Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM (ERC0352)

Australian Energy Market Commission

Final Draft Report

12 February 2024

Disclaimer

IES makes no representation or warranty that any calculation, projection, assumption or estimate contained in this report should or will be achieved or is or will prove to be accurate. The reliance that the Recipient places upon the calculations and projections in this report is a matter for the Recipient's own commercial judgement and IES accepts no responsibility whatsoever for any loss occasioned by any person acting or refraining from action as a result of reliance on this report.

Version History

Version	Date	Change
V01a	19 December 2023	Initial draft.
V02d	12 January 2024	Revised draft. Reframed costs, clarifications, and edits.
V03d	29 January 2024	Exec summary, terminology changes, edits and clarifications.
V04e	12 February 2024	Additional clarifications and edits, chart formatting.

Contents

1 Executive summary 5

2 Introduction 19

2.1 Background 19

2.2 Scope of work 19

2.3 Report notes 21

3 Approach and considerations 22

3.1 Definition of price-responsive resources 22

3.2 Dispatch and actual outcomes 23

3.3 Modelling framework 25

3.4 Virtual Power Plants and Demand-side Participation 27

3.5 Benefits and functional areas 33

3.6 PLEXOS modelling 34

3.7 Modelling limitations 38

4 Assumptions 40

4.1 Supply outlook 40

4.2 Virtual Power Plants 42

4.3 Frequency control ancillary services 46

4.4 Demand-side participation 48

4.5 Other 50

5 Modelling results 51

5.1 Overview 51

5.2 VPP modelling 56

5.3 DSP modelling 65

5.4 Generation and network investment 67

5.5 Key findings 68

Appendix A Abbreviations 72

Appendix B Calculation of costs 74

Appendix C Historical analysis - other 76

1 Executive summary

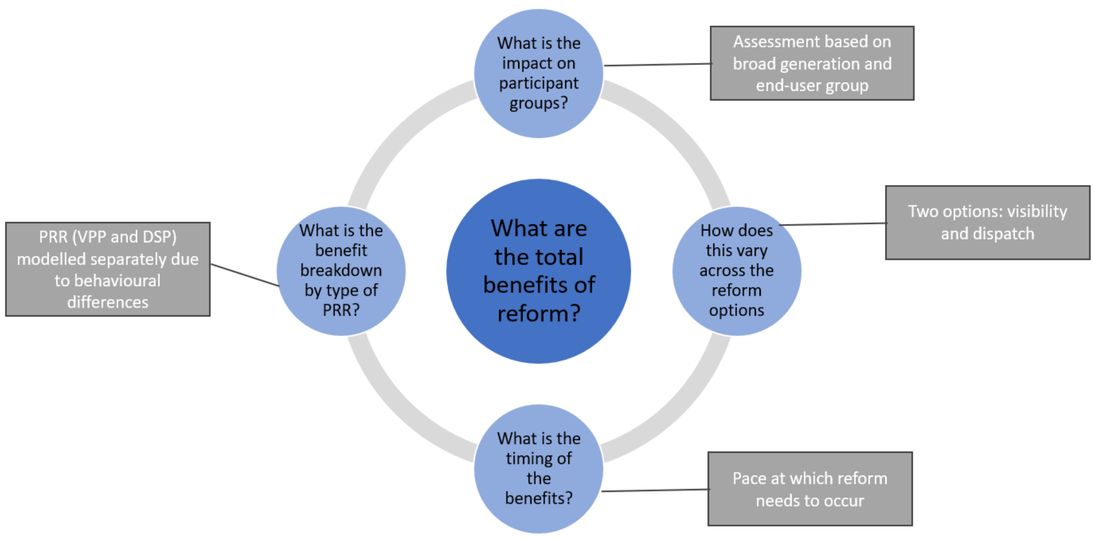
The Australian Energy Market Commission (AEMC) initiated a rule change request, ERC0352: Integrating price-responsive resources into the NEM, following the Australian Energy Market Operator's (AEMO) submission to introduce a 'scheduled lite' mechanism into the National Electricity Market (NEM). The rule change request seeks to better integrate non-scheduled price-responsive resources (PRR) into AEMO's existing scheduling processes either through the provision of operational information and/or direct participation of these resources. Reform is expected to reduce costs for all consumers through improved dispatch and planning efficiency.

Intelligent Energy Systems was commissioned to assess the maximum potential benefits of integrating PRR in the NEM through a visibility and dispatch model. These are generic reforms that integrate resources through the provision of operational information and/or direct participation of the resources, rather than an assessment of the solutions as designed by AEMO.

Scope of work

The modelling objective was to quantify the potential benefits of integrating PRR that are not currently scheduled through the market dispatch process, and do, or could, respond (individually or as part of aggregation) to market price signals. In-scope PRR includes aggregated energy storage systems (ESS) and vehicle-to-grid (V2G), referred to as Virtual Power Plants (VPP), and Demand-Side Participation (DSP). Four additional key questions, in Figure 1, are addressed to provide further context around the total benefits of reform.

Figure 1 Scope of work and key questions

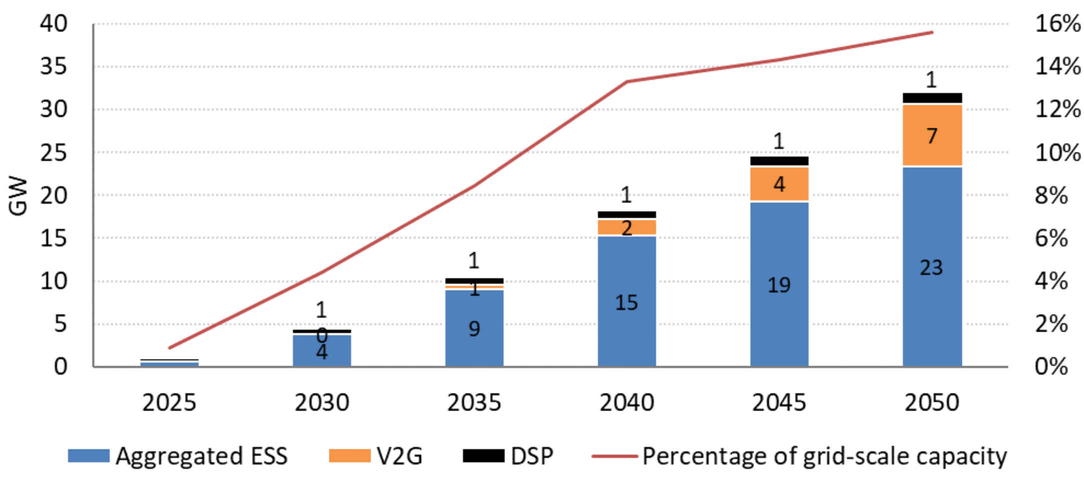


Unscheduled price-responsive resources and dispatch

The current uptake of PRR is relatively low but is forecast in the 2022 Integrated System Plan (ISP) Step Change scenario to rapidly increase to 31 GW by 2050 (Figure 2). The operations of PRR encompassing aggregated ESS, V2G and DSP, is assumed to be aligned with wholesale pricing outcomes and system requirements irrespective of AEMO's ability to accurately forecast operations of the PRR. Under the current arrangements, AEMO has limited information on when these resources operate. Despite this limitation, AEMO needs to account for PRR in its scheduled demand forecasts. It is challenging to do this accurately, and consequently impacts the level of dispatched scheduled resources. For example, during periods of tight system conditions, PRR is likely operating. Without information of its operations, AEMO is likely to under-estimate the PRR operating and rely more on scheduled generators (refer to the evening peak in Figure 3).

In the absence of reform, AEMO will need to rely on its forecasting systems to identify PRR in its demand forecast without access to specific reliable information provided by the party responsible for the PRR. While we assume in the modelling that AEMOs ability to improve its forecasting will occur, it is hard to predict the extent to which it will. Substantial PRR volumes over time could lead to material forecasting errors and drive inefficient dispatch outcomes. Such a scenario is expected to result in higher generation costs because forecast scheduled demand would be higher than actual scheduled demand, and higher scheduling inaccuracies and frequency deviations will translate into higher FCAS (regulation) requirements and costs over time.[1]

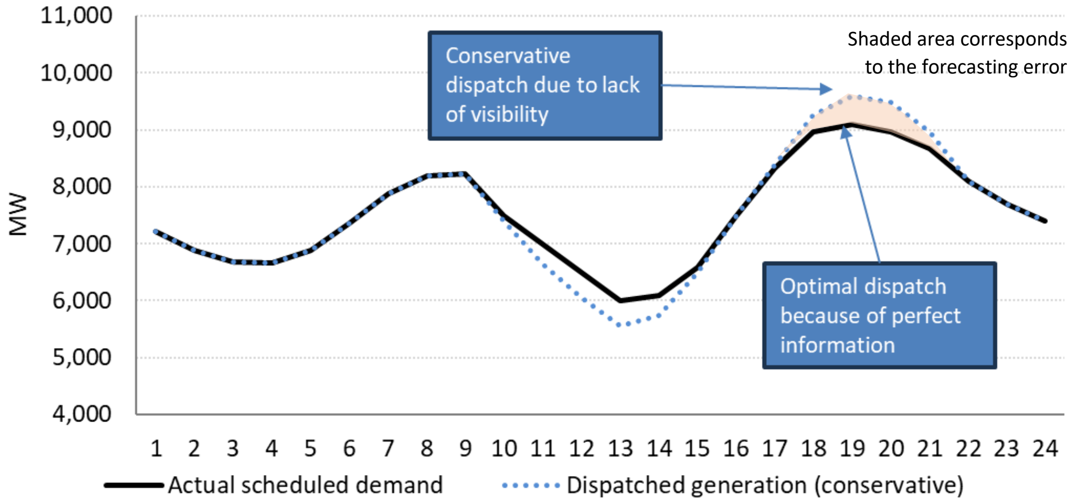
Figure 2 Price-responsive resource capacity outlook



Source: AEMO ISP 2022, Step Change scenario. DSP excludes wholesale demand response and reliability volumes.

[1] At a simplistic level, as assumed in this modelling, despite dispatch inaccuracies, total generation will always match actual demand because regulation-providing generators adjust its output accordingly. However, the generation mix may vary based on the extent of dispatch inaccuracies, leading to differences in overall system costs.

Figure 3 **Example dispatch with and without PRR information**



Approach and cases

To quantify the benefits of potential reform, modelling was conducted in PLEXOS to simulate a Base case and two representative reform options, see Figure 4. The main difference across these cases relates to the extent of participation in the reform mechanisms and, consequently, the information provided to AEMO leading to lower forecasting errors.[2] The Visibility and Dispatch options are complementary but have been modelled as two distinct scenarios. I.e., actual reform may allow for both Visibility and Dispatch participation options, however, the modelling does not account for resources moving between these options, but rather alternative reforms.

Figure 4 **Base, Visibility and Dispatch options**

- Current arrangements where AEMO's forecasting systems attempt identify potential PRR in its demand forecast without specific reliable information
- Substantial PRR volumes over time lead to material forecasting errors and inefficient dispatch outcomes.

- PRR would remain unscheduled and operate outside central dispatch
- Arrangement for PRRs to submit operational info to AEMO
- Lower barriers of entry which will incentivise higher participation offset by informational inaccuracies

- Integrate unscheduled PRR into the NEM central dispatch and scheduling processes
- Higher barriers to entry than Visibility, but central dispatch means higher conformance
- Higher participation in FCAS markets because of dispatchability

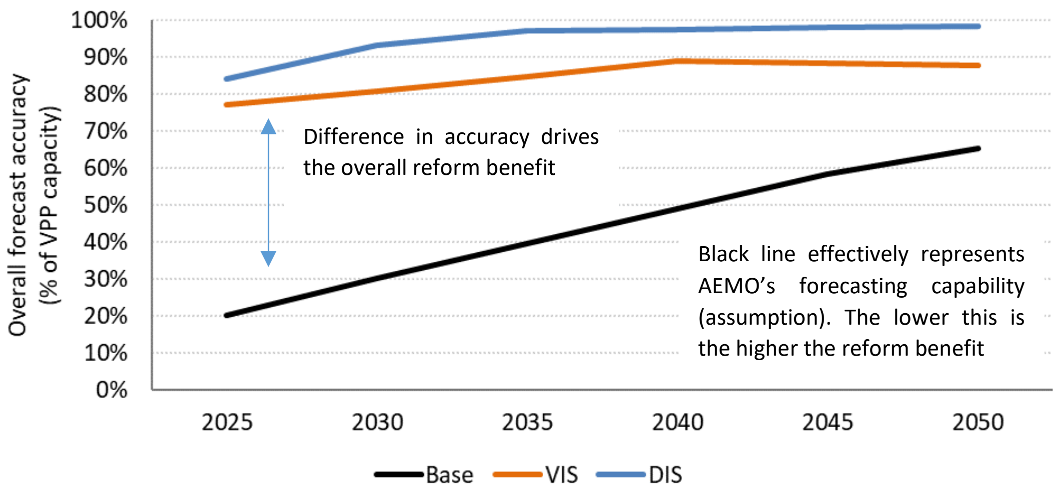
[2] Actual scheduled demand is the same across all modelled cases.

The modelled benefits are largely contingent on the varying levels of demand forecast accuracy in the Base, Visibility and Dispatch cases. This forecast accuracy is based on three key factors outlined below.

1. **Participation or provision of information**: This factor is contingent on the operational data provided to AEMO through the amount of participation in reform mechanisms.
2. **Conformance**: The degree to which the actual operational outcomes align with the information provided.
3. **Forecasting capability**: This relates to AEMO's proficiency in addressing structural errors or inaccuracies arising from both the lack of operational information received (point 1) and the level of conformance observed (point 2).

Increased accuracy, or a reduction in the forecast error as depicted by the shaded area in Figure 3, corresponds directly to enhanced efficiency in dispatch outcomes, resulting in lower associated costs. The overall forecast accuracy assumption for VPPs is summarised in Figure 5.

Figure 5 Overall forecast accuracy assumption (VPP)



Virtual Power Plants and Demand-side Participation

The benefits of integrating VPPs and DSP were modelled separately across the three cases due to the difference in nature of their operations. VPPs are expected to operate regularly throughout the year, whereas DSP are expected to trigger very infrequently and only during high price events. The sum of benefits across both PRR types is the total benefit from integrating unscheduled PRR.

- **VPP**: VPP is more likely to operate during imbalanced supply and demand conditions which may not be accurately picked up by AEMO's forecasting systems. The modelling aims to capture the typical cost and energy price reductions associated with accounting for VPP operations more accurately.

- **DSP**: The modelling focuses on capturing infrequent high price events that trigger demand-side reductions. In the absence of DSP operating information, AEMO is assumed to exclude DSP from its scheduled demand forecasts in the Base case. Instead, it would depend on more scheduled generation to meet periods of high demand representing high prices. However, it is important to note that DSP would still be activated, resulting in over-dispatch. As DSP is modelled separately from VPP, any forecast errors associated with VPP are not included to avoid potential double-counting.

Results

The results are divided into two groups; social benefits which captures all the cost reductions (such as reduced FCAS enablement) and wealth transfer which captures all the price reductions. All figures, unless stated on an annual basis, are presented on a Net Present Value (NPV) basis discounted to 2025 at a rate of 7% per annum.

Results – Social benefits

The social benefit, as observed in the Visibility and Dispatch cases in comparison to the Base case, are $1.5 and $1.9 billion on a NPV basis over the study horizon, respectively. These are comprised of a reduction in costs from a decrease in regulation FCAS enablement volumes, reductions in emissions, and reductions in generation and RERT costs.

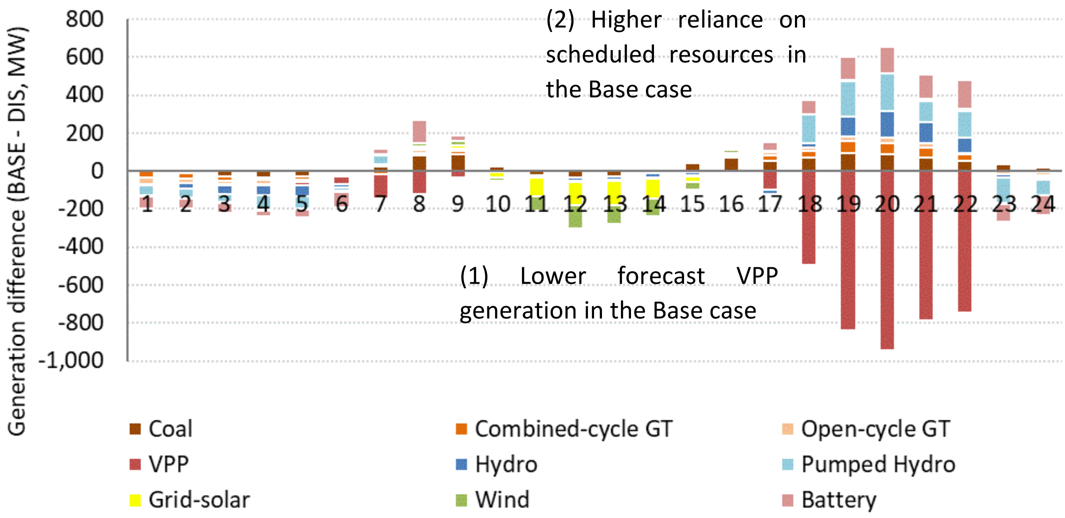
Generation cost reductions

Generation cost savings ($154 and $186 million for Visibility and Dispatch, respectively) stem primarily from lower levels of forecast VPP contribution during the Base case evening peak due to the lack of forecast information (Figure 6). This results in additional scheduled generation, which includes thermal generation, resulting in higher generation costs under the Base case than the reform scenarios.

Generation cost reductions are summarised by time of day and show discernible savings during daily peak hours (Figure 7). However, these savings are slightly offset by higher costs during overnight periods.

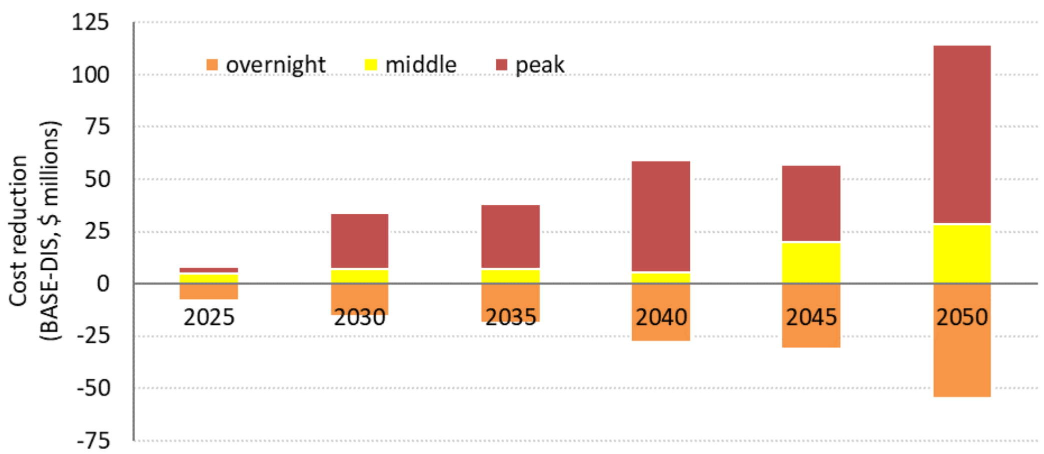
The reductions in generation costs under the modelling approach are likely to be understated because investment levels are held constant. I.e. the level of generation and storage capacity is the same across the scenarios. It is reasonable to assume that higher prices would have driven generation investment in the Base case compared to the reform cases. This would mitigate some of the pricing impacts or the wealth transfer effect, but would introduce a material new cost saving in the form of a generation capital cost benefit. The result is that the benefits effectively lead to a conservative estimation of the actual generation cost reductions (i.e., accounting for generator capital expenditure) under the reform cases.

Figure 6 Typical daily scheduled generation difference (NEM, Base - Dispatch, 2030)



Note: Between 17:00 and 22:00, there is up to 900 MW less forecast VPP generation in the Base case which results in more scheduled generation relative to the Dispatch case. The Base case also has lower scheduled demands outside peak periods and is related to lower forecast VPP charging requirements. VPP are unscheduled but has been included here to show the relative impact.

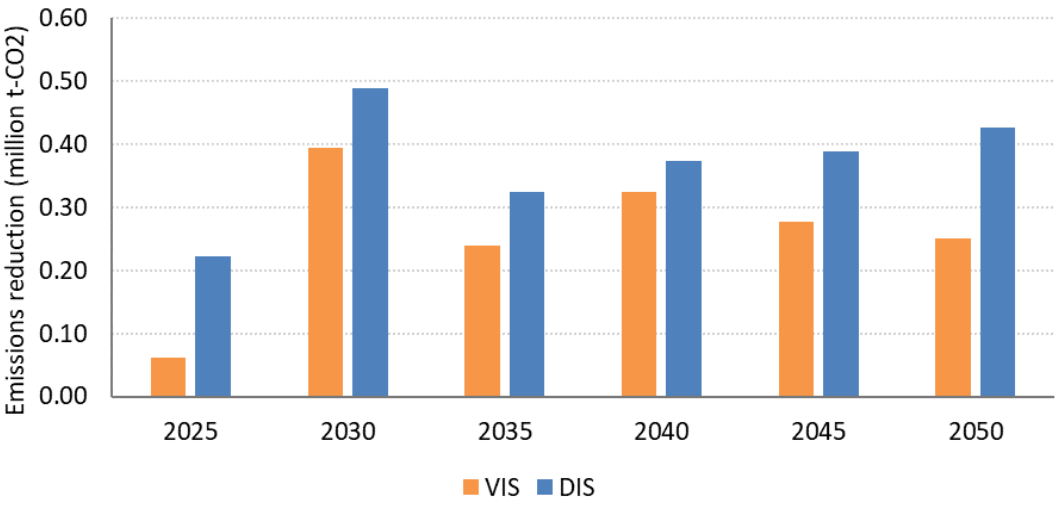
Figure 7 Social benefit - generation cost reduction by time slice (VPP, Dispatch - Base)



Emissions

The emissions reduction aligns with the generation cost outcomes. As the base case leads to the over-scheduling of peaking (thermal) generation. Notably, savings of up to 0.5 million tonnes of CO_2 per annum, or $514 and $720 million on an NPV basis, are realised in the reform cases. This reduction represents approximately 0.8% of the total modelled NEM emissions. The cost assessment of the emissions reduction has been based on the NSW Government's carbon value and is intended to be replaced with the Commonwealth Government's Value of Emission Reductions if and when it becomes available.

Figure 8 **Social benefit – Emissions reduction from Base case (VPP)**



FCAS enablement

FCAS benefits, under the VPP modelling, arise from both enablement and price impacts. The social benefit, however, pertains exclusively to the change in volume, assuming constant prices. The level of forecast inaccuracy, in capacity terms, increases over time due to the rapid uptake of PRR and underlying forecasting accuracy assumptions. Under the Base case this reaches 10 GW by 2050, leading to significant forecasting errors. Consequently, the modelled raise regulation requirements, designed to address the maximum deviation between forecast and actual demand and set based on a first pass of modelling outcomes, surpasses 4 GW in the Base case (Figure 9). This is due to the underestimation of actual VPP charging operations during the middle of the day. The additional regulation requirement result in up to $180 million pa in additional (opportunity) costs over time, or $711 to $889 million over the modelling period (Figure 10).

