AEMC

AUSTRALIAN ENERGY MARKET COMMISSION

RULE

Rule determination

National Electricity Amendment (Integrating price-responsive resources into the NEM) Rule 2024

Proponent

AEMO

19 December 2024

Inquiries

Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: ERC0352 & RRC0051

About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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Summary

1 The Australian Energy Market Commission (AEMC or Commission) has made a more preferable final rule (final rule) to allow aggregated consumer energy resources (CER) to be scheduled and dispatchable in the National Electricity Market (NEM). This framework, named 'dispatch mode', will allow aggregated small and medium size price-responsive resources to compete with large-scale generators and storage in the NEM. It allows these resources to be bid into the market, set spot prices, receive and follow dispatch instructions and access markets that require scheduling (e.g. regulation frequency control ancillary services). This will result in lower electricity and ancillary service costs, lower emissions and ultimately lower prices for consumers.

2 Much of the focus of dispatch mode has been on household-based virtual power plants (VPPs). However, the Commission emphasises that dispatch mode is designed to facilitate a wide variety of aggregated small and medium size price-responsive resources participating in the spot market. For example, we consider that the earliest entrants are likely to be aggregated mid-size batteries (for example, multiple 4.9 MW batteries). Dispatch mode also opens up new opportunities for demand response to participate in central dispatch because it will smoothly facilitate large customers, or third parties (including retailers) on behalf of large customers, bidding in their load. This could include data centres, irrigation and pumping loads, commercial and industrial heating, cooling and chilling loads and a range of future technologies. Most participation in dispatch mode is likely to occur through aggregating resources, but individual resources above certain sizes could also participate.

3 As the proportion of resources that respond to prices in the NEM becomes increasingly distributed and owned by consumers, effectively integrating these resources into the spot market is crucial to supporting an affordable and reliable supply of electricity for all consumers. To drive participation in dispatch mode to achieve these outcomes, the Commission has included short-term incentive payments in the final rule. This will be achieved through an Australian Energy Market Operator (AEMO) tendering mechanism that seeks to overcome the barriers for early entrants participating in dispatch. In the longer term, the Commission considers that market and network access should provide incentives for participation.

4 Many price-responsive resources will not be capable of, or choose to participate, in dispatch mode. As the magnitude of these resources grows AEMO will face further challenges forecasting demand in the NEM. To help understand the magnitude of this issue, the final rule introduces monitoring and reporting functions for AEMO and the Australian Energy Regulator (AER). The reporting framework will position the market bodies and participants to evaluate the impact of unscheduled price-responsive resources on AEMO's forecasts. It will also provide evidence on whether changes are required to help AEMO improve its operational demand forecasting. Alternatively, if this is not possible, a visibility market model, where retailers become responsible for forecasting their price responsiveness, is likely to be necessary.

CER are growing rapidly and the Commission has a package of reforms to support this growth

5 Australian households and small businesses are embracing CER. More than three million households and businesses have solar panels and every second household is expected to have them by 2040. More than fifty thousand small-scale battery systems have been installed in the past seven years and 22 million purchases of electric vehicles are expected to be made by 2050. People are also using smart devices to control traditional assets such as hot water systems and

air conditioners, and programming multiple devices in their houses through home energy management systems. Retailers and aggregators, acting on behalf of consumers, are increasingly tapping into these resources through VPPs to respond to market price signals.

6 Developments are also occurring in the large business sector. Traditional commercial and industrial resources (for example, commercial chillers), and new types of large loads (for example, data centres) are increasingly active in the NEM. The volume of independent small generators and batteries is also growing (for example, community batteries).

7 Across Australia, governments are seeking to achieve net zero emissions by or before 2050, including through policies to accelerate CER uptake. CER and distributed energy resources (DER) will play a critical role in Australia's energy transformation, helping to reduce overall system costs, improve reliability and achieve a secure, low-emission energy supply for all.

8 If these resources are integrated well, the power system will operate more smoothly, and consumers and industry will enjoy the benefits of cheaper supply. Importantly, consumers without CER will also benefit from the lower system costs resulting from effectively integrating price-responsive resources.

9 Successful integration of CER would also mean fewer large-scale infrastructure projects needing to be constructed to keep the system running. This would contribute to the achievement of a net zero system, as existing lower emitting resources would be used rather than building new resources.

10 CER integration will require a multifaceted approach that matches the complexity of the task. A CER Taskforce convened by energy ministers has developed and published an implementation plan in the form of a CER Roadmap. It defines and will help to drive the CER integration actions needed. The AEMC is a member of this Taskforce and is leading the 'Distribution system and market operation' (DSO) workstream.

11 The AEMC is also driving reforms required to effectively integrate CER into the power system for the transition to net zero in the grid, and the years beyond. These rule changes and reviews are crucial building blocks that will help to pave the way for the innovation in the market that becomes change, and the change that becomes transformation. For example:

- we have recently completed rule changes to accelerate the roll-out of smart meters and unlock CER benefits through flexible trading, and
- we have recently commenced reforms to allow customers access to real time energy data and get the regulatory frameworks right for electricity pricing for CER in the future.

12 This final determination is in response to a rule change request from AEMO and is a key part of this package of reforms. It is the main rule change in the AEMC's work program that focuses on integrating these resources into the wholesale electricity market.

13 The Commission notes that for the remainder of this summary, we use the term unscheduled price-responsive resources to refer to:

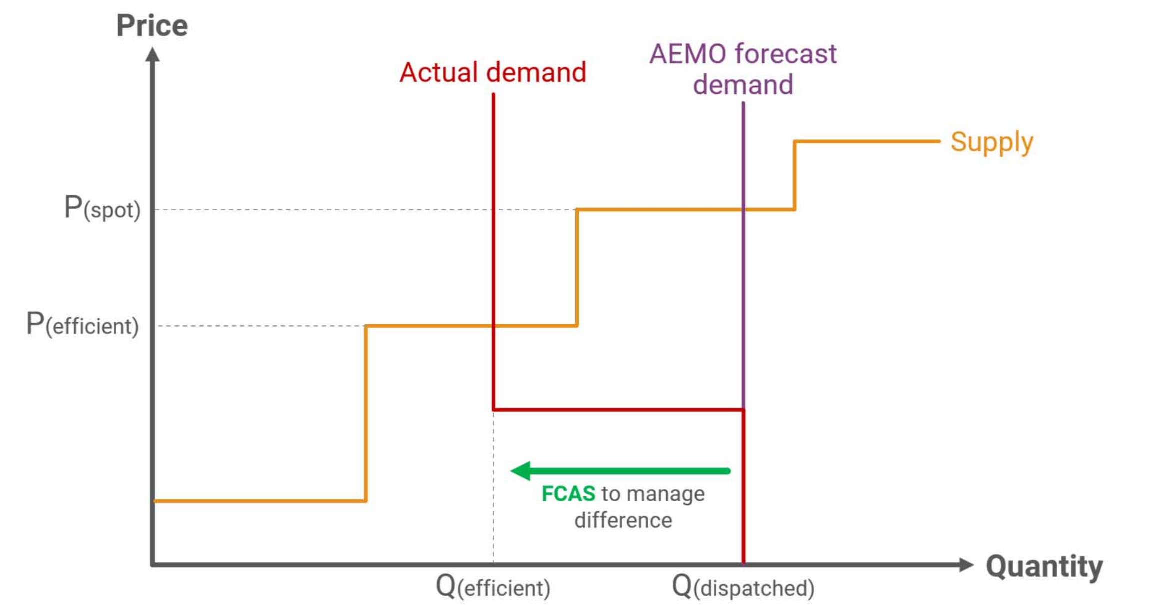
- the wide range of residential, community, commercial and industrial energy resources and load that are not currently scheduled through the market dispatch process, and
- do or could respond, individually or as part of aggregation, to market price signals.

Optimally integrating unscheduled price-responsive resources would lower total system costs by billions

14 Unscheduled price-responsive resources are not currently fully integrated into the spot market. They are not appropriately considered when determining how much energy demand needs to be met, how to meet this demand, or the price at which it is purchased. Energy, security and reliability services could be provided more efficiently if these resources were fully integrated. Over time, this would reduce the total cost of providing consumers with a reliable electricity supply and therefore decrease prices for all consumers.

15 Under existing processes, AEMO produces a price inelastic demand forecast for every dispatch interval. Figure 1 demonstrates the outcomes in prices, dispatch costs and frequency control ancillary services (FCAS), when unscheduled price-responsive resources respond to prices in a dispatch interval.

Figure 1: Inaccurate demand forecasts cause higher than efficient spot prices, and generation and FCAS costs



Source: AEMC

16 As AEMO does not know the intentions of these resources, it forecasts demand to determine $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of $P_{(spot)}$. However, where there are unscheduled price-responsive resources that will reduce their consumption or increase generation at this price point, actual demand will be $Q_{(efficient)}$ and the efficient price would have been $P_{(efficient)}$. To balance supply with the actual demand level, FCAS are required. This shows that:

- the energy spot price is higher than the efficient level and therefore consumers pay more than is necessary
- unnecessary costs were incurred by scheduled resources to meet the over forecast of demand
- costs are incurred to bring supply and demand back into balance through FCAS
- because there is a close correlation between high marginal cost generators and high emissions generators, it is likely that emissions are higher than necessary

- if demand and supply conditions are particularly tight, the demand forecast error may lead to the triggering of the reliability emergency reserve trader (RERT) and its associated costs.

17 When these operational inefficiencies are repeated they drive inefficiencies in investment timeframes. These include:

- higher energy prices, which drive inefficient investment in generation, storage and demand response
- greater demand forecast errors, which increase FCAS requirements and prices.

18 In the past, the limited amount of unscheduled price-responsive resources meant that not accounting for price elasticity in demand forecasting had little consequence. However, with the rapid uptake of CER this is changing. To quantify the magnitude of these inefficiencies in the future, the Commission tasked Intelligent Energy Systems (IES) to undertake market modelling out to 2050. IES's estimates are set out in Table 1. They reveal that as the magnitude of unscheduled price-responsive resources grows, the errors become substantial, resulting in a combined efficiency loss of $1,467-1,832m. IES's full report and explanations of its modelling techniques are provided with this final determination.

Table 1: Estimated cost reductions from integrating unscheduled price-responsive resources

Cost areas	Costs ($m, 2023, NPV)
FCAS	831-1,053
Generation	189-234
RERT	122
Emissions	325-423
Total	**1,467-1,833**

Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report, 24 June 2024

19 IES also demonstrates that, absent integration, energy and FCAS prices would be substantially higher due to demand forecast errors, resulting in consumers paying $12-13b (2023, net present value (NPV)) more over the period than necessary. These are not efficiency gains, they are wealth transfers from generators to consumers, and therefore we do not include them in our benefit estimates. However, IES's modelling did not attempt to model the additional generation and storage entering the market and this would come with a material cost. We therefore note that the above efficiency gains are likely understated.

Our final rule introduces dispatch mode to integrate unscheduled price-responsive resources into the NEM

20 The final rule introduces a framework known as 'dispatch mode' into the NEM. It allows currently unscheduled price-responsive resources to be scheduled and dispatchable in the NEM, in aggregations or individually. This will allow virtual power plants, community batteries, flexible large loads and other price-responsive small resources to compete with large-scale generators and storage. It will allow them to bid into the spot market, set prices, receive dispatch instructions and earn revenue in markets that require scheduling (for example, regulation FCAS). By explicitly including currently unscheduled price-responsive resources in dispatch, AEMO will no longer need to forecast their actions in the spot market, therefore reducing demand forecast errors and their consequential inefficiencies.

21 The key features of dispatch mode and their benefits are:

- It is a purely voluntary mechanism. It is given effect in the final rule through the concepts of a voluntarily scheduled resource (VSR) and a VSR provider (VSRP). It allows the financially responsible market participant (FRMP, usually a retailer) at the connection point to nominate qualifying resources, either individually or aggregated, as a VSR and participate in central dispatch. With the mechanism only applying to FRMPs, even when they choose to participate, there is no requirement on consumers to change their behaviour or cede control over their assets.
- A number of small resources can be aggregated such that they are treated as one VSR for the purposes of central dispatch. This means that the VSR will be provided with, and assessed against, aggregated dispatch instructions. No individual resource within this aggregation is required to follow dispatch instructions. Instead, the participant must meet the dispatch instructions in aggregate.
- The underlying connection point classification for VSRs will not change. For instance, if a retailer (Market Customer) aggregates several of its market connection points as a VSR, these will still be market connection points but will also be part of the VSR. By not creating a new classification for VSRs, or requiring a change in the classification of connection points participating, participants will have greater flexibility and implementation costs will be reduced.
- It uses the bidirectional unit (BDU) framework introduced in the *Integrating Energy Storage Systems* rule changes as the basis for the requirements in the rules. Using the BDU design allows bids for both generation and load, providing flexibility for how VSRs can operate in central dispatch.
- It follows existing conventions regarding regulatory decision-making. Most importantly:
  - The NER set out the key legal requirements for participation in central dispatch, such as bidding, dispatch and conformance. This will create certainty for market participants as the NER provides stability and familiarity through the application of existing regulations.
  - AEMO guidelines will establish the specific operational and technical details for participants to follow. This will allow AEMO to update these details more regularly than if they were placed in the rules and allow them to be tailored to the requirements of participants utilising aggregated small resources.
- It sets out principles to guide AEMO in determining the operational and technical details of participation within its guidelines. Most importantly, it guides AEMO to facilitate the ease of participation in central dispatch by VSRs and apply restrictions on VSRs only to the extent reasonably necessary to manage power system security and reliability. This explicitly recognises that VSRs are not the same as large scheduled generators and BDUs, and therefore should not face the same requirements. We consider that this is important to reflect that:
  - Participation in dispatch mode is voluntary. Strict requirements will result in low participation and therefore low benefits for consumers.
  - Market participants are still learning and developing their capabilities to control aggregated CER and should be given time to develop these capabilities.
  - Participation is likely to build up over time. In the early years, the small size of each VSR participating means they are unlikely to have a material impact on power system security and therefore leniency comes at a low risk.

- It creates flexibility for VSRPs through:
  - The creation of new mechanisms that allow them to drop in and out of dispatch smoothly. It creates a deactivation mechanism which is designed to allow participants to drop out of dispatch for short periods of time. This will likely be to address technical issues. It also introduces a hibernation mechanism to allow participants to drop out of dispatch mode for up to eighteen months. This will allow participants to do things like participating in summer but not winter.
  - The ability to participate at either connection points or secondary settlement points. Secondary settlement points were created in the Commission's *Unlocking CER benefits* rule change and will sit behind a connection point, allowing the splitting of resources at a customer's premises. This means that participants can separate out flexible and inflexible resources behind a connection point and only include the flexible resources (or any combination they choose) in their VSR.

22 The Commission has only made minor changes to dispatch mode between draft and final rules. This reflects that stakeholders largely supported dispatch mode in its proposed form. The most important of the changes between draft and final are:

- We have increased the flexibility of the opt-out mechanisms. In particular, we have removed the restriction on the maximum length of time the deactivation framework applies (previously being seven days). While this mechanism will likely be used for short periods of time, we consider that there is no need for this restriction and agree with stakeholders that it could unnecessarily limit its usefulness.
- We have introduced a requirement on distribution network service providers (DNSPs) to consult with VSRPs when designing flexible export limits (FELs). Throughout this rule change, participants have highlighted that a barrier to participation in dispatch mode will be their ability to follow dispatch instructions if FELs change close to a dispatch interval. The Commission agrees that this is a material issue. However, similar to our position in the draft determination, we do not consider that in the current development phase of FELs it is beneficial to regulate them in this rule change. To balance these positions, we consider DNSPs should consult with VSRPs when developing flexible export limits, with a specific focus on FEL finalisation timing.

The final rule provides incentives for participation in dispatch mode in the short term

23 The final rule includes a time-limited incentive mechanism to drive participation in dispatch mode in its early years. It does this by requiring AEMO to conduct tenders to pay participants to enter dispatch mode in the first five years of the mechanism. The payments are capped at the estimated benefits per MW of participation. This means that even in the years that the payments are made, consumers still benefit from participation.

24 The final rule also caps the overall payments under the framework at $50m. We consider $50m is likely to achieve an appropriate balance between:

- limiting the impact on consumers of the payments to approximately one dollar per year, and
- providing enough funding to cover a material proportion of early entrants costs to drive participation.

25 The Commission considers that this incentive mechanism is necessary because of the combination of these factors:

- the majority of the benefits from participating in dispatch mode accrue to all consumers, not the participant
- there are well recognised inherent disincentives to being scheduled in the NEM (for example, meeting the communications and data sharing requirements)
- the mechanism is new and therefore there are likely to be positive effects on later participation from early entry.

