Focussing on one such component and dropping the component subscript, j, we have for the kth DI:

FDP_Component(t) = Weighting_Pricet(k) x Metric(t) x Constant (23)

We can re-arrange this to make a unitless constant *Constant0* by dividing by *Constant* by the targeted standard deviation of frequency *SigmaF*. Under current frequency performance standards, assuming a normal distribution in normal operation and making an allowance for uncertainty, *SigmaF* would be of the order of 30 mS.

FDP_Component(t) = Weighting_Price(k) x Metric(t) x Constant0 / SigmaF (24)

For a deviation *x(m,t)* from a unit *m* at time t, we have a single measurement interval settlement amount of:

Settlement(m,t) = (Metric(t) x x(m,t)) x Weighting_Price(k) x Constant0 x dt / SigmaF (25)

Summing over the interval and multiplying and dividing by the number of samples, gives:

Settlement(m,k) = MPF(m,k) x Weighting_Price(k) x Constant0 x TDI / SigmaF

where

TDI is the duration of the dispatch interval

MPF(m,k) – Mean(Metric(t) x x(m,t)) (Mean Performance Factor)

Constant0 is dimensionless and must be of order 1, but is subject to adjustment to get a desired outcome (26)

This is a settlement formula that can be applied for each of the chosen metrics for all units and the residual over all dispatch intervals, subject to some possible adjustments for regulation enabled units.

C.2 Re-interpreting the FDP Unit Settlement Amount for Comparison with AEMC Draft Determination

We can sum the settlement amount for all metered units from the settlement formula (3)

Settlement(k) = Sum over m(*MPF(m,k)) x Weighting_Price(k) x Constant0 x TDI / SigmaF*
= MPFM(k) x *Weighting_Price(k) x Constant0 x TDI / SigmaF*

where MPFM(k) is the Mean Performance Factor for all metered units in the kth DI (27)

We note that, the MPF for the Residual, *MFPR*, is given by:

[23] See equation (2) in Section 2.1 and the Control and Pricing Theory Report for a more detailed justification. The *Weighting_Factor* term included in this Appendix reflects the more complete analysis in that Report.

$$MPFR(k) = -MPFM(k) \quad (28)$$

MPF(m,k)/MPFM is the fraction of the payment by the residual going to the *mth* unit. The settlement amount associated with *MPFM* is a net payment which includes both positive and negative payments to and from metered entities. Using the Residual as a benchmark rather than all negative performers avoids the problematic task of deciding whether negative or 'bad' performance is to be determined at the 4 second, 5 minute or some other level. The Residual is always 'bad'.

We can now re-write the settlement formula (30) in the following set of terms:

$$Settlement(m,k) = (MPF(m,k)/MPFM) \times (MPFM/(SigmaF \times SigmaX)) \times (Weighting\_Price(k) \times SigmaX) \times (Constant0 \times TDI) \quad (29)$$

We observe the following terms:

- The first term *MPF(m,k)/MPFR* is a fraction of a total payment due to unit m, m
- The second term *(MPFR/(SigmaF x SigmaX))* is an adjustment that recognises the level of cost incurred in the interval relative to the long term.
- the third term (*SigmaX x Weighting_Price(k))* is a system wide constant, which is the standard deviation of the Aggregate Dispatch Deviation (ADE), *SigmaX* multiplied by the *Weighting Price* to get a dollar amount.
- The term *(Constant0*TDI*) is a constant, where *Constant0* is a dimensionless tuning constant of order 1 and TDI is the DI duration.

The above is an interesting interpretation of the FDP settlement formula because we can relate it term-by-term to the terms in the AEC Draft Rule settlement formulae. The terms are different but their intent is the same. However, the basic FDP settlement formula is much simpler to understand and implement:

$$Settlement(m,k) = MPF(m,k) \times Weighting\_Price(k) \times (Constant0 \times TDI / SigmaF) \quad (30)$$

Once the MPF for the unit is calculated, one simply applies the weighting price and a constant to get the settlement amount for the DI for that Metric. However, under the FDP approach, a specific procedure is required to pay for regulation enablement. Such a procedure is set out in Section 5.1.9

Appendix D Modelling of Specific Cases

D.1 Overview

In this Appendix we present the results of modelling that addresses some operational issues identified in Section 3.3 of the Project Inception Report. Rearranged for convenience and supplemented, the modelled cases are:

- System in 2021 – Base Case;
- System with high battery presentation;
- System with low inertia;
- System with more variability in forecasting and dispatch;
- System with bad behaviour by some units; and,
- System circa 2031.

In Section 4.1 and Appendix A of the Project Analysis Report we outlined a model that implements key elements of an FDP system. With some additional enhancements, we use that model in the following studies. An important addition from the model described in the Analysis Report is the ability to target a specific standard deviation of frequency performance which supports direct comparison of different situations.

The physical model remains simple but captures most of the key elements that might affect system performance. It consists of a generator and a load of the same size. The generator and load both have properties of inertia, damping (PFR) and control (regulation). Data for the base case following is shown in Figure 21.

The data used are indicative only with no pretence at precision. The cases studied will generally be variations on the base case with a single parameter changed, except for the final case when multiple changes are made. Thus, the studies will indicate potential trends rather than absolute outcomes.

In all cases the target standard deviation for frequency is 30mHz, slightly more than the rather tight control of around 25mHz currently maintained by the 15mHz dead band of the mandatory PFR requirement.

D.2 System in 2021 – Base Case

A simulation over one hour for this case is shown in Figure 22. The 30 mHz theoretical target is confirmed in the text box in the bottom left frequency and time deviation chart, with the standard deviation over the one hour measured as 33.44mHz.

Of interest are the time constants TC) in this system, set up to approximate the current real system

- TC of 4 seconds corresponds to damping (PFR);
- TC of 30 seconds corresponds to regulation;
- TC of 300 seconds corresponds to the load mean reversion assumption, meant to reflect the action of the energy market; and,
- TC = 3600 + reflects the time correction requirement.

D.3 System with High Battery Penetration

For this case we reduce the cost of ramping *RCost* by a factor of 100. This models the rapid ramping capability of batteries. We make no attempt to model lifetime issues. The results of this change are shown in Figure 23. For this case we observe the following:

- the system achieved target performance with 4 second measurement interval (bottom left)H;
- prices and costs are significantly lower costs (top right);
- the regulation TC is much lower at 7 seconds, nearly the same as PFR (bottom right);
- the power responses and frequency responses are more rapid; the system is 'twitchier' (left hand charts); and,
- the power balance (top left) has not changed much as it's driven by the driven by the size of the disturbances.

The interesting conclusion from this study is that the rapid response capability of batteries does not present an inherent problem for a system with high inertia. The batteries can and do adjust to the slow responding system. Metering at 4 seconds is adequate (given the model assumptions).

D.4 System with Low Inertia

For this case we reduce the cost of inertia in the system as represented *Inertia* by a factor of 10 for the generator. This models the loss of inertia as thermal plant retires. For the purpose of study, we change only this parameter. The results of this change are shown in Figure 24. For this case we observe the following:

- For a 4 second meter measurement interval the system was unable to maintain frequency at a 30mHz standard deviation. To ger a stable result, we reduced the measurement interval to 1 second.
- The PFR and regulation TCs are reduced (in fact, the PFR TC is off the chart at the low end – see bottom right)).
- Prices and costs are very high (top right).
- The system is very 'twitchy'.

The conclusion from this is the control with low inertia is possible if the metering can be provided at a higher resolution. However, costs would be impracticably high.

D.5 System with More Variability in Forecasting and Dispatch

For this case we increase the variability of the load by a factor of 2, suggestive of the increased level of variability from higher renewable penetration in the system as represented by *Sysnoise*. The results of this change are shown in Figure 25 For this case we observe the following:

- 4 second metering gives stable outcome.
- Very high prices and costs (top right).

- Note imaginary component TC for PFR (bottom left). This suggests an oscillatory system. Oscillatory components can be removed to give a more stable system.