Figure 9 Time of day regulation enablement requirements by case (VPP, 2050)

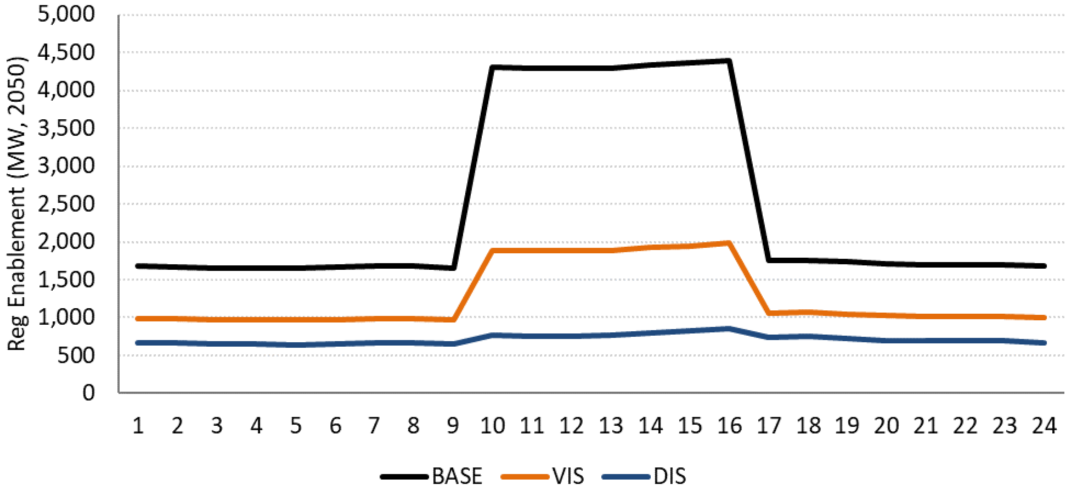
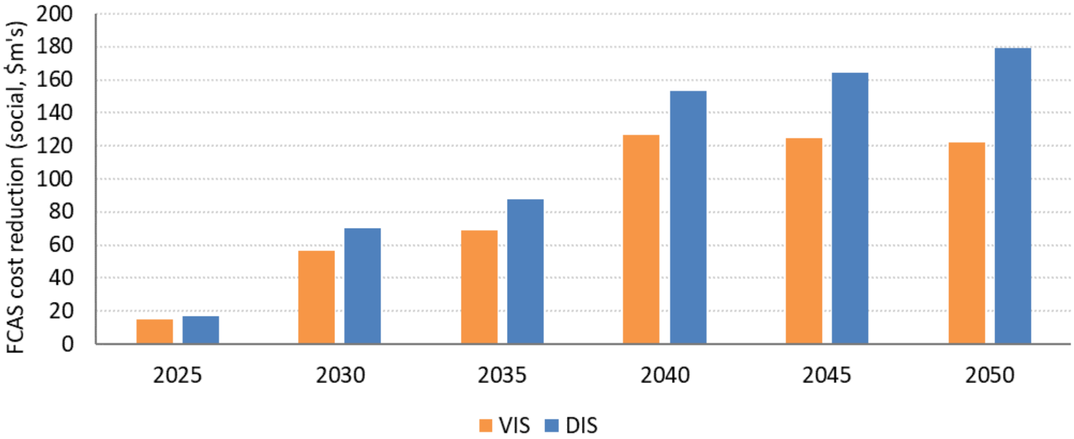


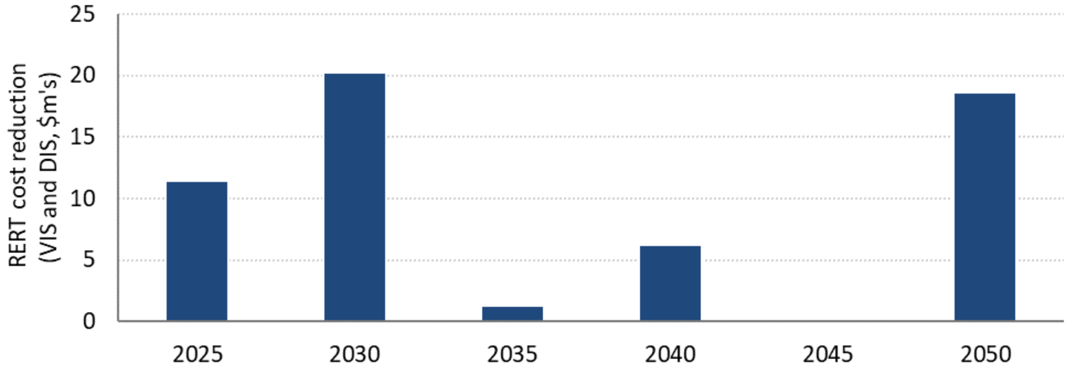
Figure 10 Social benefit - FCAS cost reduction from Base case (VPP)



RERT

In the Base case, when tight forecasting situations arise AEMO calls on Reliability and Emergency Reserve Trader (RERT) capacity to ensure supply. Information related to DSP operation in the reform scenarios reduces the amount of RERT needed. There are substantial RERT/intervention cost savings on a per event/interval basis because of the reduction in RERT volumes from having more reliable DSP operational information. However, the overall cost is low due to the limited number of events at which RERT is expected to be required (Figure 11).

Figure 11 Social benefit - RERT cost reduction (DSP)



Results – Wealth transfers

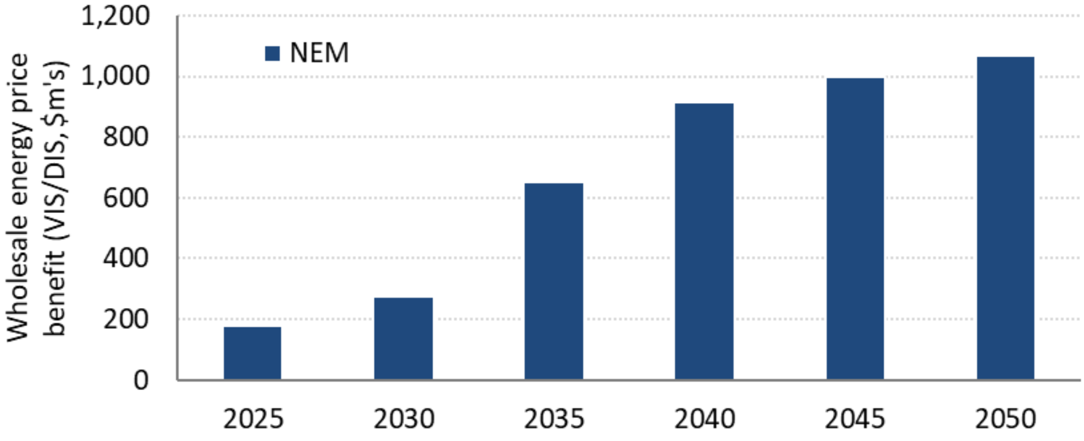
Wealth transfers, associated with changes in prices, as modelled in the Visibility and Dispatch cases in comparison to the Base case, range from $11 billion to $12 billion. These are largely comprised of the impact of energy price reductions from more efficient scheduling. The wealth transfer effect is notably higher than the social benefit. As noted in the generation cost section above, the modelling assumption to hold generation and storage entry/exit constant, likely overstates the wealth transfer effect. This is because the higher prices in the base case would likely drive additional generation and/or storage entry to the market.

DSP energy prices

Wholesale energy price differences account for most of the benefit from DSP reforms. This arises due to over-dispatch (or higher scheduled demands) in the absence of accurately forecasting DSP, resulting in much higher spot prices during tight supply periods.

The difference in spot prices reaching up to $2,500/MWh, escalates proportionally with increasing DSP volumes over time, anticipated to reach approximately 1.4 GW by 2050. This pricing impact applies across the entire scheduled demand, and each instance of accurately forecasting DSP results in potential benefits ranging from $1 to $8 million per 5-minute interval. These benefits when annualised using historical weightings result in a benefit of $5.5 billion.

Figure 12 **Wealth transfer – energy prices (DSP)**



VPP energy prices

There are also substantial wealth transfers from a change in energy prices under the VPP modelling ($4.9 to $5.8 billion). While DSP energy cost benefits is concentrated in a handful of intervals per year, energy pricing benefits under the VPP modelling occurs on a regular basis. The scheduling of more generation resources during the peak under the Base case result in higher energy prices.

In the Visibility and Dispatch cases by 2050, scheduled demand during the evening peaks is approximately 2.5 GW and 3.5 GW lower than the Base case, respectively. This reduction translates to lower energy prices, averaging $25/MWh and $30/MWh lower as observed in the Visibility and Dispatch cases (Dispatch case shown in Figure 13). The peak period impacts are mitigated by higher energy prices and energy costs related to higher forecast charging requirements outside of the evening peak hours under the reform cases (Figure 14).

Figure 13 Daily energy price reduction from Base case (NEM-level, Dispatch, VPP)

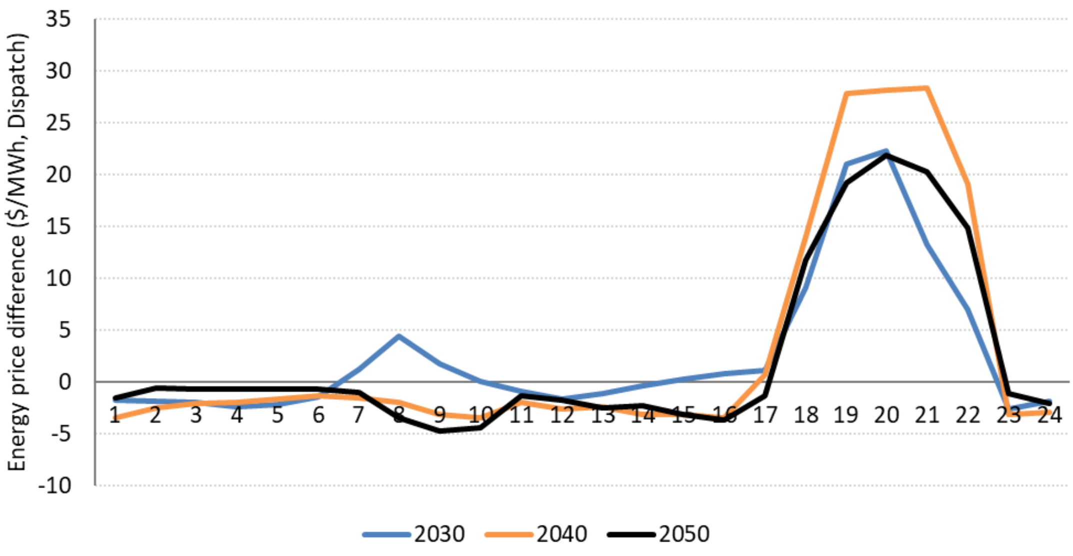
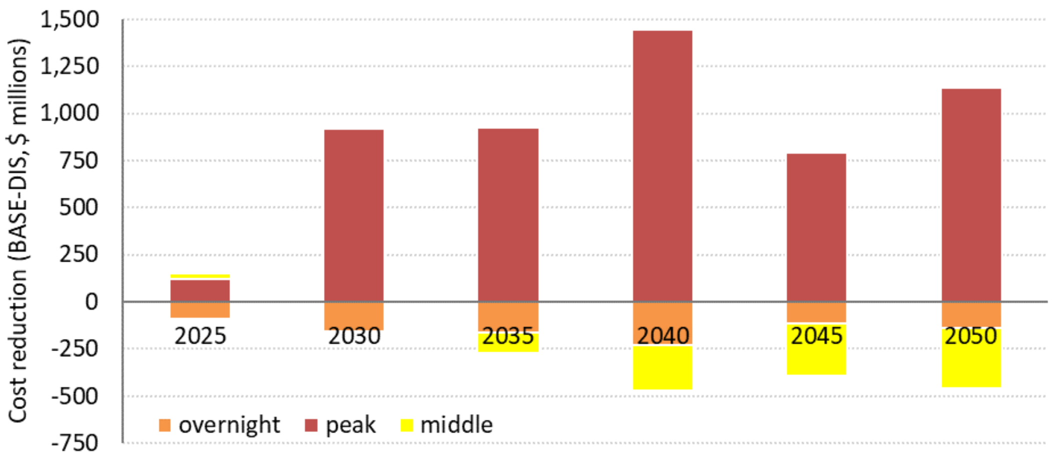


Figure 14 Wealth transfer – energy prices (VPP)



FCAS prices

In the Base case, the combination of higher regulation requirements and lower FCAS provision assumptions across VPPs results in higher regulation prices (Figure 15) and costs relative to the reform cases. The wealth transfers arising from reduced FCAS prices, by holding FCAS enablement levels constant, amount to $586 to $738 million across the Visibility and Dispatch cases, respectively (Figure 16).

Figure 15 Wealth transfer – regulation FCAS prices (time-weighted, VPP)

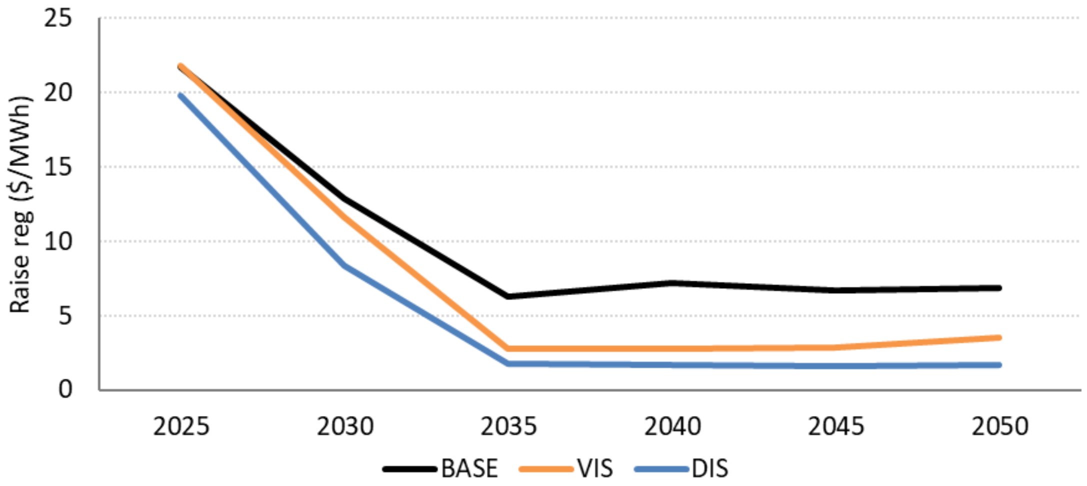
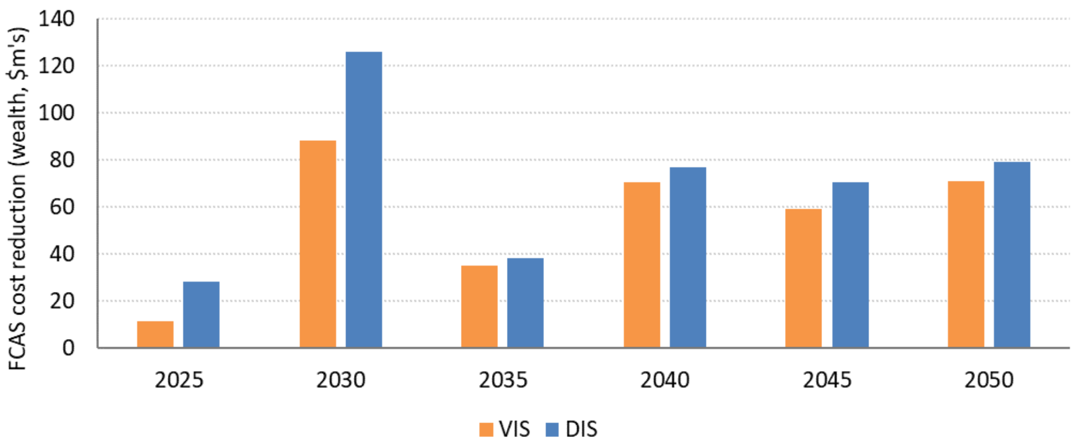


Figure 16 Wealth transfer – FCAS prices (VPP)

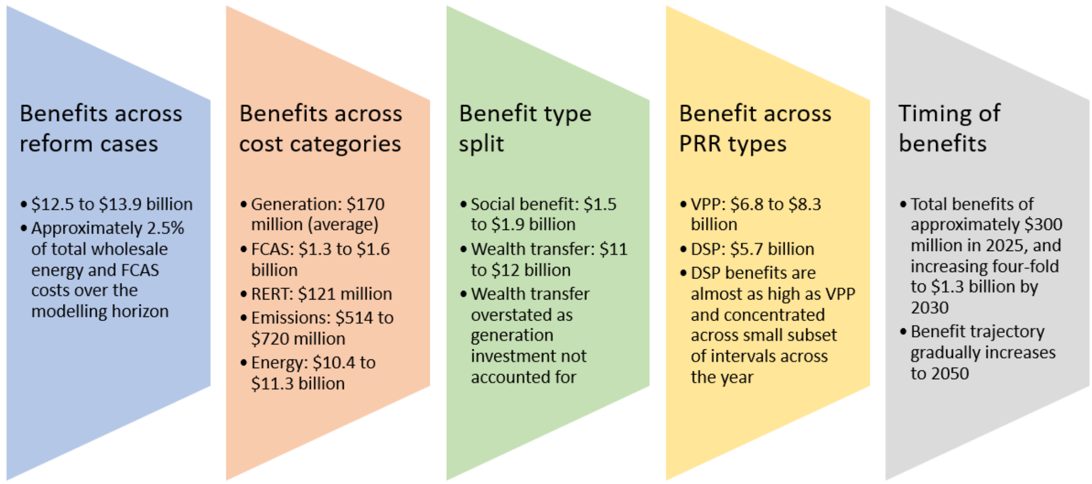


Key findings

The widespread adoption of PRR is forecast in AEMO's 2022 ISP to reach 31 GW by 2050. The lack of operational information available to AEMO under the current rules is expected to contribute to scheduling issues and increasing challenges to maintain the NEM. Improved visibility of VPP and DSP operations, leading to increased forecast accuracy, would allow AEMO to dispatch fewer scheduled resources during peak periods and reduce the need to procure significant amounts of regulation FCAS enablement. Total benefits derived from integrating unscheduled PRR into dispatch are substantial across both reform cases and in terms of social benefits and wealth transfers, and is summarised in Figure 17, and Table 1 and Table 2.

- **Social benefits** Of the total social benefit ($1.5 to $1.9 billion), approximately 46% is attributed to reduced FCAS enablement costs, and 35% is associated with emissions reductions across both reform cases. Notably, the contribution from generation costs, accounting for 10% of the total, is likely understated due to holding generation investment constant. RERT costs comprises a smaller share due to the frequency of activations.
- **Wealth transfers** of $11 to 12 billion is primarily due to energy pricing impacts. Wealth transfers are equally significant across both PRR types and significantly higher than the social benefit. However, the modelling holds generation investment constant which would have otherwise occurred in the Base case due to higher pricing signals.
- **Timing**. There is a sharp increase across all benefits and PRR types observed between 2025 and 2030 and is closely tied to the adoption of PRR and forecast accuracy assumptions (Figure 18). Social benefits on a per annum basis are in excess of $150 million pa under the Visibility case from 2030.

Figure 17 Total benefit breakdown summary



Note: Quoted ranges are for the Visibility (lower bound) and Dispatch cases (upper bound).

Figure 18 Timing of benefits by PRR type and reform option

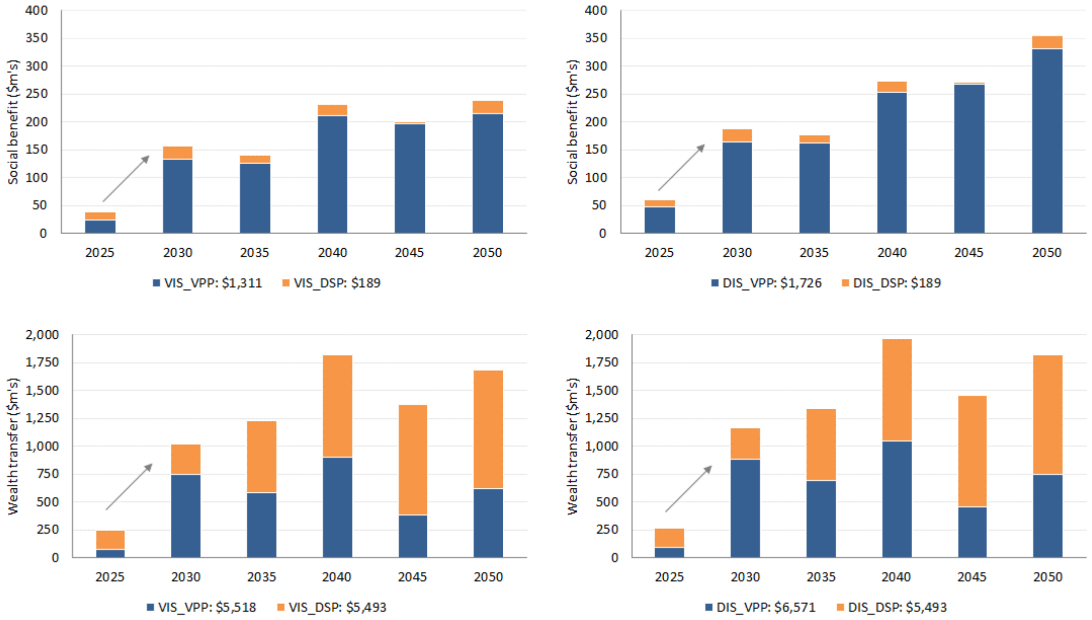


Table 1 Benefit and cost type – Visibility (NPV, millions)

Cost component	Social benefit	Wealth transfer	Total benefit
Energy	0	10,425	10,425
FCAS	711	586	1,297
Generation	154	0	154
RERT	121	0	121
Emissions	514	0	514
Total	1,500	11,011	12,511

Table 2 Benefit and cost type – Dispatch (NPV, millions)

Cost component	Social benefit	Wealth transfer	Total benefit
Energy	0	11,326	11,326
FCAS	889	738	1,627
Generation	186	0	186
RERT	121	0	121
Emissions	719	0	719
Total	1,915	12,064	13,979

2 Introduction

2.1 Background

The Australian Energy Market Commission initiated a rule change request, ERC0352: Integrating price-responsive resources into the NEM, following the Australian Energy Market Operator's submission to introduce a 'scheduled lite' mechanism into the National Electricity Market. The rule change request seeks to better integrate non-scheduled price-responsive resources into AEMO's existing scheduling processes either through the provision of operational information and/or direct participation of these resources. Reform is expected to reduce costs for all consumers through improved dispatch and planning efficiency.

Intelligent Energy Systems was commissioned to assess the potential maximum benefits of integrating price-responsive resources in the NEM through a visibility and dispatch model. These are generic reforms that integrate resources through the provision of operational information and/or direct participation of the resources, rather than an assessment of the solutions as designed by AEMO.

2.2 Scope of work

The modelling objective was to quantify the potential Phase A benefits of integrating PRR that are not currently scheduled through the market dispatch process, and do, or could, respond (individually or as part of aggregation) to market price signals. The uptake of PRR has been based on the expected trajectory from AEMO's Integrated System Plan 2022 Step Change scenario. Benefits were assessed from 2025 through to 2050 based on either the Visibility or Dispatch option. The modelling scope captures the primary reform features and will not precisely reflect the actual operational design. The benefits are categorised by functional area as summarised in Table 3 and four additional key questions, in Figure 19, are addressed to provide further context around the total benefits of reform.

Table 3 Scope of work summary

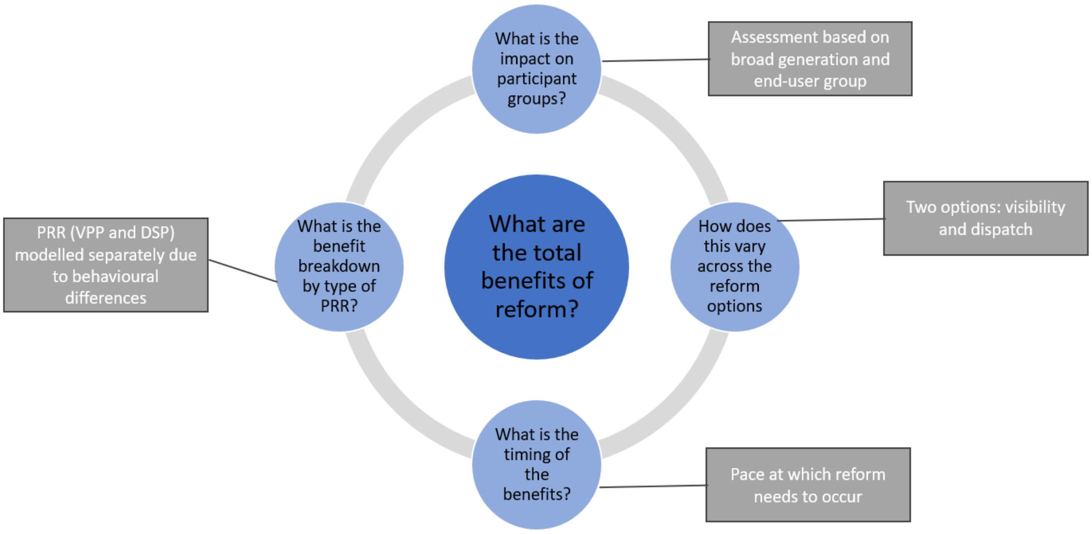
Option	General reform features	Functional areas of benefits[3]
Visibility	The Visibility model is designed to provide visibility (information) of price-responsive, distributed resources and their market intentions, leading to more accurate short-term load and price forecasting. PRR remains unscheduled.	**Generation costs** — knowing when PRR can be used to reduce demand (particularly at higher cost times), improves demand forecasting and reduces generation resources that AEMO dispatches to meet demand; **Security of supply (FCAS costs)** — by reducing the need for additional, potentially more expensive generation reserves to balance the market, system security will be achieved at lower cost;
Dispatch	The Dispatch model will integrate unscheduled price-responsive resources into the NEM central dispatch and scheduling processes.	

[3] Request for Proposal for Services: a benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, or 'size of the prize', AEMC (Sep 2023).

Option	General reform features	Functional areas of benefits[3]
	Through participation in dispatch, traders could also access existing or potential future markets that require services from scheduled resources.	**Reliability of supply (RERT costs)** — the ability to schedule these available resources could improve planning and lower intervention costs; **Emissions costs**– improved dispatch may potentially also reduce total emissions; and **Energy prices** — by better matching supply and demand, the price of energy would be more efficient, potentially reducing energy costs.

Note: The modelling aims to capture the primary reform features with the aim of establishing key dynamics. The results may not precisely reflect the actual operational design.

Figure 19 Scope of work and key questions



2.3 Report notes

The basis of figures quoted in this report, unless otherwise stated, is listed in Table 4. AEMO's Integrated System Plan refers to the June 2022 release.[4]

Table 4 Reporting basis

Reference	Basis
Years	Financial year basis starting 1 July to 30 June
Capacity and generation	As generated
Demand	Operational sent out basis
Dollars	Real, June 2023 Australian dollars
Average prices	Time-weighted
Discount rate	7% pa (real)
Net present value	As of 2025

4 https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

3 Approach and considerations

3.1 Definition of price-responsive resources

Price-responsive resources span residential, commercial and industrial sectors and can include PV panels, batteries, (home and other) energy management systems, EVs, water heating elements, pool pumps, and commercial chillers. Price-responsive resources influence scheduled demand and generation through load curtailment, changing the patterns of energy consumption (and export) from PV generators, EV energy exchange with the system and battery charging and discharging. Retailers and aggregators access these resources to manage network infrastructure (such as batteries embedded in distribution networks), manage energy fluctuations, and assist retailers (and consumers) to reduce their wholesale costs. Although these resources influence the energy dispatched from (large-scale) scheduled resources they do not bid directly into the NEM. AEMO, and the market generally, does not see their intentions. The expected growth of price-responsive resources across all sectors and growing awareness of the need to manage these resources but a lack of current mechanisms to do so, is expected to increase the challenge of maintaining the NEM in a secure and reliable state.