26 The Commission noted in the draft determination that this mechanism is not a natural fit in the NER and that we would be working with ARENA, the Commonwealth and jurisdictional governments regarding alternatives in the final rule. We have made substantial progress on this front and consider there is a material chance that these avenues will address the participation disincentives highlighted above to some degree. However, this is still not certain and we therefore consider it appropriate to retain the incentive scheme in the final rule.

27 Stakeholders largely supported the need for incentives. The few stakeholders that commented on the design of the incentive mechanism in the draft determination supported it. The only material changes we have made between draft and final rules are:

1. Increasing the per MW payment cap from fifty to a hundred per cent of the estimated benefits. EnergyAustralia highlighted that this is appropriate because the scheme will result in participation in the long run, which consumers will benefit from. Therefore, paying up to the benefits of participation to participants in the short run will still benefit consumers overall.
2. Introducing the ability for governments to add additional funds to the mechanism to provide more than $50m. This change is in response to a request from AEMO and Alinta to provide the ability for more funding to be available if governments so choose.

28 The Commission considers that long-term participation incentives are likely to be best provided through market and network access. For example, participants in dispatch mode should have access to the full suite of markets for services they are capable of providing. In the future, this may include access to new system security markets or access to capacity payments.

Our final rule introduces an AEMO and AER monitoring and reporting framework for unscheduled price-responsive resources

29 The combination of the level of control required to participate in dispatch mode and the wide range of functions, capabilities and business models for CER mean that the majority of price-responsive resources are unlikely to participate in dispatch mode. The IES analysis shows that as the magnitude of these resources grow, they will create challenges for AEMO's demand forecasting in the NEM and this may have large consequences for efficient market operation. To address these issues, the final rule introduces a monitoring and reporting framework for AEMO and the AER. The key features of the framework are:

- Monitoring and reporting by AEMO to identify the presence and issues created by increased unscheduled price-responsive resources. This requires AEMO to report annually on the impact of this response on its operational forecasting and the measures it takes to improve it to account for unscheduled price-responsive resources.
- Monitoring and reporting by the AER to assess the estimated efficiency implications and costs associated with actual demand deviating from forecasts due to unscheduled price-responsive resources.

30 This reporting framework will provide more transparency on the materiality of deviations of actual demand from forecast demand, and the inefficiencies that they cause. This transparency will facilitate analysis of AEMO's operational demand forecasting methods and whether changes can reduce such inefficiencies should they materialise. Collectively, this reporting and transparency framework will help understand how unscheduled price-responsive resources are changing and their impact on market outcomes. It will also provide evidence for the AEMC to consider whether to introduce structural changes to demand forecasting or a visibility market model in the future.

31 Before deciding on the monitoring and reporting framework the Commission assessed AEMO's proposed 'visibility mode'. This was a light-handed version of dispatch mode. It included participants submitting bids for unscheduled price-responsive resources in a similar manner to dispatch mode, but the bids would not be directly incorporated into dispatch and requirements for accuracy would be low. The Commission ruled this solution out because we considered that without direct incorporation into dispatch it would not result in substantial benefits and would still come at material cost.

32 The Commission also assessed a visibility market model where participants would bid price-responsive demand deviations into central dispatch from an AEMO price-inelastic demand forecast. The Commission considers that this solution has considerable merit and analysed it in detail. The Commission engaged Creative Energy Consulting to work up a design of this model, which is published with this final determination. The Commission considers the benefits of this model include:

- By transferring responsibility to market participants (for example retailers) for forecasting the price-responsiveness of their customers, risks are efficiently allocated. Retailers purchase energy on behalf of customers in the spot market and on sell it to them. Generally, they possess the best information about the price-responsiveness of their customers because they have the retail contract that passes through prices and invest significant resources to know how much energy they will be purchasing at different times and price levels.
- With retailers undertaking forecasts, financial incentives could be created for accurate forecasting through the use of frequency performance payments.

33 However, after detailed design discussions with AEMO and our technical working group, the Commission concluded that this solution is not yet warranted. While the volume of unscheduled price-responsive resources is growing, it has not yet reached a point where it is materially challenging AEMO's demand forecasting and it would come with material costs to produce the necessary forecasts.

34 We consider that the monitoring and reporting framework established in the final rule will place us in a good position to determine:

- when AEMO's demand forecasts are being materially challenged
- if challenges can be addressed by AEMO changing its demand forecasting methods
- whether a move to retailer-led forecasting of price-responsiveness is warranted.

35 Stakeholders strongly supported the introduction of the monitoring and reporting framework in the draft rule. The Commission has not made any material changes between draft and final rule to the monitoring and reporting framework.

Our final rule will result in significant benefits for consumers

36 The Commission has tested whether the final rule is in the long-term interest of consumers. To do so, we have assessed the final rule against five assessment criteria. These criteria and our assessment of dispatch mode rule against them are:

- **Security and reliability** — would greater visibility and dispatchability of price-responsive resources promote a secure and reliable electricity system at the lowest cost through more accurate forecasting and operation?
  - The primary effect of dispatch mode on security is that the quantity and cost of FCAS to maintain a secure system is substantially lower. IES modelling indicates that with dispatch mode, operational demand forecast errors are substantially lower over time, which reduces the quantity, cost and price of FCAS.
  - Dispatch mode also has benefits for the cost of maintaining a reliable supply. With certainty of the response of currently unscheduled price-responsive resources to high price events, RERT is needed less.
- **Concepts of efficiency** – to what extent will increased visibility and integration of price-responsive CER in the scheduling process lead to productive, allocative and dynamic efficiency?
  - Dispatch mode results in significant productive efficiency gains. With greater accuracy of the response of currently unscheduled price-responsive resources, less high-cost generation is dispatched.
  - The decrease in operational demand forecast deviations from dispatch mode results in more efficient spot prices. These will result in allocative efficiency gains through more efficient responses in operational timeframes. Furthermore, these more efficient prices will be lower and less volatile. They therefore result in dynamic efficiency gains through signalling the need for less generation, storage and demand response in investment timeframes.
- **Emissions reduction** — would the solution efficiently contribute to the achievement of government targets for reducing, or that are likely to reduce, Australia's greenhouse gas emissions?
  - Because there is a close correlation between high marginal cost generators and high emissions generators, as less high cost generation is dispatched when VSRs participate in dispatch, emissions also decrease with the introduction of dispatch mode.
- **Implementation costs** — what will be the costs to participants, consumers and AEMO of implementing the solution? What will the costs be to participants, consumers and AEMO of complying with the solution over time?
  - Dispatch mode will result in costs to AEMO to implement and maintain. However, these are kept to a minimum through the use of recently implemented frameworks in the NER (for example, the bidirectional unit framework in the Integrating energy storage systems rule change).
  - Where participants choose to participate in dispatch mode they will also incur incremental costs to meet the standards and specifications. In the first five years of dispatch mode, the incentive scheme is likely to cover many of these costs for participants.
  - The incentive scheme results in costs for AEMO to implement and maintain. However, AEMO has experience running similar auction frameworks, and the Commission has closely liaised with AEMO on detailed design of the mechanism, to keep costs to a minimum.

- **Flexibility** — would the solution be future-proof, resilient and able to accommodate market, technological, policy and other changes?
  - Dispatch mode is highly flexible and resilient to future market and technology changes. At its core, dispatch mode is a platform for aggregated small-scale resources to be completely integrated into market dispatch. It is flexible to a wide range of resources, technologies and business models, and therefore robust to changes to all of these factors over time.
  - Similarly, dispatch mode is resilient to future regulatory reforms. The basic functions of participants bidding the response of currently unscheduled price-responsive resources to different spot prices, and following these bids, is important under any future regulatory framework.

37 For dispatch mode, the Commission has quantified the likely benefits of the mechanism through market modelling. The Commission tasked IES to adapt its size of the prize modelling to include projected uptake rates of dispatch mode and then use the same methodology as described above to estimate its benefits. There is material uncertainty regarding the uptake of dispatch mode and we therefore had IES take a probabilistic approach to modelling the benefits. IES models a high, medium and low participation scenario and then gives them weights based on the likelihood of them eventuating. This provides a weighted benefit that the Commission primarily considers for its National Electricity Objective (NEO) assessment. These are set out in Table 2. AEMO also provided an initial cost estimate of its costs to implement the mechanism, and for upfront and ongoing costs for the incentive mechanism and these are included in Table 2.

Table 2: Benefit and cost estimates of dispatch mode ($m 2023, NPV)

	Low	Medium	High	Probabilistic
Security benefits — FCAS	220	403	617	411
Reliability benefits — RERT	100	100	100	100
Productive efficiency — energy	63	120	180	121
Emissions reduction value	140	199	274	203
Total efficiency gain	**523**	**821**	**1,170**	**834**
Implementation costs of dispatch mode and incentive scheme	34			
Net Benefit	**489**	**787**	**1,136**	**800**

Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024

38 The Commission considers that these estimates provide a strong case that dispatch mode and the dispatch mode incentive scheme meet the NEO and should be implemented. Our probabilistic assessment is a net benefit of $800m. Furthermore, even in the low uptake scenario modelled by IES, the net benefits of dispatch mode are $489m, an order of magnitude greater than the costs.

39 We note three other relevant factors in our NEO assessment:

1. Participation costs. There will also be costs for participants that choose to use the mechanism. These need to be considered when weighing the overall benefits of the mechanism. However, given the large modelled benefits, and that these costs are only incurred

for participants that use the mechanism, we do not consider there is a material risk that the costs would impact our overall NEO assessment.

2. Dynamic efficiency gains through avoiding unnecessary large-scale generation and storage. As set out in paragraph nineteen, IES did not estimate the likely material dynamic efficiency gains arising from dispatch mode. We therefore consider that the total efficiency gains are likely understated.
3. Incentive scheme. We have taken into account the implementation costs and effect on likely participation of the incentive scheme in our quantitative assessment. However, we do not include the $50m of incentive payments from consumers to participants in dispatch mode in this assessment. This is because (similar to the FCAS and energy prices) this is a wealth transfer from consumers to participants, not an efficiency loss.

40 We have also assessed the monitoring and reporting framework against the NEO and our assessment framework qualitatively. The main benefits from the approach are that it will position the market bodies to decide if and when changes are needed to AEMO's forecasting methods. This will include determining if structural changes to the way that forecasting is done in the NEM are needed (for example, placing responsibility on retailers). We consider that this approach is likely to result in timely reforms being made to improve demand forecasting in the NEM in the future. This has the potential to materially increase allocative, productive and dynamic efficiency in the long run. Furthermore, we consider that the analysis functions in the final rule are ones that AEMO and the AER are likely to undertake in-house over time regardless of the rule. The increase in costs as a result of that being done formally and publicly is unlikely to be material.

41 Our assessment of the final rule against the NEO has not materially changed from our assessment of the draft rule. We consider that the limited changes between draft and final rule mean updates to the market modelling undertaken by IES to assess dispatch mode are not required. Similarly, stakeholders did not raise any issues requiring reassessment.

Our final rule provides an effective implementation schedule

42 The final rule provides a schedule for implementation of dispatch mode, the incentive mechanism and the monitoring and reporting framework. Our overriding approach has been to implement these mechanisms at the earliest possible date within AEMO's and the AER's capabilities and resources. The resulting schedule is provided in Table 3 below.

Table 3: Final rule implementation schedule

	2025	2026	2027
Dispatch mode	December: AEMO VSR guideline published		May: dispatch mode commences
Incentives		Before December or first tender process: AEMO publishes tender guidelines April: incentive period commences	
Monitoring and reporting	December: AEMO and AER publish final reporting guidelines	April: AEMO to publish first quarterly report September: AEMO to publish first annual report December: AER to publish first annual report	September: AEMO to publish second annual report December: AER to publish second annual report

Source: AEMC

43 We have materially changed the implementation schedule between draft and final rule in two ways:

1. We have extended the implementation date for dispatch mode from November 2026 to May 2027. We consider this is necessary to allow AEMO to successfully implement dispatch mode. This was supported through AEMO's consultation on its high level impact assessment of the draft rule and determination.
2. We have brought forward the start of the incentive period from January 2027 to April 2026 to allow AEMO to commence the tenders earlier. This will give potential entrants in dispatch mode time to receive notice that they were successful in their application for funding before they commence in dispatch mode.

We have consulted widely and deeply, and your feedback has improved our final rule

44 In reaching the final rule we have consulted extensively on AEMO's rule change request. This has included:

- publication of consultation paper (34 written submissions), update paper and draft determination (22 written submissions)
- public forums on the update paper and draft determination, with 111 and 130 attendees respectively
- more than 95 bilateral discussions with a range of stakeholders and six meetings with industry working groups
- six sessions with our technical working group, comprising market body representatives, consumer groups and industry.

45 The Commission would like to thank all stakeholders for their collaborative and constructive

engagement in this rule change. We note that stakeholder views and analysis have driven the solutions in the final rule. In particular:

- The final rule is substantially different from AEMO's visibility proposal and the Commission's early policy development of a market based forecasting model. Stakeholders emphasised the need for greater transparency and analysis of operational demand forecasts in relation to unscheduled price-responsive resources and this heavily influenced our move to the monitoring and reporting framework in the final rule.
- The Commission has been able to test the detailed design of dispatch mode extensively with stakeholders. In particular, technical working group input was invaluable in shaping the draft rule. Similarly, submissions to the draft rule provided valuable detailed feedback to enhance the final rule.

How you should read this final determination

46 This final determination is deliberately set out in three layers for the different audiences interested in our work. First, if you are interested in a simply expressed overview of our entire rule change, this executive summary provides it. Second, for those interested in the background and reasons for our decisions:

- chapter 1 provides context for the rule change
- chapter 2 provides an explanation of the problem
- chapter 3 outlines the solutions we have reached to solve the problem
- chapter 4 sets out our rule-making tests and the evidence that these solutions best meet the NEO.

47 Third, for those in industry, market bodies, or other experts interested in the technical details of dispatch mode, incentives design or our monitoring framework, these are set out in appendices A, B and C. Appendix D summaries other issues from submissions to the draft determination. Additionally, Appendix E provides a summary of the final rule and Appendix F covers the legal requirements to make a rule. The final rule is published with this determination.

48 Important other documents for our final determination are also available on our website. These include:

- IES size of the prize modelling, final report
- IES benefits modelling of dispatch mode, sensitivity modelling results
- Creative Energy Consulting updated visibility market model.

Contents

Tables

Figures

1 The Commission has made a final determination

The Australian Energy Market Commission (the Commission or AEMC) has decided to make a more preferable final electricity rule (and no retail rule) in response to a rule change request submitted by the Australian Energy Market Operator (AEMO).

This chapter provides an overview of:

- the rule change request from AEMO (section 1.1)
- the input from stakeholders that has shaped our determination (section 1.2)
- how this rule change fits within the Commission's consumer energy resource (CER) work program (section 1.3).

1.1 AEMO requested changes to integrate aggregated CER into the NEM

AEMO considers that over time the growing quantity of unscheduled price-responsive resources in the National Electricity Market (NEM) will play an increasingly important role in how the energy system performs. Ensuring that these resources can contribute to and operate within system requirements will be key to achieving an affordable, reliable, secure, and low emissions energy supply for all consumers in the future.

AEMO stated that its proposed mechanism would:[1]

- provide critical visibility and dispatchability services required to address complex and emerging power system challenges, avoiding the need for increasing reliance on interventions to manage system security and reliability
- enable innovation and enhanced competition in consumer service offerings, delivering supplementary revenue streams to consumers beyond existing feed-in tariffs and off-market retail demand response offerings
- harness the potential of price-responsive distributed resources, thereby facilitating the optimal allocation of resources to meet the demand for energy services over time
- lower costs to all consumers.

AEMO proposed changes to the National Electricity Rules (NER) to establish the new mechanism. AEMO proposed two modes in its rule change request:[2]

- **Visibility mode**: this mode was designed to allow participants to provide bids on the intentions of price-responsive resources. However, the bid would not be directly incorporated into dispatch and conformance requirements would be low.
- **Dispatch mode**: this mode was designed to integrate price-responsive resources into the NEM central dispatch and scheduling processes. Participants would be able to provide bids for their generation and load, receive and follow dispatch targets.

1.2 Stakeholder support for flexibility shaped our determination

The views expressed by stakeholders in response to our consultation paper, update paper, public forums, draft determination, in technical working groups and bilateral meetings have shaped our final determination.