This result should not be taken too literally. However, it does confirm that, absent newer technologies, the control of system frequency could increase markedly with higher renewable penetration.

D.6 System with Bad Behaviour by Some Units

We have chosen not to simulate this case. If some units fail to perform adequately, this is can be viewed as just additional system noise that other well-controlled units would need to correct for. It is conceivable that a large block of badly behaved units could destabilise the system. The possibility of such a situation could justify AEMO implementing some form of registration and information sharing, at least initially

D.7 System Circa 2031

The system in about 10 years is assumed to capture all of the elements that we have modelled separately in the previous sub-sections. Thus, we expect to have:

- more batteries;
- lower inertia; and,
- more load and dispatch variability.

To model this case, we simultaneously applied all the parameter changes described in the previous sub-sections. The results of this change are shown Figure 26. For this case we observe the following:

- as with the low inertia case, we could nor achieve stable control unit we reduced the measurement interval to 1 second;
- the system is very 'twitchy' but stable (right hand charts);
- Costs are higher than the base case but within reasonable bounds; and,
- TCs for PFR and regulation are much lower than the base case (PFR is off the chart at the low end).

D.8 Conclusions

The key conclusion from these studies is that, with all these changes to the system, stable control at some likely reasonable cost appears achievable with this FDP approach. However, higher resolution metering suitable for FDP settlement would be required.

Figure 21: Base Data for Studies of Specific Cases

	Value	Description
SysType	1	System type
dt	4	Measurement Interval
TDurn	3600	Run Duration
DI	300	Dispatch interval
Seed	0	Random seed
fe0	0	Frequency error initial value
te0	0	Time error initial value
Macc	100	Target control matrix accurac
TR	0	RoCoF Time Constant
TI	3600	Time Error Time Constant
Wt	1.00...	Controlled Function Weight
f0	50	Reference Frequency
feSD	1.00...	Frequency Measurement No
TeSD	1.00...	Time Error Measurement No.
eps	1.00...	Tiny value
VFlag	1	Flag to exclude/include syst..
XFlag	0	Flag to start from initial/previ.
feSDTarget	30	Frequency Deviation Target
TFlag	1	Flag for whether to target fe..

Name	Type	Rating	PFactor	RevTC	Inertia	Droop	QCostF...	RCostFac	SysNoise	MW0
Gen1	Gen	500	50	1000000	30	5	1	5	1	0
Load1	Load	500	50	300	1	10	0	0	5	0

	ISE	SE	Gen1	Load1
ISE	1	0	0	0
SE	0	1	0	0
Gen1	0	0	1.0000	0.5000
Load1	0	0	0.5000	1.0000