The cumulative benefits expected from integrating PRR are contingent upon the uptake over time. AEMO's ISP work forecasts the adoption rates of PRR that are categorised as either distributed, coordinated, or as demand-side participation. The modelling carried out by IES covers coordinated resources and DSP, i.e., resources that are managed by energy service providers (retailers or aggregators) and respond to both wholesale price changes and system requirements.[5] Coordinated resources are modelled as VPPs in the ISP, either actively participating in central dispatch or providing regular, accurate, operational information to enable AEMO to efficiently dispatch scheduled resources. DSP corresponds to expected voluntary consumer demand-side reductions in response to high wholesale prices.

Coordinated PRR and DSP from households, business and industrial facilities encompass various sub-categories outlined in Table 5. The classification in this context pertains to how these resources are modelled to evaluate the benefits linked to accurately forecasting its operations (see Section 3.4). References to visibility relate to the provision of coordinated PRR and DSP operational information to AEMO, which is currently not available based on current market arrangements. References to PRR from this point in the report relate specifically to the in-scope resources that are classified as either VPP or DSP. PRR are embedded by definition and are non-scheduled in the current market arrangements.

[5] In practice, VPPs may also respond according to the contracts established between the retailers or aggregators, the customers' needs, as well as other incentives such as network tariff structures.

Table 5 In-scope coordinated price-responsive resources

Type	Description	Classification
Resources participating in the Wholesale Demand Response (WDR) mechanism	Already participates in the central dispatch process and is therefore already visible.	Excluded
Resources participating in Reliability Emergency Reserve Trader	Already participates in out-of-market scheduling and is therefore already visible.	Excluded
Electric vehicle to grid (V2G)	V2G are called on by a retailer or aggregator and would not be visible.	Included as VPP. Regular operations.
Aggregated embedded battery energy storage systems	Operated through a retailer or aggregator and would not be visible	Included as VPP. Regular operations.
Flexible demand responding to high prices (non-scheduled and non-aggregated, non-WDR volumes)	Demand-side reductions triggered by high prices in the spot market. Demand response is not accounted for in AEMO's operational forecasts, i.e., this segment is not visible.	Included as DSP. Infrequent operations/triggers.
Flexible demand responding to low prices (non-scheduled and non-aggregated, non-WDR volumes)	Same resources as the above, except the response is an increase in demand due to low/negative prices in the spot market.	Excluded due to data availability.
Non-scheduled generation	Refers to 'normally off' embedded generators that respond to high prices which are not accounted for in AEMO's operational forecasts.[6]	Included as DSP. Infrequent operations/triggers.

3.2 Dispatch and actual outcomes

It is important to make a clear distinction between dispatch and actual outcomes in the NEM. AEMO operates the NEM through a centrally coordinated dispatch process, wherein AEMO needs to forecast the scheduled demand level and issues generation targets for all scheduled generators for each 5-minute interval. This occurs on an ex-ante basis, and any discrepancies in scheduling, such as inaccuracies in demand forecasts or generator non-compliance, are rectified by other generators providing FCAS.[7] At a simplistic level, as assumed in this modelling, despite dispatch inaccuracies, total generation will always match actual demand because regulation-providing generators adjust its output accordingly. However, the generation mix may vary based on the extent of dispatch inaccuracies, leading to differences

[6] 'Normally on' non-scheduled generators potentially responding to negative prices is out of scope.
[7] The scope of work focuses on demand forecasting inaccuracies and regulation FCAS.

in overall system costs. For example, AEMO could over-forecast demand, leading to over-dispatch of high price generation, leading to regulation (lower) enabled generators having to ramp down (cheaper) generation. The accuracy of AEMOs forecast of PRR, and therefore scheduled demand, holding all types of other real world forecasting errors constant, will impact the level of system costs.

The operating profile of PRR encompassing VPP and DSP is assumed to be aligned with wholesale pricing outcomes and system requirements irrespective of AEMO's ability to forecast PRR operations. The ISP assumes that the PRR are visible and/or centrally dispatched which enables AEMO to dispatch the system optimally, i.e., the ISP implicitly assumes mechanisms that facilitate the full provision of PRR operating information or participation in the dispatch process. However, without reform, AEMO will need to estimate the operating profiles of PRR in both operational and planning timeframes, leading to scheduling and investment inefficiencies. Inefficiencies in dispatch may lead to higher (incorrect) price signals for generation investment that would otherwise not be needed with more accurate forecasting of PRR operations. The rule change seeks to improve information and dispatch efficiency, ultimately leading to enhanced outcomes for consumers.

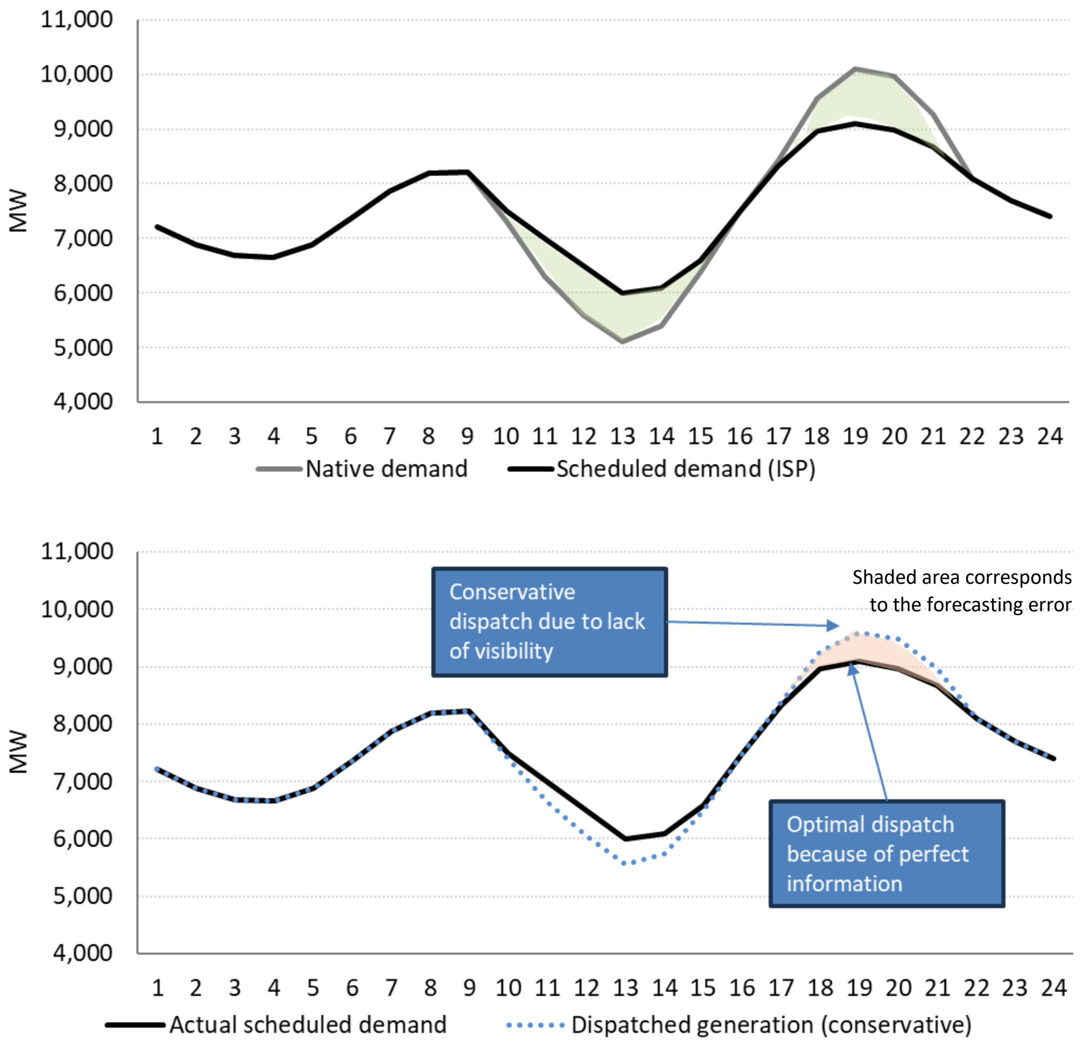
Figure 20 provides an illustrative example highlighting the impact of AEMO's ability to forecast VPP on dispatch. The first chart shows native demand (grey) and scheduled demand (black) after accounting for up to 1 GW in VPP operations (green area). The black line corresponds to the most efficient dispatch as the contribution from VPP is known and fully accounted for in dispatch. However, in the absence of VPP operating information, AEMO would have to conservatively anticipate less VPP capacity (500 MW as an example) operating during the system peak. This leads to AEMO scheduling more peaking generation, as indicated by the dotted blue line in the second chart. The actual operation of the VPP is 1 GW regardless of AEMO's forecasting ability. The main consequence of this over-dispatch is two-fold:

- Higher spot prices and energy costs compared to the black line during the evening peaks. Generation costs are also likely to be higher over the peak period. Conversely, when the dotted blue line is positioned above the black line, an opposite effect occurs, and the overall benefit represents the net impact of these differences.
- Scheduling inaccuracies will lead to AEMO purchasing additional FCAS regulation enablement to avoid fluctuations in power system frequency. In the example, Regulation lower and raise services would be needed to address the higher *actual* load during the middle of the day and lower *actual* loads during the evening peak respectively. This directly translates to higher system security costs. The black line (actual demand) is fixed irrespective of AEMO's dispatch instructions.

It is important to note underlying consumption is adjusted for the impact of PRR (unscheduled and embedded by definition) to determine scheduled demand or demand that is ultimately met by the scheduled generators in the NEM. AEMO does not dispatch PRR under the current market arrangements, but rather needs to accurately forecast its operations when dispatching scheduled generators.

Throughout this report, the actual scheduled demand is the same across all modelled cases. The only difference among the cases relates to the forecast scheduled demand, influenced by the level of visibility and AEMO's capability to accurately forecast PRR operations.

Figure 20 Example of dispatch implications

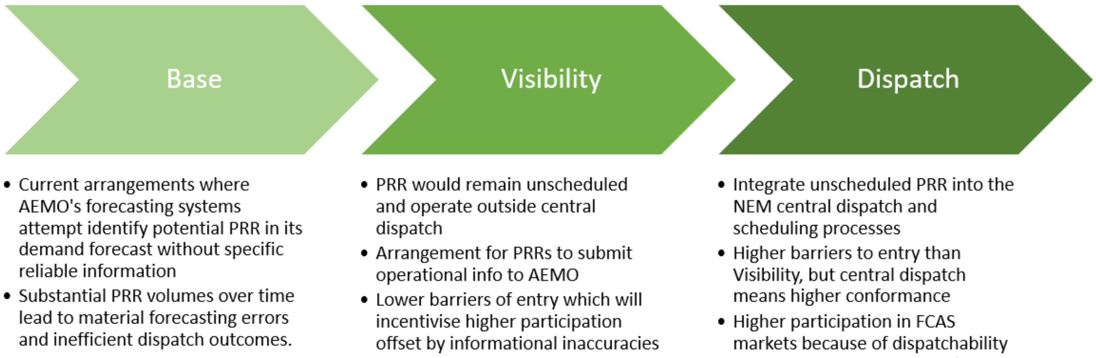


Note: Scheduled demand in the ISP is the same as the actual scheduled/operational demand.

3.3 Modelling framework

To quantify the benefits of improved PRR visibility in AEMO's operational forecasts, modelling was conducted in PLEXOS to simulate a Base case and two representative reform options (Figure 21), and the corresponding dispatch outcomes and associated costs.

Figure 21 Base, Visibility and Dispatch options



- **Base case**: The Base case represents the current arrangements where AEMO has limited scheduling information to incorporate PRR into its demand forecast and relies on its forecasting systems to correctly identify underlying scheduling inaccuracies relating to PRR. However, there is a limit on forecasting efficacy when substantial PRR are present which leads to forecasting errors and inefficient dispatch outcomes.
- **Two reform cases**: The introduction of the Visibility and Dispatch option would enhance AEMO's ability to correctly account for a higher level of PRR in its dispatch process. While there may still be forecasting errors directly related to predicting PRR, the errors in the reform cases would be lower than the Base case due to the enhanced visibility.[8]
  - **Visibility case (VIS)**: PRR provides forecast generation and consumption information to AEMO. This increased visibility is anticipated to improve AEMO's forecast accuracy. There is a higher participation rate than the Dispatch case participation rate because of the lower barriers, however, there would also be a higher level of inaccurate information provided to AEMO.
  - **Dispatch case (DIS)**: PRR actively participates in the central dispatch. Participation in central dispatch results in higher informational accuracy and conformance than the Visibility case. The Dispatch case is modelled to have the highest forecasting accuracy among the three cases.

The Visibility and Dispatch options are complementary but are modelled as two distinct scenarios. I.e., actual reform may allow for both Visibility and Dispatch participation options, however, the modelling does not account for resources moving between these options, but rather alternative reforms.

Across the three cases given varying levels of visibility, it is assumed that AEMO would conservatively forecast PRR operations, i.e., some portion of the fleet would be forecast as self-use and not dispatched to system requirements, which results in a lower forecast peak

[8] The term visibility is used generally to describe increased information available to AEMO for scheduling, and/or higher controllability of PRR and therefore visibility, through its participation in central dispatch.

demand contribution. The actual VPP capacity and operations, and therefore actual scheduled demand, remains the same under all cases.

3.4 Virtual Power Plants and Demand-side Participation

The two types of PRR, as summarised in Table 6, are categorised based on whether their operations are regular, or if they infrequently trigger at high prices (Table 6). The modelling of VPP and DSP is conducted separately due to the nature of its operations and to assess the cost reductions separately. PRR are assumed to respond to wholesale price changes and system requirements.[9]

The total benefit associated with varying levels of forecast accuracy across the three cases is the sum of both PRR groups as illustrated in Figure 22.

- **VPP**: VPP is more likely to operate during imbalanced supply and demand conditions which may not be accurately picked up by AEMO's forecasting systems. The modelling aims to capture the typical cost and energy price reductions associated with accounting for VPP operations more accurately.
- **DSP**: The modelling focuses on capturing infrequent high price events that trigger demand-side reductions. In the absence of DSP visibility, AEMO would exclude potential DSP from its scheduled demand forecasts. Instead, it would depend on more scheduled generation to meet periods of high demand representing high prices. However, it is important to note that DSP would still be activated, resulting in over-dispatch. As DSP is modelled separately from VPP, any forecast errors associated with VPP are not included to avoid potential double-counting.[10]

Table 6 PRR modelling components

Category	PRR type	Modelling approach for snapshot years
VPP	Aggregated embedded ESS and V2G	Modelling full snapshot years to assess total NEM costs.
DSP	Flexible demand and non-scheduled generation (normally -off)	Modelling based on targeting specific high-priced interval events only. The specific intervals are weighted based on the expected number of high priced intervals to derive expected annual costs. See Section 4.4.3.

Figure 23 provides an illustrative example of the modelling. The black line corresponds to the Base case where the forecast peaks are higher, but the middle-of-the-day forecast demands are lower. In the reform cases, a higher level of VPP visibility and therefore accuracy is assumed, resulting in the dispatch of the red dotted line. The red dotted line does not include DSP, and the cost difference associated with the pink area relates solely to higher VPP visibility and more efficient dispatch. Another run is conducted allowing for VPP and DSP, represented

[9] System requirements include energy and FCAS only. DSP cannot provide FCAS.

[10] In practice, VPP would also provide support, however, only DSP is considered to enhance dispatch efficiency during tight supply conditions.

by the dotted blue line, which is then compared to the dotted pink line to infer the DSP cost difference. The total cost difference between the base and reform cases is simply the sum of the pink and blue shaded areas.

Figure 22 VPP and DSP modelling overview

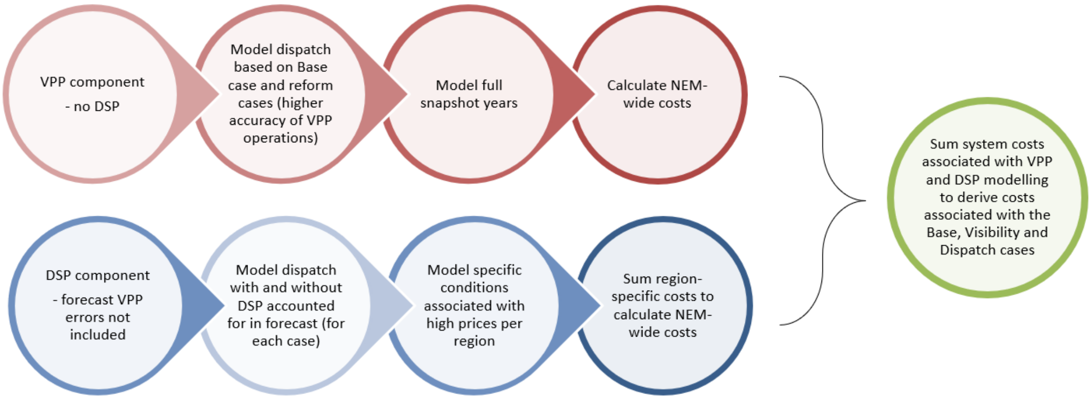
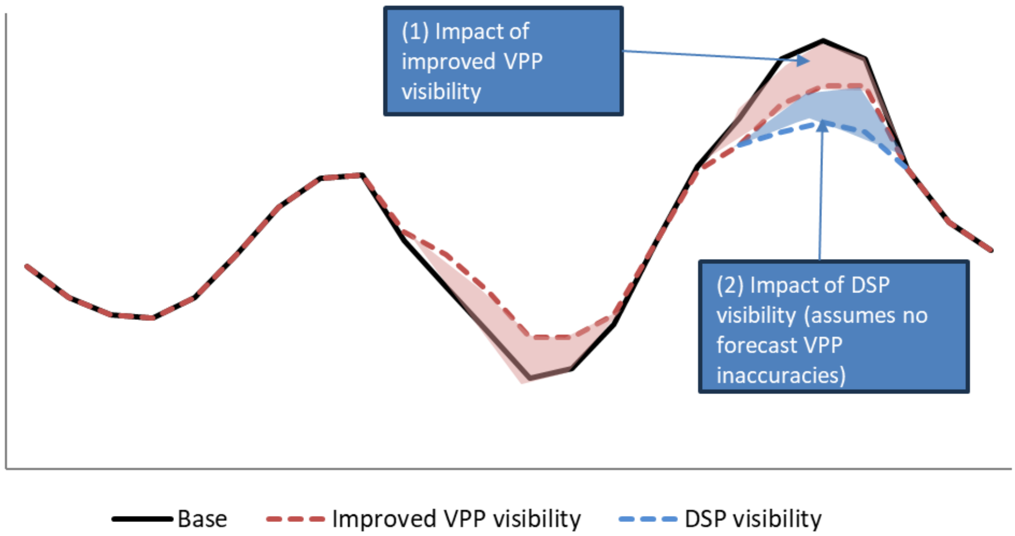


Figure 23 VPP and DSP modelling example



3.4.1 VPP modelling

The level of demand forecasting, or scheduling, errors is dependent on AEMO accurately forecasting the operations of aggregated ESS and V2G. Aggregated ESS and V2G operate exactly the same under the Base, Visibility and Dispatch cases, i.e., actual scheduled demand is also the same.[11] The modelling approach assumes that if this information is not provided,

[11] All other types of forecasting errors including generator non-compliance are ignored.

AEMO will conservatively forecast the non-visible VPP capacity to operate in accordance with its non-Virtual Power Plant equivalent, i.e., non-aggregated ESS for aggregated ESS and vehicle-to-home (V2H) for V2G. However, the approach also acknowledges that AEMO's forecasting systems will naturally identify structural errors over time, allowing for corrections to be made for the non-visible VPP component. The modelling of forecasting accuracy is based on three key factors outlined below:

1. **Participation or provision of information**: This factor is contingent on the operational data provided to AEMO through the participation of reform mechanisms.
2. **Conformance**: The degree to which the actual operational outcomes align with the information provided.
3. **Forecasting capability**: This relates to AEMO's proficiency in addressing structural errors or inaccuracies arising from both the lack of operational information received (point 1) and the level of conformance observed (point 2).

The percentages applied in the Base, Visibility and Dispatch cases are detailed in Section 4.2.2. At a high level, the Base case, even after the natural forecasting correction, would have the largest forecasting errors absent any mechanism to inform AEMO of the VPPs operational intent. Table 7 summarises how this is treated in the PLEXOS modelling. The PLEXOS modelling captures the forecast/dispatch requirements as a function of the level of accuracy associated with the three cases, and subsequent post-processing is carried out to adjust for impacts against actual demand outcomes.

Table 7 PLEXOS modelling treatment

VPP component	Treatment to model dispatch requirements
Aggregated ESS	Reduce the aggregated ESS capacity by the assumed non-visible MW from the ISP model and add the equivalent non-aggregated ESS profile to the operational sent out trace.
V2G	Reduce the V2G capacity by the assumed non-visible MW from the ISP model and add the equivalent V2H profile to the operational sent out trace.

3.4.2 DSP modelling

The DSP modelling focuses on high price intervals with and without DSP considerations in dispatch and excludes the impact of VPP forecasting inaccuracies. Without reform, AEMO would (conservatively) discount the potential demand response from DSP during high price events which effectively leads to over-dispatch of scheduled generation. The objective of the DSP modelling is to quantify the benefits under these conditions. Key modelling features include:

- The Base case assumes no DSP is accounted for in forecast scheduled demand and dispatch whereas the reform cases (Visibility and Dispatch) assume full DSP visibility which is triggered upon reaching certain price thresholds.[12] The periods where DSP is triggered in the Visibility and Dispatch cases are compared to the same interval in the Base case for comparison of interval-level costs.
- DSP assumptions for the Visibility case are based on the latest 2023 IASR workbook.[13] The Dispatch case also assumes the same level of DSP capacity as DSP would not be dispatched and would be subjected to the same participation conditions, i.e., the Visibility and Dispatch cases collapse into a single reform case.
- The benefits calculated here are contingent on high price events which can be uncertain and can differ from year to year. The approach is to simulate costs corresponding to specific conditions and then weight these accordingly to arrive at annualised figures. The weighting is discussed in Section 4.4.3.

3.4.2.1 Conditions

The scope of costs applies exclusively when demand response is triggered, and is likely to be specific to different market conditions. This supports the approach of running the DSP modelling to target relevant intervals only. These conditions encompass one or more of the following factors:

- High prices during periods of low or high demand.
- Varied demand response levels triggering at different price thresholds.
- Demand and supply levels that pose a threat to reliability and result in RERT activations.
- Different regions, as the level of DSP varies significantly due to regional size and underlying generation mix.

These combinations are summarised in Table 8. Historical analysis is used to inform the weights to arrive at the annualised costs for the Base and reform case.

Table 8 DSP conditions modelled

Condition	Variations	Description
Snapshot years	Every 5 years to 2050	Interpolate for all other years
Regions	NSW, QLD, VIC, SA, TAS	Cover all regions since the underlying gen mix can be different.
Demand response range	Clearing of all DSP quantity and price pairs up to the highest price band	Benefits are unlikely to be linear so modelling several points helps describe the cost impact.
Dispatch outcome	Market dispatch, and outcomes with RERT	The RERT condition covers reliability interventions.

[12] DSP is assumed to be co-optimised in dispatch irrespective of the Visibility and Dispatch cases.
[13] Wholesale demand response and reliability volumes have been excluded. The DSP forecast is based on a P50 outlook.

3.4.2.2 Reliability and Emergency Reserve Trader and unserved energy

RERT is included in the DSP modelling as it is also infrequent and is triggered based on similar supply conditions as DSP. The modelling of RERT assumes that AEMO does not consider (non-RERT) DSP when making decisions about RERT procurement. The various types of RERT are outlined in Table 9, and the modelling approach for RERT is summarised as follows:

- Short-notice RERT is modelled and treated as a suitable representation of the entire RERT category, as both RERT types function similarly within the context of this project.
- RERT is triggered/activated when there is an equivalent of Lack of Reserve condition 2 (LOR2) in the PLEXOS simulation.
- LOR2 is considered TRUE when the available supply, accounting for interconnector import limits and the operational sent-out demand, has a margin lower than the capacity of the largest generating unit in the region.[14]
- Assume that RERT is activated for a 30-minute period at a capacity of X MW, where X addresses the LOR2 condition. X is capped at the reliability response and DSP assumption provided in the 2023 IASR DSP assumptions.
- The modelling should give priority to RERT, regardless of its cost, before generating unserved energy (USE) outcomes.
- Once RERT is triggered, all prices in the NEM will be based on intervention pricing. i.e., intervention prices are based on the same interval solution assuming RERT was not activated.
- A single set of RERT costs will be used for all regions, based on historical procurement (see Section 4.4.2).

Table 9 RERT summary

RERT type	Short	Medium and Long
Notice period	3-7d	Medium: 7d - 10wks Long: +10wks
RERT Pricing	Agreed beforehand	Negotiated when required
Spot market pricing	Intervention pricing is applied in the market	Intervention pricing is applied in the market
Trigger	Lack of reserve condition	Low reserve condition
Actual trigger	LOR2 condition is TRUE when reserve levels are lower than the single largest supply resource in a state	If conditions breach standards
Quantity	Address LOR2 or LOR3	Bring back to standard
Other	At this level, there is no impact to the power system, but supply could be disrupted if a large incident occurred. Once a forecast	

[14] Capped at 2 GW per REZ.

RERT type	Short	Medium and Long
	LOR 2 is declared, AEMO has the ability to direct generators or activate the RERT mechanism to improve the supply demand balance	

An illustration of how the modelling was conducted is provided in Figure 24 and Figure 25 for both the Base and reform case. Unserved energy only becomes a factor if the combined available supply and RERT is inadequate (not shown here).