1 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 1.

2 For further details on how the modes were proposed to operate, please see the Consultation Paper and AEMO rule change request.

Throughout all of our consultations, stakeholders have agreed that an increasing amount of unscheduled price-responsive resources in the NEM would result in inefficiencies and challenges for the operation of the system.[3]

Feedback between the consultation paper and draft determination significantly shaped the solutions that were considered.[4] During these stages we undertook extensive stakeholder consultation including additional stages to our process:

- an update paper on 14 December 2023[5]
- a public forum on 19 February 2024, with 111 stakeholders, to discuss the benefits modelling and next steps[6]
- we formed a technical working group (TWG).[7] The TWG commenced in February 2024 and comprised 18 representatives from stakeholder groups including market participants, aggregators, gentailers, networks, industry bodies, Australian Renewable Energy Agency (ARENA), and academia. The TWG met on six occasions over three months, providing detailed feedback on the solutions as we developed them.[8]

The key issues raised and the way the Commission addressed each issue were:

- Some stakeholders expressed caution in terms of how significant the problem is at the moment. These stakeholders were concerned that AEMO had not clearly defined the problem, that it could be overstated, and recommended that the Commission seek to quantify it.[9] In response, we commissioned market modelling of the size of the inefficiencies (referred to as 'size of the prize') out to 2050 by Intelligent Energy Systems (IES).[10] The IES modelling identified substantial benefits in addressing these inefficiencies as these resources grow. Chapter 4 describes these further.
- Stakeholders considered that there is significant diversity in the firmness of price-responsive resources and that visibility mode as proposed would not incorporate many of the less firm resources.[11] The significant range of unscheduled price-responsive resources impacts the likely costs and benefits of participating in dispatch and the alternatives that we have considered. Chapter 2 sets out our consideration of the range of firmness and appendix A sets out how our new framework is designed with these resources in mind.
- Many stakeholders also raised material issues with visibility mode as proposed in the rule change request. There were concerns because the information provided by participants was not proposed to be directly incorporated into dispatch demand forecasts.[12] In response to these, we commissioned an alternative visibility model by Creative Energy Consulting.[13] This model has significant benefits and would incorporate unscheduled price-responsive resources into dispatch. However, after detailed design discussions with AEMO and our TWG, the

3 Submissions to the draft determination, Shine Hub, p. 1, Origin, p. 1.
Submissions to the consultation paper, Powerlink, p. 1, Stanwell, p. 1, Shell Energy, p. 1, Mondo, p. 3, Grids, SwitchDin, p. 3, Red Energy and Lumo Energy, p. 2, Energy Queensland, p. 2, Energy Locals, p. 1, Rheem and CET, p. 3, sonnen, p. 3.

4 We received 34 written submissions to the consultation paper in September 2023, AEMC, Integrating price-responsive resources into the NEM project page.

5 AEMC, Integrating Price-Responsive Resources into the NEM Update Paper.

6 AEMC, Integrating price-responsive resources into the NEM project page, which provides forum slides and Q&A.

7 Submissions to the consultation paper provided feedback that additional consideration through this type of process would be beneficial, Jemena, AEC, Tesla, CS Energy and the CEC.

8 Slides and minutes from the TWG meetings are available on the project page.

9 Submissions to the consultation paper, Simply Energy, p. 1, Enel X, p. 2, CS Energy, p. 2.

10 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report June.

11 Submissions to the consultation paper, Evergen, p. 4, Origin, p. 2, AEC, p. 3, AGL, p. 2.

12 Submissions to the consultation paper, Enel X, p. 2, AEC, p. 2, CEC, p. 1, Flow Power, p. 3.

13 Creative Energy Consulting, A Market Design to integrate Demand Response into NEM Pricing and Dispatch, 25 July 2024.

Commission concluded that the visibility market model is likely to have high cost and complexity for AEMO to implement and maintain, and the solution is not yet warranted. The draft determination outlined a new monitoring and reporting approach to understand the impact of unscheduled price-responsive resources on demand forecasting. See section 3.4.

- The need for, and lack of, incentives to participate in the scheduling process was the most significant feedback. Stakeholders generally agreed that there is limited to no incentive to participate, even if the market benefits generally.[14] This has significantly shaped our investigation including consideration of additional incentives in our more preferable rule. Incentives are required to drive participation of unscheduled price-responsive resources. See appendix B.

Feedback to the draft determination and public forum in August generally agreed with the direction of our draft rule.[15] Stakeholders' key feedback at this stage and our responses in the final determination include:

- Reiterated the need for incentives to participate in dispatch mode.[16] Stakeholders shared our preference for a third party (for example ARENA or Capacity Investment Scheme (CIS)) providing the incentive.[17] Given that we have been unable to secure a third party providing this incentive, our final rule retains the incentive mechanism, with changes based on stakeholder feedback.
- Supported dispatch mode and provided feedback on the specific operation of the rule and framework. See section 3.2 for discussion on these.
- Supported the monitoring and reporting framework with limited feedback on the operation of the framework.

Our formal consultation was complemented by engagement with a diverse range of stakeholders in bilateral and multilateral discussions.

1.3 This rule change fits within the Commission's CER work program

Australian households and businesses are embracing CER. More than fifty thousand small-scale battery systems have been installed in the past seven years and 22 million purchases of electric vehicles are expected to be made by 2050. People are also using smart devices to control traditional assets such as solar panels, hot water systems and air conditioners, and programming multiple devices in their houses through home energy management systems. Retailers and aggregators, acting on behalf of consumers, are increasingly tapping into these resources (individually or aggregated through a virtual power plant (VPP)) to respond to market price signals.

Developments are also occurring in the large business sector. Commercial and industrial resources (for example, commercial chillers), and new types of large loads (for example, data centres) are increasingly active in the NEM. The volume of independent small generators and batteries is also growing (for example, community batteries).

Government are achieving net zero emissions by 2050 through policies to accelerate CER uptake.[18] CER and distributed energy resources (DER) will play a critical role in Australia's energy

14 Submissions to the consultation paper, Stanwell, p.4, Fortescuse, p. 3, Evergen, p.3, Enel X, p. 4, Flow Power, p. 4.

15 Our public forum on 27 August 2024 had 130 stakeholders in attendance, and we received 22 written submissions to our draft determination in September 2024. Information on these can be found on our project page.

16 Submissions to the draft determination, SA Water, p. 1, Alinta, p. 1, CEC, p.4, Shine Hub, p.1, Enel X, p. 2, CS Energy, p. 4.

17 Submissions to the draft determination, AEC, p. 2, Hydro Tasmania, p. 2, Origin, p. 4, Enel X, p. 2, Ausgrid, p. 1, Shell Energy, p. 2, CEC p. 3, Alinta, p. 2, EUAA, p. 4.

18 Relevant government targets are set out in the emissions target statement.

transformation, helping to reduce overall system costs, improve reliability and achieve a secure, low-emission energy supply for all.

If these resources are integrated well, the power system will operate more smoothly, and consumers and industry will enjoy the benefits of cheaper supply. Importantly, consumers without CER will benefit from the lower system costs from integrating price-responsive resources. Successful integration of CER would additionally mean fewer large-scale infrastructure projects would need to be constructed to keep the system running. This would contribute to the achievement of a net zero system as existing lower emitting resources would be used rather than building new resources.

CER integration will require a multifaceted approach that matches the complexity of the task. A CER Taskforce convened by energy ministers has developed a CER roadmap that defines and drives the CER integration actions needed.[19] Market bodies are driving a series of interrelated reforms that aim to integrate these resources and realise their full potential. The Energy Security Board's (ESB) end-of-program CER report outlined the CER reform work.[20] The AEMC is a member of this task force and is leading the workstream examining the future role for Distribution Service Operator (DSOs). Through this workstream, the AEMC will help to develop a functional map of what it will take to integrate CER into the energy system and market. If there is a reform on DSOs, a number of subsequent rule changes would be required. The interaction between DSOs and the wholesale market will be important to consider through this review. DSO arrangements may impact the participation or success of dispatch mode, depending on the responsibility DSOs are given. We do not consider we should delay this rule change to wait for agreement on DSOs because we are not sure when these issues will be resolved.

The AEMC is also driving keystone reforms required to effectively integrate CER into the power system for the transition to net zero in the grid, and the years beyond. These rule changes and reviews are crucial building blocks that will help to pave the way for the innovation in the market that becomes change, and the change that becomes transformation.

Several recently completed reforms intersect with this rule change, including:

- ***Unlocking CER Benefits Through Flexible Trading* rule change** — This rule change allows financially responsible market participants (FRMPs) to create secondary settlement points, making it easier for large customers to have multiple FRMPs. Small customers would retain one retailer, but could separately meter their 'flexible' CER loads and their 'passive' loads such as lights and fridges.[21] The *Unlocking CER Benefits* rule change makes it easier to participate in dispatch under this rule change. TWG members highlighted the importance of the relationship between the two rule changes. They indicated that forecasting passive load would be a challenge for some participants in dispatch mode and could limit participation as conformance and compliance requirements could be challenging to meet if passive loads were included.
- **Accelerating smart meter deployment rule change**— On 28 November 2024, we published a final determination and final rules for the *Accelerating smart meter deployment* rule change project.[22] The final rules deliver a fast, efficient, and effective rollout of smart meters to all customers by 2030. The final rule increases the amount of information available to consumers about their energy use, allows consumers to better understand and manage their bills, and

19 Department of Climate Change, Energy, the Environment and Water, National Consumer Energy Resources Roadmap, July 2024.

20 ESB, Consumer energy resources and the transformation of the NEM, February 2024.

21 AEMC, Unlocking CER benefits through flexible trading project page. The final determination was made on 3 August 2024.

22 AEMC, Accelerating smart meter deployment, rule determination, 28 November 2024.

opens up access to new and better retail service options. This also includes new consumer safeguards.

- **The AER's guidelines on flexible export limits (FEL)** — The Australian Energy Regulator (AER) has published a final guidance note on export limits, which will help guide DNSPs in setting both static and flexible export limits efficiently.[23] CER connected to distribution networks are generally limited to a static export limit, typically 5 kW for single-phase connections.[24] These static limits are set to a level that keeps shared generation from each CER connected within the network hosting capacity, particularly during high congestion. Given the forecast uptake of small-scale/distributed solar and batteries, distribution network service providers (DNSPs) need to manage the increase in generation within the network limits. FELs can allow consumers to export more from their resources at times and locations where there is "spare" unallocated capacity rather than be restricted to (potentially lower) static limits. FELs would play an important role in how FRMPs, particularly retailers (market customers), would participate in dispatch mode. See appendix A.4 for further commentary on this.

The AEMC has commenced additional workstreams that will interact with this rule change, including:

- **The pricing review: Electricity pricing for a consumer driven future** — The AEMC started a broad, forward-looking review to examine the future of electricity products and services, and the prices consumers pay for these. The review will consider how energy markets and regulatory frameworks can provide the products and services that match consumer preferences now and into the future.[25] This forms a core component of the overall CER workplan. In particular, this review is focusing on market arrangements, the role of distribution networks, and the role of retailers and energy service providers.[26]
- **Real time data for consumers rule change** — The AEMC is considering how to improve consumers' and their authorised representative's access to real-time data from their smart meters. Improved access to smart meter data could allow customers to have more control over their bills with improved insights on energy use. Further, this saves consumers duplicating costs by installing separate devices to provide real-time data. This data could also improve product and service offerings from retailers.[27]
- **Review of the wholesale demand response mechanism (WDRM)** — The AEMC is conducting a review of the costs, benefits, and effectiveness of the WDRM.[28] The review will consider the range of mechanisms available to demand response in the NEM. Including dispatch mode established in this final determination as well as the final determination for *Unlocking CER benefits through flexible trading*.

23 AER, Final Export Limits Guidance Note, 23 October 2024.

24 AER, Response to flexible export limits consultation, 31 July 2023, p. 2.

25 AEMC The pricing review: Electricity pricing for a consumer-driven future, terms of reference.

26 AEMC, The pricing review: Electricity pricing for a consumer-driven future, Consultation Paper, 07 November 2024, p. 12.

27 AEMC, Real time data for consumer, Consultation paper, 10 October 2024.

28 AEMC, Review of the Wholesale Demand Response Mechanism project page.

2 Unscheduled price-responsive resources present a problem and opportunity in the NEM

There are a wide range of energy resources (for example, batteries) that enable consumers, or parties acting on their behalf, to respond to wholesale market price signals. The increasing number and magnitude of these unscheduled resources is a significant opportunity for consumers, retailers and the broader electricity system. However, this responsiveness is not currently integrated into the wholesale market or generally visible to the market or AEMO.

This chapter sets out:

- the types of unscheduled price-responsive resources and the expected growth of them in the future (section 2.1)
- how they create potential inefficiency in the energy market, but also an opportunity if harnessed appropriately (section 2.2).

2.1 Technology is enabling the demand-side to be more responsive to wholesale spot prices

We use the term unscheduled price-responsive resources to refer to:

- the wide range of residential, community, commercial and industrial energy resources and load that are not currently scheduled through the market dispatch process
- do or could respond (individually or as part of aggregation) to market price signals.

It includes:

- Household CER such as batteries, electric vehicles (EVs), flexible hot water systems and pool pumps. These resources allow consumers to generate their own energy, store it and/or adjust when they consume from the grid. Increasingly, they are also coordinated or orchestrated by retailers and aggregators.
- Smart devices that control traditional assets such as hot water systems and air conditioners, and controlling or programming their entire household use through home energy management systems.
- Industrial loads with components of controllable demand (for example smelters, foundries and manufacturing facilities) that may alter their production to change their electricity consumption. Some of these resources may be part of other schemes like the reliability and emergency reserve trader (RERT).
- Small non-scheduled generating and storage units. These include backup generators, units that can generate electricity from production byproducts and bidirectional units, such as community batteries that are below 5 MW. There are 171 small generator sites and over 1,845 standalone and non-registered exempt generation in the NEM.[29]

For this final rule we focus on the party for each market connection point in the NEM that is exposed to the spot price. This party is known as the FRMP. In most cases, this is a retailer, but it can also be the owner/operator of the resources, such as a Small Resource Aggregator (SRA) or ancillary service providers.

29 AEMO, NEM registration and exemption list (accessed 14 November 2024). Small generator sites refers to those that are exempt as they do not fulfil the requirement for automatic exemption but AEMO has granted exemption. AEMO provided that this results in 1845 NMI sites, including small generating units (and, post-IESS, small bidirectional units) that are exempt from the requirement to register with AEMO (automatic or by application).

2.1.1 There are varying levels of price-responsiveness

In addition to there being a range of resources responding to price signals, there are also a wide range of business models governing the relationship between the FRMP and the consumer. These business models have a material impact on how and when the resources are used. These allow consumers to decide between how responsive they want to be and how much control they have over it. For example:

- **VPPs** where a number of customers are aggregated to provide services. Providers contract customers on differing basis, such as fixed payments at different periods or payment per kWh that is provided.[30] This usually entails some agreement to use the resources during certain periods or to assist customers in managing and lowering their bills. FRMPs acting on consumers' behalf, could adjust how these devices produce or consume electricity in response to wholesale market prices. This could be part of an aggregation to provide a range of services such as contingency FCAS. With these types of arrangements, the FRMP can be highly certain of its response and can do so quickly. However, mostly this is limited to a certain number of times in a year. This results in difficulty in being able to forecast different VPP responses across price events.
- **Tariffs** such as controlled loads that provide reduced charges for certain devices that can operate at lower cost times, for example pool pumps. With these types of arrangements, the FRMP has high certainty but low control. The consumer demand still needs to be provided within certain parameters.
- **Spot price pass-through** where the customer is exposed to some degree to the wholesale spot price. With these scenarios the FRMP may not have certainty that their customers will respond to price changes. In addition, it may have limited impact on their business if the customer does respond. This is because the customer ultimately pays based on the spot price and the FRMP has more limited risks than other contract arrangements.
- **Behavioural nudges** where the FRMP provides messages or other incentives to adjust demand (demand-response). This could be due to significant price spikes and the FRMP offers customers an incentive (such as sporting tickets) to reduce demand. The FRMP in these scenarios may have limited certainty on the level of response that the incentive will elicit.

Through submissions and our TWG we heard that this variety can impact the level of certainty a FRMP has on the response that would be elicited. While some FRMPs control the devices and can predict the response completely, this is not always the case. TWG members noted that there is a time dimension to this as well.[31] Commercial and Industrial (C&I) customers may require that the response is for a certain period of time. For example a minimum reduction of two hours. This requires the FRMP to accurately predict future prices and commit in advance with the customers.