Figure 22: System in 2021 - Base Case Simulation

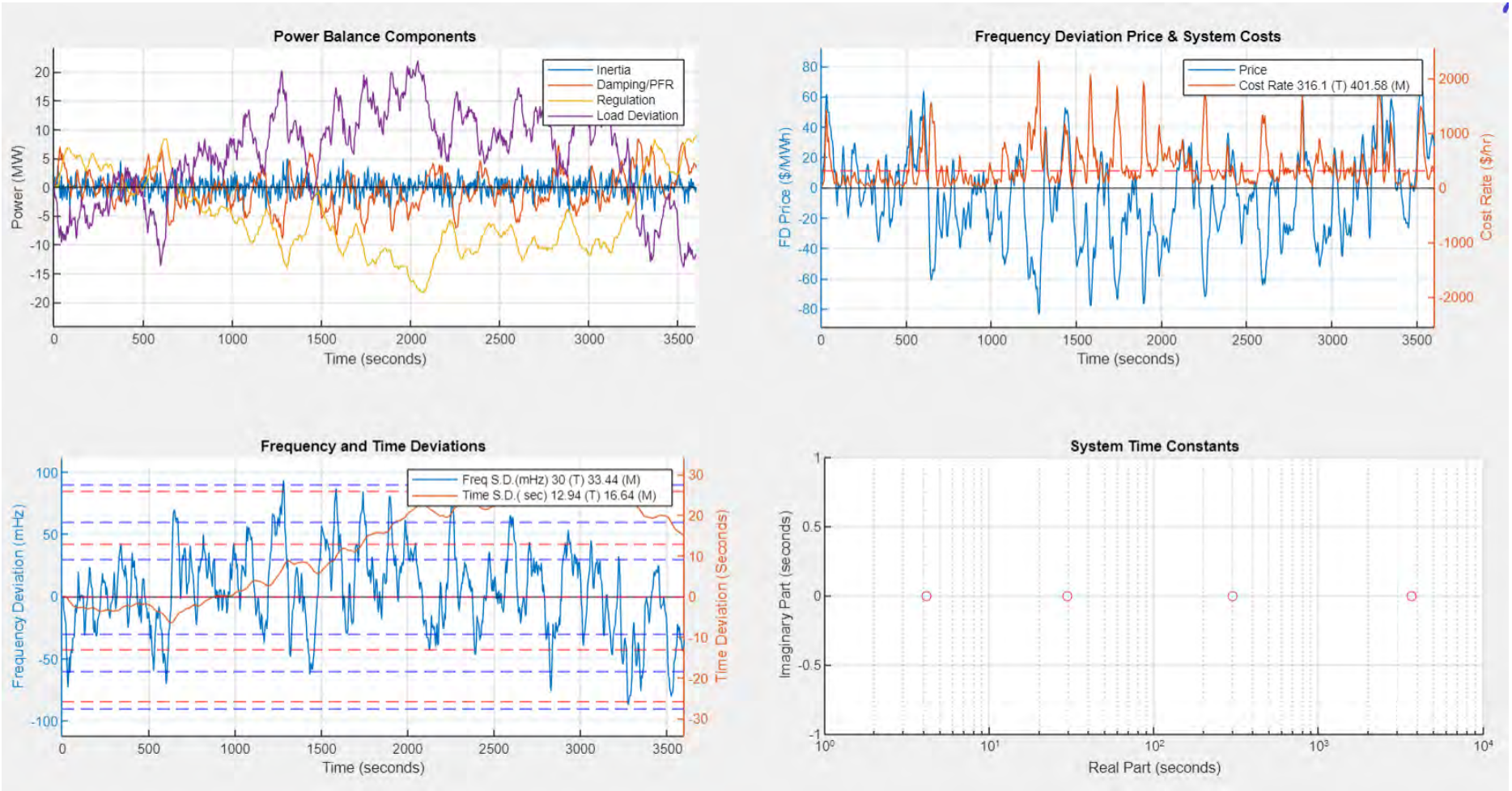


Figure 23: System with high battery penetration simulation

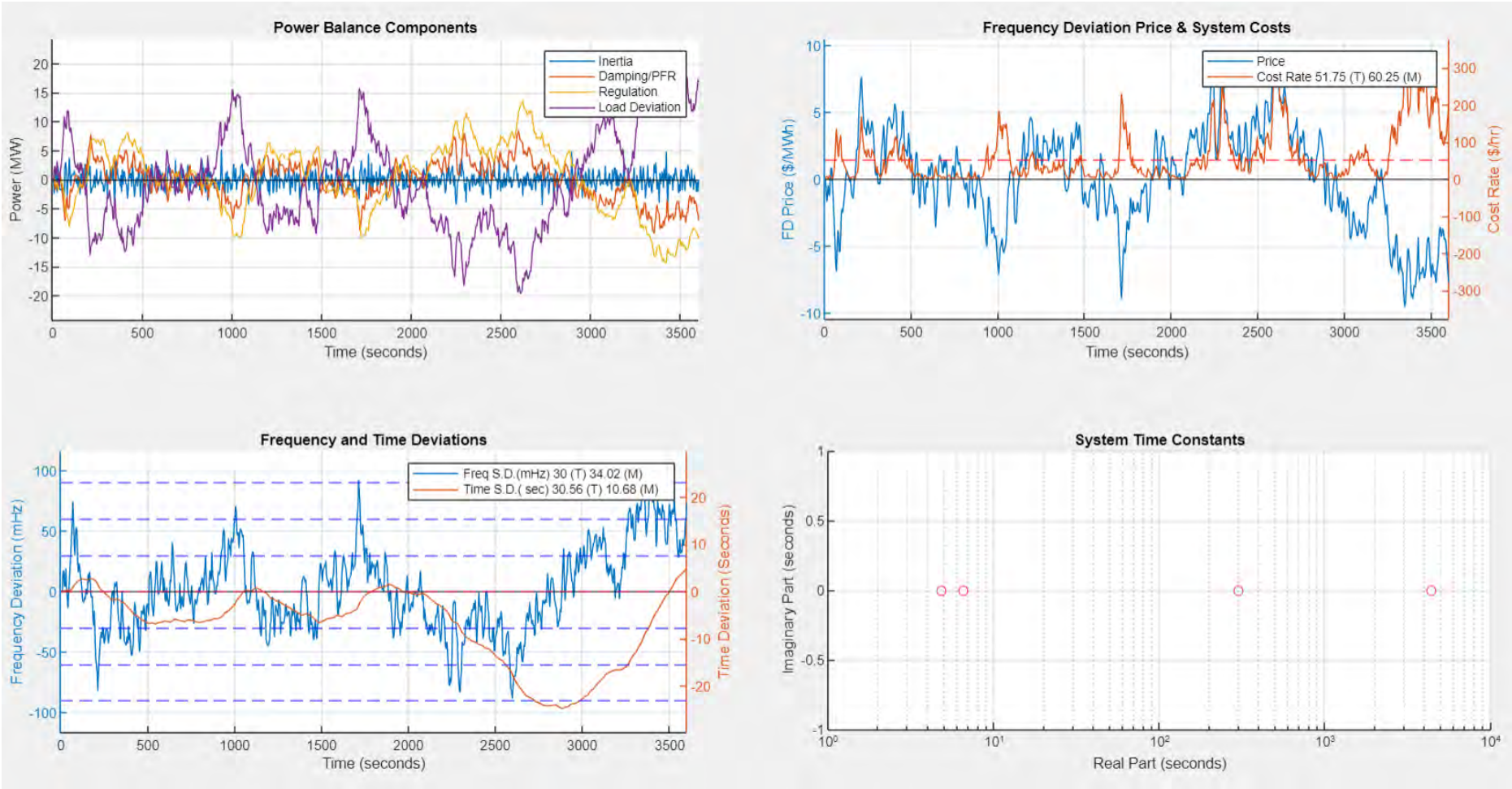


Figure 24: System with low system inertia simulation

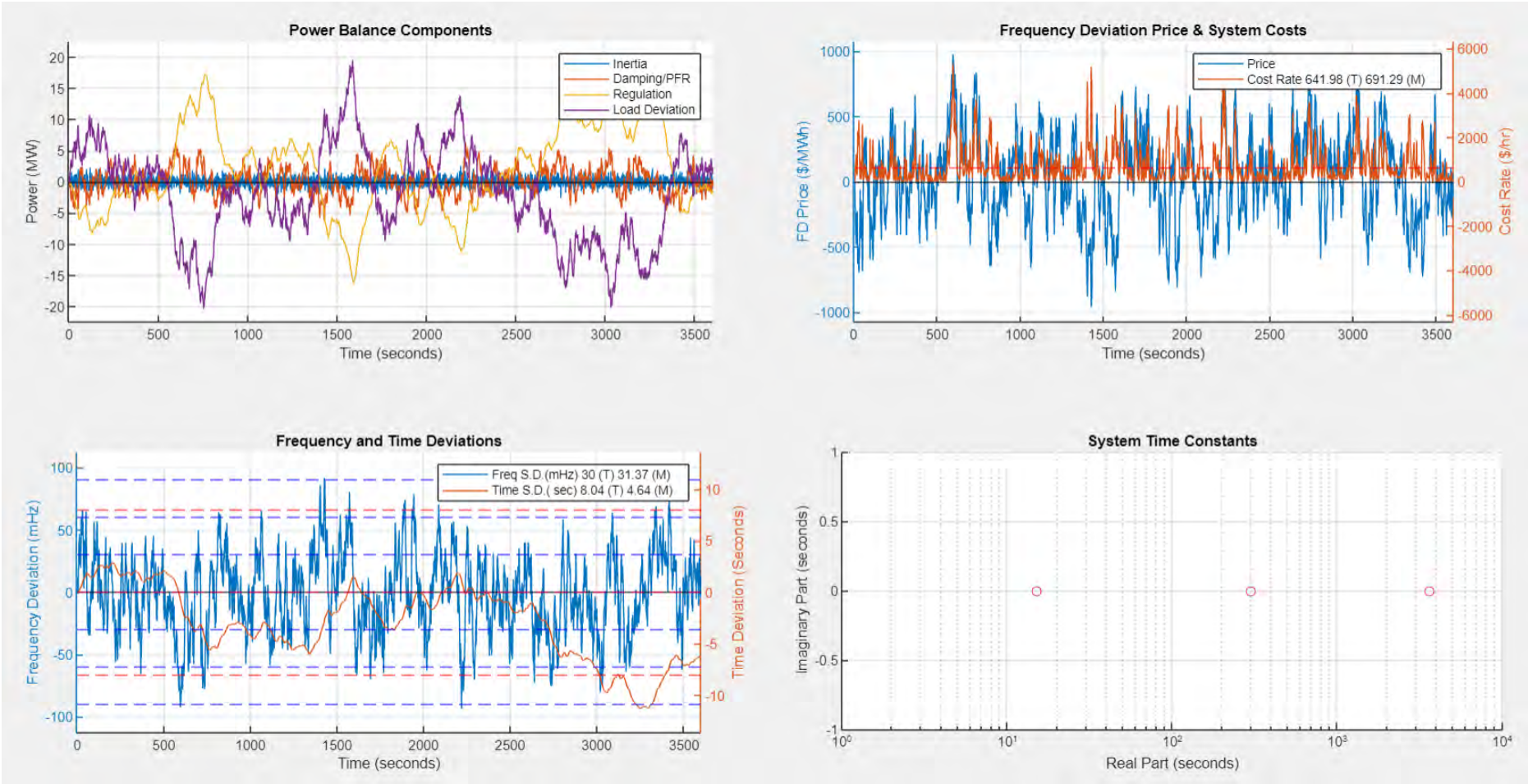


Figure 25: System with more variability in forecasting and dispatch simulation

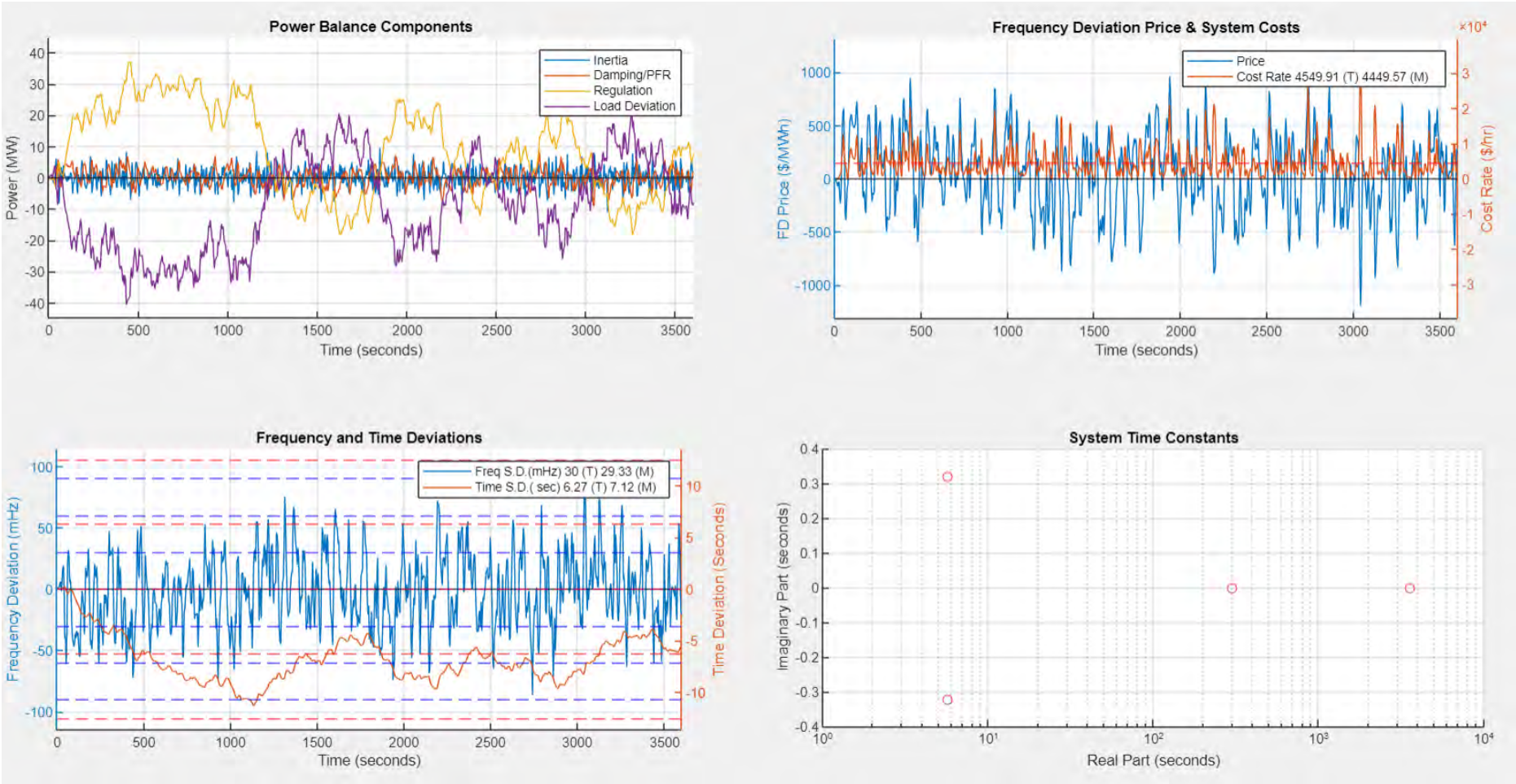
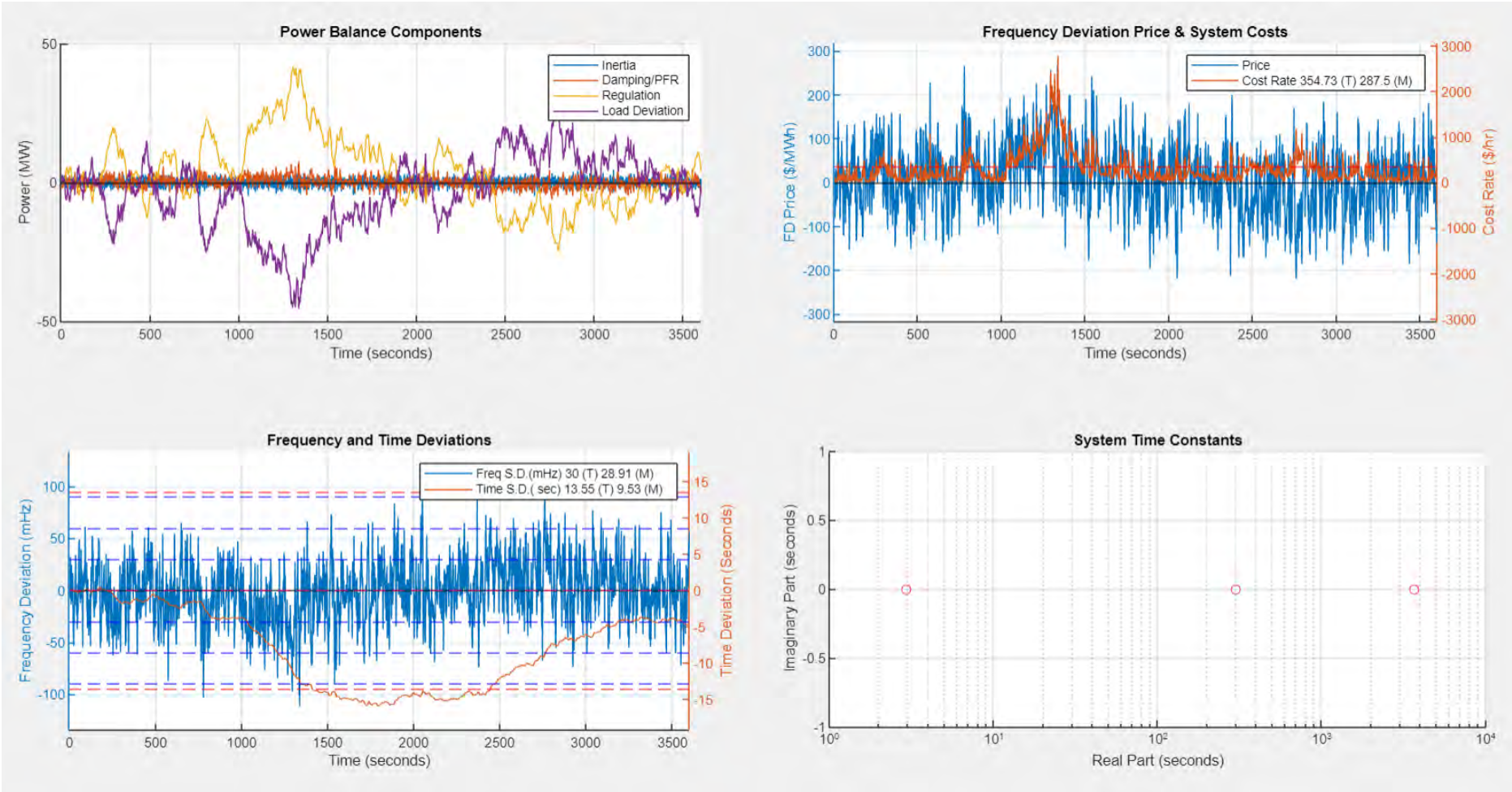


Figure 26: System circa 2031 simulation



Appendix E Results of Back-casting Studies

E.1 Back-casting Engine

The back-casting engine or toolkit is a modular software that uses MMS and AEMO Causer Pays data to calculate settlement amounts according to some programmed procedure. Each functional part of the procedure can be parameterised and/or componentised allowing continues experimentation with little effort.

The engine also supports caching by default, allowing the results of repetitive calculations to be stored saving processing time for future calculations.

In the engine, interconnectors are treated as 2 virtual units (one in each connected region); hence, when one virtual unit is generating the other is loading. This representation allows us to analyse the net contribution of the interconnector, when one virtual unit is a provider the other is probably a causer, however the net payment is an indicator of how well the interconnector played a role in responding imbalances.

E.2 AEMC Draft Determination Option

The AEMC has provided some aspects of a proposed procedure to incentivise adequate frequency response. Some aspects of the procedure are not yet defined but left to AEMO to determine through their consolation on the procedure. Some of these aspects are crucial to ensuring that the system will appropriately incentivise good response. Some of these and associated details are provided below:

- The performance metric (weighting on each 4sec period)
    - Under the current Causer Pays procedure, FI (an output from the AGC) plays this role
    - In the back-casting results, IES has used ACE which is a precursor to FI and accounts for time deviation and frequency deviation correction
    - Other options for consideration: FI, ACE+ACEI, -Hz, - (Hz + Smoothed_Hz) (Proposed IES metric)
- The regulation requirement metric (RR in rules, the weighting on each 5minute period)
    - There is no associated metric under the current Causer Pays procedure, this quantity must also be in MW units
    - The maximum dispatch error within the DI from each region (accounting for all units and interconnectors) is assumed to play this role
    - Other options for considerations: max(FI), AGC calculated quantity, max(ACE), max(ACE+ACEI)

Results

The period under investigation is the week starting on 1 May 2021. This was chosen as it is well after the mandatory PFR rule was implemented. Be aware of the different vertical axis scales on these charts.