Table 10 Modelled RERT example

Case	Description
Base	- When demand exceeds the supply margin condition, LOR2 is triggered and AEMO procures RERT (lowest supply occurs hour 14-17) - Target RERT capacity corresponding to the capacity shortfall to reduce maximum (residual) demand back to grey dotted line - RERT is activated in blocks of firm capacity. In this example from hour 12-19
Reform (Visibility of Dispatch)	- Assume DSP triggers up to 100 MW over this period - If DSP is included in the demand forecast, the capacity shortfall wouldn't have been as large and therefore the procured RERT would be lower - RERT is activated in blocks of firm capacity the same as in the Base case example

Figure 24 RERT example (Base case)

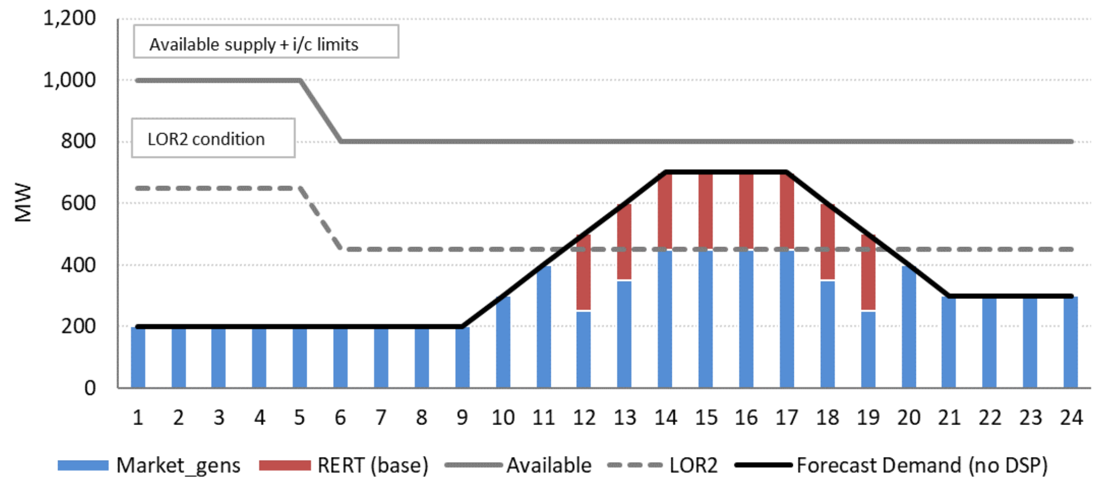
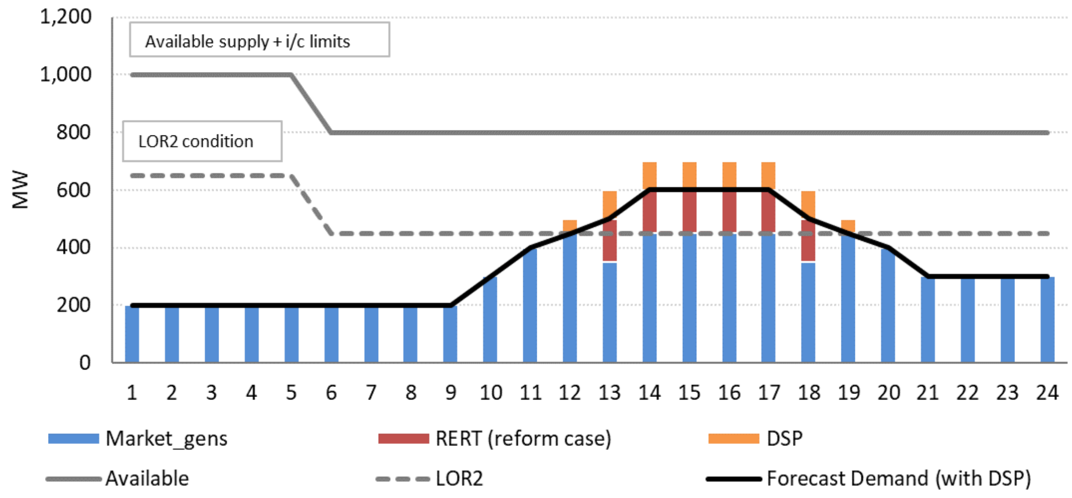


Figure 25 RERT example (reform case)



3.5 Benefits and functional areas

Cost reductions resulting from the modelled dispatch outcomes associated with the reform cases when compared to the Base case are expected to arise across several functional areas of the NEM. The cost reductions, or benefits, are expected to be applicable to two broad participant groups, generators and consumers, and were therefore considered separately. These are discussed below:

- **Social benefit**: refers to improvements in economic efficiency, or reduced system costs, relating to improved forecast accuracy of PRR and scheduled demand requirements. The primary driver of social benefits relates to reduced peak generation requirements.
- **Wealth transfer**: refers to changes in the price of energy and FCAS without shifts to the underlying demand being served. The change in price reflects a wealth transfer from one group to another, generally expected to occur from generators to consumers with higher PRR forecast accuracy.
- **Total benefit**: this is the cumulative effect of social benefits and wealth transfers and is assumed to be passed on to consumers.

The functional areas identified as sources of benefits and how they are captured in the modelling are summarised in Table 11. Investment costs relating to generation and network are out of scope which potentially overstates the wealth transfer energy cost component - the high-level impact is discussed in Section 5.4. The cost calculations are detailed in Appendix B.

Table 11 Assessment of functional areas

Area	Description	Assessment
Generation costs	Knowing when PRR is operating (particularly at higher cost times),	Comparison of variable generation costs relating to the modelled cases.

[Social benefit]	improves demand forecasting and reduces the generation resources (fuel and variable operating and maintenance costs) that AEMO dispatches to meet forecast demand.	The impact on generation investment is out of scope.
Reliability of supply (RERT costs) [Social benefit]	The ability to account for DSP resources could improve planning and lower intervention costs	Scenarios to be run based on very tight demand and supply conditions, leading to AEMO RERT triggers to mitigate reliability issues.
Emissions cost [Social benefit]	More efficient dispatch may reduce emissions-intensive generation	Comparison of emissions levels and corresponding costs across the cases.
Energy costs [Wealth transfer]	By better matching supply and demand, the price of energy would be more efficient (lower), reducing wholesale energy costs.	Comparison of interval-level spot energy prices and costs. The assessment holds generation investment constant.
Security of supply (FCAS costs) [Social benefit and wealth transfer]	By reducing the need for additional and potentially more expensive generation reserves to balance the market, system security will be achieved at lower cost.	Comparison of reserve enablement levels and prices with respect to varying visibility of PRR. Social benefit is calculated based on the volume reduction in enablement requirements representing an opportunity cost, and wealth transfer is based on to the pricing impact only.

Note: For consistency across the cases, PRR is considered non-scheduled in all cases when assessing costs.

The relevant cost components across the VPP and DSP modelling is summarised in Table 12. The DSP modelling excludes FCAS impacts as that is already captured in the VPP modelling. FCAS impacts, including instances of intervention, associated with the tight supply conditions modelled in the DSP component is out of scope.

Table 12 Functional areas by modelling component

Area	VPP modelling	DSP modelling
Generation costs	Yes, variable costs only	Yes, variable costs only
RERT costs	No	Yes
Emissions costs	Yes	Yes
Energy costs	Yes	Yes
FCAS costs	Yes	No

3.6 PLEXOS modelling

The modelling was conducted using PLEXOS, specifically using the time-sequential ST module, and includes co-optimised reserves modelling. An overview of the PLEXOS modelling elements is provided in Table 13.

The proposed approach is to base the Base, Visibility and Dispatch cases on the AEMO ISP 2022 central case (step change scenario), which represents the most likely scenario for demand, generation mix, and VPP and DSP development. To manage the computational load, IES ran snapshots of years at five-year intervals up to the year 2050.

Table 13 PLEXOS modelling approach

Component	Description or assumption	Comments
NEM database	AEMO ISP 2022 Step Change database	Adjusted by IES based on previous internal modelling (see Section 4.1)
Network configuration and constraints	NEM modelled as five-regions (by state) with no intra-regional network constraints other than REZ transmission limits as per ISP 2022	
Services modelled	Co-optimised energy and two (2) raise frequency control ancillary services	The PLEXOS outputs will be used to derive the full set of FCAS costs (see Section 3.6.2)
Modelling horizon and PLEXOS phases	Snapshot years, using the PASA, MT Schedule, ST Schedule. Deterministic solve	DSP modelling: Extracts intervals where DSP triggers to calculate costs for snapshot years VPP modelling: Based on entire snapshot years
Resolution	30-min resolution	Underlying data is at 30-min resolution only. PLEXOS costs have been scaled to 5-min interval costs for the DSP component
Generator bidding	DSP: LRMC portfolio bidding VPP: SRMC bidding + volatility adjustment	DSP: increased fixed costs to capture a range of high price events/volatility VPP: post-process SRMC prices. Refer to Section 3.6.1.
Planned maintenance	Yes	
Ramp rates	Yes	
Unit commitment	Rounded relaxation	
Samples	1 outage sample based on AEMO's rolling reference year	

3.6.1 Volatility adjustment

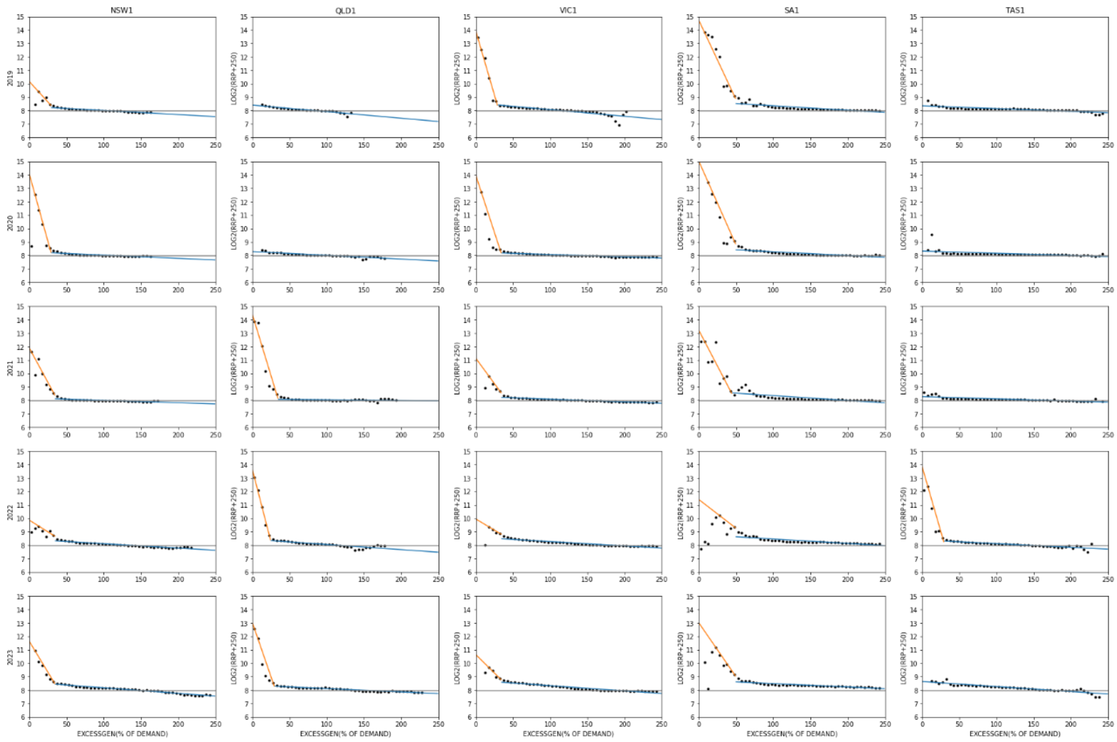
The modelled benefits from VPP and DSP are contingent on underlying market volatility; however, PLEXOS fundamentally solves for operational requirements assuming perfect foresight.[15] This presents a challenge, particularly over the modelling horizon, given the significant influx of storage capacity expected by 2050. Modelled price outcomes from PLEXOS show significantly less volatility than expected.

[15] Constraints and settings were applied across planning and operational timeframes in the modelling, however, the level of volatility observed was still lower than historical outcomes.

The adopted approach was to run PLEXOS on a Short Run Marginal Cost (SRMC) basis and post-process the prices to adjust for price-markups related to tight supply periods.[16] Historical analysis was conducted on spot prices against the calculated reserve margin expressed as a percentage of demand in each of the regions over the previous 5 financial years. The average spot price (logged) was then averaged for each 5% reserve margin increment to produce the series of charts shown in Figure 26.[17] These charts generally depict a strong relationship between regional price and supply margin.

The relationship was used to post-process the equivalent modelled supply margins out of PLEXOS to apply a price adjustment or mark-up. An example of the original SRMC-based prices and adjusted prices is shown in Figure 27 for 2050 in NSW. A similar process was carried out to determine FCAS prices.

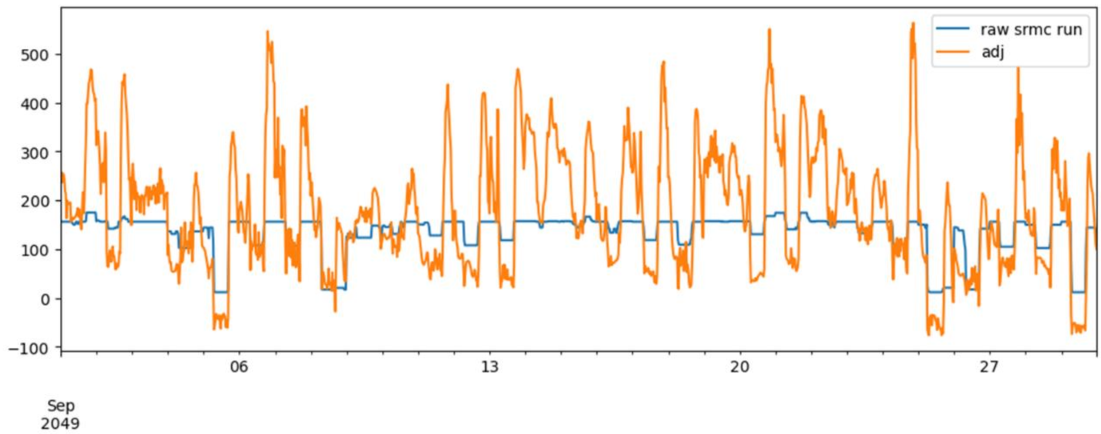
Figure 26 Historical relationship between energy prices and supply margin



Note: the y-axis is in $/MWh with log base 2 applied.

[16] Applies only to the VPP modelling. Relevant high price events were modelled directly in PLEXOS.
[17] Using the average metric incorporates skew but also won't produce the same extremities seen in the spot market.

Figure 27 Example energy price outputs before and after adjustment ($/MWh)



3.6.2 FCAS modelling and requirements

Actual FCAS requirements are influenced by a combination of underlying demand forecasting and generator non-conformance errors, making it challenging to replicate in the PLEXOS modelling. Baseline FCAS requirements have been estimated by scaling typical monthly raise regulation requirements in FY2023 (Figure 28) by the annual increase in operational sent-out demand. The profiles indicate a minimum procurement of 220 MW, roughly scaling in accordance with typical demand (generation) levels throughout the day. Figure 29 presents the baseline regulation raise requirements for snapshot years.

Forecasting errors resulting from AEMO's lack of visibility of VPP operations are expected to lead to additional regulation procurement to address frequency fluctuations. The approach involves profiling the additional regulation requirement to cover the largest forecast error in the modelling. Primary frequency response has been excluded as the benefits from this are likely to be overshadowed by the level of PRR modelled here. More fundamentally primary frequency response does not negate the need for regulation reserves as it acts on a different time scale. The modelled raise 60s contingency requirement is based on the largest generation risk in the modelling.[18]

[18] The modelling caps this at 2 GW across the renewable energy zones.

Figure 28 Typical daily regulation enablement profile by month

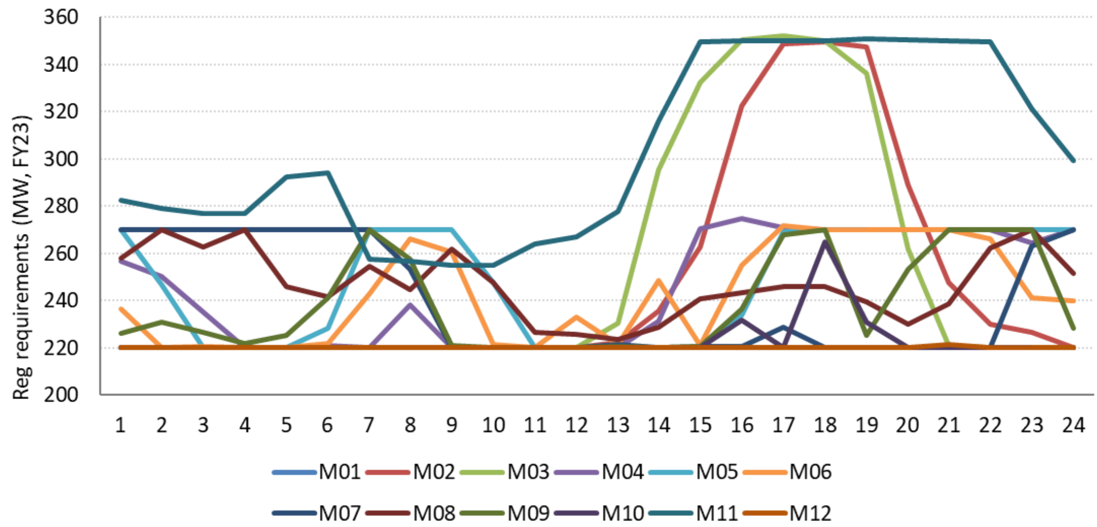
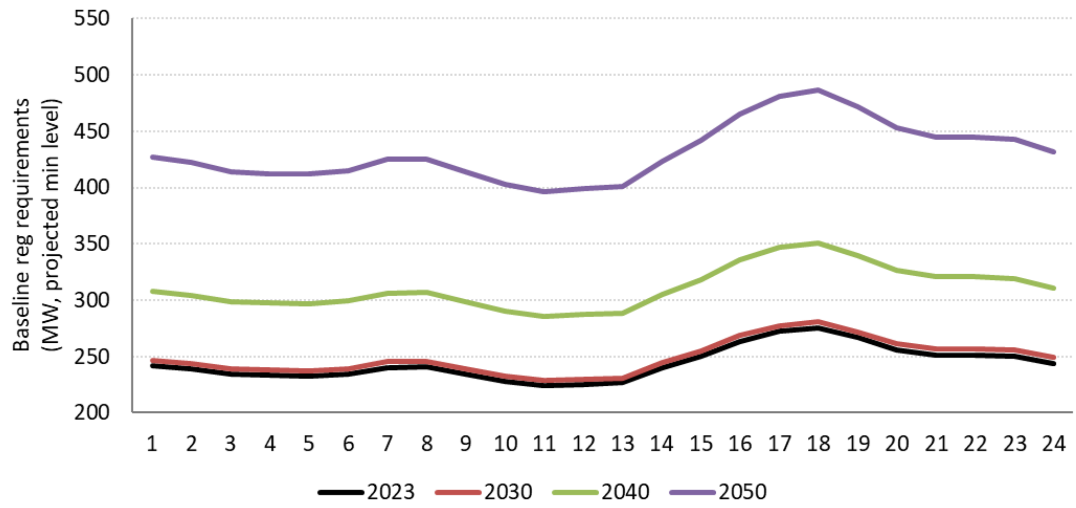


Figure 29 Typical baseline regulation requirement



3.7 Modelling limitations

There are many uncertainties and limitations associated with estimating the potential benefits relating to integrating PRR in the context of the reform cases. The list of limitations, below, from our perspective, is unlikely to exhibit a strong bias in any particular direction unless otherwise indicated. Nonetheless, it remains crucial to emphasise these limitations when interpreting the results.

- The broader supply and demand assumptions modelled was based on AEMO's 2022 ISP Step Change scenario. The Step Change scenario represents the most likely outcome over the modelling horizon, however, there are many other possible combinations and assumptions updates such as the speed of VPP uptake that have not been considered.
- There are assumptions based on historical analysis which is expected to differ with structural changes to the supply and demand balance in the NEM over time. An example includes the price and supply margin relationship to derive forecast price volatility.
- The assumptions relating to the percentage of VPP and DSP capacity that is visible or can be corrected for through forecasting processes, and inaccuracies relating to the provision of scheduling information is inherently uncertain but is a critical driver of the benefits.
- The formation of the regulation requirement is based on our understanding of the underlying drivers but is also contingent on AEMO's forecasting efficacy of PRR operations. A lower assumed forecasting efficacy than actual performance would overstate the FCAS benefits of integrating PRR in the NEM. One of the objectives of the modelling was to understand the 'size of the prize'.
- The DSP modelling assumes conditions and/or levels of out-of-market interventions which is uncertain and operationally contingent on real-time power system conditions that are not reflected in the PLEXOS modelling.
- The PLEXOS modelling assumes perfect foresight and leads to efficient dispatch outcomes which would potentially have the impact of understating the level of benefits assessed.
- The weighting of the conditions under the DSP modelling, and persistence of demand forecast inaccuracies over time will also drive the overall level of benefits.
- The planning benefits relating to reduced generation and network investment have not been quantified, however, are potentially significant. The omission of this is likely to bias or overstate the wealth transfer benefits related to changes in the energy price.
- The modelling of PRR, specifically the VPP component, excludes distributed resources dispatched for self-consumption. These resources could potentially convert to VPP operations (coordinated PRR) as a result of reform measures.

4 Assumptions

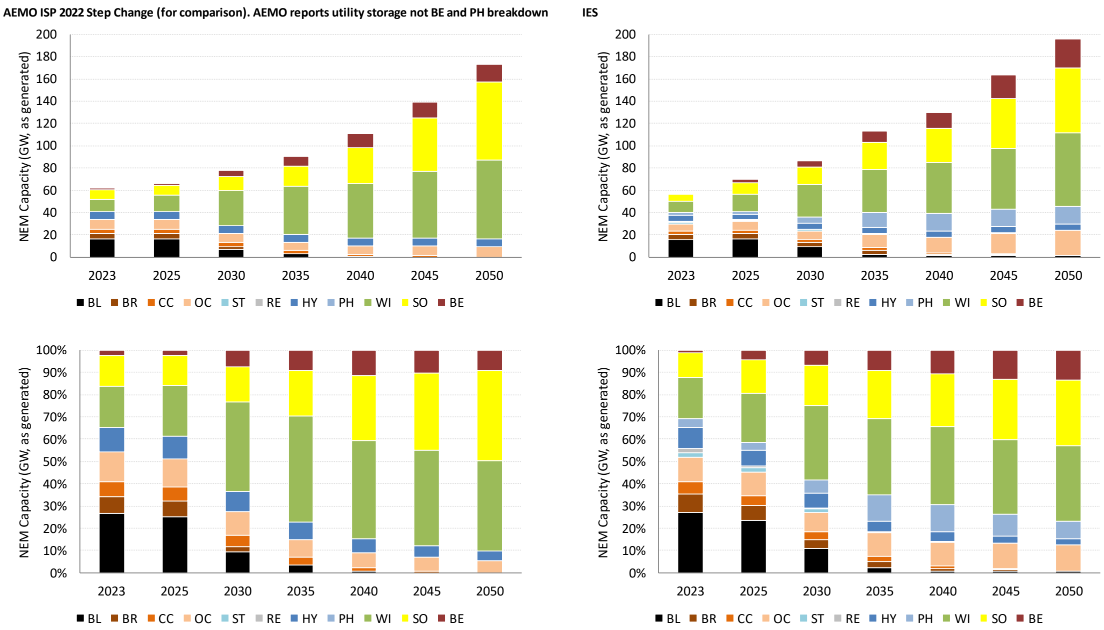
4.1 Supply outlook

IES' internal modelling of the NEM supply outlook is based on AEMO's Step Change scenario (ISP 2022), but departs from it in two critical areas of assumption:

- The modelling does not include a carbon budget, which leads to more investment in peaking gas generation. The decision to exclude the ISP 2022 carbon budget was influenced by the absence of policy details pertaining to Australia's net-zero trajectory.[19]
- The modelling was conducted after the release of the ISP 2022 and announcement of the Queensland Energy and Jobs Plan. The Queensland Energy and Jobs Plan has been accounted for along with the related coal retirements in Queensland.

A comparison of the capacity outlook between the IES and AEMO ISP 2022 step change outlooks is depicted in Figure 30. The IES outlook encompasses an additional 8 GW of peaking gas capacity, on average starting from 2035, in contrast to the ISP 2022 outlook. A comparison is provided in Figure 31, including the Draft ISP 2024 capacity outlook for additional context.[20] The higher gas capacity potentially impacts the level of emissions associated with the modelling work.

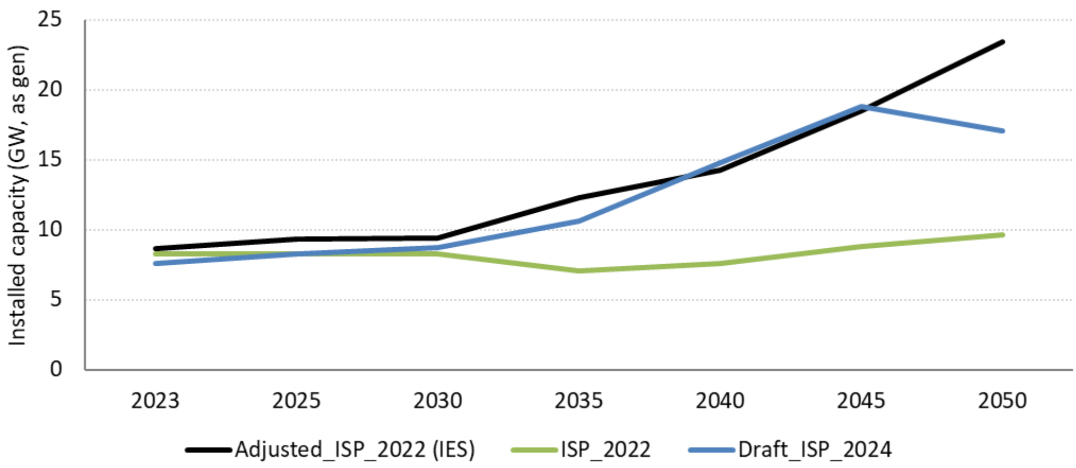
Figure 30 IES supply outlook comparison to AEMO Step Change



[19] The projected outlook still achieves significant reductions in carbon emissions through to 2050.
[20] December 2023 release. This category is referred to as 'flexible gas' which more broadly includes other forms of gas.