There is not a one size fits all response

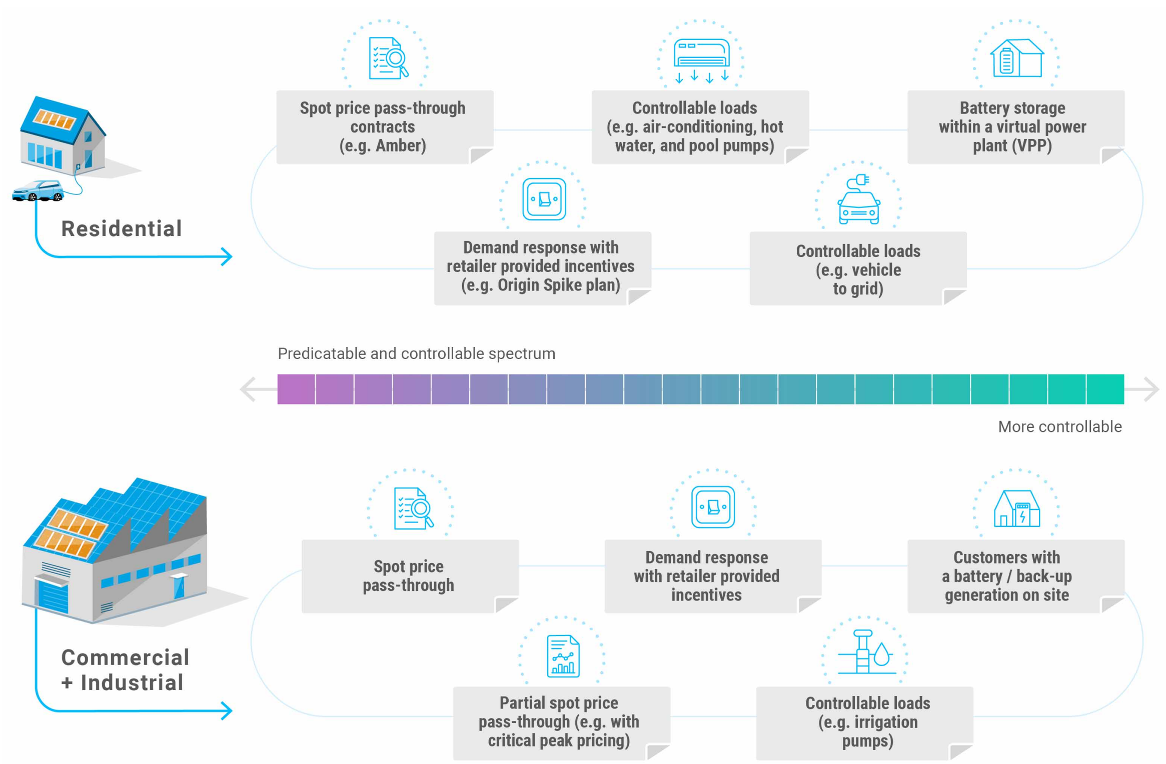
The rule provides different solutions based on the certainty and controllability spectrum of unscheduled price-responsive resources. Those that are more predictable and controllable are more likely to be able to participate in dispatch. Most unscheduled price-responsive resources would not currently be suitable for dispatch due to not exhibiting the level of predictability and control needed.

30 Grids, 2023 DER in Energy Markets, free report.

31 AEMC, TWG meeting #2, 28 February 2024.

This is not to say that a FRMP could not participate in dispatch with any type of load or price-responsive resources. It is recognition of the variety of resources that exist. Figure 2.1 provides an example of the spectrum of unscheduled price-responsive resources that exist.

Figure 2.1: There is a spectrum of unscheduled price-responsive resources



Source: AEMC

For our monitoring and reporting solution (outlined in appendix C), we are focused on understanding the impact of resources that likely can not or will not participate in dispatch. This recognises that FRMPs are only likely to participate in dispatch with resources that meet a range of criteria. The concept of the dispatchability of an energy resource can be considered as the extent to which its output can be relied on to 'follow a target'.[32] For example:

- The controllability of a resource relates to the resource's ability to reach a set point (output target) requested by an AEMO dispatch process. This could be zero megawatts, the maximum available capacity of the unit, or something in between.
- System operators need to have some level of confidence that resources are available. The firmness of a resource relates to the resource's ability to confirm its energy availability.
- The ability of the system to respond to expected and unexpected changes in the supply-demand position. For example, changes in variable renewable energy generation output, generation failures, and variations in demand, over all necessary timeframes.

32 AEMO, Power System Requirements, 2020, pp. 6-7.

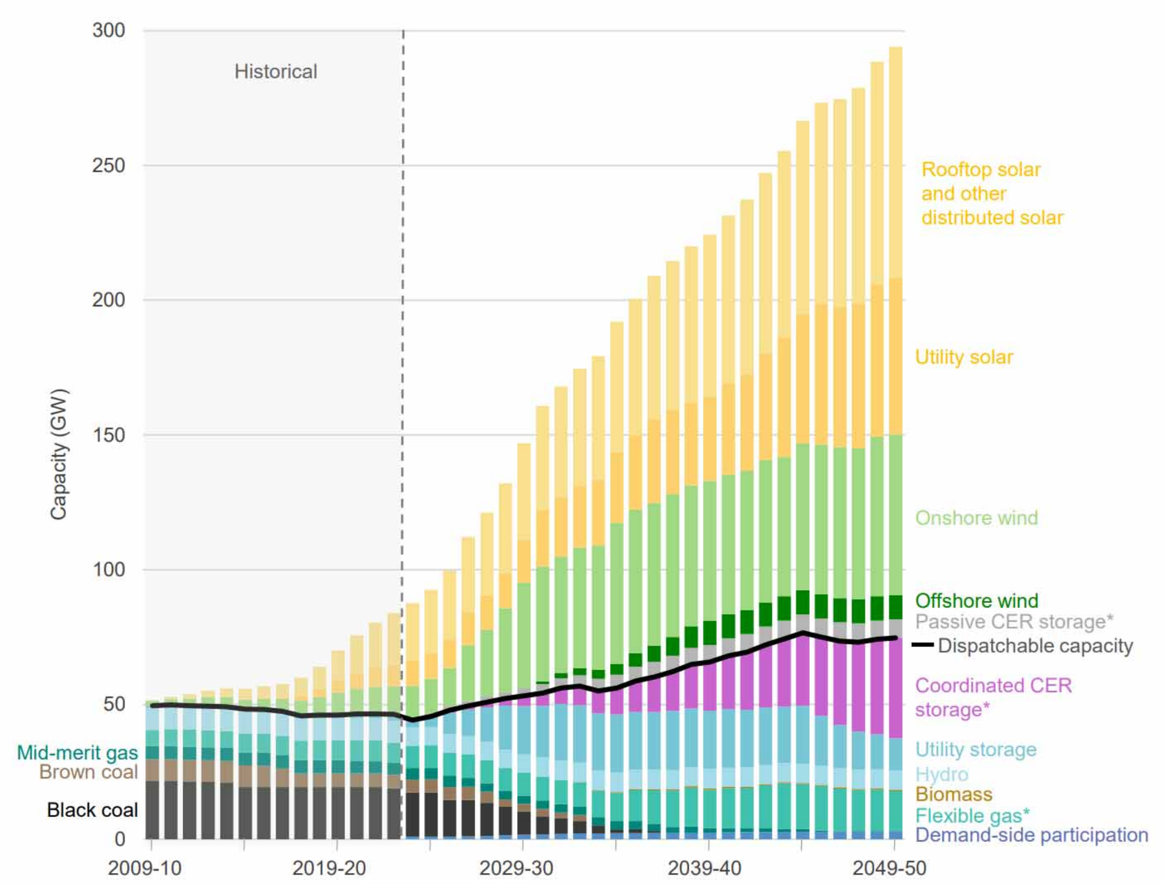
2.1.2 These resources are expected to grow substantially

It is difficult to estimate how many unscheduled price-responsive resources currently exist in the NEM or the extent to which they are price-responsive. AEMO reported that 5,032 MW of firm response existed in 2024, however, this includes a huge range of resources and contracts.[33] Some of it will be coordinated and some of it will not.

What is very clear is that these resources represent a growing amount and proportion of price-responsive resources in the NEM. For example, AEMO's Integrated System Plan (ISP) modelling forecasts that by 2050, VPPs, Vehicle to grid (V2G) and other emerging technologies (referred to as Coordinated DER Storage) will need to provide 37GW of dispatchable storage capacity under an optimal development path.[34]

Figure 2.2 highlights the growth in these resources (purple 'coordinated CER storage' bar) between now and 2050.

Figure 2.2: The ISP indicates a growing amount of coordinated CER storage



Source: AEMO's 2024 ISP

AEMO expects that these resources will be needed in order to operate the grid with large amounts of variable renewable energy.

33 From data gathered through the Demand-Side Participation Information Portal (DSPIP) and released through the Electricity Statement of Opportunities, 2024, p. 172.

34 AEMO, Integrated System Plan, 2024, p. 67.
Note that the benefits modelling and assumed participation rates throughout this report were used with the 2022 ISP as the input.

There may be some debate about the exact amount in the future, but we consider there is no doubt that the volume of coordinated unscheduled price-responsive resources is going to grow substantially.

2.2 Price-responsive resources present a problem for the operation of the wholesale market

As the volume of unscheduled price-responsive resources increases, the impact that it has on total system costs will grow. This section sets out:

- how FRMPs currently use and benefit from unscheduled price-responsive resources (section 2.2.1)
- how existing regulation and processes do not properly integrate unscheduled price-responsive resources (section 2.2.2)
- the problems that the lack of integration causes (section 2.2.3)
- IES's estimates of the magnitude of the problem (section 2.2.4).

2.2.1 How FRMPs currently use and benefit from unscheduled price-responsive resources

FRMPs purchase electricity on their customers' behalf in the spot market regardless of whether they are scheduled or unscheduled. Given this exposure to wholesale market prices, FRMPs can use unscheduled price-responsive resources to reduce the costs they incur without being scheduled in the wholesale market.

FRMPs are increasingly engaging customers in arrangements to use these resources. This provides them with the ability to manage their overall load profile, provide ancillary services and as a substitute to large scale generation investments or greater hedging requirements.[35]

2.2.2 How existing regulation and processes do not properly integrate unscheduled price-responsive resources

These unscheduled price-responsive resources are not effectively integrated into the NEM. They are not appropriately considered when determining how much electricity demand needs to be met, how to meet this demand and the price at which electricity is purchased.

The NEM is not set up to consider or integrate unscheduled price-responsive resources on two fronts: it does not incorporate price into demand forecasting and small distributed resources cannot participate easily.

Price is not an input into demand forecasting

AEMO is responsible for determining the level of expected demand in the NEM. It does this using models in the Demand Forecasting System to best predict how demand will change under certain conditions (for example the day and time). However, it does not consider how much demand will change as the price changes.[36] This is partly due to customers not responding to spot prices in the past. Most customers were on flat pricing and therefore faced limited incentive to move their consumption to different periods. Furthermore, on the small consumer side, many of the resources which are capable of responding to prices now and in the future were not available. As such, price has not featured as a sensitivity in demand forecasting in the NEM to date.[37]

35 See for example AGL, FY 24 half-yearly results, slide 19.

36 AEMO, power system operating procedures, accessed 26 June 2024.

37 AEMC, TWG meeting #2, 28 February 2024.

An added complexity is the impact of including price changes into demand forecasting. If AEMO makes assumptions about the level of response to a given high (or negative) price, it would signal to the market the adjusted price. This adjusted price includes a response to avoid the high or low price that the market was unaware of. However, the response may not actually materialise at this adjusted price, resulting in the less efficient market outcome.

With this forecast demand amount (without price sensitivity) AEMO orders the offers from scheduled participants, from least to most expensive, and determines which resources will be dispatched. AEMO dispatches generators needed to meet expected customer demand at the lowest cost.

Small distributed resources cannot participate in central dispatch easily

Since the start of the NEM, with some exceptions, the NER has required generators greater than 30 MW to be either scheduled or semi-scheduled.[38] In 2021, the Commission decided that batteries above 5 MW would be required to be scheduled for their load and generation.[39]

Many of the requirements of being dispatched exclude or result in significant costs for smaller resources. For example:

- The minimum bidding amount is 1 MW. For resources that are smaller than 1 MW, this rules out their participation. For resources that are greater than 1MW but still not significant, it limits how much they can participate during different periods depending on the current status and capability.[40]
- Onerous requirements to communicate with AEMO. Current arrangements best suit participants that have telemetry connections through network service providers (NSP) using the Inter-control Centre Communications Protocol (ICCP). Smaller, non-NSP connected providers face a number of barriers to connecting and, ultimately accessing markets such as regulation FCAS.
- Larger scheduled generators are designed for constant participation in central dispatch. If they experience an issue they can disconnect from the grid to resolve it. Their primary, and potentially sole, purpose is to sell energy. Small aggregated resources (such as VPPs) are usually participating as a secondary function (for example, their primary function is usually providing energy to the household which needs to remain connected). There is not the same ability to disconnect from the grid if there are technical issues because they need to continue being supplied energy from the grid.

Due to size of the individual resources and the temporal nature of when they are price-responsive, the current mechanisms may not suit these resources to formally engage with the wholesale market. This means that while resources controlled by the same market participant could, in aggregate, be over the generator threshold, they cannot participate on the same level or do not have to meet the same requirements. There is no requirement for them to participate in the wholesale market. They are also unable to compete with large-scale generators and storage, even though they may have the capabilities.

38 See clause 2.2.2 of the NER.

39 AEMC, Integrating Energy Storage Systems into the NEM, 2 December 2021, p. 20.

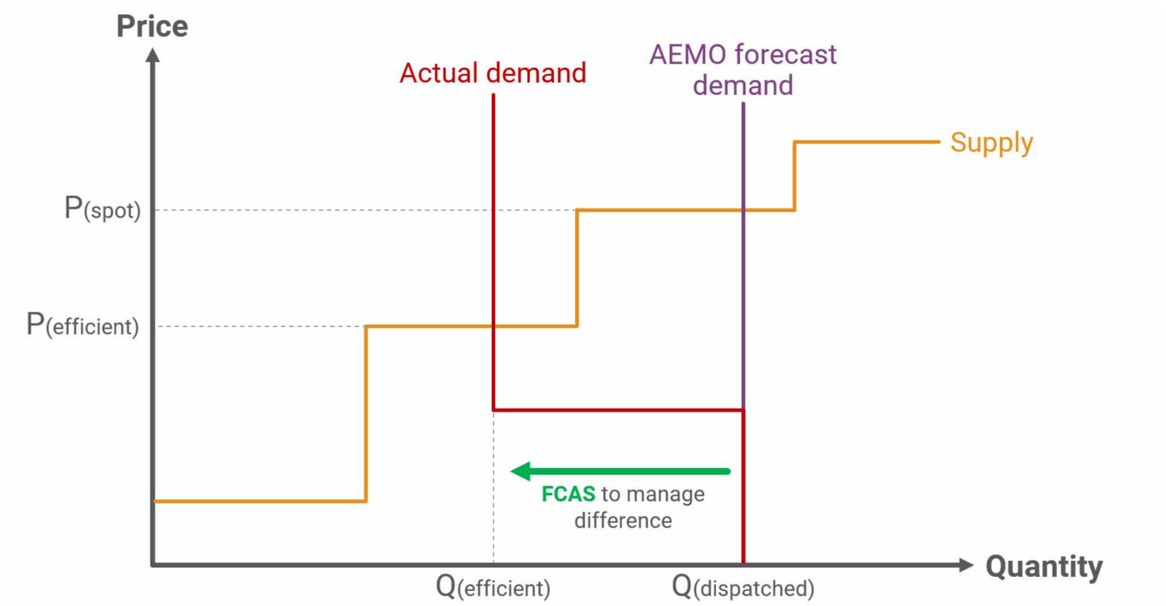
40 Grids, submission to the consultation paper, p. 5.

2.2.3 The problems that the lack of integration causes

As unscheduled price-responsive resources increase, if current processes are maintained, we expect to see increasingly inefficient market outcomes. This will primarily be driven by the inability to accurately determine the level of demand that needs to be met.

Figure 2.3 provides a stylised example of the outcomes in dispatch costs, prices and FCAS use, when price-responsive resources are not included in the market demand forecast. As AEMO does not know the intentions of these resources, it forecasts demand to determine $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of $P_{(spot)}$. However, where there are unscheduled price-responsive resources that will reduce their consumption or increase generation at this price point, actual demand will be $Q_{(efficient)}$ and the efficient price would have been $P_{(efficient)}$. To balance supply with the actual demand level, frequency control ancillary services (FCAS) are required.