Figure 27 Hourly costs/revenues attributed to units grouped by fuel

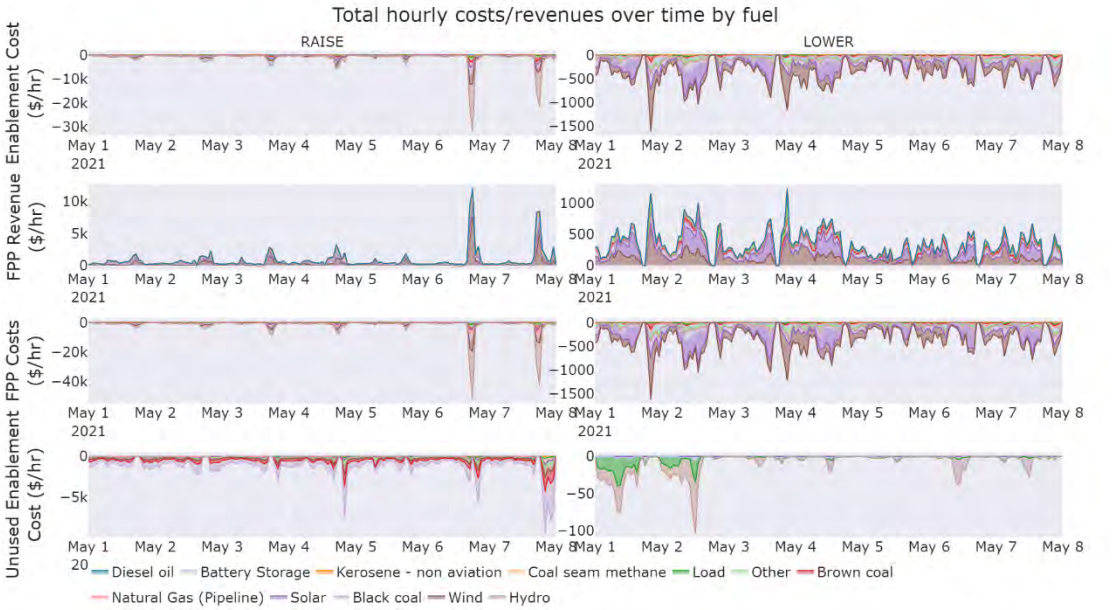


Figure 28 Hourly costs/revenues attributed to the residual (non-metered components)

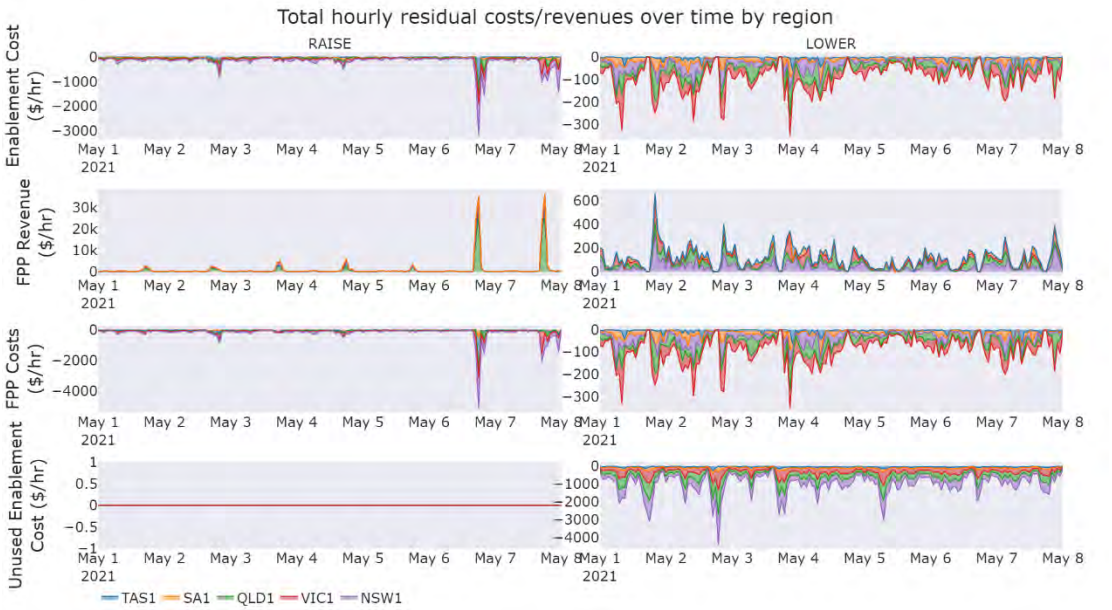


Figure 29 Total revenue/costs attributed to units grouped by fuel

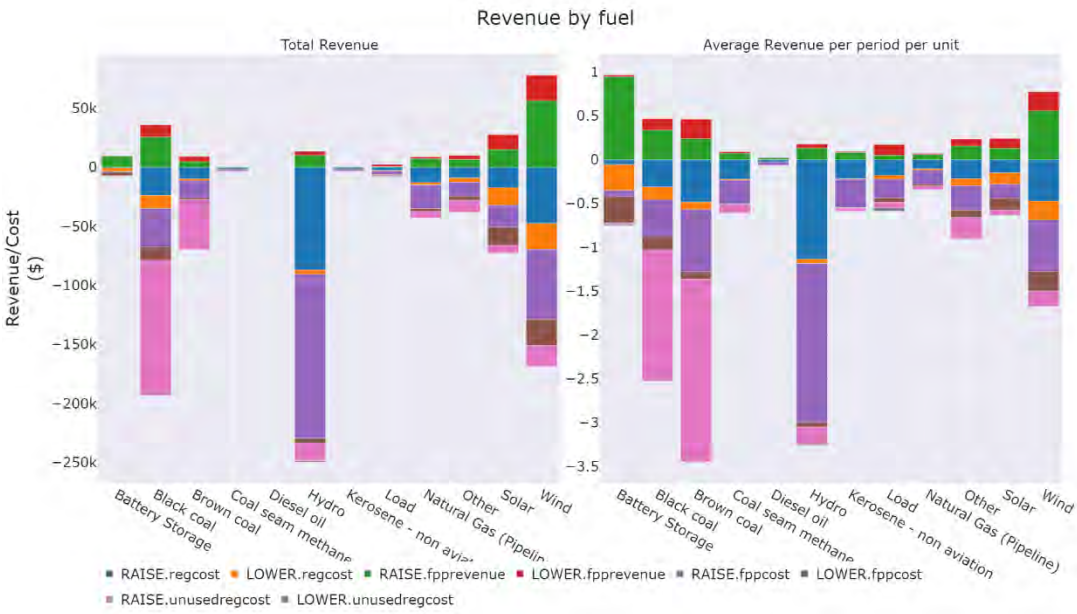
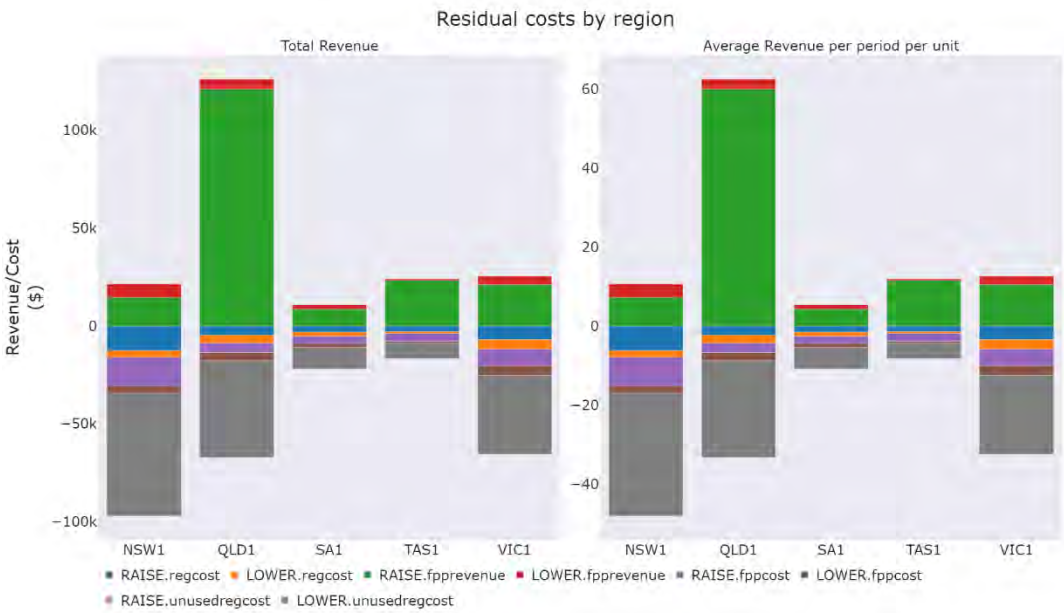


Figure 30 Total revenue/costs attributed to the residual (non-metered components)



Observing Figure 29 & Figure 30, it can be noted that (at least for the period under investigation) the non-metered components were net positive, and the metered components were net negative.