Notes: BE=BESS, CO=coal, CC=CCGT, OC=OCGT/flexible gas, PH=Pumped hydro, HY=Hydro, SO=grid solar PV, WI=wind.

Figure 31 IES supply outlook comparison to AEMO Step Change (OCGT/flexible gas)



Detailed supply outlook assumptions can be found in Table 14. The supply outlook was not re-run to adjust for the added FCAS requirements.

Table 14 Supply outlook assumptions

Assumption	AEMO Step Change scenario (ISP 2022 assumptions) with IES adjustments	Comments
Energy and Peak Demand	Step Change 10POE, IASR 2022	Uses single demand/weather reference year (rolling).
FCAS pricing	Based on historical relationship with supply margin	This is not modelled by AEMO.
FCAS requirements	Explicitly model two raise services (regulation and contingency).	
FCAS supply	Existing and new generator supply capability based on maximum historical enablement levels (2018-2023) as a percentage of installed capacity	
Demand side participation	Step Change, IASR 2023	The WDR component is excluded in the DSP modelling
Virtual power plants	Step Change, IASR 2022	
Electric Vehicle to Grid	Step Change, IASR 2022	
Hydro inflows	ISP 2022 traces corresponding to rolling reference year	
Solar traces (utility-scale)		
Wind traces (utility scale)		
Committed new entrants	IASR 2022	
Coal retirements	IASR 2022 (based on announced and technical life) adjusted for QEJP outlook and economic retirements (where required)	
Policy-based generic new entrants	IASR 2022 assumed trajectories of the QRET, VRET, TRET and NSW	

Assumption	AEMO Step Change scenario (ISP 2022 assumptions) with IES adjustments	Comments
	Infrastructure Roadmap targets. Includes QEJP but not VIC offshore wind	
Commercial generic new entrants	IASR 2022 new entrant options	Includes IES annual build limits on VRE
Solar and wind bidding, and coal min-stable level	Existing VRE at close to negative LGC, and new VRE at VOM. Coal min stable levels bid in at negative $150/MWh	
Generator operating parameters	IASR 2022	
Generator forced outages	IASR 2022	
Generator planned maintenance	IASR 2022	
Generator fuel costs	IASR 2022	
Generator operational costs and parameters	IASR 2022	
Transmission augmentations	ODP. ISP 2022 Group 1+2+3	Transmission (including REZ transmission) post-2035 has been augmented as required
Carbon constraints or carbon budgets	None	AEMO's carbon budgets not included
AEMO RERT	Separately formulate PLEXOS conditions/constraints targeting these dispatch outcomes	
New market reforms	Current market arrangements only	

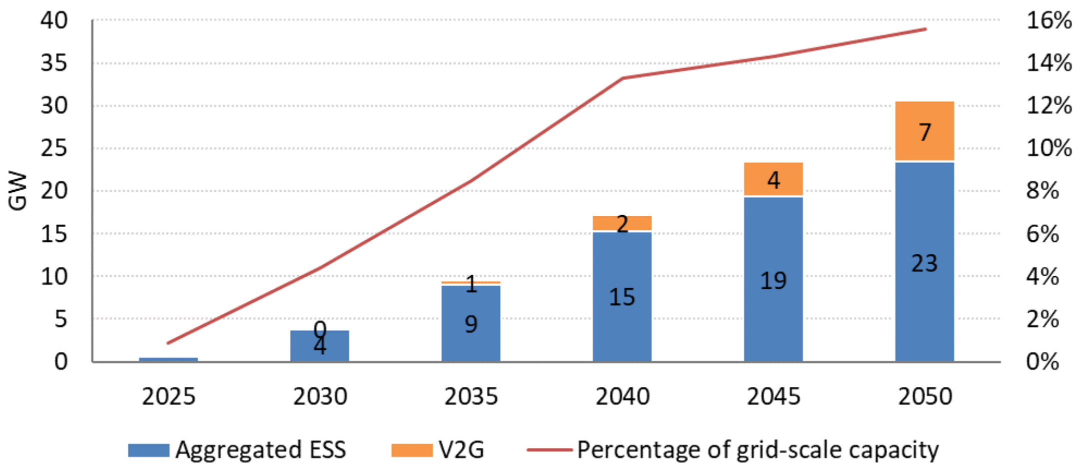
4.2 Virtual Power Plants

4.2.1 VPP capacity outlook

Total VPP capacity projected in the ISP 2022 Step Change scenario is plotted in Figure 32 and shows a linear growth trajectory comprised of aggregated ESS and V2G reaching 30 GW by 2050. This capacity is assumed to be known to AEMO, however, the mode under which these assets operate under, either self-consumption or dispatched against system requirements, is uncertain. In percentage terms, the amount of VPP capacity grows to 15% of scheduled generation capacity and will become increasingly important for AEMO to forecast accurately to efficiently dispatch scheduled resources.[21] However, the level of visibility available to AEMO is highly contingent upon the visibility and dispatch options explored in this work.

[21] The equivalent percentage in the latest Draft 2024 ISP is higher.

Figure 32 Total VPP capacity outlook



4.2.2 VPP forecast accuracy assumptions

The Base, Visibility and Dispatch cases are associated with varying levels of forecast accuracy. Forecast accuracy is a function of (1) participation of reform mechanisms leading to the provision of operational information to AEMO, (2) conformance or the degree to which the actual operational outcomes align with the information provided, and (3) AEMO's proficiency in addressing structural errors or inaccuracies arising from (1) and (2). The percentages for aggregated ESS and V2G are listed in Table 15 and Table 16 respectively for each of the three cases and summarised below and in Figure 33.

- **Base**: without any reforms, AEMO relies solely on its forecasting systems, assumed to improve over time, to correct its demand forecasts to account for VPP operations, however, large errors are expected to persist.
- **Dispatch**: assumes early reform implementation and leads to a high participation rate, across all VPP capacity. A small percentage of the remaining capacity not participating in the reform mechanism, is still corrected through AEMO’s forecasting systems. All cases assume the same level of forecasting correction.
- **Visibility**: assumes a very high level of participation than the Dispatch case due to lower barriers for participation. However, a further adjustment is made to account for the lower levels of conformance due to the nature of the visibility mechanism.

The overall accuracy percentage of VPP operations is presented in Figure 33 and shows very low overall accuracy under the Base case without reform, whereas the assumptions relating to the Visibility and Dispatch options provide significant informational benefits for scheduling. Over time, the gap in accuracy between the Base and reform cases closes as AEMO’s forecasting systems are assumed to improve.

Table 15 Accuracy assumptions (aggregated ESS)

Agg ESS	Case	2025	2030	2035	2040	2045	2050
Participation	Base	100%	100%	100%	100%	100%	100%
	DIS	20%	10%	5%	5%	5%	5%
	VIS	10%	5%	3%	3%	3%	3%
Conformance	Base	n/a	n/a	n/a	n/a	n/a	n/a
	DIS	100%	100%	100%	100%	100%	100%
	VIS	75%	80%	85%	90%	90%	90%
Forecast correction	All	20%	30%	40%	50%	60%	70%

Table 16 Accuracy assumptions (V2G)

V2G	Case	2025	2030	2035	2040	2045	2050
Participation	Base	100%	100%	100%	100%	100%	100%
	DIS	20%	10%	5%	5%	5%	5%
	VIS	10%	5%	3%	3%	3%	3%
Conformance	Base	n/a	n/a	n/a	n/a	n/a	n/a
	DIS	100%	100%	100%	100%	100%	100%
	VIS	65%	70%	75%	80%	80%	80%
Forecast correction	All	10%	20%	30%	40%	50%	50%

Figure 33 Overall forecast accuracy assumption (VPP)

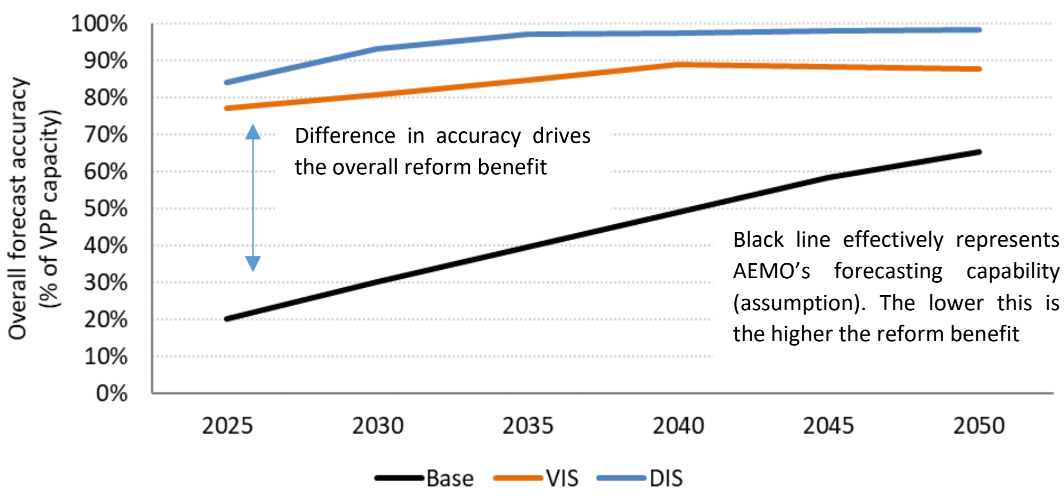


Table 17 Factors driving forecast accuracy assumption (VPP)

Assumption	Base	Visibility	Dispatch
Participation, or provision of info	None, no reform	Very high	High
Conformance	n/a	Med-high	100%
Forecast	Improves over time. Rate of improvement is held constant across all cases		
Accuracy %	20-65	80-90	85-99

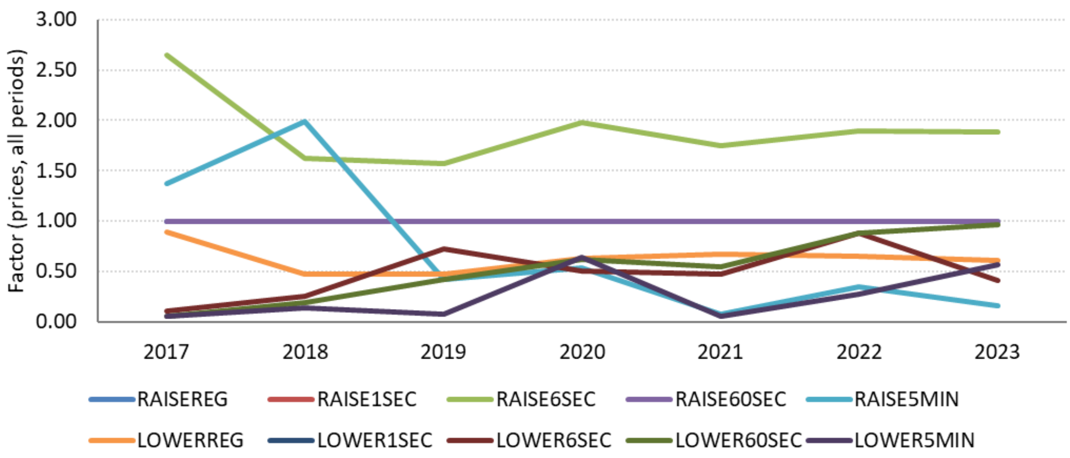
4.3 Frequency control ancillary services

4.3.1 Prices and requirements

The modelling approach is to only include the Raise regulation and raise 60s contingency services, which are representative of regulation and contingency requirements in the NEM. Modelling all FCAS significantly increases computational requirements and raise services are generally more important than lower services with respect to enablement quantities and overall costs. However, dispatch costs depend on all 10 frequency control ancillary services. The costs of the other services have been inferred from historical analysis of the prices and enablement quantities in relation to raise regulation and raise 60s for regulation and contingency, respectively, to calculate the full FCAS cost.

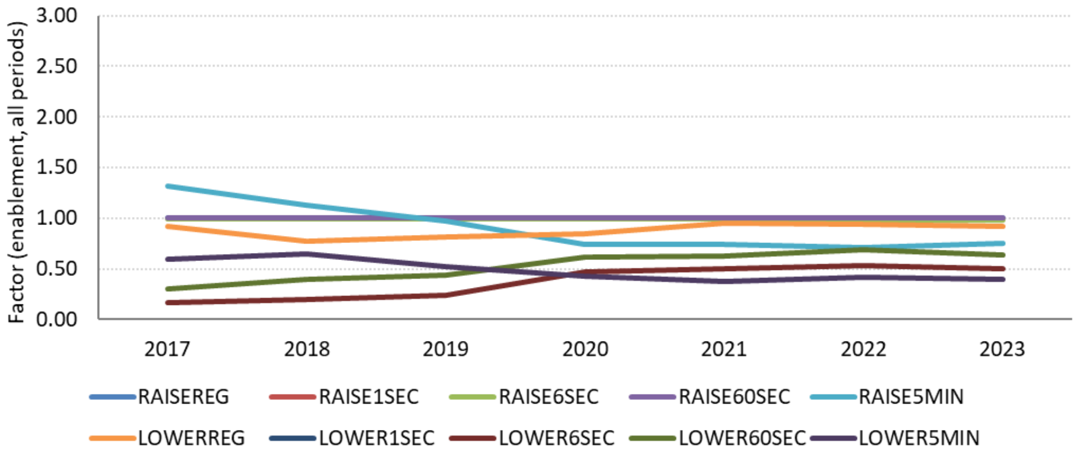
The historical analysis of these services in connection with system-level raise regulation and raise 60s is depicted in Figure 34 and Figure 35, displaying the pricing and enablement factors from the calendar years 2017 to 2023. The factors are relatively stable and form the basis of scaling up the FCAS results from the PLEXOS modelling.

Figure 34 Annual FCAS price factors



Note: The factors for all regulation and contingency services are in relation to raisereg and raise60sec, respectively.

Figure 35 Annual FCAS enablement factors



Note: The factors for all regulation and contingency services are in relation to raisereg and raise60sec, respectively.

4.3.2 Provision

Generator FCAS provision for the current generation types have been based on the maximum historical enablement levels.[22] The assumptions for VPP FCAS provision are summarised in Table 18. Generally, VPP under the Base case would be limited in providing regulation or contingency, however, this increases slightly under the visibility mode and significantly more under the dispatch option. Aggregated ESS would have a higher capability given the resources are stationary relative to electric vehicles which may not be connected to the grid during the day.

Table 18 VPP FCAS provision (percentage of max power)

VPP type	Case	Raise reg	Raise 60s (contingency)
Aggregated ESS	Base	0%	10%
Aggregated ESS	Visibility	0%	20%
Aggregated ESS	Dispatch	40%	60%
V2G	Base	0%	5%
V2G	Visibility	0%	10%
V2G	Dispatch	10%	20%

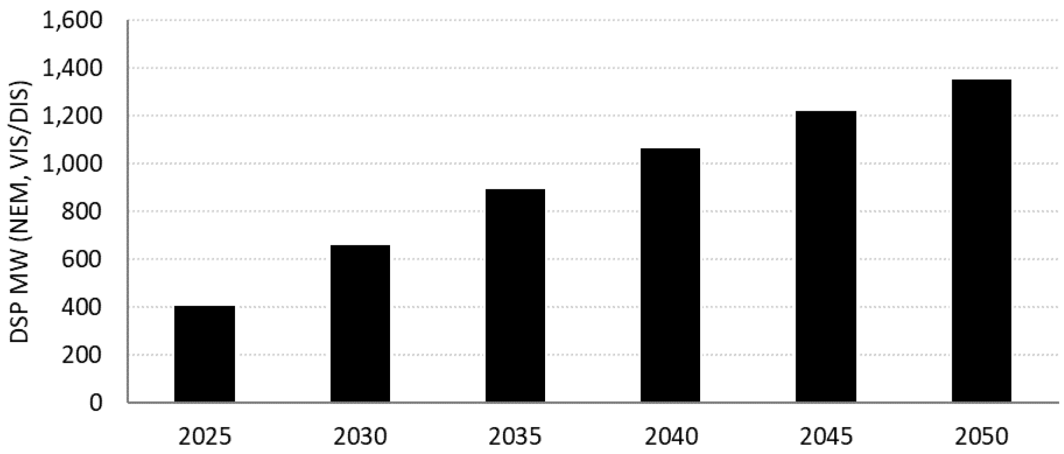
[22] The percentage of capacity that can be provided for raise regulation and contingency requirements

4.4 Demand-side participation

4.4.1 Volumes

Current and projected levels of demand response at various price thresholds have been based on AEMO's latest IASR 2023 and is provided on a P50 basis. NEM-wide volumes at $7,500/MWh, excluding the WDR component is plotted in Figure 36.[23] The remaining capacity in the DSP information specifically relates to either demand-side reductions or non-scheduled (normally-off) generator responses to high prices. The DSP assumptions are based on the current market price cap. The Base case assumes there is no visible DSP and AEMO therefore would need to dispatch more scheduled resources to meet scheduled demand. The reform cases assume AEMO has full visibility of the DSP price and quantity pairs.

Figure 36 Demand side participation outlook (reform cases)



Notes: excludes wholesale demand response and reliability volumes.

4.4.2 RERT and unserved energy costs

The cost of RERT has been calculated based on the most recent RERT costs, specifically for QLD and NSW in FY2022-2023. This cost is composed of two elements:

- Pre-activation charge, also known as the standby cost.
- Activation charge, which applies when the RERT is utilised.

The cost of unserved energy will be determined by the value of customer reliability for the state in which unserved energy occurs.

[23] WDR volumes are already 'visible' to AEMO and therefore are out of scope.

Table 19 RERT cost assumptions

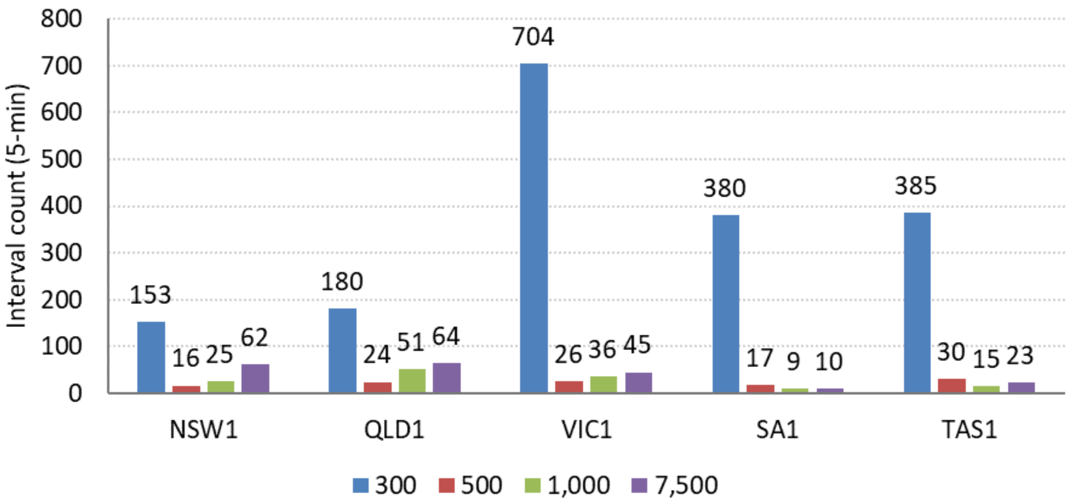
Type	Description	Inclusion	Cost assumption (all regions)
Availability/Pre-activation ($/MW)	Paid for being on stand-by regardless of activation	Included	27,655
Activation ($/MWh)	Actual RERT trigger/use	Included	15,287
Intervention	Intervention not in scope	Not included	n/a
Early termination	Costs for this not reported	Not included	n/a

** Costs have been based on average RERT triggers in FY 2022 and FY2023. The modelling assumes an activation length of 30-min for every trigger.*

4.4.3 Weighting of conditions

Historical analysis into the number of intervals prices across high price bands for each state is used to inform the weights to apply to the DSP modelling results to arrive at an annualised cost. The weights based on the average of 2020 and 2021 financial years interval counts is provided in Figure 37.[24] The weight applied for the RERT-triggered results is 1 occurrence per year for each region, however, actual RERT costs are contingent on actual LOR2 conditions triggered in the PLEXOS modelling.

Figure 37 Weighting example (no RERT)



[24] The inclusion of FY 2022 and/or 2023 significantly skews the number of interval occurrences.

4.5 Other

Other assumptions are listed in Table 20.

Table 20 Other assumptions

Assumption	Value
Value of Emissions Reduction[25]	\$130/t CO_2 in 2023 increasing to \$216/t CO_2 in 2050.

[25] Technical note to NSW Government Guide to Cost-Benefit Analysis TPG23-08, NSW Treasury (Feb 2023). Values from 2032 were linearly extrapolated by IES to 2050. All values have been converted to real 2023 dollars. To be updated with Commonwealth figures if and when available.

5 Modelling results

5.1 Overview

The modelling indicates that the total benefit, comprised of social benefits and wealth transfers, relating to the Visibility and Dispatch cases to be $12.5 and $13.9 billion, respectively (Figure 38). The main driver of the total benefit are wealth transfers, $11 to 12 billion, from generators to consumers relating to more efficient dispatch pricing primarily influenced by the increased forecast accuracy of VPP operations and DSP, especially during evening peaks.

Social benefits ranging from $1.5 to $1.9 billion are significant but is likely to be understated because investment levels were held constant. It is reasonable to assume that higher prices would have driven generation investment in the Base case compared to the reform cases. This would mitigate some of the pricing impacts or the wealth transfer effect, but would introduce a material new cost saving in the form of a generation capital cost benefit. This impacts the overall split between social benefits and wealth transfers; however, it would be reasonable to assume total benefits would remain at similar levels.

Other key results based on a breakdown of the social benefit category is summarised below:

- The benefits associated with the Visibility and Dispatch case are similar due to the underlying assumptions around overall forecast accuracy (Figure 39). Although the forecast accuracy in MW terms increases post-2040, the relative importance diminishes in the context of total installed generation capacity in the NEM, and the timing of the benefits are further reduced through present value discounting.
- Improved forecasting accuracy of VPP comprises 55%-60% of the total benefit across the reform cases. However, DSP is almost as significant as VPP despite only triggering over a very limited number of intervals across the year. Within the social benefit category, VPPs account for a substantial portion, making up to 90% of the total (Figure 41).
- Approximately 47% of the social benefits in both reform cases are attributed to FCAS cost reductions, while emissions reductions account for around 36% (Figure 40). The FCAS benefit in the reform cases is linked to substantially reduced scheduling inaccuracies, leading to reduced regulation requirements. The emissions benefit stems from more efficient scheduling of thermal resources and the Value of Emissions Reduction, projected to reach $216/t CO_2 by the year 2050.
- There is a sharp increase across all benefits and PRR types observed between 2025 and 2030 and is closely tied to the adoption of PRR and forecast accuracy assumptions. Social benefits across the PRR types increase more than three-fold from approximately $50 million pa in 2025 to $172 million in 2030 (Figure 41 and Figure 42).