Figure 2.3: Inaccurate demand forecasts cause higher spot prices, generation and FCAS costs



Source: AEMC

The outcomes as a result of the above scenario are:

1. the energy spot price is higher than the efficient level and therefore consumers pay more than is necessary
2. unnecessary generation costs were incurred to meet the over forecast of demand
3. costs are incurred to bring supply and demand back into balance through FCAS
4. because there is a close correlation between high marginal cost generators and high emissions generators, it is likely that emissions are higher than necessary
5. if demand and supply conditions are particularly tight, the demand forecast error may lead to the triggering of RERT and its associated costs.

When these operational inefficiencies are repeated they drive inefficiencies in investment timeframes. These include:

- higher energy prices cause inefficient investment in generation, storage and demand response
- greater demand forecast errors increase FCAS requirements and prices.

Box 1 provides a simplified example of the impact of not integrating these resources.

Box 1: Example of the impact of unscheduled price-responsive resources

Take, for example, a retailer (or FRMP) with a number of price-responsive customers. The customers and FRMP have an agreement to reduce consumption or increase exports at certain prices. This could primarily be to minimise customers bills.

During a high price time, responsiveness from its customers benefits the FRMP. This occurs as the FRMP's overall quantity of electricity that they must pay for is lower during the high price time. The FRMP's customers also benefit as they would have paid more for electricity during this period had they not responded. Additionally (or alternatively depending on the arrangement), they may receive payments from the FRMP for producing or exporting during this time.

Currently, only the FRMP and its customers benefit.

The level of response was not known to the market operator or other participants. The market was operated assuming that there was not going to be changes in demand based on prices. The level of response that the FRMP (and its customers) made, could have had an impact on the price during that period.

If the lower level of demand was accounted for, the overall demand that needed to be met would have been lower. As a result less generation, and potentially less expensive generation, could have been used. This could reduce total system costs and lower the price of energy during that time.

If this could be achieved, then in the long term system costs would be lower for everyone. As these resources grow, the number of times and size of the impact is expected to grow. Importantly, FRMPs or customers do not need to change their behaviour or intentions to achieve this; AEMO just needs to be informed of their intentions and therefore be able to operate the system more efficiently.

Source: AEMC

In submissions, stakeholders agreed with integrating these resources. Shine Hub noted that it provides an opportunity for these resources to contribute to reducing the risks associated with high prices.[41] Mondo said that we should avoid a system where these resources operate in opposition to the market.[42] Other submissions went further and noted that not integrating the resources negatively impacts the operation of other players. Sonnen highlighted that pre-dispatch accuracy has a disproportionately material impact on smaller players as they are less likely to use alternative forecasting, reducing their ability to efficiently use CER flexibly for its customers.[43]

2.2.4 IES's estimates of the magnitude of the problem

We engaged IES to answer the question "what is the size of the potential benefit (or 'size of the prize') of better integrating unscheduled price-responsive resources into the NEM from 2025 to 2050?".[44] The IES modelling simulated the anticipated benefits over time from integrating forecast increases in price-responsive resources into market processes.

IES modelled three different potential worlds between 2025 and 2050.

- **Base case** – this is the no reform world, where no rule change is made. AEMO's forecasting systems attempt to identify potential price-responsive resources in its demand forecast without specific reliable information in operational timeframes. Substantial increases in these

41 Shine Hub, submission to the draft determination, p. 1.

42 Mondo, submission to the consultation paper, p. 3.

43 Sonnen, submission to the consultation paper, p. 3.

44 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report, 24 June 2024.

resources over time lead to material demand forecasting errors and consequential inefficiencies.

- **Visibility** – this is a generic visibility reform. It has the following core features, but is not related to a specific visibility proposal. Price-responsive resources remain unscheduled and are not dispatched by AEMO. However, participants submit information in operational timeframes to AEMO which reduces demand forecasting errors. The lower barriers to entry incentivise higher participation than the dispatch world. However, this is offset by lower forecast accuracy than in the dispatch world.
- **Dispatch** – this is a generic dispatch reform. It has the following key features. Resources are integrated into central dispatch and scheduling processes. Modelling assumed higher barriers to entry than visibility, resulting in lower participation. However, participation in central dispatch means higher forecast accuracy and higher participation in frequency control markets because of dispatchability.

By comparing these scenarios we can understand the benefit that integrating these resources can have to the energy system, and the change in emissions.

Box 2: IES approach to modelling benefits

IES market modelling quantified the benefits of integrating unscheduled price-responsive resources into the NEM dispatch process. The modelling was conducted in PLEXOS to simulate a Base case and two representative reform options, visibility and dispatch. The modelling focused on the impacts for VPPs and Demand Side Participation (DSP):

- VPP: represents the ISP values for aggregated embedded storage and V2G. These resources were modelled with perfect foresight and operate to meet system conditions, consistent with the ISP.
- DSP: is the same as the ISP and represents a wide range of resources and consumer behaviour to reduce demand during infrequent high price events.

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 infrequently and only during high price events. Across all scenarios the actual VPP and DSP and operations, and therefore actual scheduled demand, remained the same.

Our base case modelled a scenario where price-responsive resources remain unscheduled and AEMO is required to forecast their operation. For instance, lower levels of forecast VPP contribution to evening peak result in additional scheduled generation. This results in imbalances between the dispatched generation and demand.

The two reform cases modelled different rates of VPP participation in dispatch, resulting in lower forecasting errors. Using the example above the VPP contribution to the evening peak is included in the dispatch calculation and the correct amount of generation is dispatched.

Source: AEMC

The IES market modelling demonstrates that if these resources could be perfectly integrated, it is likely to result in significant benefits.[45] IES estimates cost savings of between $1.4 and $1.8b net present value (NPV, 2023) to 2050. These efficiency gains are made up of:

- lower FCAS requirements (between $831m and $1,053m NPV)
- lower use of scheduled generation;
  - resulting in lower emissions (between $325m and $423m NPV)
  - lower generation costs (between $189m and $234m NPV)
- lower requirements for emergency reliability measures ($122m NPV).

In addition, reform is expected to lower spot prices (between $12b and $13b NPV) and FCAS prices (between $678m and $814m NPV). IES's modelling held market entry constant between the scenarios. Given the magnitude of higher revenues they would likely result in additional market entry and that this entry would come with a material cost. We therefore note that the above efficiency gains are likely understated.

Additional generation could be required if we do not integrate these resources into processes

In its rule change request AEMO identified an alternative approach to understand what the system would require if we do not integrate unscheduled price-responsive resources – that is requiring additional investment in large scale firming capacity.[46] AEMO stated that needing to duplicate the projected coordinated price-responsive resources through investment in additional shallow grid-scale storage would cost between $1.8b and $4.4b.

The 2024 ISP sensitivity analysis of not having coordinated CER also indicates that $4.1b of assets would need to be duplicated.[47]

45 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report, 24 June 2024, p. 17.

46 AEMO, Rule change request – Scheduled Lite mechanism in the National Electricity Market, pp. 38 and 62.

47 AEMO, 2024 Integrated System Plan - A roadmap for the energy transition, 26 June 2024, p. 17.

3 The final rule integrates unscheduled price-responsive resources into the NEM

The Commission's final rule integrates unscheduled price-responsive resources into the NEM through allowing resources to participate through dispatch, creating additional incentives to participate in dispatch and creating a monitoring and reporting framework.

This chapter explains our final rule and the reasons for it. It is structured as follows:

- options to integrate unscheduled price-responsive resources (section 3.1)
- why and how the rule:
  - allows participants to nominate qualifying resources as a Voluntarily Scheduled Resources (VSR) to participate in central dispatch processes, referred to in this determination as 'dispatch mode' (section 3.2)
  - provides incentives to participants (section 3.3)
  - creates a monitoring and reporting framework to assess the impact of resources that remain unscheduled (section 3.4)
- the implementation timing of the final rule (section 3.5).

Appendix A, appendix B, and appendix C have details on how the rules for each of these areas will operate, and a summary of the rule is in appendix E.

3.1 There were two options to integrate unscheduled price-responsive resources

Chapter 2 highlighted that:

- there are growing amounts of unscheduled price-responsive resources in the NEM
- if current NEM systems and processes are not updated, these will have a significant impact on total system costs.

When considering how to address the impact of growing amounts of unscheduled price-responsive resources, two options were available: improving supply information or improving demand forecasting.

1. Improve supply information by scheduling the price-responsive resources that are capable of being dispatched.
   a. Pro: information from scheduled resources provides AEMO with the current position on energy demand in the NEM. It directly improves demand forecasting. By explicitly including unscheduled price-responsive resources in dispatch, AEMO will no longer need to forecast their actions in the spot market and therefore inefficiencies will be reduced.
   b. Cons: Many unscheduled price-responsive resources are not capable of being dispatched. For those that are capable, there are material costs to being scheduled. Furthermore, because the majority of benefits from resources being scheduled accrue to the market as a whole, not the participant, there is a challenge incentivising scheduling.
2. Improve forecasting of unscheduled price-responsive resources. This could be achieved in a few ways:
   a. AEMO explicitly incorporates price elasticity in its operational demand forecasts
      i. Pros: this is likely a lower-cost system upgrade solution.

   ii. Cons: it is likely very challenging to accurately predict responses at different price levels. To do so would require AEMO to be able to predict the response of the wide range of business models and resources highlighted in chapter 2 across the entire NEM.

b. Participants become responsible for providing information about the price-responsiveness of their customers to AEMO (for example the visibility market model that we developed and investigated)
   i. Pros: information is likely to be more accurate as it is being provided by the FRMP that has control and information over its contracts and positions.
   ii. Cons: it requires changes to how demand forecasting is currently done by AEMO and requires FRMPs to provide information to AEMO. This could be costly for both.

Our final rule includes option 1 and a monitoring and reporting framework intended to help AEMO develop option 2(a), given the range of unscheduled price-responsive resources that exist.

3.2 We are enabling predictable and controllable price-responsive resources to be integrated into dispatch

Our final rule creates a voluntary framework, known as 'dispatch mode', for currently unscheduled price-responsive resources (for example VPPs) to participate in dispatch as scheduled resources.[48] This framework allows aggregated, or large standalone, price-responsive resources to compete with large-scale generators and storage in the NEM. It allows these resources to be bid into the market, set spot prices, receive and follow dispatch instructions and access markets that require scheduling (for example, regulation frequency control ancillary services (FCAS)).

By explicitly including currently unscheduled price-responsive resources in dispatch, AEMO will no longer need to forecast their actions in the spot market and therefore the inefficiencies caused by errors in these forecasts will be removed.

This section outlines:

- key features of dispatch mode
- stakeholders supported introducing dispatch mode
- changes made since the draft rule to assist participation.

3.2.1 Dispatch mode offers a voluntary and flexible pathway to participate in central dispatch

Our final rule to introduce dispatch mode is largely consistent with the draft rule and has the following key features and benefits:

- It is a purely voluntary mechanism. The rule introduces the concept of VSRs. It allows the FRMP at the market connection point to nominate a qualifying resource, either individually or aggregated, as a VSR and participate in central dispatch. With the mechanism only applying to FRMPs, even when they choose to participate, there is no requirement on consumers to change their behaviour or cede control over their assets.
- A number of small resources can be aggregated such that they are treated as one VSR for the purposes of central dispatch. This means that the VSR will be provided with, and assessed against, aggregated dispatch instructions. No individual resource within that VSR is required to

48 We use 'dispatch mode' to refer to the package of final rule amendments to incorporate voluntarily scheduled resources in dispatch-related provisions, namely amendments to chapters 3, 4, 4A and 10 (other than the provisions relating to VSR incentives and monitoring and reporting, discussed below).

follow dispatch instructions. Instead, the VSR must meet the dispatch instructions in aggregate.

- The underlying connection point classification for VSRs will not change. For instance, if a retailer (Market Customer) aggregates several of its market connection points as VSR, these will still be market connection points but will also be part of the VSR. By not creating a new classification for VSRs, or requiring a change in the classification of connection points participating, participants will have greater flexibility and implementation costs will be reduced.
- It uses the bidirectional unit (BDU) framework introduced in the Integrating Energy Storage Systems (IESS) rule change as the basis for the VSR requirements in the rules. Using the BDU design allows bids for both generation and load, providing flexibility for how VSRs can operate in central dispatch.
- It follows existing conventions regarding decision-making. Most importantly:
  - The NER sets out the key legal requirements for participation in central dispatch, such as bidding, dispatch and conformance. This will create certainty for market participants as the NER provides stability and familiarity through the application of existing regulations.
  - AEMO guidelines will establish the specific operational and technical details for participants to follow. This will allow AEMO to update these details more regularly than if they were placed in the rules and allow them to be tailored to the requirements of participants utilising aggregated small resources.
- It sets out principles to guide AEMO in determining the operational and technical details of participation within its guidelines. Most importantly, it guides AEMO to facilitate the ease of participation in central dispatch by VSRs and apply restrictions on VSRs only to the extent reasonably necessary to manage power system security and reliability. This explicitly recognises that VSRs are not the same as large scheduled generators and BDUs, and therefore should not face the same requirements. We consider that this is important to reflect that:
  - Participation in dispatch mode is voluntary. Strict requirements will simply result in low participation and therefore low benefits for consumers.
  - Market participants are still learning and developing their capabilities to control aggregated CER and should be given time to develop these capabilities.
  - Participation is likely to build up over time. In the early years, the small size of each VSR participating means they are unlikely to have a material impact on power system security and therefore leniency comes at a low risk.
- It creates flexibility for participants (referred to as Voluntarily Scheduled Resource Providers, or VSRPs) through:
  - The creation of new mechanisms that allow them to drop in and out of dispatch smoothly. For example, it creates a hibernation mechanism where a participant could choose to participate in dispatch in summer, and drop out for winter.
  - The ability to participate (and aggregate) at either connection points or secondary settlement points. Secondary settlement points were created in the Commission's *Unlocking CER benefits through flexible trading* rule change and will sit behind a connection point, allowing the splitting of resources at a customer's premises. This means that participants can separate out flexible and inflexible resources behind a connection point and only include the flexible resources (or any combination they choose) in their VSR.

- Establishing principles aimed at ensuring the ease of participation by VSRs and the requirements on VSRs are only to the extent reasonably necessary for AEMO to manage the power system.

3.2.2 Stakeholders broadly supported the introduction of dispatch mode

Stakeholders broadly supported our proposal for a dispatch mode in the draft determination, highlighting that it will:[49]

- Allow a greater mix of resources to participate in dispatch and that this should deliver market benefits through displacing higher cost generation, lower emissions, improving reliability and reducing the levels of FCAS required.
- Create an effective mechanism for owners and operators of any price-responsive resources that are firm and of a large enough scale to generate revenue in wholesale and FCAS markets. Allowing owners to be better placed to realise the full value of their assets and increase competition in these markets for the benefit of all consumers.
- The voluntary nature of the mechanism provides flexibility to market participants, allowing them to determine the suitability of engaging in dispatch mode based on their specific operational capabilities and business models. Voluntary participation also avoids unnecessary complexity or compliance burdens for participants not equipped to participate. Maintaining a voluntary approach is crucial to fostering innovation and ensuring that the benefits of dispatch mode are realised without creating barriers to entry. See section 3.3.3.

This was consistent with feedback received on the consultation paper.[50]

Origin, Ergon and Energex, and Erne Energy considered that dispatch mode was unnecessary, noting that:[51]

- It is inefficient to spend a significant amount of time and effort to develop a solution that will only be used by a small subset of the market.
- The proposed mechanism will not solve the issues identified by the AEMC, due to limited customer participation in the mechanism.
- Mechanisms already exist for CER to participate in the wholesale market. Data indicates that it might be better to focus on identifying the causes of significant inaccuracies in its forecasting, such as Large Industrial Load (LIL) and the “residual”.

This mirrored some feedback previously received to our consultation paper.[52]

Consistent with the draft determination the Commission considers that a framework is needed to allow aggregated predictable and controllable price-responsive resources to participate in the NEM. Our national electricity objective (NEO) assessment that this is in the long term interests of consumers is set out in section 4.2. In response to the arguments set out against the introduction of dispatch mode the Commission:

- Recognises that not all resources will be able to or want to participate in dispatch mode. In particular, participating in dispatch is likely to only be suitable for FRMPs with forecastable and controllable resources. We do not consider that this framework should or would be able

49 Submissions to the draft determination; AEC, p. 1. CS Energy, pp. 2-3. Ausgrid, p. 1. EnergyAustralia, p. 1. Hydro Tasmania, p. 1. Red Energy, p. 1. CEC, p. 2. AGL, pp. 1-2. Shell Energy, pp. 1-2. SAPN, p. 1. SA Water, p. 1. EUAA, p. 1.