Figure 31 Best performers in each region by total revenue

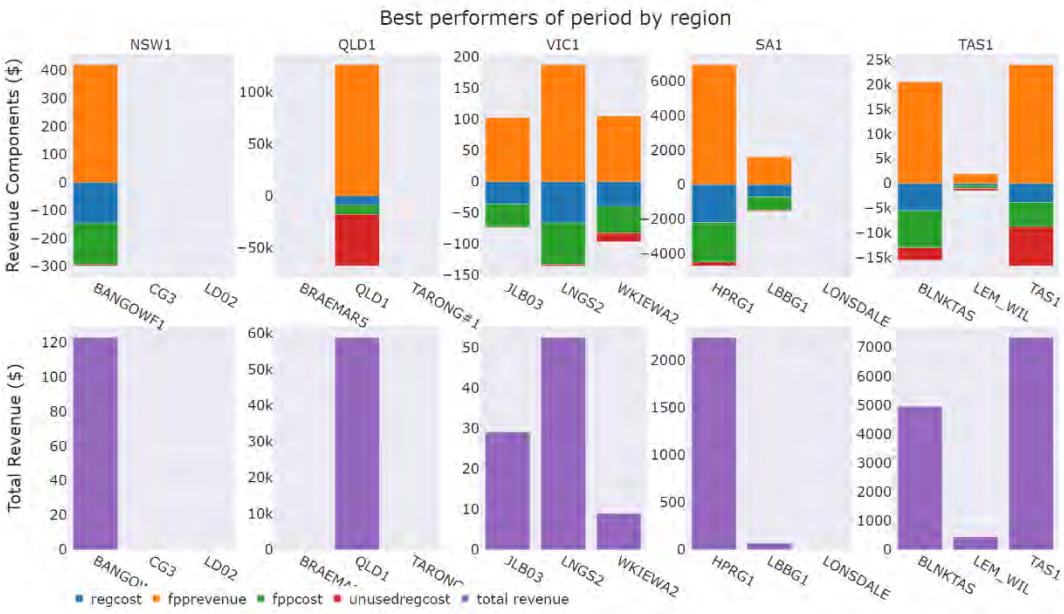
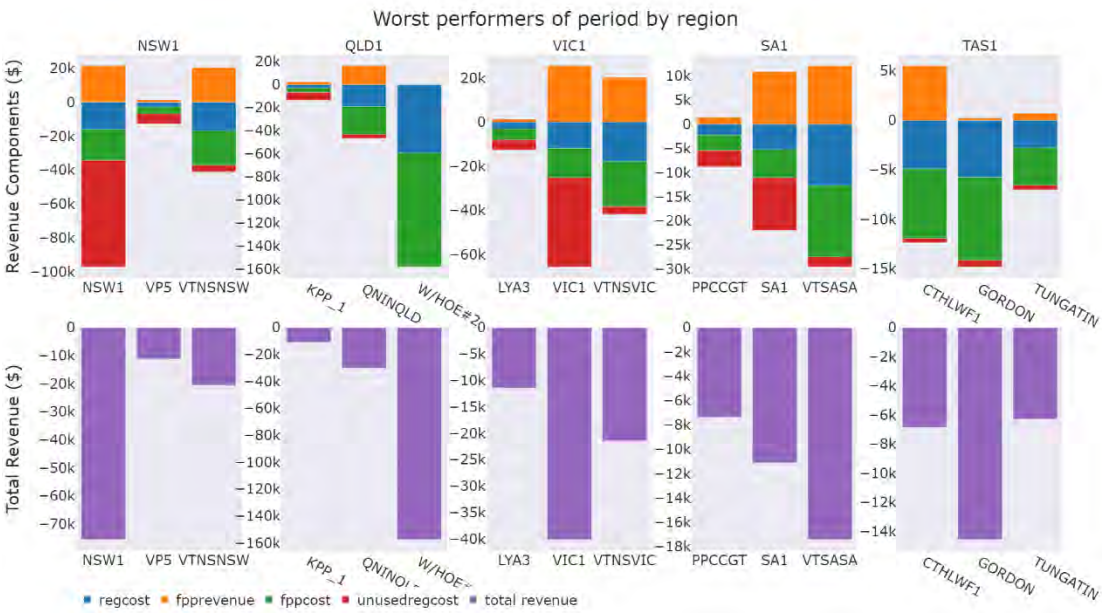


Figure 32 Worst performers in each region by total revenue



The AEMC method would benefit from further investigation as there are some salient features that would not be ideal. For example, it seems that the residual is net positive, and units are generally net negative. This is likely due to the choice of the performance metric (ACE) which does not have a slow-moving component and incorporates an offset for time deviation correction, but further investigation is required.

E.3 Revised Project Option

The Project method can be summarised using the following formula

$$SettlementAmount = Deviation \times Metric \times gain \times Weight \times SettlementConstant \times dt$$

From the above formula, a formula can be obtained for the deviation price (Where $SettlementAmount = Deviation \times DeviationPrice \times dt$)

$$DeviationPrice = Metric \times gain \times Weight \times SettlementConstant$$

For ease of calculation, 5-minute factors and settlement amounts are calculated. In essence, the procedure laid out in this Project is settled every 4 seconds and a unique 4 second deviation price can be calculated according to the above formula.

See the table below for an overview of the different inputs to the formula.

Table 5: Formula Inputs

Name	Information
Deviation	Deviation from trajectory (MW)
Metric	Performance metric (either instantaneous or smoothed frequency)
Gain	Factor to allow AEMO to choose relative weighting of the 2 performance metrics
Weight	Represents the cost of supply (uses regulation price in back-casted results)
SettlementConstant	A global constant that is calculated to target a specific average ratio of FDP costs relative to enablement costs. (Targeting enablement costs may change in future, this is also a controllable lever available to AEMO)

Results

The same period (week starting on 1 May 2021) as for the AEMC back-cast was chosen for the proposed Project back-cast.