Figure 38 Benefits by case and type of PRR (NPV)

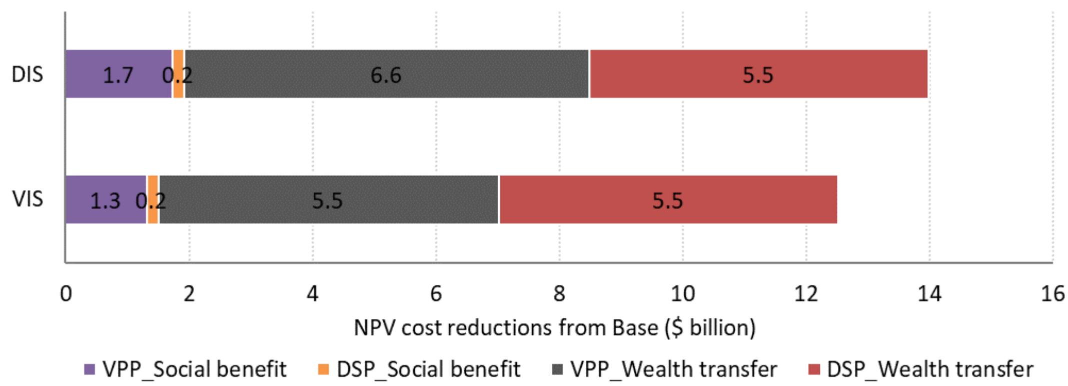


Figure 39 Relative forecast accuracy of reform cases against Base case (VPP, MW)

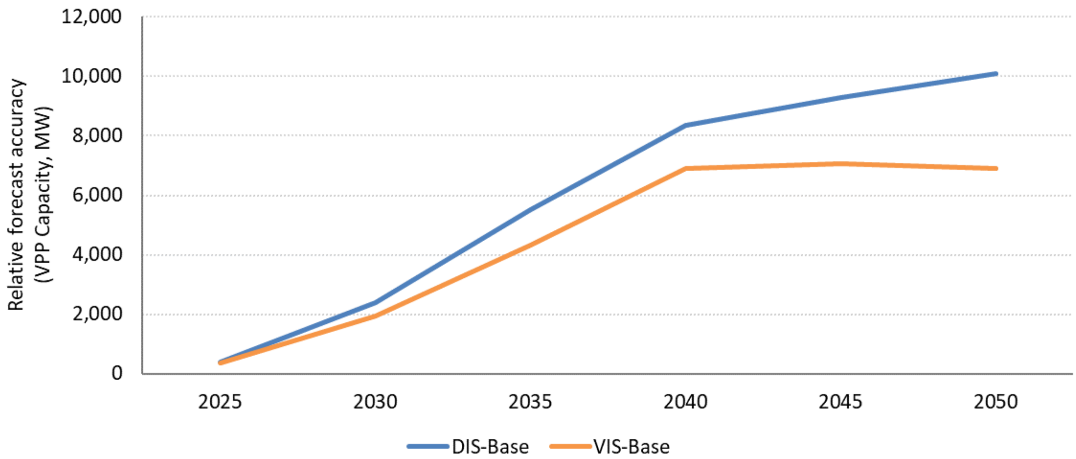


Figure 40 Social benefit cost categories by case (NPV)

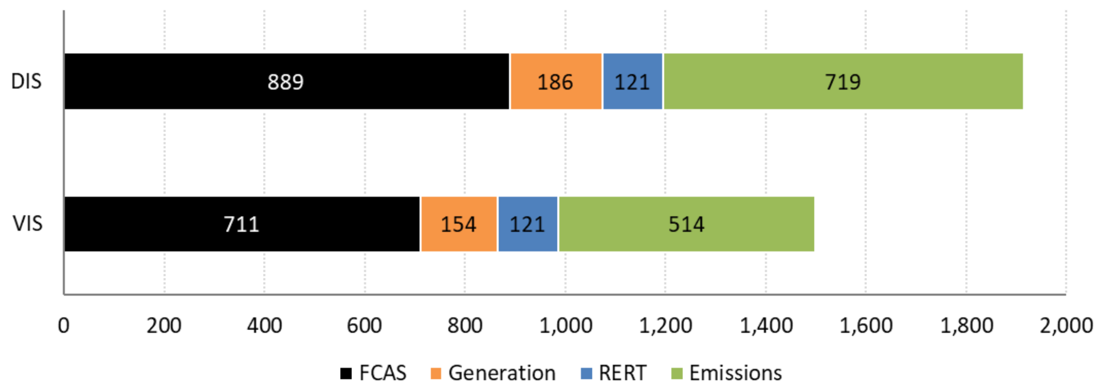


Figure 41 Timing of social benefits by PRR type (Visibility)

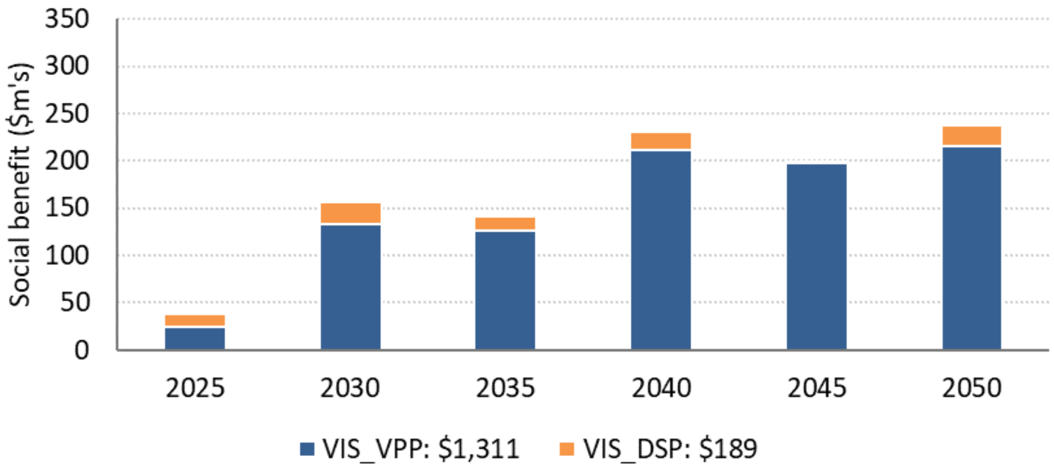
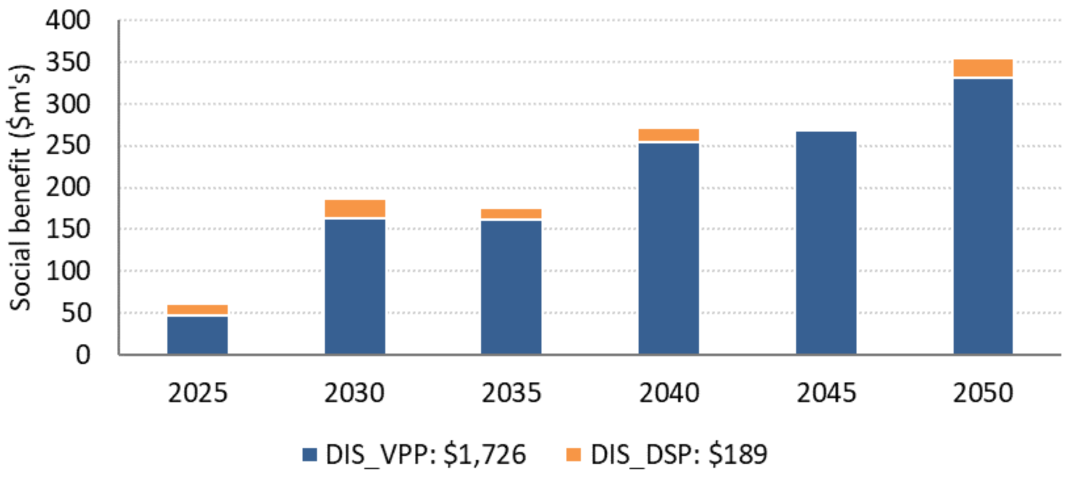


Figure 42 Timing of social benefits by PRR type (Dispatch)



5.1.1 Social benefits

Social benefits arise from a reduction in system costs and comprise generation, RERT, emissions and reduced FCAS volumes.[26] The social benefit across the reform cases by cost component is summarised in Table 21 and discussed below.

Table 21 Cost reduction by case (social benefits, NPV)

$ millions	Visibility	Dispatch
Generation	154	186

[26] FCAS cost reductions from a reduction in price is considered in Section 5.1.2.

Emissions	514	719
FCAS	711	889
RERT	121	121
Energy	0	0
Total	1,500	1,915

Note: Energy costs is strictly a wealth transfer and has not been included here. The FCAS cost reduction is based on holding prices constant across the cases.

- **Generation**: Better forecast accuracy of VPP operations in the reform cases results in reduced expensive peak generation requirements, however, this is also offset by increased generation requirements outside the evening peak to support higher forecast VPP charging requirements. Thermal generation only comprise a smaller share of the set of marginal generators impacted by the change in forecast VPP operations across the cases. The reduction in generation costs refers to VOM and fuel costs only and is likely understated given generation investment impacts were not included in scope.
- **Emissions**: The reductions are derived mainly from the VPP modelling outcomes which allows for lower dispatch of scheduled generators during the evening peaks which at the margins include peaking gas generation. Consistent with generation costs, the reductions in emissions over the peak periods is offset by a slight increase in emissions during overnight periods where the same peaking gas generation is required at times to support or firm up variable renewable energy. The level of OCGT capacity in the supply outlook is a significant driver of the emissions reduction and paired with the Value of Emissions Reduction assumption of \$216/t CO_2 by 2050 produces an emissions benefit ranging from \$514 to \$719 million under the Visibility and Dispatch cases, respectively.
- **FCAS**: The cost reduction across FCAS primarily relates to the reduction in regulation enablement requirements. Under the Base case, the lack of visibility and higher demand forecasting errors results in significant scheduling inaccuracies leading to much higher peak regulation requirements up to 4.5 GW relative to 2 GW and 0.9 GW in the Visibility and Dispatch cases, respectively. The lower enablement requirements in the reform cases represent a significant reduction in generator opportunity costs.
- **RERT**: RERT cost reductions reflects lower RERT procurement with improved visibility of DSP volumes which is assumed to increase to almost 1.4 GW by 2050. The social benefit relating to this category is high at the interval level, conditional on RERT being activated, however, RERT activations are infrequent resulting in a low social benefit relative to the other cost types.

5.1.2 Wealth transfers

Wealth transfers relate to reductions in prices with no corresponding change to the level of demand served and leads to a redistribution of wealth from generators to consumers in the modelling. The wealth transfers occur from energy and FCAS price changes and is summarised in Table 22.

Table 22 Cost reduction by case (wealth transfers, NPV)

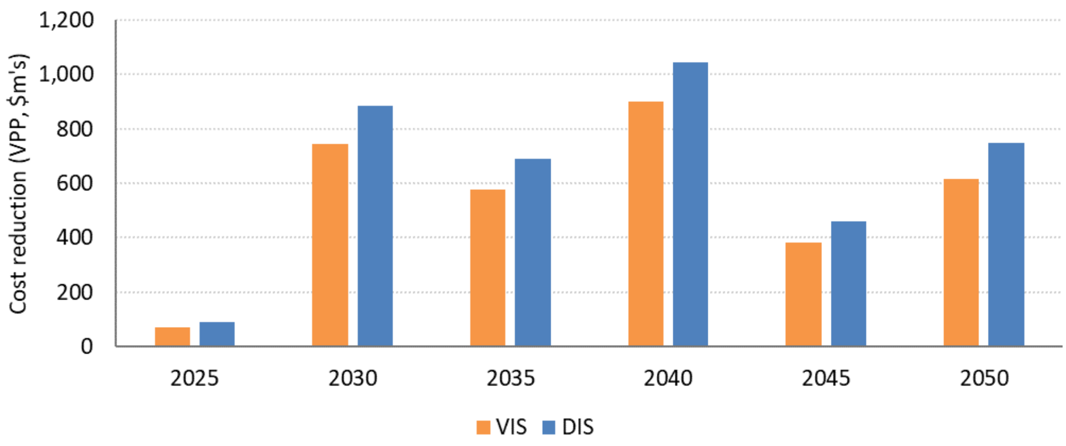
$ millions	Visibility	Dispatch
Energy	10,425	11,326
FCAS*	586	738
Generation	0	0
RERT	0	0
Emissions	0	0
Total	11,011	12,064

** Related to price reductions only, holding enablement levels constant.*

In the Dispatch case, the VPP cost reduction is higher than the Visibility case by $100 million pa on average due to greater levels of certainty around VPP operations in the Dispatch case (Figure 43). The higher certainty allows for more accurate (lower) demand forecasts and lower energy prices by up to $30/MWh on average across the evening peak in 2040. The FCAS price impact under the Dispatch case is a reduction of up to $5/MWh in the annual regulation price, a direct consequence of lower enablement volumes and increased regulation supply from VPPs. Across both reform cases, the annual cost reduction attributed to the VPP component surpasses $900 billion by 2040 but experiences a decline thereafter and is influenced by two primary factors:

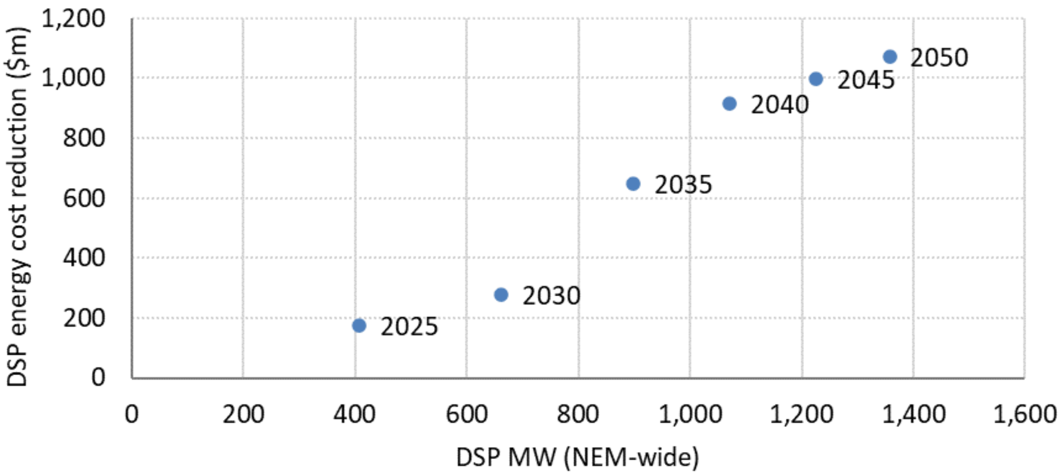
- Forecast accuracy in the Base case rises from 20% to 70% of total VPP capacity, whereas this percentage across the reform cases remains relatively high throughout the horizon (Figure 33).
- Increasing VPP capacity that is not accurately forecast in the Base case relative to the reform cases is outpaced by overall demand growth and growth in other scheduled generation resources, resulting in a diminishing impact over time. By 2050, this corresponds to 10 GW of VPP capacity and $600 to $750 million in potential dispatch inefficiencies.

Figure 43 Energy and FCAS cost reduction (wealth transfer, VPP modelling)



The DSP modelling, applicable to both Visibility and Dispatch cases, shows annual cost reductions from pricing impacts in the Base case increasing from $170 million initially and reaching $1 billion by 2045 (Figure 44). The increase is a function of DSP volumes accounted for in demand forecasts under the reform cases which steadily rises from 400 MW initially and to almost 1,400 MW by 2045 which reduces high price events by up to $2,500/MWh per interval.

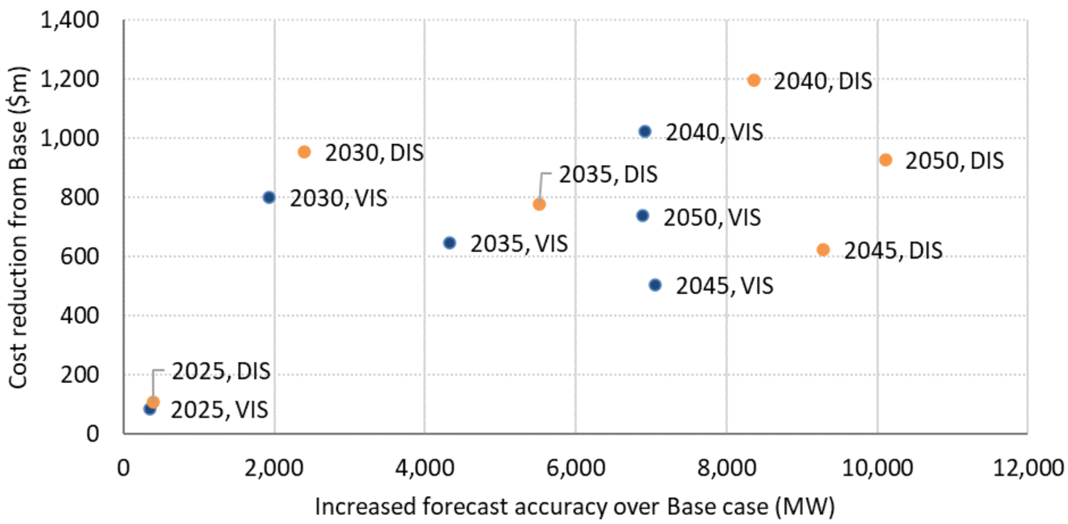
Figure 44 Energy cost reduction and DSP volumes (wealth transfer, DSP modelling)



5.2 VPP modelling

The VPP modelling reveals substantial cost reductions linked to the integration of PRR in the Visibility and Dispatch cases, escalating to $1.2 billion in 2040 under the Dispatch case. The cost reductions exhibit an upward trajectory with increased forecasting accuracy in the reform cases over time. However, the gap in cost difference with the Base case starts diminishing from 2040. Figure 45 illustrates the levels of cost reduction plotted against the increased forecast accuracy in the Visibility and Dispatch cases. Notably, the data points for both cases in 2045 and 2050 recede from its peak in 2040 but is consistent with its diminishing impact (see Figure 39).

Figure 45 Energy and FCAS cost reduction and visibility difference (VPP)



5.2.1 Energy price (wealth transfer)

The reduction in wholesale energy costs is a consequence of lower spot prices resulting from more efficient dispatch of scheduled resources during evening peak periods. In the reform cases, the provision of operational information allows AEMO to dispatch fewer scheduled resources due to the higher forecast contribution of VPP during these peaks. Across the energy and FCAS cost components, energy constitutes over 70% of the total reduction. The energy cost reduction is explained further through the following charts of typical daily outcomes across the NEM:

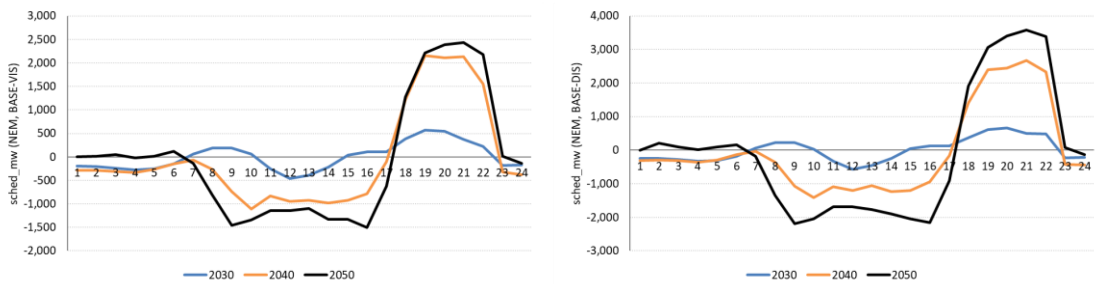
- Figure 46 shows the difference in forecast scheduled demand between the Base and reform cases. The forecast evening peak is on average 2.5 GW and 3.5 GW lower across the Visibility and Dispatch cases than the Base case in 2050. The difference is lower than in Figure 39 as the forecast VPPs aren't always operating at maximum power, and the non-visible VPP capacity is forecast as operating in accordance with its non-aggregated equivalents.[27] Increased forecast accuracy of VPPs in the reform cases also include the expectation of increased charging during the middle of the day and, generally, higher discharge throughout the overnight periods.

[27] Non-aggregated energy storage systems and vehicle-to-home. These resources are also forecast to operate during the evening peak, but at substantially lower levels.

- The higher evening peaks in the Base case result in higher energy prices, as shown in Figure 47 with a difference of 2.5 GW and 3.5 GW in 2050 equivalent to $25/MWh and $30/MWh on average across the evening peak. The total energy cost reduction across the evening peak corresponds to this energy price difference multiplied by the actual demand level, which is the same across all cases.[28]
- The energy price difference in 2050 is lower than in 2040 despite more accurate forecasts, in MW terms, in the reform cases. This is because the MW difference, expressed as a percentage of system installed capacity, decreases post-2040, indicating that the increase in system capacity outpaces the increase in the relative forecast inaccuracies of VPP MW over time in the Base case. VPP uptake that is not accurately forecast grows to 8 GW in 2040 and 10 GW in 2050 under the Base case relative to the Dispatch case. This is equivalent to 6.5% of the total installed NEM capacity in 2040 and drops to 5% by 2050. Although the relative inaccuracy in MW terms under the Base grows, the energy price impact declines after 2040, as it is also dependent on the size of the rest of the market.
- The figures clearly show cost reductions across the evening peaks due to higher scheduled demands leading to higher prices under the Base case. However, there are periods outside of the evening peak where improved forecast accuracy of VPP operations leads to higher dispatch requirements leading to higher prices. This is particularly evident across the middle of the day and to a smaller extent overnight. The higher costs across these periods offset the cost reductions across the evening peaks. A summary of this dynamic is plotted in Figure 48 which aggregates the annual costs by time slice.

The total wholesale energy cost reduction for the Visibility and Dispatch cases is significant. Expressed as a percentage of the total energy cost under the Base case amounts to approximately 1.0% to 2.5%, with a higher percentage share in earlier years due to the larger forecasting accuracy difference between the Base and reform cases (Figure 49).

Figure 46 Relative difference in forecast scheduled NEM demand (Base - reform, VPP)



[28] In the case of over-dispatch, lower regulation-enabled generators would reduce its output to adjust for scheduling errors.

Figure 47 Daily energy price difference (NEM-level, Base – reform, VPP)

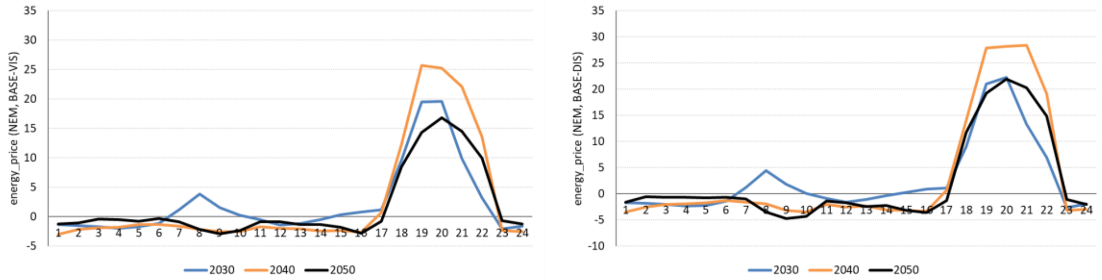


Figure 48 Wholesale energy cost reduction by time slice (VPP)

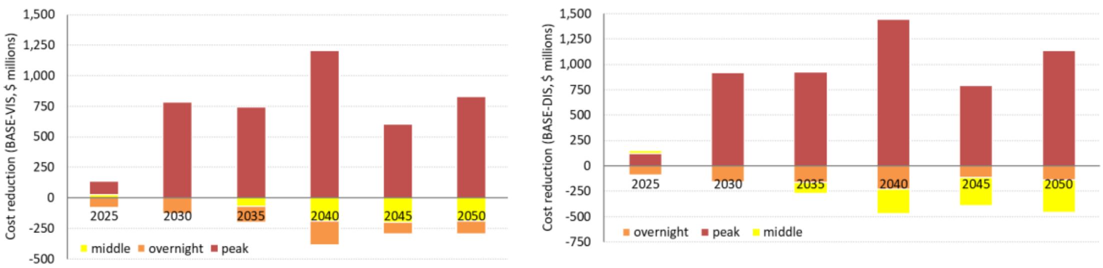
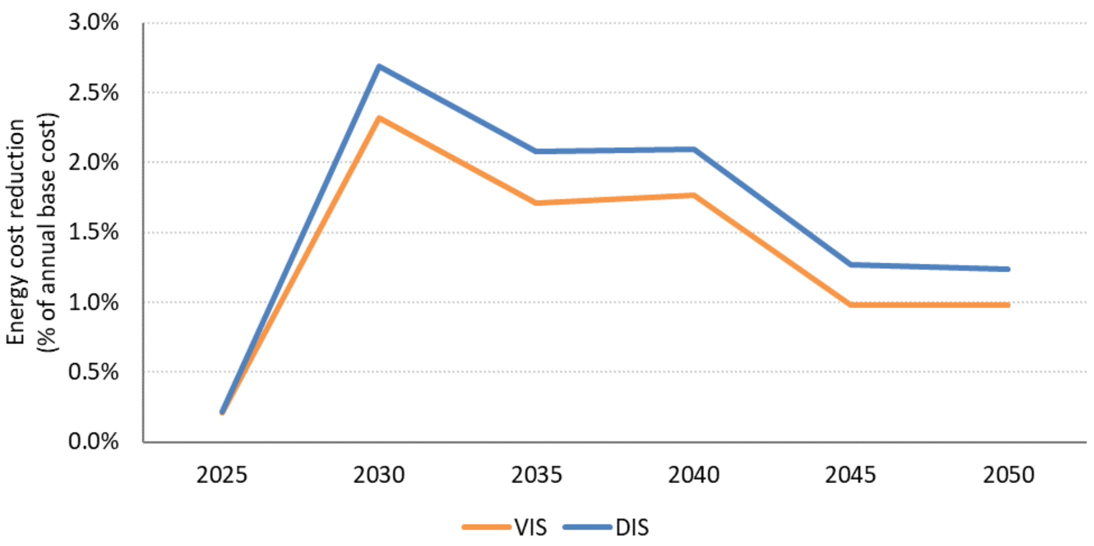


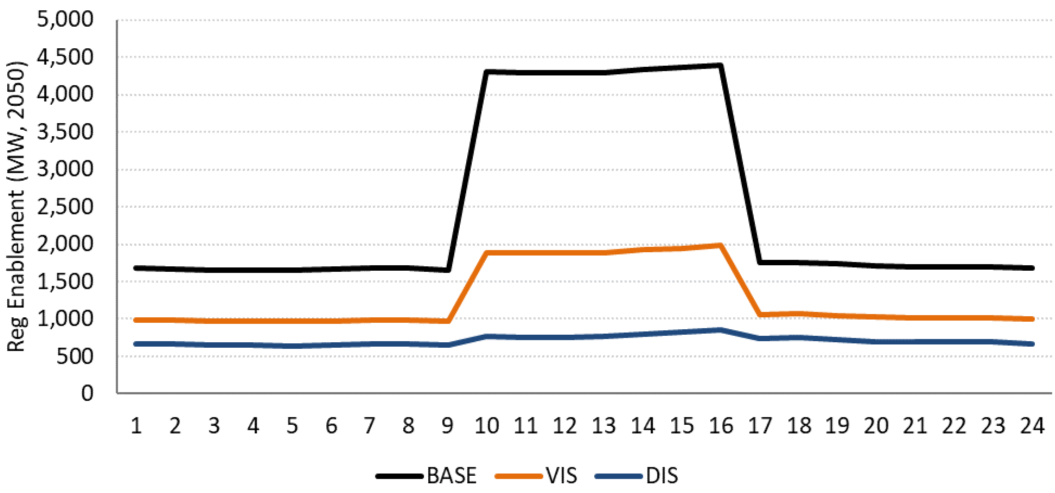
Figure 49 Total energy cost reduction (percentage of Base case cost, VPP)



5.2.2 FCAS cost (social benefit and wealth transfer)

FCAS, including both volume and price impacts, constitute approximately 20-25% of the total wholesale energy and FCAS cost reduction compared to the Base case. This reduction is notable due to the increase in regulation requirements resulting from forecast inaccuracies of VPP operations in the Base case. By 2050, there is an average of 3.5 GW of forecast demand inaccuracy during the evening peak and 2 GW during the middle of the day (refer to Figure 46). The regulation requirement was set to address the largest deviation between forecast and actual scheduled demands, necessitating a raise requirement exceeding 4 GW across the middle of the day.[29] In 2050, there is approximately 10 GW of VPP that is not accurately accounted for due to the lack of reform. The 10 GW capacity translates to a smaller operational difference as VPP do not always operate at its max power. Figure 50 illustrates the average daily requirement, comprised of a baseline quantity scaling with demand and incremental regulation pertaining to VPP scheduling inaccuracies across the cases in 2050. The volume difference drives the social benefit calculated in Section 5.1.1. In practice, AEMO's forecasting performance will differ to that assumed here which will impact the level of regulation required.