50 Submissions to the consultation paper; EnergyAustralia, p. 3. Tesla, p. 2. Reposit, p. 1.

51 Submissions to the draft determination, Origin, p. 3. Ergon and Energex, pp. 1-2. Erne Energy, p. 1.

52 Submissions to the consultation paper, Origin, p. 4. SwitchDin, p. 1.

to accommodate all types of currently unscheduled price-responsive resources. However, this should not prevent the introduction of dispatch mode because:

- the credible forecasts of the increase in price responsive resources in the future means a subset of these resources participating in dispatch mode still results in material efficiency gains
- the design of dispatch mode means costs are minimised and are substantially less than the benefits.

- Agrees that incentives are important to drive participation and market design should reward participants for the benefits that they provide the system. Section 3.3 provides further information on our analysis of the incentives to participate.
- Notes that our rule establishes a monitoring and reporting framework (see section 3.4 for further details) for resources that will not participate in dispatch. These frameworks will work in tandem to address the problems identified with unscheduled price responsive resources.
- Does not agree that there are existing mechanisms that allow CER to participate in the wholesale market. While AEMO's current demand forecasts may not have a significant issue with CER, as these resources become price-responsive AEMO will face further challenges forecasting demand in the NEM.

Stakeholders did not suggest any other viable approaches

In response the consultation paper Enel X and the AEC questioned if amendments to other current categories, such as the WDRM or SRA, could be used to integrate unscheduled price-responsive resources.[53]

Consistent with our response in the draft determination, the Commission does not consider this is feasible.[54] At a high level this was because:

- WDRM is a bespoke mechanism for demand response coordinated by a party that is not the FRMP at the connection point to be included in central dispatch. It is designed to overcome issues of access and exposure to spot prices for parties that are not retailers.
- Rather than create or change existing participant categories, dispatch mode allows existing registered participants to nominate their connection points as part of a VSR to allow them to be included in dispatch. The types of registered participants who could do this includes small resource aggregators (SRAs), market customers (retailers), generators and (more broadly) Integrated Resource Providers (IRPs).

In response to the draft determination Ergon and Energex considered an alternative approach that should be considered is how dynamic operating envelopes (DOEs) could further benefit customers through:[55]

- increasing customer network access when network is not constrained
- providing greater opportunities for customers to participate
- avoiding further constraints of the network in times of congestion.

We consider that DOEs will play an important role in ensuring CER can utilise distribution networks efficiently. However, DOEs do not allow participants access to central dispatch. Leaving a gap for resources to be able to set spot prices and earn revenue in markets that require scheduling (for example, regulation FCAS).

53 Submissions to the consultation paper, Enel X, p. 6, AEC, p. 5.

54 See section 3.2.1 of the draft determination for more information.

55 Ergon and Energex, submission to the draft determination, pp. 1-2.

3.2.3 We have made minor changes to assist participation in dispatch mode

Some stakeholders noted that the requirements of participating in dispatch mode will limit participation:

- EnergyAustralia outlined that dispatch mode still has high compliance requirements, including civil penalty obligations, which do not apply to VPPs operating behind the meter and off market.[56]
- Origin and AGL considered the requirements of dispatch mode onerous, with AGL noting that it would be difficult for many resources to meet.[57]
- Shine Hub stated that batteries co-located at residential households, such as those in VPPs, will face uncertainty associated with the household devices. Making compliance with dispatch instructions particularly challenging.[58]

We have made a number of changes since the draft rule to reduce the complexity of participating in dispatch mode. The most important of these changes are:

- additional flexibility is being provided to participants to choose to deactivate or hibernate for longer periods
- we have introduced a requirement on DNSPs to consult with VSRPs when designing flexible export limits (FELs).

This is in addition to the features of dispatch mode in the draft rule that have been maintained that are aimed at reducing the complexity of participating, such as:

- the ability to participate at either connection points or secondary settlement points, and as either an individual resource or an aggregated resource
- guidance to AEMO to set the technical parameters of dispatch mode in its guidelines at a level that explicitly balances the costs of participating with power system security benefits from higher standards.

We have also made a number of other minor changes since the draft determination in response to stakeholder feedback and discussions with AEMO; these are explored in detail in appendix A and appendix E. Section 3.3 addresses the financial incentives to participate in dispatch mode.

In previous consultations there were concerns raised that being dispatched would significantly amend or limit what unscheduled price-responsive resources could do. We do not consider this to be the case. Box 3 outlines what participating in dispatch means for a FRMP.

56 EnergyAustralia, submission to the draft determination, pp. 3-4.

57 Submissions to the draft determination; Origin, p. 3. AGL, p. 2.

58 Shine Hub, submission to the draft determination, p. 1.

Box 3: Being dispatched is doing what you said you wanted to do

In general, being dispatched simply means:

- That you told AEMO that you wanted to consume or export a certain amount of energy at certain price points.
- The price point that you submitted was at or lower than the price point to clear the market at the time. Therefore, you are dispatched by AEMO to do what you submitted to do at that price point.

Generally, if a participant does not want to consume or export, they can bid zero amounts of energy. Alternatively if they want to consume or export, regardless of the price, they can bid the cap or floor price. In normal circumstances, they will be dispatched to the level they want.

Importantly, being dispatched can be compatible with any other agreements the FRMP might have. For example, if a FRMP is providing services to networks it could reflect this in its bids. This way AEMO knows the intentions of these resources and can factor these in.

Through the bidding and dispatch process, AEMO does not control or direct how much a participant offers in terms of amounts of energy or prices. Once a participant is dispatched they must do what they said they would do. AEMO can then operate the market, knowing these intentions will be delivered.

Source: AEMC

3.3 We created additional incentives to drive participation

Our final rule introduces a time-limited incentive mechanism to drive VSRP participation in dispatch in its early years. It also provides additional incentives to participate by excluding participants from RERT and directions cost recovery.

This section outlines how and why:

- current direct benefits from participating in dispatch are unlikely to drive material participation (section 3.3.1)
- external market incentives are uncertain (section 3.3.2)
- we do not propose to make participation mandatory (section 3.3.3)
- the final rule provides additional incentives (section 3.3.4)
- in the future, the AEMC will consider how being scheduled could be made more desirable for participants (section 3.3.5).

3.3.1 Current direct benefits from participating in dispatch are unlikely to drive material participation

In our draft determination we noted that there are some direct benefits to participants, such as access to the regulation FCAS market. Amendments to the rules are not required to provide these benefits. Submissions to the draft determination had reservations about the level of participation that these direct benefits would drive.

Provide regulation FCAS

VSRPs will be eligible to participate in regulation FCAS markets. This aligns VSRs with other scheduled resources currently eligible to provide regulation FCAS and opens a new opportunity for VSRPs to participate in the NEM. Through the TWG and bilateral meetings with prospective participants, we heard that the revenue stream from providing regulation FCAS is a material incentive.[59]

However, submissions to the draft determination noted that the regulation FCAS market may only provide small benefit to participants. EnergyAustralia noted that regulation FCAS revenues are declining due to market saturation from the entry of several large batteries and will therefore provide limited incentive to participate even in the short term.[60] CEC also noted that the more VSRs that participate in dispatch, the lower the price for regulation FCAS services is likely to be, further reducing the incentive to participate in dispatch mode.[61]

We recognise that regulation FCAS may not be sufficient to drive large participation in dispatch mode.

Eligible for frequency performance payments

VSRPs will be eligible for frequency performance payments (FPPs). This aligns VSRPs with other scheduled resource providers that, when the FPP rule takes effect, will be subject to FPPs.

Submissions to the draft determination raised concerns that this was unknown and therefore difficult to assess the value that this incentive might represent.[62]

We note that FPPs will be new for the market and it may take some time to understand the significance of these payments for participation.

Co-optimise energy and FCAS

AEMO's NEM Dispatch Engine (NEMDE) will co-optimise VSRP bids for energy and for FCAS in the same way as it does for other scheduled resources. This will maximise the bids of VSRPs in FCAS and the wholesale market by enabling their optimal dispatch.

Stakeholders did not provide comments on this, however, we note that it would most benefit participants who already, or intend to, provide contingency FCAS.

This supports our consideration that current direct benefits are unlikely to drive material participation

Section 2.2.2 set out the benefits of integrating unscheduled price-responsive resources into the market. These benefit areas (for example, reduced FCAS costs) accrue to the market, and not individual participants in dispatch. FRMPs are already exposed to the spot price and individually benefit from reduced consumption during high price periods, whether or not they are scheduled. Additionally, there are well recognised inherent disincentives to being scheduled in the NEM (for example, meeting the communications and data requirements).

Submissions to the draft determination support that the current direct benefits may not be material and that a key element of participation in dispatch mode is getting the incentives to participate right. The Commission agrees and therefore, considered what further incentives need to be provided to participants to ensure they receive a share of the benefits that arises from them participating in dispatch mode.

59 Submissions to the consultation paper, CEC, p. 2, Enel X, p. 5, Evergen, p. 8, Shell, pp. 3-4, sonnen, p. 7, Tesla, p. 11. AEMC, TWG Minutes #4, 12 March 2024.

60 EnergyAustralia, submission to the draft determination, p. 2.

61 CEC, submission to the draft determination, p. 6.

62 Submission to the draft determination, CEC p. 2, EnergyAustralia, p. 2.

3.3.2 External market incentives are uncertain

The draft determination noted that the NER were not a natural fit for an incentive mechanism and that we would be working with ARENA, the Commonwealth and jurisdictional governments regarding alternatives. Many stakeholders supported a third party (such as ARENA) providing the incentives as the preferred approach.[63] One stakeholder, SA Water, had a preference for AEMO to provide the incentives.[64] This was due to AEMO having an understanding of the challenges faced by participants and being better placed to operate a scheme that balances the needs of those participants with the appropriate controls and oversight.[65]

We have made substantial progress regarding securing an external funding mechanism to provide incentives. However, this is still not certain and we therefore consider it appropriate to retain the incentive mechanism in the final rule.

We note that this leaves the potential that funding will be available from multiple sources. We do not consider this is a problem because:

- The incentive mechanism that we are including is a tender process. A participant receiving funding from other sources would lower the price that they offer into the mechanism. This would result in lower tender offers from VSR participants, and
- The funding mechanisms potentially work together, rather than providing multiple payments for the same outcome. CEC noted that an incentive program and the CIS are not necessarily mutually exclusive.[66] The CIS provides a helpful price floor for market participants but incentives under the NER will provide an important bridge in creating that initial uptake while these market revenues are unclear. We understand that the Department of Climate Change, Energy, the Environment and Water (DCCEEW) will be giving consideration to the eligibility of VPPs for the CIS.

We note that price-responsive resources, participating as VSRs through dispatch mode, would provide substantial benefits to the energy market and would provide visibility of their resources. This would assist in achieving many benefits, including increasing the potential to integrate lower-cost, lower-emitting resources, reduce overbuilding of networks and helping to transition to a net zero system. This would deliver sizeable benefits to Australian energy consumers.

There are features of participation that are appropriate for, and VSRPs would benefit from, further incentives and support. It is novel for smaller, currently unscheduled price-responsive resources to participate in dispatch. There are a number of technical capabilities that need to be developed. For example, the use of aggregated resources at the distribution level to provide regulation FCAS. Supporting potential VSRPs to understand the capabilities of their resources will further unlock the benefits from integrating these resources.

As there is so much benefit from unscheduled price-responsive resources being integrated into the wholesale market, the Commission supports any external funding for these resources (such as CER) being linked to participation in dispatch.

63 Submissions to the draft determination, AEC, p. 2, Hydro Tasmania, p. 2, Origin, p. 4, Enel X, p. 2, Ausgrid, pp. 1-2, Shell Energy, p. 2, Red Energy, p. 4, EUAA, p. 4.

64 SA Water, submission to the draft determination, p. 1.

65 AEMO, submission to the draft determination, p. 1.

66 CEC, submission to the draft determination, p. 3.

3.3.3 We are not making participation mandatory

Submissions to the draft determination largely supported our decision to keep participation in dispatch mode voluntary.[67]

Our final rule does not make participation in dispatch mode mandatory. The Commission considers that for scenarios where the FRMP is contracting with small customers to orchestrate their devices (such as VPPs), it is not viable or desirable to mandate participation. FRMPs do not own the individual assets and have no right to control them without consumers' consent. Mandatory participation would require FRMPs to have significant control over the resources that underpin their participation in dispatch. This would mean FRMPs would need to have contracts with consumers providing them with control of consumers' CER. To allow this, the rules would need to empower FRMPs to gain such control. The Commission considers that this is highly undesirable and likely infeasible.

A more feasible solution would be to mandate participation of price-responsive large loads or mid-sized generators (1-30 MW) and storage (1-5 MW). We note this would be similar to previous proposals to lower the scheduling threshold. However, this approach would require these mid-sized resources to participate in dispatch as VSRs, rather than changing the existing scheduling categories. The Commission does see some merit in this option. We note that it may need to be looked at closely in the future if the breadth and volume of these unscheduled price-responsive resources start to have significant impacts on the efficiency of the NEM. For example, if we see very large price-responsive loads like electrolysers connect to the NEM and not participate in dispatch mode, or if a large volume of aggregated mid-sized batteries connects and does not participate in dispatch mode.

While mandating these types of resources to participate would have benefits, we note that it would come with challenges. These have been explored in a previous rule change project by the Commission assessing the scheduling threshold, which concluded:[68]

- It is unlikely to substantially increase the resources that are scheduled, as any new threshold can be avoided. There are instances of participants avoiding the existing requirements by ensuring new assets are under the relevant threshold. For example, there are a number of batteries with a capacity of 4.9 MW, and 29 MW generators. Reducing the threshold would likely be challenging and ineffective as participants would seek to avoid the new thresholds with assets below the new thresholds.
- Mandates are a blunt tool that force all participants above the threshold, regardless of cost, to participate.
- It would require consideration of grandfathering for existing assets.

In addition, we would still be faced with needing to incentivise aggregated CER to participate in dispatch. Therefore, we consider it preferable to develop incentives for participation in dispatch rather than mandates.

3.3.4 The final rule provides additional participation incentives

Our final determination is that the direct benefits outlined above are not sufficient to drive participation in dispatch at levels that would benefit the market. Additional incentives will be required, and therefore the final rule introduces two additional incentives.

67 Submission to the draft determination, AEC, Ergon and Energex, Hydro Tasmania, CEC, AEMO, Alinta, SA Water and EUAA.

68 AEMC, Non-scheduled generation and load in central dispatch rule change, 2017.

A time-limited payment mechanism for participating in dispatch mode

The final rule includes a time-limited incentive mechanism to drive participation in dispatch mode in its early years.

The key features of this incentive mechanism are:[69]

- incentive payments will be awarded through at least 2 tenders processes between 1 April 2026 and 31 December 2031
- AEMO will operate the incentive mechanism
- the objective of the incentive mechanism is to increase dispatch mode participation in the long run, at the lowest cost
- a per MW price cap will ensure value for money
- the incentive mechanism will be capped to $50m, but external funding can also be used (in addition to, or instead of, the $50m - at AEMO's discretion)
- operational details will be determined through AEMO procedures
- resources will only be eligible for one incentive agreement
- VSRPs must meet requirements set out in the participation agreements
- payments to successful tender participants will be recovered from Cost Recovery Market Participants, and administrative fees will be recovered from Market Participants, after accounting for any funding from external providers
- AEMO will publish a report annually and at the end of the incentive period.

There was limited feedback on the design of the incentive framework in the draft determination. The following changes were made between the draft and final rule:

- bringing forward the commencement date of the incentive mechanism from January 2027 to April 2026
- increasing the per MW payment cap to be less than the estimated benefits
- minor amendment to clarify the objective of the incentive mechanism
- allowing for external funding to be used with the mechanism
- extending the time for the AER to consider the Contracts and Firmness Guidelines by four months
- clarifying the cost recovery equation.

Appendix B.1 provides a detailed explanation of all of these features and the changes between draft and final rule.

VSRPs are excluded from RERT and directions cost recovery

The Commission's final determination is to amend the rules to exclude a VSRP's adjusted consumed energy from RERT and directions cost recovery calculation.

See appendix B.2 for details.