Figure 33 Hourly revenues/costs attributed to units grouped by fuel

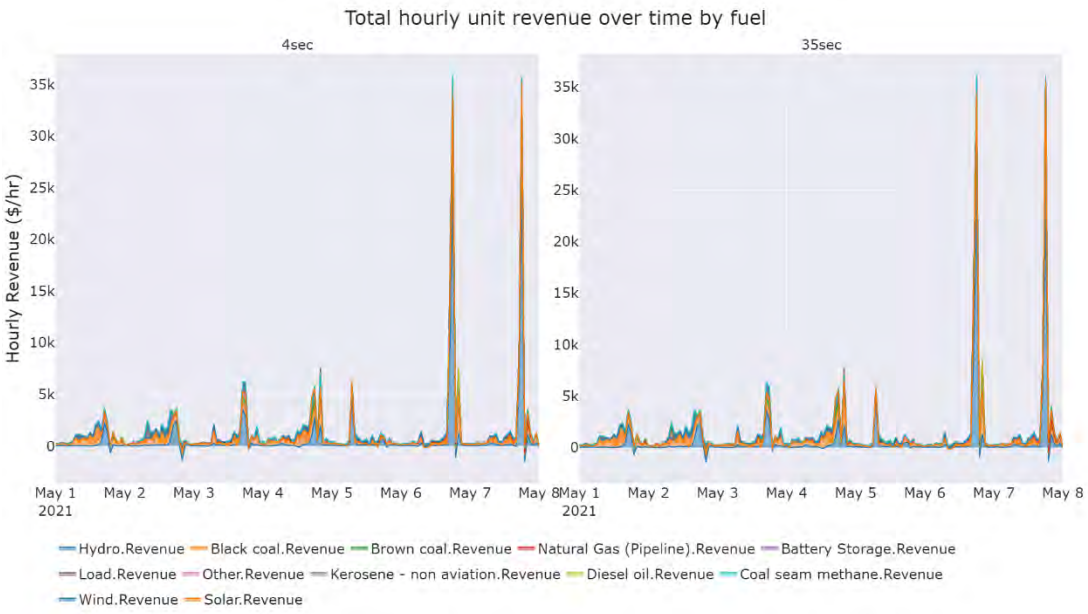
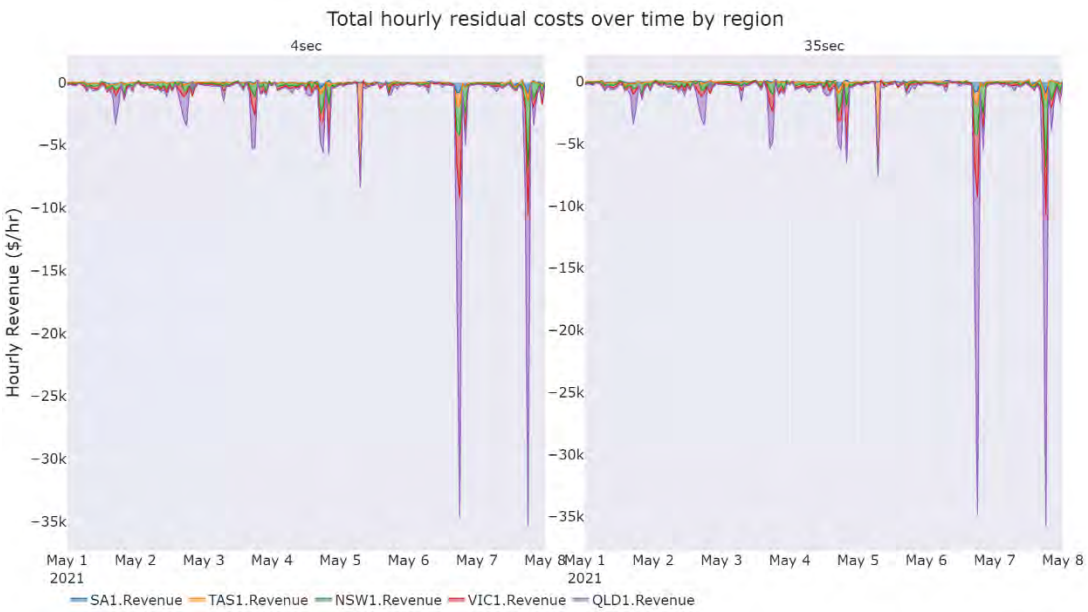


Figure 34 Hourly costs attributed to the residual (non-metered components)



Generally metered units are net positive (i.e., are receiving payments) and the residual are net negative. This is consistent with expectations after the implementation of mandatory PFR, where frequency performance has greatly improved amongst metered components.

Consistent with the proposal (See section 4.5), the enablement costs are completely recovered from non-metered components. This is also the most significant cost (as seen from Figure 37).

Figure 35 Hourly enablement costs per region

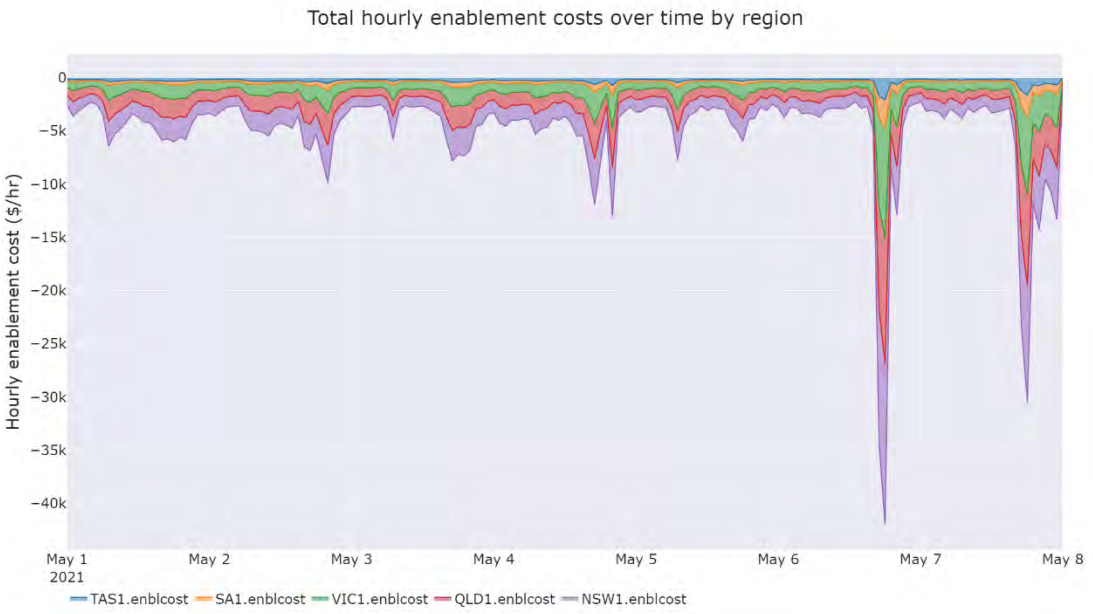


Figure 36 Total and average revenue attributed to units grouped by fuel and performance metric