Figure 50 Time of day regulation requirements by case (VPP, 2050)



The elevated requirements in the Base case, combined with lower FCAS provision assumptions across VPPs, lead to higher regulation prices and costs. Conversely, there are substantial cost reductions observed across the reform cases - considered a wealth transfer from generators to consumers. Annual raise regulation and raise contingency prices are depicted in Figure 51, highlighting higher regulation prices under the Base case. The overall cost reduction increases from $25 million up to $250 million pa over the horizon (Figure 52), driven by the significant enablement reduction under the reform cases. The percentage cost reduction from the Base case is plotted in Figure 53.

[29] Includes the impact of AEMO's assumed forecasting capability. In 2050, there is approximately 10 GW of VPP that cannot be accurately accounted for due to the lack of reform. The 10 GW capacity translates to a smaller operational difference as VPP do not always operate at its max power.

Figure 51 Annual FCAS price by case (time-weighted, VPP)

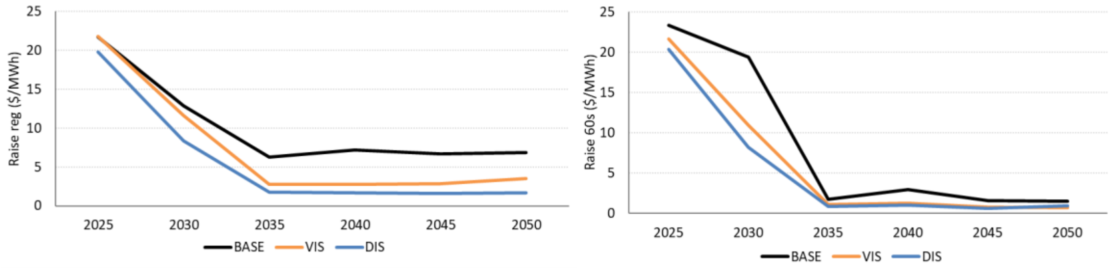


Figure 52 FCAS cost reduction from Base case (VPP)

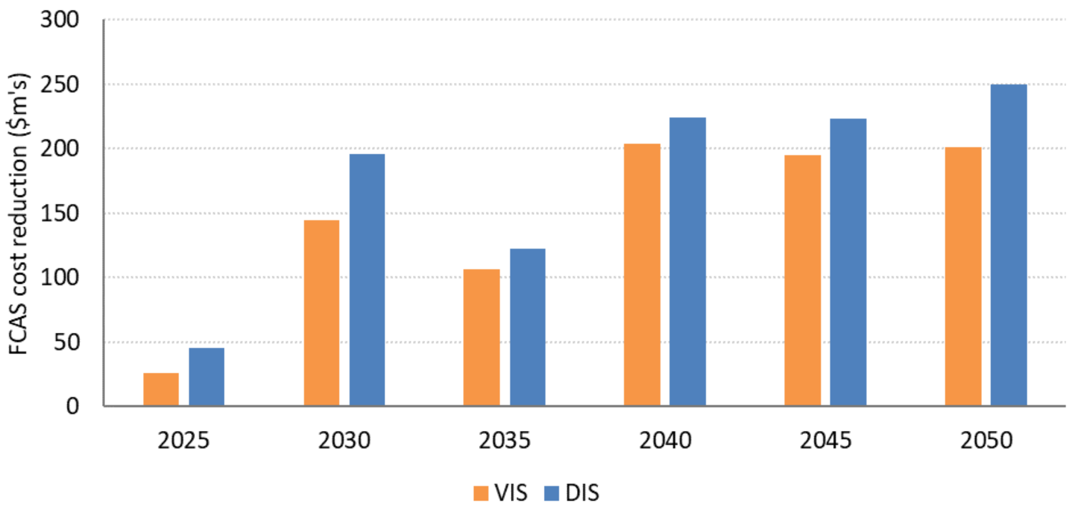
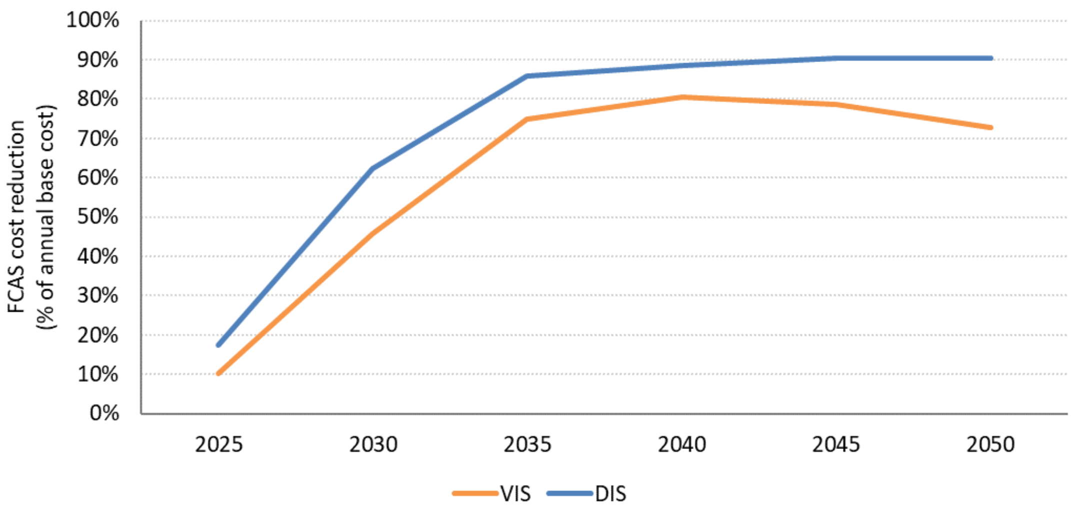


Figure 53 Total FCAS cost reduction (percentage of Base case cost, VPP)

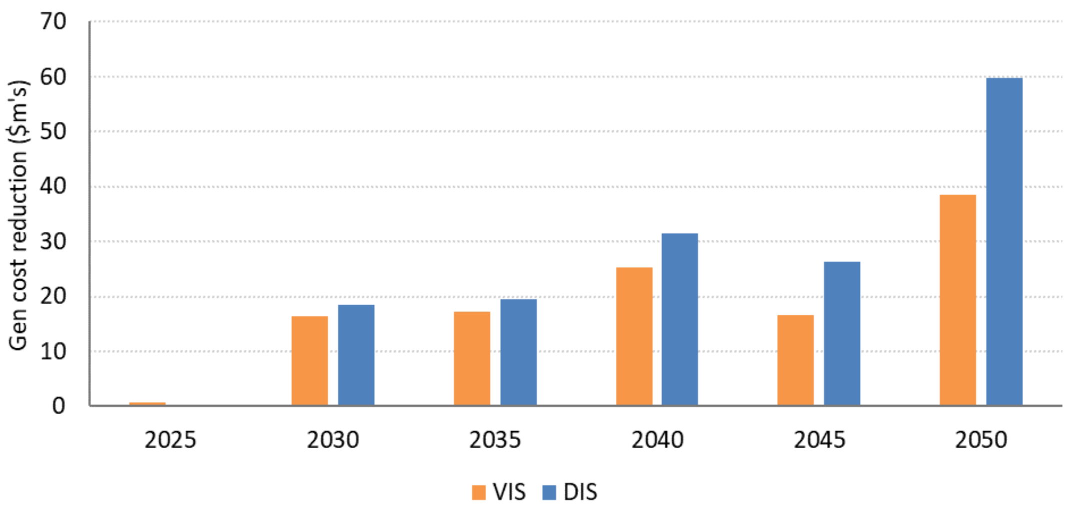


5.2.3 Generation cost (social benefit)

Generation cost reductions range from $15 million up to $60 million by 2050, representing less than 0.9% of the Base case generation cost (Figure 54). The generation cost difference is notably lower than the wholesale energy and FCAS cost reductions reported earlier due to several factors:

- Generation cost differences only pertain to the subset of generation at the margins, whereas the wholesale energy cost reduction, stemming from lower spot prices, applies to the entire demand base.
- Thermal generation, particularly peaking gas plant, comprises a smaller share of the set of marginal generators impacted by the change in forecast VPP operations across the cases.
- The decrease in more expensive peak generation requirements, resulting from lower peak demand dispatched due to a higher forecast VPP contribution, is counteracted by increased generation requirements outside the evening peak to support higher forecast VPP charging requirements.
- More importantly, the generation cost presented here only covers variable costs (fuel and VOM) whereas generation costs incorporating potential reductions to generation investment were excluded from the scope. The result is that the generation cost benefits would effectively lead to a conservative estimation of the actual cost reductions (i.e., accounting for generator capital expenditure) under the reform cases.

Figure 54 Generation cost reduction by case (VPP)



The differences in generation across the Base and reform cases are most pronounced during the evening peaks, where the Base case forecasts less VPP contribution and relies on additional scheduled resources to meet the higher forecast peak demand. An example from 2030 is illustrated in Figure 55, demonstrating up to 1 GW less VPP generation being compensated by various other generation types. Notably, there is additional coal and gas generation during the evening, with a lesser extent during the morning peak, incurring additional fuel and variable operating and maintenance costs (VOM). This is offset by slight increases in thermal generation during overnight periods to support higher forecast demand resulting from increased forecast VPP charging in the reform cases. The generation cost reduction by time slice is depicted in Figure 56.

Figure 55 Typical daily scheduled generation difference (NEM, Base - Dispatch, 2030)

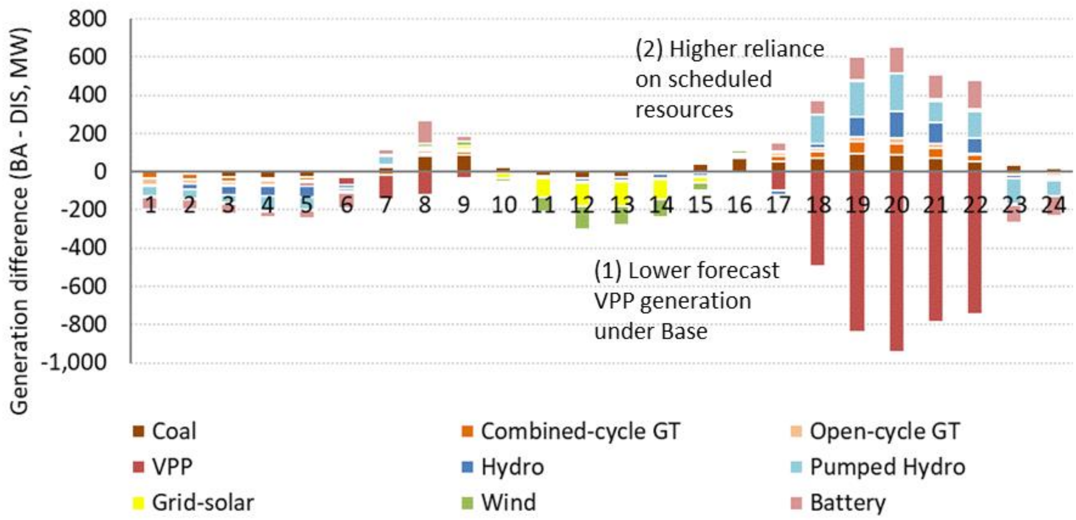
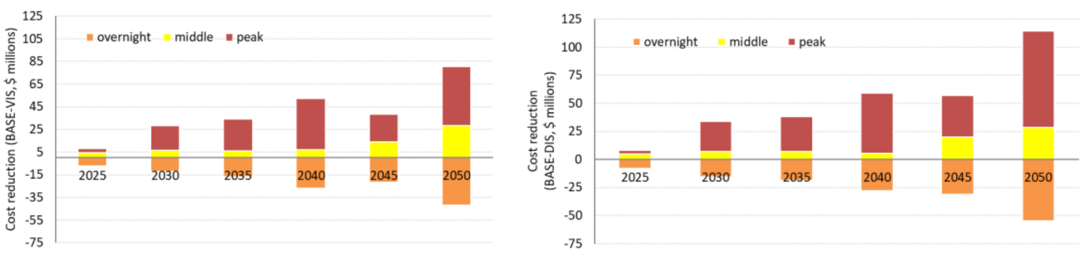


Figure 56 Generation cost reduction by case and time slice (VPP)



5.2.4 Emissions cost (social benefit)

The change in emissions from improved forecasting accuracy of VPPs in the reform cases is driven by the subset of marginal generators at the time of forecast VPP operations. An average dispatch profile in 2040 under the Base case (Figure 57) shows OCGT operating across the evening peak and overnight periods across the NEM. The reform cases have lower dispatched generation across the evening peak which leads to reduced emissions but is slightly offset by higher dispatched generation across the overnight periods. The net emissions reductions against the Base case span 0.1 to 0.5 Mt CO_2 pa, amounting to less than 0.8% of Base case emissions over the modelling horizon (Figure 58). The cost assessment of the emissions reduction has been based on the NSW Government's carbon value and is intended to be replaced with the Commonwealth Government's Value of Emission Reductions if and when it becomes available (Figure 60).

Figure 57 Typical daily NEM generation profile (Base, 2040, VPP)

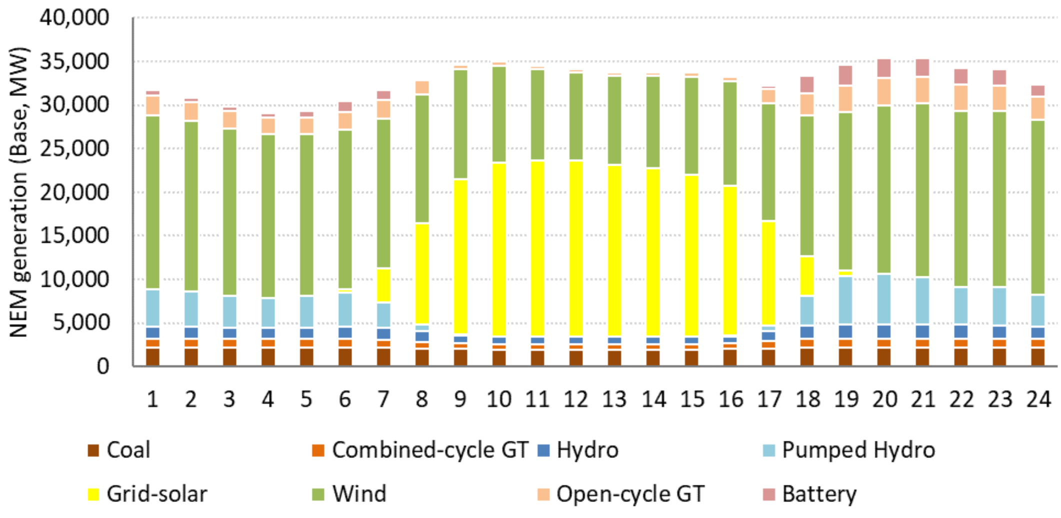


Figure 58 Emissions reduction from Base case (VPP)

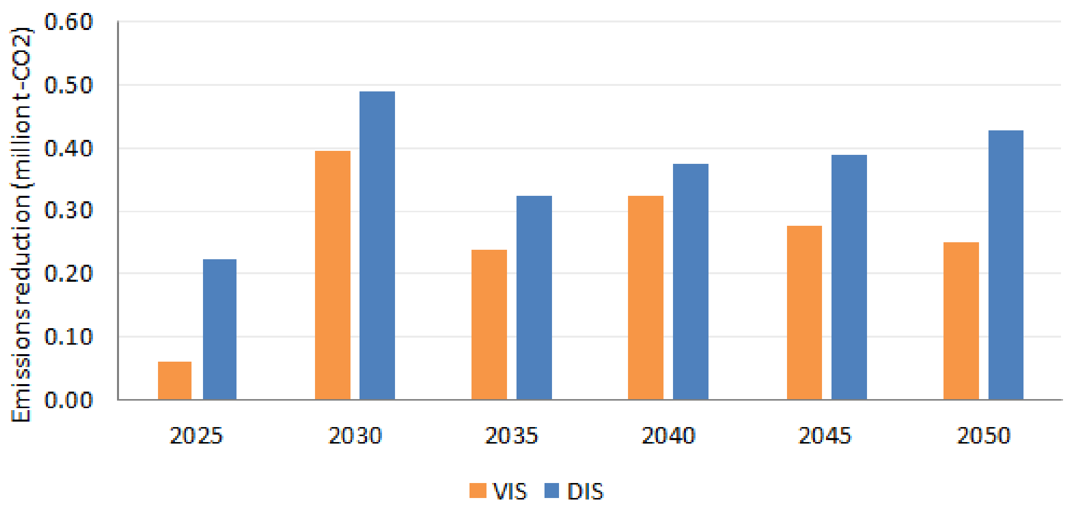
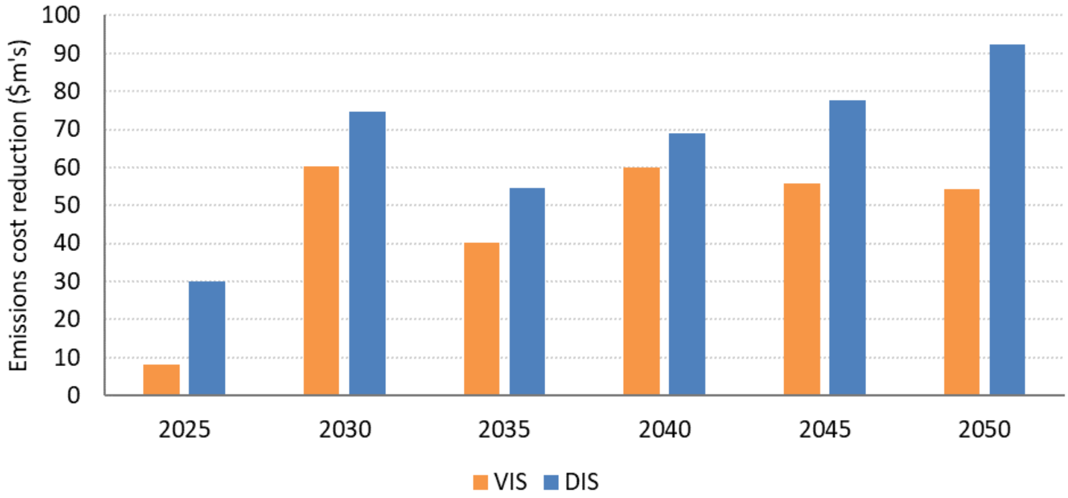


Figure 59 Emissions cost reduction by case (VPP)

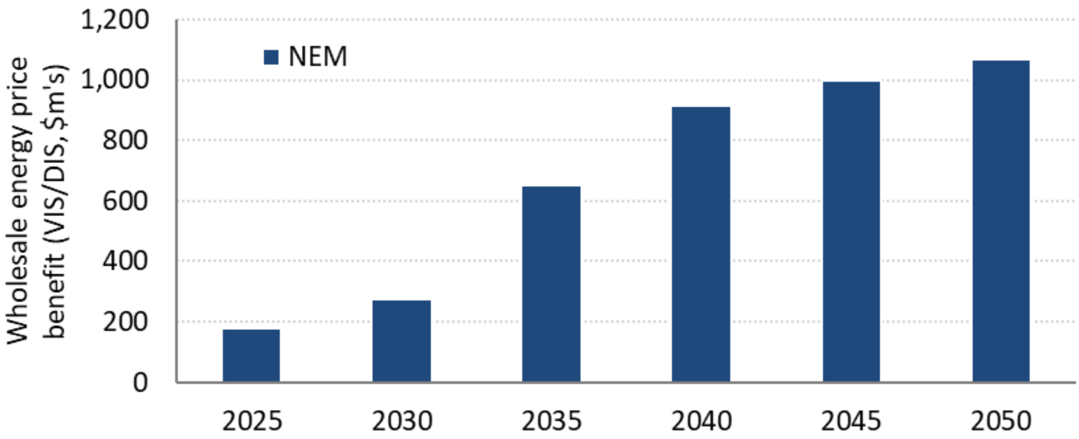


5.3 DSP modelling

5.3.1 Energy price (wealth transfer)

The cost differences between the Base and reform cases under the DSP modelling are primarily driven by wholesale energy costs. The impact of this across the horizon is shown in Figure 60 which shows increasing cost differences across high price events between the reform cases and the Base case. This discrepancy arises due to over-dispatch in the absence of integrating DSP, resulting in higher spot prices.

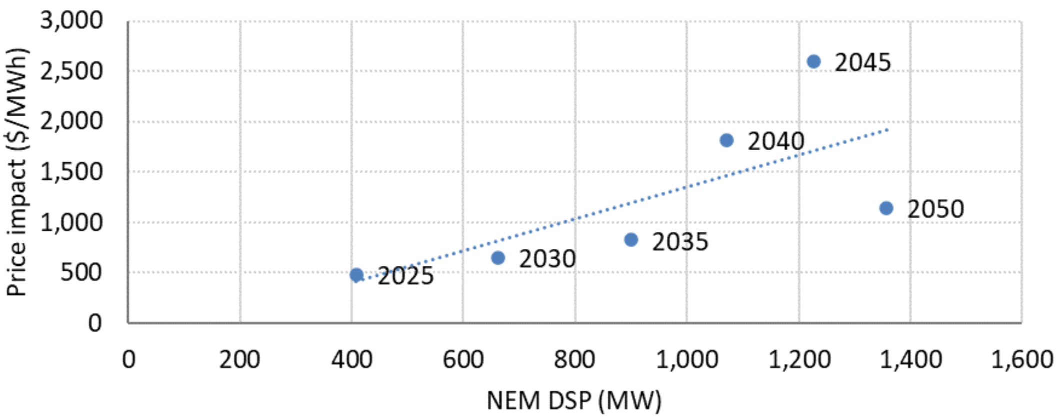
Figure 60 Energy cost impact of visible DSP (NEM, DSP)



The level of DSP capacity increases over time, amplifying the relative per interval cost difference during periods of high prices because of the magnified price impact. Figure 61 depicts NEM-wide price differences weighted by DSP volume for periods above $7,500/MWh.

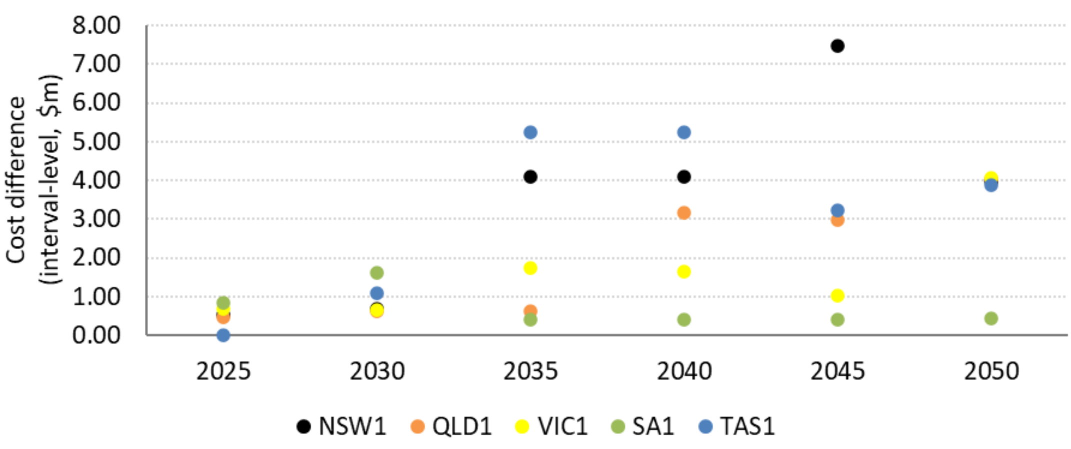
Simulated high-price events have been aggregated for each price band and averaged to determine the average price and cost impact. The cost impact per interval, presented in Figure 62, demonstrates significant variance across the years and regions, consistent with the inherent characteristics of price volatility in the NEM. The cost difference outcomes for a single high-price interval range from $0.5 million to $8 million but is generally more conservative than equivalent outcomes based on historical analysis, where pricing impacts above $5,000/MWh have been observed for lower volumes of DSP (refer to Appendix C.2).[30] The per interval costs were weighted using historical interval counts for the corresponding price band to determine the annualised costs (Figure 60).

Figure 61 Average spot price impact and DSP capacity (NEM, DSP)



Note: For intervals where prices exceed $7,500/MWh, and RERT is not triggered.