69 See rule 3.10B of the final rule.

3.3.5 The AEMC will continue to consider how being scheduled could be made more desirable for participants

There are a number of reforms and potential future changes expected in the NEM. The Commission considers that long term participation incentives are also required. These are best provided through market and network access.

The Commission considers a key principle in this work is that scheduled participants should have access to the network commensurate with the benefits they are providing the broader system. Crucially, this needs to result in the opposite outcome to our current regulations at the transmission system where unscheduled generators have preference over scheduled and semi-scheduled generators. In particular, consideration could be given to:

- Greater market access for scheduled resources. It is possible in a future wholesale market design that some form of dispatchability payments or an enduring government scheme is introduced to support formal participation in the market, which would require being scheduled as a condition of payment. Participants in dispatch should have access to markets for the full suite of services they are capable of providing. In the future, this may include access to new system security markets or access to capacity payments. CS Energy noted that there is likely a strong case to adopt frameworks that incentivise the participation of resources in AEMO's scheduling process. These incentives could include providing scheduled resources greater market/network access that commensurate with the broader system benefits that they contribute.[70]
- Greater network access for scheduled resources. Reforms on distribution operating envelopes and flexible export limits are currently being explored. It is possible that being scheduled will have some benefits in these reforms. Shell Energy proposed excluding VSRs from emergency backstop mechanisms.[71] While being unable to consider this as part of the rule change, we do consider that future markets will need to further consider the benefits of participating visibly in the market through dispatch mode.

As the AEMC considers future rule changes, we will give consideration to how any reforms or amendments could be made more preferential to scheduled participants. These participants have demonstrated a technical capability to be coordinated with the rest of the system. If there are rule changes regarding distribution network limits for example, we will consider how preferential access could be provided to the resources in dispatch.

3.4 We are establishing an AER and AEMO monitoring and reporting framework

Despite the incentives outlined above, the majority of unscheduled price-responsive resources are unlikely to participate in dispatch mode in the near term, and potentially into the future. However, they will create challenges for AEMO's demand forecasting in the NEM and this may have large consequences for efficient market operation.

This section sets out how:

- our final rule introduces a monitoring and reporting framework for AEMO and the AER to assess the impact of price-responsiveness (section 3.4.1)

70 CS Energy, submission to the draft determination, p. 4.

71 Shell Energy, submission to the draft determination, p. 2.

- we considered AEMO's visibility mode proposal but consider it would be high cost and not enable the efficiency benefits due to the information not being used in central dispatch (section 3.4.2)
- we considered alternatives raised in submissions and through further work (section 3.4.3 and section 3.4.4).

3.4.1 The final rule creates an obligation for AEMO and the AER to report on the use and impact of unscheduled price-responsive resources

Our final rule introduces a monitoring and reporting framework for AEMO and the AER.

This reporting framework will provide more transparency on the materiality of deviations of actual demand from forecasts and the inefficiencies that these deviations cause. This transparency will facilitate analysis of AEMO's operational demand forecasting methods and whether changes can reduce such inefficiencies, should they materialise. Collectively, this reporting and transparency framework will help us understand how unscheduled price-responsive resources are changing and their impact on market outcomes. It will also provide evidence the AEMC will consider when determining whether to introduce structural changes to demand forecasting or a visibility market model in the future.

Specifically, the final rule introduces:

- Monitoring and reporting by AEMO to:
  - identify the presence and issues created by increased unscheduled price-responsive resources[72]
  - publish its methods and assumptions for regional demand forecasting in operational timeframes and the measures it takes to improve this forecasting to account for unscheduled price-responsive resources.[73]
- Monitoring and reporting by the AER to assess the efficiency implications and costs associated with increased unscheduled price-responsive resources.[74] To the extent that AEMO can account for price-responsive resources through forecasting or participation in dispatch mode, this would reduce the efficiency implications and costs associated with increased price-responsive resources.

Stakeholder feedback to the draft determination broadly supported the monitoring and reporting framework and we have not made any material changes to the draft rule in the final rule. Minor changes that we have made in response to detailed suggestions from AEMO for clarity are outlined in appendix C.

This new reporting framework complements and builds on the existing reporting requirements for AEMO and the AER which are set out below.

- AEMO's current reporting requirements:
  - It has a range of reporting requirements concerning forecast accuracy and whether/how it accounts for unscheduled price-responsive resources. However, these are limited to the planning timeframe and focus on reliability and the extent to which forecast errors have contributed to AEMO's planning (Electricity Statement of Opportunities (ESOO)) or operations (such as declaring a lack of reserve condition).

72 See clauses 3.10C.2(b)(1)-(6) of the final rule.

73 See clause 3.10C.2(b)(7) of the final rule.

74 See rule 3.10C.3 of the final rule.

    - It is already required to publish how it considers demand-side participation information in forecasts in general terms.[75] However, the focus of this new reporting requirement is on unscheduled price-responsive resources, which would be a subset of this analysis.
    - It is required to prepare pre-dispatch and dispatch forecasts. However, the methods within these processes are opaque and AEMO does not provide much detail in its operating procedures. For example, AEMO's load forecasting procedure sets out one paragraph of information on how it produces load forecasting in the dispatch period.[76]
- The AER has a principles-based reporting framework in the National Electricity Law (NEL) and NER to consider effective competition and market efficiency in relevant energy markets. The draft rule creates a new requirement for the AER to consider the impact of unscheduled price-responsive resources on market efficiency, as part of its market monitoring functions under NEL s 18C.

3.4.2 We considered AEMO's proposed visibility mode but it would not be used in dispatch

AEMO's rule change request included a 'visibility mode' that was designed to enable FRMPs to directly bid their demand-response into the market to improve situational awareness. The proposal included the following key features:

- Participants could voluntarily register National Meter Identifiers (NMIs) in a light scheduling unit (LSU). Participating FRMPs would be required to provide indicative bids for the forecast of generation and consumption.
- The framework would allow for flexible participation, rather than the ongoing active operation requirements in place for other market participants.
- The indicative bids would not be included in AEMO demand forecasting or dispatch. They would be used to improve AEMO situational awareness.

Informed by stakeholder feedback and further analysis, the Commission considered that AEMO's visibility proposal had material weaknesses that would be difficult to overcome.[77] These include:

- AEMO's proposal would not incorporate indicative bids into dispatch. This would mean that the IES 'size of the prize' modelled benefits of improved dispatch outcomes or reduced FCAS costs would not occur.
- AEMO's proposal requires NMIs to be registered within a LSU to participate in the visibility mode. This requirement creates a high barrier to entry because of the real-time metering and telemetry requirements and would limit the resources that can participate. We also considered the lack of integration in central dispatch would mean AEMO's visibility mode would not be likely to meet the national electricity objective.

3.4.3 We considered an alternative visibility market model with significant upside

The Commission considered issues raised by stakeholders in submissions to the consultation paper and the deficiencies with AEMO's visibility mode. In the draft determination, we explored an alternative visibility market model prepared by Creative Energy Consulting that would incorporate bids directly into AEMO's forecasting and dispatch.[78] While this model has significant benefits and would incorporate unscheduled price-responsive resources into dispatch, it has high costs, and we considered in the draft determination that it is not yet warranted. Stakeholder submissions to the

75 See rule 3.7D of the rules.

76 AEMO, Load Forecasting procedure, May 2023, p. 8.

77 Submissions to the draft determination, Ergon and Energex, p. 1, Enel X, p. 2, Origin, p. 1, Alinta, p. 1.

78 Creative Energy Consulting prepare for the AEMC, *A Market Design to integrate Demand Response into NEM Pricing and Dispatch*, 25 July 2024.

draft determination broadly supported this position, and we have maintained it in the final determination.[79]

Under the alternative visibility market model, participants would bid unscheduled price-responsive resources and these bids would be used by AEMO in central dispatch to form a price-elastic demand forecast. The Commission considers that the visibility market model has considerable merit and analysed it in detail. This model has some key design differences relative to AEMO's visibility mode that we consider would materially increase benefits and lower costs for market participants:

- quasi-bids would be submitted for unscheduled price-responsive resources by FRMPs on a regional aggregate basis rather than through a LSU
- the quasi-bids would be used by AEMO in central dispatch, thus improving the accuracy of demand, dispatch instructions and price formation
- FPPs would be used to drive incentives for participants to provide accurate quasi-bids.

The Commission considers that this visibility market model would be likely to deliver the following benefits and could potentially contribute to the achievement of the national electricity objective:

- It would efficiently allocate risks to those best placed to manage them. By transferring responsibility to market participants (for example, retailers) for forecasting the price-responsiveness of their customers, risks are efficiently allocated. Retailers purchase energy on behalf of customers in the spot market and on sell it to them. Generally, they possess the best information about the price-responsiveness of their customers because they have the retail contract that passes through prices and invest significant resources to know how much energy they will be purchasing at different times and price levels.
- It would include incentives that would appropriately reward the provision of accurate information. With retailers undertaking forecasts, financial incentives could be created for providing accurate quasi-bids through the use of frequency performance payments.
- It would reduce market inefficiencies associated with unscheduled price-responsive resources. By AEMO incorporating quasi-bids into dispatch, it would have a more accurate view of demand, thus improving price formation, dispatch instructions, and reduce the reliance on RERT.

However, after detailed design discussions with AEMO and our TWG, the Commission concluded that the visibility market model is likely to have high cost and complexity for AEMO to implement and maintain, and the solution is not yet warranted. The Commission's analysis and relevant stakeholder feedback considered in reaching this conclusion is set out below:

- While the volume of unscheduled price-responsive resources is growing, it has not yet reached a point where it is materially challenging AEMO's demand forecasting and it would come with material costs to produce the necessary forecasts. We consider that the monitoring and reporting framework will place us in a good position to determine when AEMO's demand forecasting is materially challenged, and if these challenges can be addressed adequately by changes to AEMO's demand forecasting methods, and therefore whether a move to retailer-led forecasting of price-responsiveness is warranted. EUAA expressed support for the visibility market model and also considered this should be reviewed if improvements to AEMO's forecasting do not materialise.[80]

79 Submissions to the draft determination, Red Energy, p. 2, AEC, p. 2, Alinta, p. 1, AGL, p. 3.

80 EUAA, submission to draft determination, p. 3.

- Stakeholders, through the TWG, raised concerns with implementing a large regulatory solution without evidence that AEMO has tried and not succeeded to improve its forecasting. The Commission received clear and repeated feedback from submissions and through the TWG that a large regulatory solution such as the alternative visibility model is not warranted yet. In particular, TWG members considered incremental changes such as improvements to AEMO forecasting should be explored in lieu of a significant market reform particularly since unscheduled price-responsive resources have not yet materially influenced inefficient market outcomes.

3.4.4 We considered other ways to improve visibility and transparency of unscheduled price-responsive resources

In response to the consultation paper, stakeholder submissions raised alternative approaches to address the visibility of unscheduled price-responsive resources. These included introducing a reporting framework to assess the accuracy of AEMO's demand forecasts, and improve information collection processes to make them fit for purpose. Each of these are discussed below.

Improve information collection processes to make them fit for purpose

Several submissions outlined that AEMO currently has a range of methods, such as the DER register and demand-side participation information portal (DSPIP), to collect information about unscheduled price-responsive resources. These stakeholders suggested changes to make the existing arrangements fit for purpose. These views were reiterated in TWGs and individual stakeholder discussions.[81] In particular:

- **DER register**: static register, updated for new or amended installations of battery storage and rooftop solar devices (potentially with EV chargers in the future) at residential or business locations. It shows the number and installed capacity by region, to a post-code level but not the level of control or operation of those devices.
- **DSPIP**: collected annually, the DSPIP contains information about the characteristics of DSP contracts from registered participants. The information is used to inform reliability modelling (ESOO, Energy Adequacy Assessment Projection (EAAP), Medium Term projected assessment of system adequacy (MT PASA) and the ISP).

In the draft determination the Commission considered that existing information gathering powers granted to AEMO through the DER register and the DSPIP are sufficient to meet AEMO's requirements under the new monitoring and reporting framework. Stakeholders generally agreed with this position, arguing that AEMO should not be granted additional information-gathering powers.[82] In contrast, AEMO's submission to the draft determination expressed a preference for further information-gathering powers to be granted to it to fulfil these new requirements.[83] AGL also considered that compulsory information gathering for portfolios above a certain threshold may be required for improved visibility of unscheduled price-responsive resources.[84] The Commission maintains its position from the draft determination. We consider that the broad existing powers, if used to their fullest, will allow AEMO to complete the identified functions.

81 Submissions to the consultation paper, Clean Energy Council, p. 3, Australian Energy Council, p. 4, FlowPower, p. 5, Enel X, p. 4, EnergyAustralia, p. 3, Origin, p. 3.

82 Submissions to draft determination, Hydro Tasmania, p. 1, Origin, p. 1, Red Energy, p. 5.

83 AEMO, submission to draft determination, p. 3.

84 AGL, submission to draft determination, p. 3.

Assess the accuracy of AEMO's demand forecasts and provide transparency on the materiality of the inefficiencies

Stakeholders considered that there is not sufficient transparency on AEMO's operational demand forecast errors to appropriately qualify whether a visibility mode is required. CS Energy considered that AEMO has not reasonably justified why it requires more dynamic visibility. CS Energy proposed that more transparency is needed on AEMO's demand forecast accuracy in operational forecasts and non-regulatory options for improving forecasts.[85] EUAA echoed this sentiment and proposed a regular reporting requirement for AEMO to publish forecast accuracy reports (monthly or quarterly). EUAA proposed that this report would cover all of AEMO's forecasting requirements and compare against actual market real time 5 minute dispatch outcomes, including a process for improving forecasting where an issue is identified in the report. EUAA also proposed that this report should be prepared by an independent market body such as the AER or the AEMC to ensure impartiality.[86]

The Commission considers that introducing a monitoring and reporting framework is a lower-cost and proportionate response that better serves the immediate needs of the market. Furthermore, we consider that AEMO's work to improve its forecasting to account for unscheduled price-responsive resources is worth exploring as improvements could reduce the size of the problem and the need for a higher-cost regulatory response.

3.5 Implementation and transitional provisions support the timely introduction of our rule

A suite of procedures and guideline changes by AEMO, AEMC and the AER will follow this final rule. These procedures and guidelines will specify operational and technical requirements, to ensure that the rule change operates as intended.[87]

AEMO and the AER will be required to undertake consultation processes in relation to these procedures and guidelines. Our overriding approach has been to implement dispatch mode, the incentive mechanism and reporting requirements at the earliest possible dates within AEMO's and the AER's capabilities and resources. This results in varying implementation time frames for the mechanisms, most importantly:

Dispatch mode:

- AEMO to consult on and publish the VSR guideline by 31 December 2025
- Dispatch mode commences 23 May 2027.

Incentives:

- VSR incentive procedures to be completed before the first tender process or 1 December 2026, if the first tender does not occur before then
- the incentive mechanism will run between 1 April 2026 to 31 December 2031 (the incentive period).

Monitoring and reporting:

- AEMO and the AER must release their reporting guidelines by 31 December 2025
- AEMO must publish its first quarterly report by 1 April 2026 and its first annual report by 30 September 2026

85 CS Energy, submission to the consultation paper, p. 3.

86 EUAA, submission to the consultation paper, p. 3.

87 See rule 11.180.2 of the final rule.

- the AER must publish its first report by 31 December 2026.

Further details on the implementation timing can be found at: appendix A.6, appendix B and appendix C.3.

We have materially changed the implementation schedule between draft and final rule in two ways:

1. We have extended the implementation date for dispatch mode from November 2026 to May 2027. We consider this is necessary to allow AEMO to successfully implement dispatch mode. This was supported through AEMO's consultation on its high level impact assessment of the draft rule and determination. This does not change the time frame to complete the guideline and procedures, but allows AEMO and participants time to test dispatch mode before it commences.
2. We have brought forward the incentive period from January 2027 to April 2026 to allow AEMO to commence the tenders earlier. In its submission, AEMO proposed an earlier implementation for incentives to provide investment certainty for prospective VSRPs and support VSRPs' customer acquisition, technical development and testing.[88] We agree with establishing the incentives early to encourage the greatest amount of participation.

3.5.1 AEMO will finalise its high-level implementation assessment

AEMO will finalise its high-level implementation assessment (HLIA) for this rule change in early 2025. The purpose of the HLIA is to provide a preliminary view to participants and the AEMC on how AEMO may implement its tasks under the rule change. This is intended to inform participants as they develop their own implementation timelines and impact assessments.