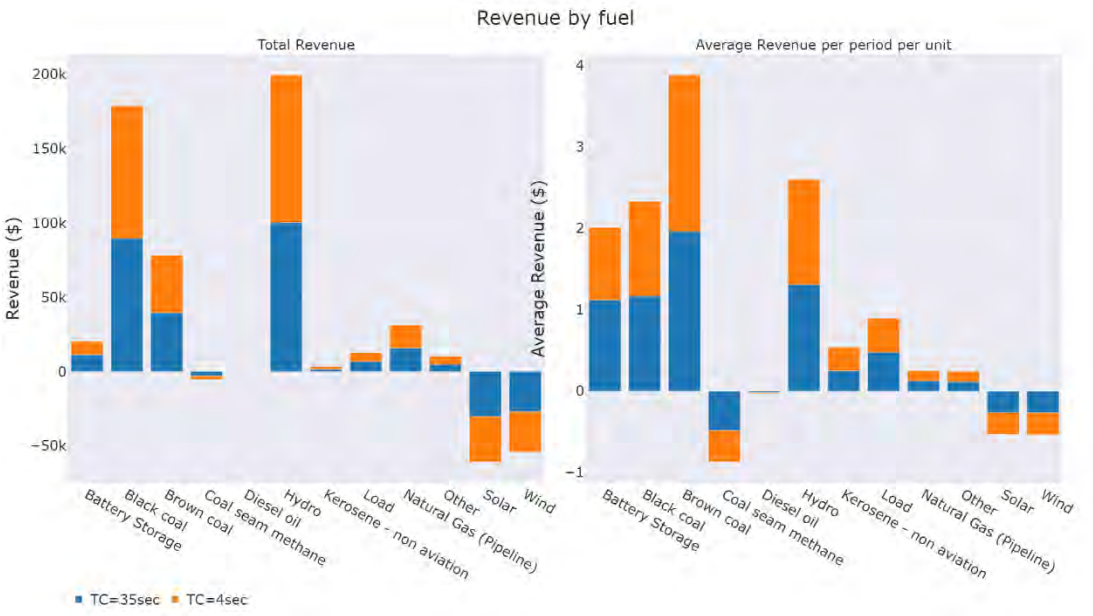


Figure 37 Total and average costs attributed to the residual

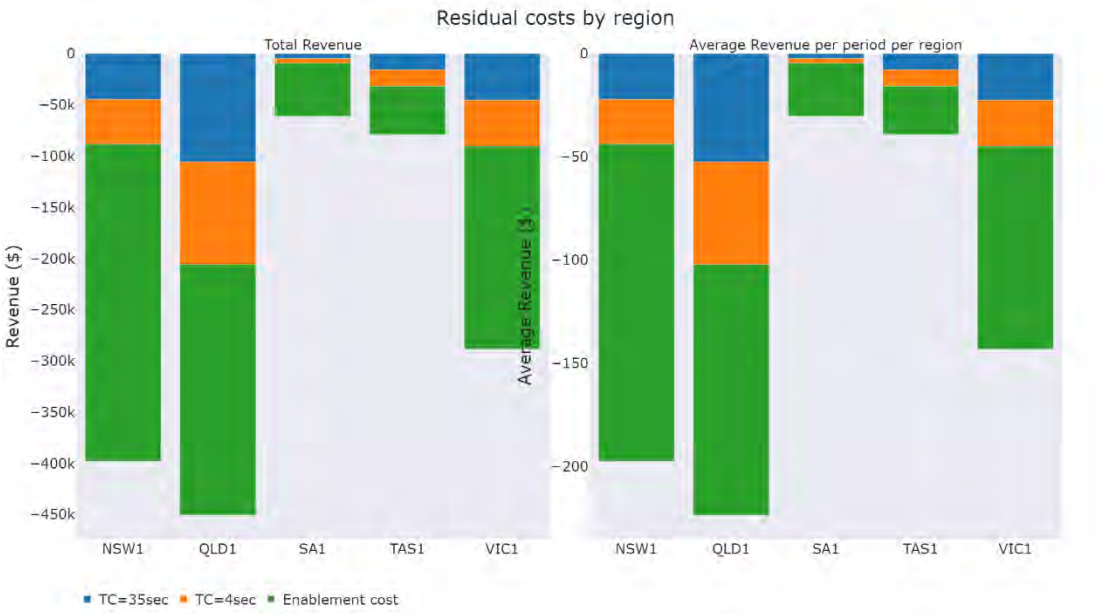


Figure 38 Best performers in each region by total revenue

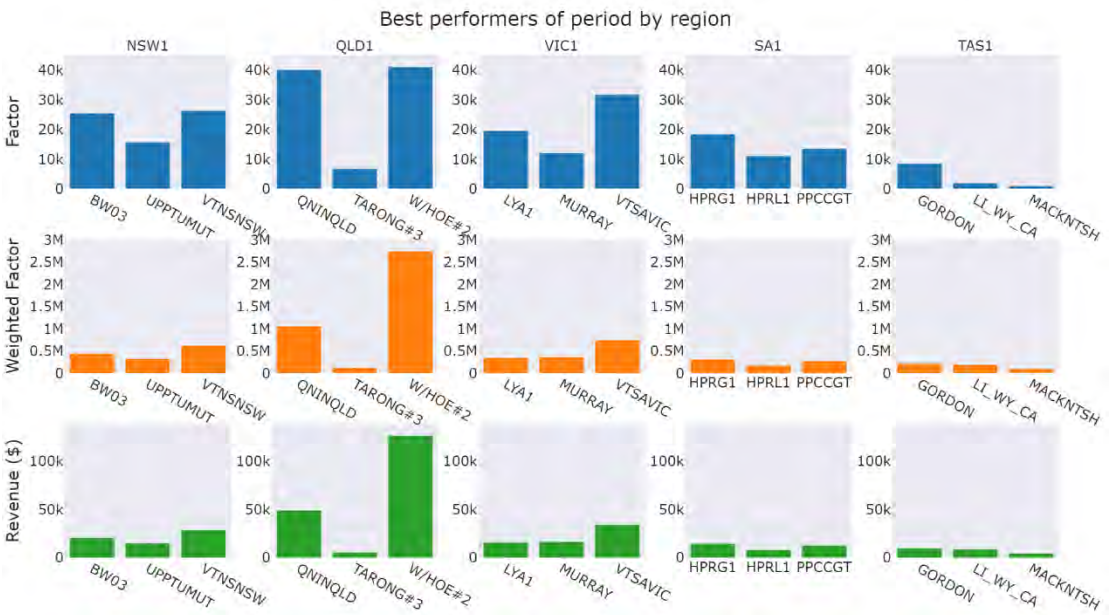
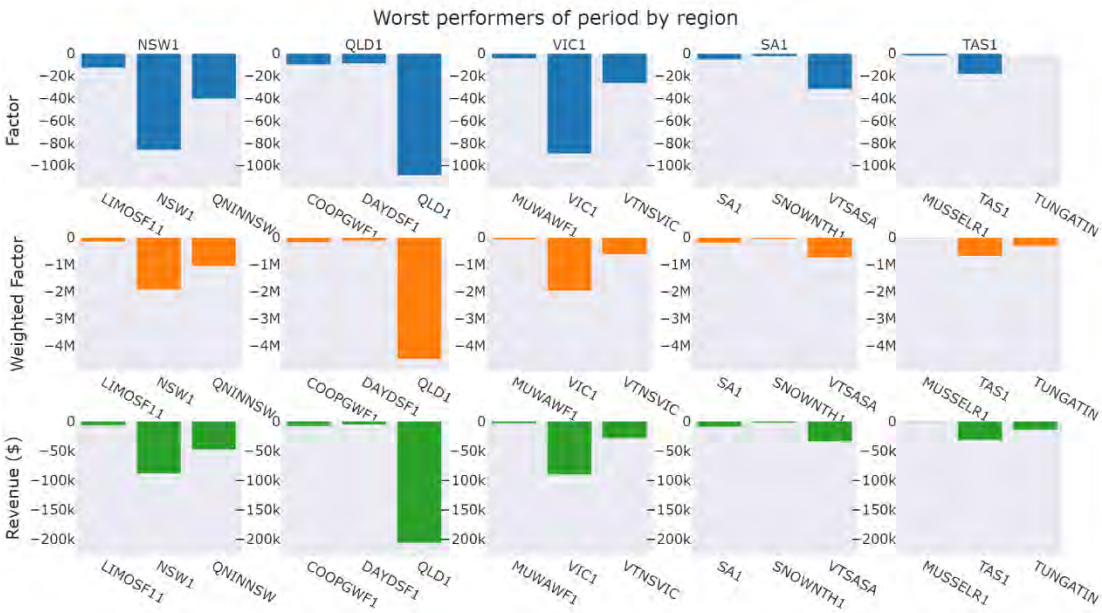


Figure 39 Worst performers in each region by total revenue



The best and worst performers are reported in Figure 38 & Figure 39. As expected, the residual (represented by the region) is usually the worst performer.

Figure 40 - top) Deviation price precursor data for a short window; middle) separate deviation price components for 4sec (instantaneous) and 35sec (smoothed) performance metrics; bottom) total deviation price

The total deviation price is the sum of both deviation price components (using the formula provided above). The deviation price is a good way to gauge the cost of decentralised frequency performance every 4 seconds.

Figure 40 displays the deviation price for a 20-minute window, when regulation price and frequency are in nominal ranges. The deviation price is quite low (~30 $/MWh) but deviation prices sometimes go as high as $20k/MWh as shown in Figure 41.

Figure 41 All total deviation prices

Due to the payment of enablement and FDP to enabled units, the costs of enablement are expected to reduce in the long term due to competition. Figure 42 displays the expected allocation of costs to the residual under a competitive scenario, i.e., in the long-term regulation costs are expected to halve such that the total cost to the residual would be equal to the enablement cost of today.

Figure 42 Total and average costs attributed to the residual (over the long term)