Figure 62 Per-interval cost impact of visible DSP ($7,500/MWh band, DSP)

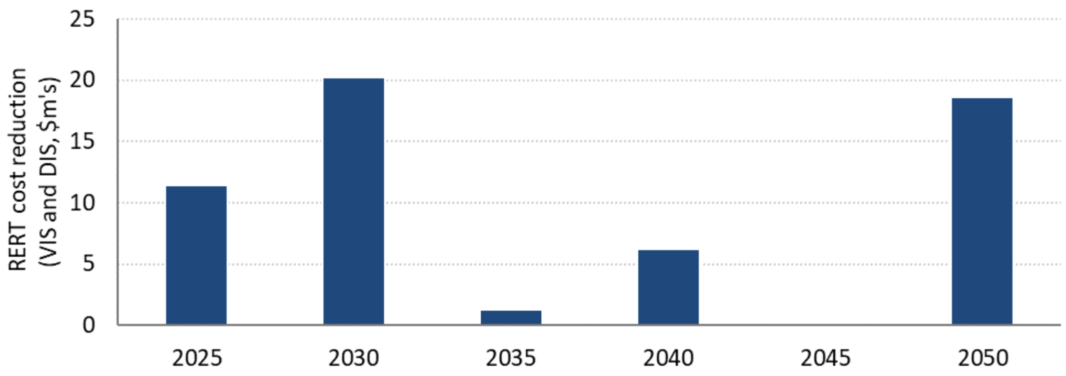


[30] The pricing impact influences the overall cost and is contingent on the gradient of the supply curve at those scheduled demand levels. It can be inferred that the supply curve modelling in PLEXOS, utilizing the LRMC recovery algorithm, is more gradual than historical outcomes.

5.3.2 RERT cost (social benefit)

The reductions in RERT costs resulting from the integration of DSP under the reform cases, plotted in Figure 63, are driven by the difference in the levels of RERT procurement. The decrease in RERT procurement is solely attributed to accounting for potential (non-RERT) DSP volumes. In intervals where LOR2 is triggered in the underlying PLEXOS modelling, the reduction in RERT capacity is multiplied by the cost of RERT. While the impact on RERT is notably higher when it is triggered (potentially $15 million for a single instance) compared to non-RERT DSP activations, the frequency at which RERT is expected to occur is significantly lower based on historical weightings.

Figure 63 RERT cost reduction (annualised, DSP)



5.3.3 Generation and emissions cost (social benefit)

There are no substantial generation and emissions cost reductions from the DSP modelling, as the number of triggered or relevant intervals (under 200 per year) is low compared to the VPP modelling.

5.4 Generation and network investment

The assessment presented in Section 5.2.3 indicates that the reduction in generation costs (social benefit) are considerably lower than that for wholesale energy costs (wealth transfer). However, the assessment excludes impacts from generation investment, which would have otherwise occurred in the Base case. The additional generation investment would be driven by the higher evening spot prices resulting from increased dispatch requirements from discounting VPP and DSP contributions, as well as investment needed to maintain the same supply margins because of the added FCAS requirements to the modelling, all else being equal. The additional investment is likely to substantially increase generation costs under the Base case and reduce the energy cost impact under wealth transfers. The scheduled demand differences in Figure 46 provides an indication of the additional investment which may be required. It would be reasonable to assume total benefits would remain at similar levels.[31]

PRR are embedded resources and the integration of PRR has the potential to also bring about reductions in network costs across both transmission and distribution. This potential is particularly pronounced due to the differences in peak demand dispatch between the Base and reform cases. However, existing network investment under the National Electricity Rules already encompass non-network options, including demand-side management.[32] The inclusion of these benefits under this potential rule change remains unclear, and the benefits associated with network planning have been excluded from the potential cost reductions presented in this work.

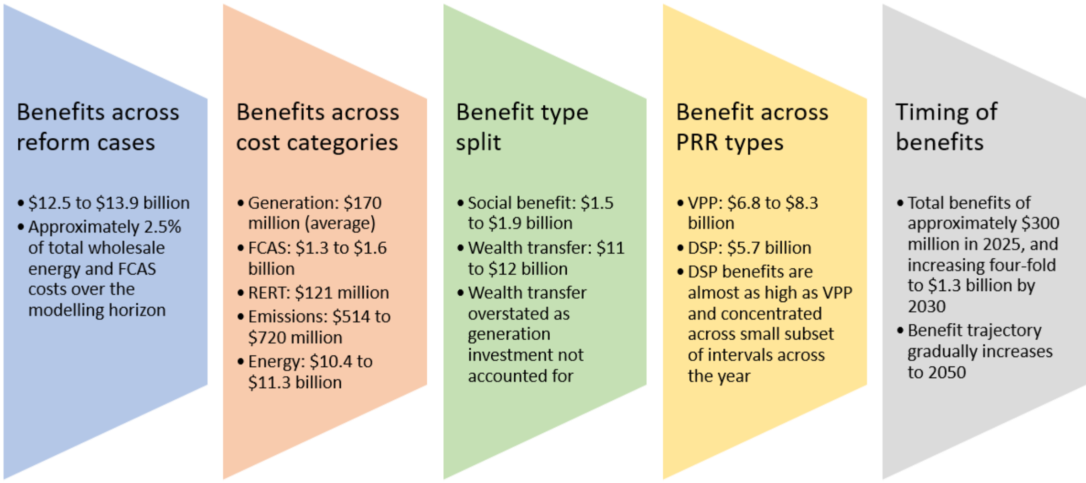
5.5 Key findings

The widespread adoption of PRR is forecast in AEMO's 2022 ISP to reach 31 GW by 2050. The lack of operational information available to AEMO under the current rules is expected to contribute to scheduling issues and increasing challenges to maintain the NEM. Improved visibility of VPP and DSP operations, leading to increased forecast accuracy, would allow AEMO to dispatch fewer scheduled resources during peak periods and reduce the need to procure significant amounts of regulation FCAS enablement. Total benefits derived from integrating unscheduled PRR into dispatch are substantial across both reform cases and in terms of social benefits and wealth transfers, and is summarised in (Figure 64).

- **Social benefits.** Of the total social benefit ($1.5 to $1.9 billion), approximately 46% is attributed to reduced FCAS enablement costs, and 35% is associated with emissions reductions across both reform cases. Notably, the contribution from generation costs, accounting for 10% of the total, is likely understated due to holding generation investment constant. RERT costs comprises a smaller share due to the frequency of activations.
- **Wealth transfers** of $11 to 12 billion is primarily due to energy pricing impacts. Wealth transfers are equally significant across both PRR types and significantly higher than the social benefit. However, the modelling holds generation investment constant which would have otherwise occurred in the Base case due to higher pricing signals.
- **Timing**. There is a sharp increase across all benefits and PRR types observed between 2025 and 2030 and is closely tied to the adoption of PRR and forecast accuracy assumptions (Figure 65). Social benefits on a per annum basis are in excess of $150 million pa under the Visibility case from 2030.

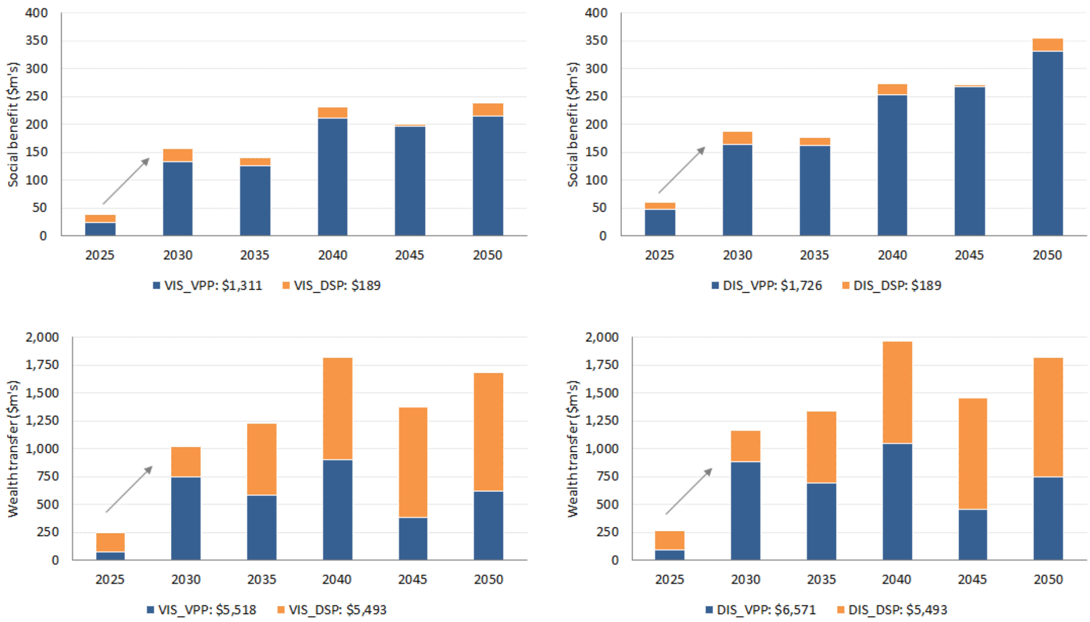
[31] Cost of new entry is directly related to the same price signals driving the energy cost component.
[32] Demand management incentive scheme, NER, clause 6.6.3.

Figure 64 Total benefit breakdown summary



Note: Quoted ranges are for the Visibility (lower bound) and Dispatch cases (upper bound).

Figure 65 Timing of benefits by PRR type and reform option



Other key findings for each cost category are summarised below and presented in Table 23 and Table 24 for each of the reform cases.

- **Generation costs**: Generation costs, excluding investment impacts and compared to the Base case, are relatively low as the reduction in peak demand dispatch is offset by increased dispatch requirements across the overnight period. The reduced generation costs, or $170 million averaged across both reform cases, are understated, as investment impacts have not been accounted for which would otherwise reduce the wealth transfer impact from energy prices.
- **Emissions costs**: The reduction in peak generation requirements under the reform cases translates to emissions reductions of up to 0.5 million tonnes of CO_2 per annum. This corresponds to a cost reduction ranging from $514 to $719 million across the Visibility and Dispatch cases, respectively.
- **FCAS costs**: Under the Base case scenario, significant regulation requirements are required to address increasing scheduling inaccuracies. Our modelling shows that improved accuracy under the reform cases reduces regulation enablement requirements and regulation prices. The FCAS cost component (up to $1.6 billion under the Dispatch case) comprises up to 12% of the total benefit. The social benefit portion accounts for approximately $711 to $889 million of this total.
- **RERT costs**: Significant interval-level savings are anticipated to minimise RERT procurement with DSP visibility. However, the overall cost reduction of $121 million under the reform cases as compared to the Base case is modest relative to the other components, as instances of procuring RERT are relatively low.
- **Energy prices**: The impact of lower scheduled peak demands under the reform cases relative to the Base case results in lower energy prices of up to $30/MWh and $2,500/MWh in the VPP and DSP modelling, respectively. The corresponding energy cost reduction ($10.4 to $11.3 billion) constitutes 80% - 85% of the total benefit across the reform cases, excluding generation investment impacts.

Table 23 Benefit and cost type – Visibility (NPV, millions)

Cost component	Social benefit	Wealth transfer	Total benefit
Energy	0	10,425	10,425
FCAS	711	586	1,297
Generation	154	0	154
RERT	121	0	121
Emissions	514	0	514
Total	1,500	11,011	12,511

Table 24 Benefit and cost type – Dispatch (NPV, millions)

Cost component	Social benefit	Wealth transfer	Total benefit
Energy	0	11,326	11,326
FCAS	889	738	1,627
Generation	186	0	186
RERT	121	0	121
Emissions	719	0	719
Total	1,915	12,064	13,979

Appendix A Abbreviations

Abbreviation	Term
ADE	Aggregate dispatch error
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BESS	Battery energy storage system
CBA	Cost benefit analysis
CCGT	Combined Cycle Gas Turbine
CO_2	Tonne of carbon dioxide
DFE	Demand forecasting error
DIS or DI	Dispatch case
DSP	Demand-side participation
ESOO	Electricity Statement of Opportunities
ESS	Energy storage systems
FCAS	Frequency control ancillary services
FOM	Fixed operating and maintenance cost
GW	Gigawatt
GWh	Gigawatt-hours
IASR	Inputs, Assumptions and Scenarios
IES	Intelligent Energy Systems
ISP	Integrated System Plan
LGC	Large-scale generation certificates
LOR	Lack of reserve condition
LRMC	Long-run marginal cost
MMS	Market management system
MPC	Market price cap
Mt CO_2	Million tonnes of carbon dioxide
NEM	National electricity market
MW	Megawatt
MWh	Megawatt-hours
NEO	National electricity objectives
NER	National electricity rules
NPV	Net present value
NSW	New South Wales
OCGT	Open cycle gas turbine
ODP	Optimal Development Path
PASA	Projected assessment of system adequacy
POE	Probability of exceedance
PRR	Price-responsive resources
QEJP	Queensland Energy and Jobs Plan
QLD	Queensland
QRET	Queensland Renewable Energy Target

Abbreviation	Term
RERT	Reliability Emergency Reserve Trader
REZ	Renewable Energy Zone
SRMC	Short-run marginal cost
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
USE	Unserved Energy
VCR	Value of customer reliability
VIC	Victoria
VIS or VI	Visibility case
VOM	Variable operating and maintenance cost
VPP	Virtual power plant
VRE	Variable renewable energy
VRET	Victorian Renewable Energy Target

Appendix B Calculation of costs

Table 25 provides a breakdown of cost calculations for each of the sub-components within each functional area along with its scope relevance.

Table 25 Calculation of costs

Functional area	Components	Calculation	How does this relate to the CBA and PRR visibility levels?	Other
Dispatch cost	Energy cost	spot_price(r,t) * actual_demand(r,t), sum for all r and t	Actual demand would remain the same across the cases but the spot price would be higher in the Base case, leading to higher costs.	
Dispatch cost	DSP cost	demand_response_mw(r,t) * demand_response_cost(r,t), sum for all r and t	The cost of this assumed to be the price at which demand response was activated (see Section 4.4).	The cost of DSP activation is the same across all cases and DSP is triggered irrespective of the forecast demand.
Dispatch cost	Generation costs	Generation_cost(g,t) * generation_level(g,t), sum for all g and t	Generation costs are expected to be higher for higher levels of dispatch.	Generation levels accounting for energy for regulation would naturally adjust for the forecasting error from regulation-enabled generators, i.e., total generation would remain the same across cases, but the mix may differ.

Functional area	Components	Calculation	How does this relate to the CBA and PRR visibility levels?	Other
Reliability of supply	Unserved energy cost	energy_shortfall(r,t) * value_of_customer_reliability(r), sum for all r and t	USE is an output of the model, however, RERT should be triggered before any USE occurs.	There should be no difference in USE volumes across the cases subject to sufficient RERT procurement.
Reliability of supply	RERT costs	RERT_capacity(r,t) * RERT_availability_$_mw(r) + RERT_capacity(r) * number_of_periods * RERT_activation_$_mwh(r), sum for all r and t	If AEMO operational procedures are based on forecast demand (and doesn't account for PRR) then underestimating PRR contribution would likely lead to over-procuring RERT	Model short-notice RERT, and assume LOR2 is based on forecast demand without adjustment (i.e., AEMO has to cover LOR2 and no judgement is applied with respect to the potential DSP volumes)
Security of supply	FCAS enablement cost	fcas_price(f,t) * enablement(f,t), sum for all f and t	The enablement cost would be expected to be higher for the Base case which would structurally have higher levels of inaccuracy because of lower levels of PRR visibility.	The social benefit is calculated holding the pricing impact constant, and the wealth transfer corresponds to the balance of costs solely from the pricing impact.
Emissions	Emissions cost	emissions_factor(g,t) * actual_dispatch(g,t) * cost_of_emissions	Over-dispatch in the Base case is likely to bias higher generation levels at emissions-producing plant.	

Note: r=region, g=generation unit, t=time/interval, f=fcas_service, y=year.

Appendix C Historical analysis - other

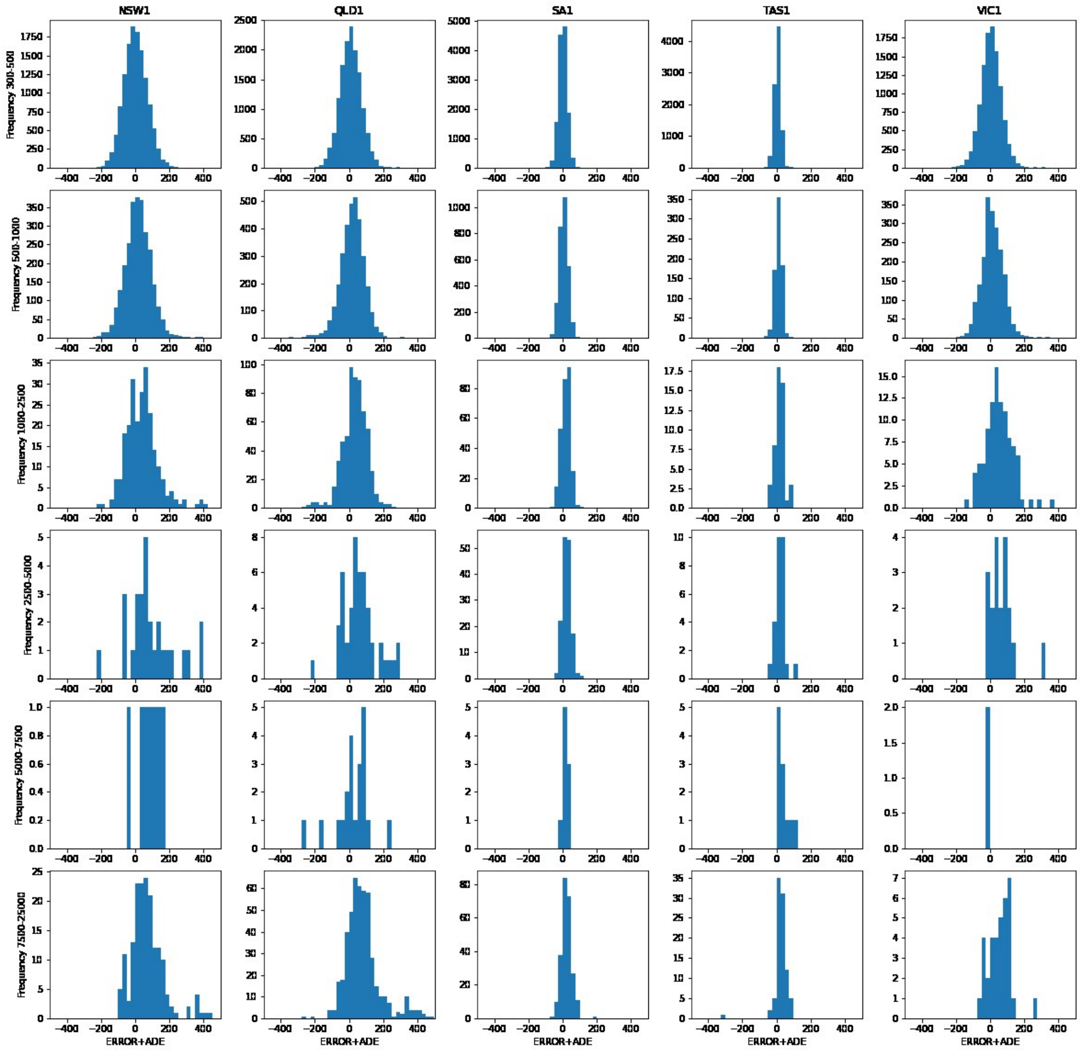
C.1 Distribution of demand forecasting errors

The 5-min total demand forecasting error (DFE) is comprised of inaccuracies from various elements of the dispatched system and is summarised in Table 26. The adjusted distribution of these errors for generator non-compliance due to providing regulation across high price bands is plotted in Figure 66. Assuming that the distribution of all other components is symmetrical around zero, errors related to price-responsive demand should cause a positive skew in the distribution of errors. This skew is visibly evident in NSW and QLD for prices exceeding $5,000/MWh.

Table 26 Demand forecasting error

Component	Description	Analysis
Non-conformance from generators providing regulation	Relates to generators that need to deviate from the dispatch target to address frequency deviations	MMS data corresponding to aggregate dispatch error (ADE) field
Generator non-conformance	Relates to whether generators are meeting dispatch targets	Assume distribution is symmetric and independent of demand and price levels
PRR not accounted for in forecasts	Demand forecasting error component in scope	Attempt to discern from historical observations
Non-scheduled generation	Relates to non-scheduled generation responding to price signals (assumes AEMO doesn't account for this in forecast)	Included in the above
Remaining demand forecasting errors	Covers all other general forecasting inaccuracies	Assume distribution is symmetric and independent of demand and price levels
Total demand forecasting error	This includes all the above elements	Calculated from - initialsupply(start of t+1) - totalcleared(end of t)
Adjusted demand forecasting error	The total demand forecasting error needs to remove errors from generators providing regulation (correcting the forecasting inaccuracy)	DFE adjusted for ADE

Figure 66 Distribution of the adjusted demand forecasting error



Note: this removes the impact of non-conformance of generators providing regulation. Period covers the 3-years to March 2023.

C.2 Estimated historical benefits

Historical analysis was conducted to provide context into the potential size of DSP benefits related to high-price intervals and the composition of such benefits across energy and FCAS markets. A summary of the analysis and findings includes:

- **Annual share of cost** (Figure 67): This plot illustrates the share of total energy and FCAS enablement costs across the year for each of the regions. The chart indicates that FCAS comprises up to 7% of total dispatch costs in SA, with a much smaller share in other regions.

- **Interval-level benefit**: The analysis estimates the size of the benefit at the interval level, comparing intervals estimated to have DSP triggering to similar demand intervals without the same DSP response within 15 minutes. The energy and FCAS costs per interval across the NEM were averaged across all identified intervals and are presented in Figure 68. The region label denotes the region where DSP was estimated to have been triggered. The chart reveals significant spot price differences with and without DSP response, with benefits at the 5-minute level potentially ranging from \$1 million up to \$10 million.
- **Benefit composition** (Figure 69): This chart shows the above benefit composition in terms of energy and FCAS, consistent with the findings in Figure 67. Specifically, the FCAS benefits are low relative to the energy benefit.

Figure 67 Annual share of dispatch cost by market

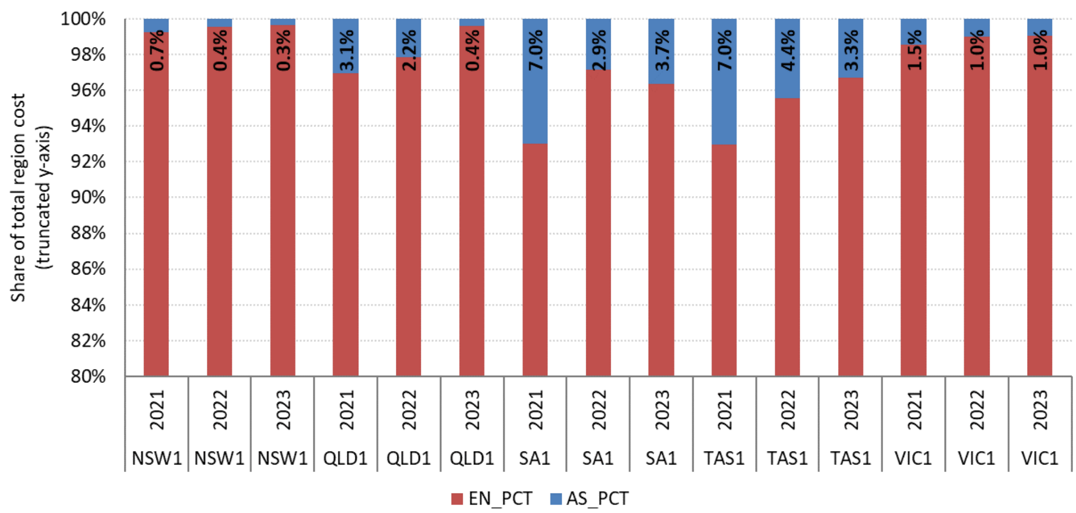


Figure 68 Historical DSP cost savings (interval level)

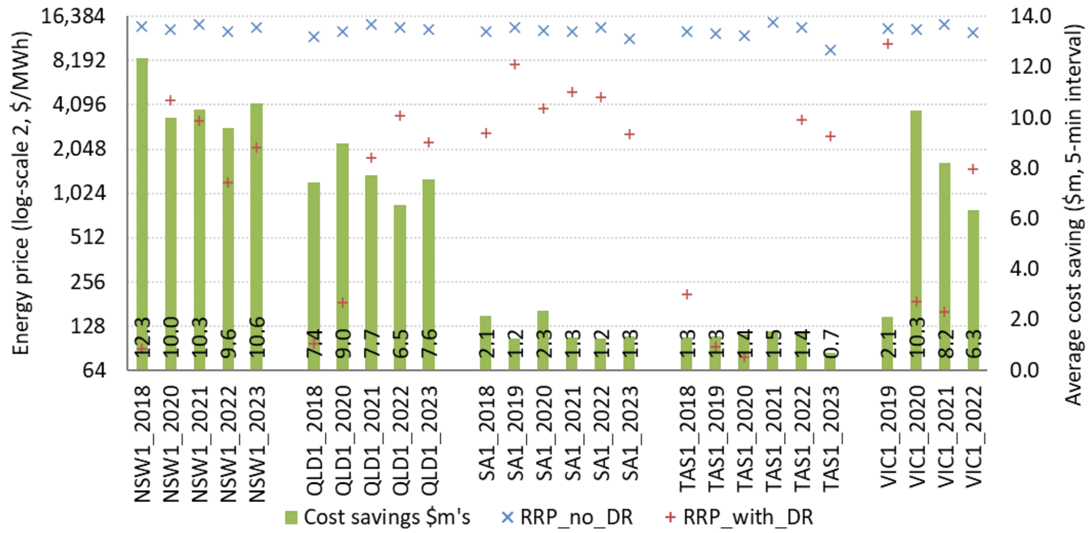


Figure 69 Historical DSP cost savings by service (interval level)