88 AEMO, submission to the draft determination, p. 6, 8 & 11.

4 The final rule will contribute to the national electricity objective

This Chapter sets out how our final rule promotes the NEO. It highlights that our final rule primarily increases the efficient operation of the wholesale market. This is in the long term interests of consumers of electricity with respect to the price, the security and reliability of the supply, and the achievement of emissions reduction targets.

Our assessment of the final rule against the NEO has not materially changed from our assessment of the draft rule. We consider that the limited policy changes between draft and final rule, and large magnitude of the positive cost-benefit result, mean updates to the market modelling undertaken by IES to assess dispatch mode are not warranted. Similarly, stakeholders did not raise any issues requiring reassessment.

This chapter describes:

- the NEO test that the Commission must apply to make the final rule (section 4.1)
- how the final rule will likely contribute to the long-term interests of consumers (section 4.2).

4.1 The Commission must act in the long-term interests of consumers

The Commission can only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the relevant energy objectives.[89] For this rule change project, we have made a final electricity rule so the relevant energy objective is the NEO.

The NEO is:[90]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[91]

There are also a number of relevant legal requirements under the NEL for the Commission to make a final rule determination. These are set out in appendix F.

4.1.1 We have made a more preferable final rule

The Commission may make a rule that is different, including materially different, to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the

89 Section 88(1) of the NEL and 236(1) of the National Energy Retail Law (NERL).

90 Section 7 of the NEL.

91 Section 32A(5) of the NEL.
Targets statement available here.

rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO.[92]

For this rule change, the Commission has made a more preferable final electricity rule. The rule is more preferable in two key ways:

1. A monitoring and reporting framework was considered more appropriate to the proposed 'visibility mode'. This is because it better balances implementation costs and assists the market bodies to decide if and when changes are needed to AEMO's forecasting methods.
2. A time-limited incentive mechanism to encourage participation in dispatch is included in the rule. This was not proposed in the rule change request. This addresses the concerns of low participation and high upfront costs.

The reasons for these decisions are set out in section 4.2 below.

4.1.2 Consequential changes to the NERR are not required

In assessing the rule change request and developing the final electricity rule, we considered whether any consequential changes to the National Energy Retail Rules (NERR) were required, such that a retail rule should be made. To make a retail rule, the Commission would need to be satisfied that the rule will or is likely to contribute to the achievement of the National Energy Retail Objective (NERO).[93]

The Commission's final determination is that no consequential amendments to the NERR are required, and therefore we have not made a retail rule or applied the NERO. We expect that a FRMP participating in dispatch would do so in a way that aligns with their and their customer's preferences. By this, we expect them to bid in at price volumes that they have agreed upon in the contracts that they have (noting that existing requirements for explicit informed consent for contracts, as well as other protections for retail customers, continue to apply). We do not expect a customer to see any noticeable difference between being part of a VPP that is participating in dispatch and one that is not. There is no requirement to change their behaviour or cede control of their assets in any shape or form. A VSRP would in aggregate provide bids that reflect how responsive its customers are. Importantly, residential and small business consumers who manage their own assets, that are not coordinated by their FRMP, are not the focus of this rule change. For example, a consumer self-consuming from their battery would not be required to do anything differently as a result of this rule change.

In submissions to the consultation paper Mondo, EUAA, Fortescue, EQL and Energy Locals argued that we should consider the impact on consumers from FRMPs participating in dispatch with their resources.[94] Erne Energy and Ausgrid raised similar issues in response to the draft determination, arguing that additional consumer protections are required as a result of the introduction of dispatch mode.[95]

Ausgrid raised that VSR customer data or data about customers' assets in VSRs could be subject to different data sharing and reporting arrangements.[96] Ausgrid suggested further work is undertaken to ensure that these issues are fully considered, and there is no impact on consumer protections before determining that no change is needed. The Commission's final rule does not

92 Section 91A of the NEL.

93 Section 236(1) of the NERL.

94 Submissions to consultation paper, Mondo, p. 7, EUAA, p. 6, Fortescue, p. 4, EQL, p. 4, and Energy Locals, p. 6.

95 Submissions to the draft determination, Erne Energy, p. 2. Ausgrid, p. 4.

96 Ausgrid, submission to the draft determination, p. 4.

introduce any new rights to customer data, only that existing rights to data can be shared effectively where needed.[97]

The Commission notes that FRMPs are already engaging, and will continue to engage, with customers to use their CER to respond to spot prices, through their contracts. This rule change does not change the nature of this engagement, or the need for appropriate consumer protections governing this engagement.

While the Commission considers that this rule does not alter the nature of relationships between FRMPs and consumers with CER, we do note that issues have been identified with these current relationships and these should be addressed. The ESB recommended that the National Energy Customer Framework (NECF) is updated to ensure that consumers can benefit from this type of innovation whilst also being protected from negative impacts.[98] This is part of ongoing consideration by the CER Taskforce.[99] In the meantime, existing consumer protections under the NECF and Australian Consumer Law will continue to apply (noting that the *Unlocking CER Benefits through flexible trading* rule change extends key protections in the NERR to secondary settlement points).

4.2 Our more preferable final rule will contribute to the NEO

The Commission has identified the following five criteria to assess whether the proposed rule change, no change, or other viable rule-based options are likely to better contribute to the NEO:

1. Security and reliability — would greater visibility and dispatchability of price-responsive resources promote a secure and reliable electricity system at the lowest cost through more accurate forecasting and operation?
2. Concepts of efficiency — to what extent will increased visibility and integration of price-responsive resources in the scheduling process lead to productive, allocative and dynamic efficiency?
3. Emissions reduction — would the solution efficiently contribute to the achievement of government targets for reducing, or that are likely to reduce, Australia's greenhouse gas emissions?
4. Implementation costs — what will be the costs to participants, consumers and AEMO of implementing any solution? What will the costs be to participants, consumers and AEMO of complying with any solution over time?
5. Flexibility — would the solution be future-proof, resilient and able to accommodate market, technological, policy and other changes?

To support our decision-making, the Commission has undertaken a regulatory impact analysis to evaluate the impacts of the final rule and other policy options against the assessment criteria. The rest of this Chapter explains why the Commission's more preferable final rule is likely to promote the long-term interest of consumers, compared to the proposed rule, no change, or other viable rule-based options.

97 See appendix A for further information.

98 ESB, Consumer Energy Resources and the transformation of the NEM, 2024.

99 Department of Climate Change, Energy, the Environment and Water, National Consumer Energy Resources Roadmap, Powering Decarbonised Homes and Communities, July 2024.

4.2.1 Creating a new framework for participation in dispatch will contribute to the NEO

Dispatch mode is a material regulatory change in the NEM. Our regulatory impact analysis has therefore included formal market modelling to quantify the costs and benefits of the change. The modelling focuses on the types of impacts within the scope of the NEO, including the cost of operating the power system reliably and securely, dynamic and productive efficiency, and the extent to which it impacts decarbonisation.

The Commission engaged IES to adapt its size of the prize modelling to include projected uptake rates of dispatch mode and then use the same methodology as described in section 2.2.4 to estimate its benefits. There is material uncertainty regarding the uptake of dispatch mode and we therefore had IES take a probabilistic approach to modelling the benefits. IES modelled a high, medium and low participation sensitivities and then gave them weights based on the likelihood of them eventuating. Box 4 provides an explanation of this approach. This provides a weighted benefit which the Commission primarily considers for its NEO assessment. These are set out in Table 4.1.

Table 4.1: IES benefits by different participation scenarios

Benefit category	Low partici-pation ($m AUD)	Medium participation ($m AUD)	High participation ($m AUD)	Weighted probability ($m AUD)
System security - FCAS benefits	220	403	617	411
Reliability - RERT benefits	100	100	100	100
Productive efficiency - Generation benefits	63	120	180	121
Emissions benefits	140	199	274	203
Total	**523**	**821**	**1,170**	**834**

Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024

AEMO provided cost estimates totalling $29m for dispatch mode (upfront ($18.2m +/-40%) and ongoing costs (approximately $10.5m over 10 years)) and $5m (+/-40%) for the incentive mechanism.[100] This results in a cost estimate of $34m for dispatch mode and the incentive mechanism.

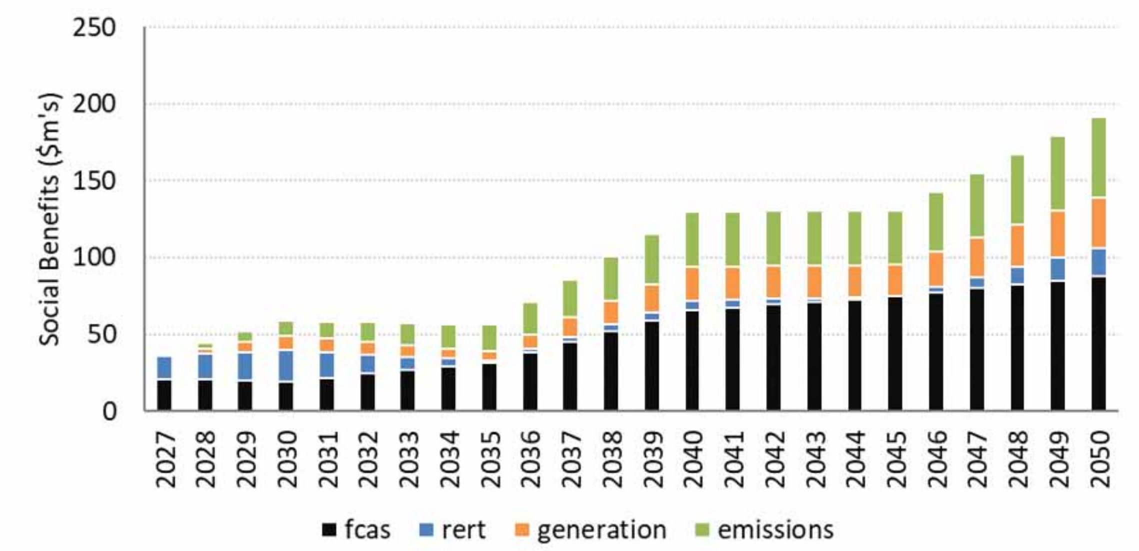
The Commission considers that these estimates provide a strong case that dispatch mode (together with the incentive mechanism) meets the NEO and should be implemented. Our probabilistic assessment is a net benefit of $805m for dispatch mode (and $800m taking into consideration the costs for the incentive mechanism). Furthermore, even in the low uptake scenario modelled by IES the net benefits of dispatch mode are $494m (or $489m taking into

100 Submission to the draft determination, AEMO, p. 6.

consideration the costs for the incentive mechanism), an order of magnitude greater than the costs.[101]

Another important feature of the IES modelling is the quantification of when the benefits of dispatch mode occur. These are plotted in Figure 4.1. Most importantly, while the benefits grow over time as the quantity of otherwise unscheduled price-responsive resources in the NEM increases, the benefits are already material by 2030. This provides strong justification for implementing the solution as soon as possible.

Figure 4.1: IES probabilistic benefits from implementing dispatch mode



Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024

Note: IES modelled snapshot years every 5 years, results have been interpolated for the remaining years.

Promotes security and reliability of the power system at the lowest possible cost

Dispatch mode promotes the security and reliability of the power system by ensuring more accurate demand forecasting and efficient operation of the NEM. It primarily does this by creating a framework for more resources to participate in dispatch. By having more price-responsive resources scheduled, AEMO will not need to forecast these resources and therefore forecast accuracy is likely to improve. This promotes:

1. System security at the lowest cost by reducing the use of generation reserves to balance the market, such as FCAS. IES's modelling estimates these cost savings to be $411m (NPV) from 2027 to 2050.
2. Reliability at the lowest cost by reducing the need for RERT. IES's modelling estimates these cost savings to be $100m (NPV) from 2027 to 2050.

Improves efficiency of investment and operations

Dispatch mode results in substantial efficiency improvements through:

- Improving operational demand forecasting, which will reduce the inefficient dispatch of generators, storage and demand response, thereby reducing the costs of operating those

101 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024.

resources (productive efficiency). IES estimates that the reduction in generation costs over 2027-2050 is $121m. IES demonstrates that this is primarily driven by dispatching less peaking generation at high price times.

- Allowing AEMO to better match supply and demand. This will reduce operational demand forecast errors, resulting in more efficient price setting. This results in lower energy prices and potentially less volatile prices, benefiting all energy consumers. IES modelling identified $8.73b NPV wealth transfer benefits from implementing dispatch mode. These benefits arise from reduced energy and FCAS prices. We have not included the lower energy and FCAS prices modelled by IES in our cost-benefit assessment. These are not true efficiency gains. Rather, they are wealth transfers from generators to consumers, and therefore we do not include them.
- The magnitude of the higher revenues earned by generators in the absence of dispatch mode would likely result in additional market entry and this entry would come with a material cost (a dynamic efficiency). IES's scope of works for the Commission did not attempt to model the additional generation and storage entering the market. This entry would come at a cost. The Commission has therefore only taken this into account as a qualitative indication that the overall IES benefits are likely understated.

It will contribute to achieving emissions reduction targets

Our final rule contributes to achieving government targets for reducing Australia's greenhouse gas emissions through more efficient operation of the wholesale market. More accurate demand forecasting and efficient dispatch may reduce the use of emissions-intensive generation. This is because there is a close correlation between high marginal cost generators and high emissions generators (for example, gas powered generators). As these high cost, high emissions generators are dispatched less often, or for shorter periods, emissions will also decrease with the introduction of dispatch mode, helping to meet jurisdictional emissions targets. IES identifies $203m in emissions savings from introducing dispatch mode, using the interim value of emissions reductions agreed by energy ministers.[102]

Balances implementation cost and complexity against the benefits

The final rule has been developed with the aim of minimising costs for market participants and AEMO while maximising benefits to the market.

Chapter 3 sets out how the final rule heavily leverages and builds on previous reforms (for example IESS). This reduces likely implementation costs for AEMO and market participants. AEMO's rule change request estimated that implementing both visibility and dispatch modes (as proposed in its request) would have an upfront cost of $18.2m (+/- 40%) + 10.5m over the first 10 years.[103]

The final costs will be determined as AEMO implements the final rule. However, given that dispatch mode is largely consistent with AEMO's proposal, we do not expect that these costs will vary significantly. These costs are recovered by AEMO through Market Participants and ultimately customers.

The final rule is resilient and future proof

Dispatch mode is highly flexible and resilient to future market and technology changes. At its core, dispatch mode is a platform for aggregated small and medium-scale resources to be completely

102 AEMC, How the national energy objectives shape our decisions, 28 March 2024.

103 AEMO, Rule change request — Scheduled Lite Mechanism in the National Electricity Market, p. 40.

integrated into market dispatch. It is flexible to a wide range of resources, technologies and business models and therefore, robust to changes to all of these factors over time.

Similarly, dispatch mode is resilient to future regulatory reforms. The basic functions of participants bidding the response of currently unscheduled price-responsive resources to different spot prices, and following these bids, are important under any future regulatory framework.

We note two other relevant factors in our NEO assessment:

1. Participation costs. There will also be costs for participants who choose to use the mechanism. These need to be considered when weighing the overall benefits of the mechanism. Ergon and Energex noted in their submission that these and customer costs should be further examined, along with potential costs for DNSPs.[104] However, given the large modelled benefits, and that these costs are only incurred for participants that use the mechanism, we do not consider there is a material risk that the costs would impact our overall NEO assessment.
2. Dynamic efficiency gains through avoiding unnecessary large scale generation and storage. We have not included the lower energy and FCAS prices modelled by IES in our cost-benefit assessment. In particular, IES estimates that prices would be substantially higher without dispatch mode, resulting in consumers paying $8,729m (NPV) more over the period. These are not true efficiency gains, they are wealth transfers from consumers to generators and therefore we do not include them. However, given the magnitude of higher revenues they would likely result in additional large scale generation and storage entering the market and this would come with a material cost – a dynamic inefficiency – that should be considered in our analysis. We therefore consider that the above efficiency gains are likely understated.

In conducting our NEO assessment we have also considered the distributional impacts of introducing dispatch mode. In general, the reduction in total system costs in the long run from the efficiency gains described above is likely to lead to lower prices for all consumers. We do not consider it is possible or necessary to identify the specific groups of customers most likely to benefit. Similarly, generators and retailers will incur lower costs in providing consumers with a reliable supply of electricity, but it is challenging to identify the specific beneficiaries of these efficiencies.

Additional modelling considered a range of potential participation rates through our new framework

In February 2024 we released modelling by IES on the potential total benefit of integrating unscheduled price-responsive resources. This modelling was a ‘size of the prize’ exercise. Section 2.2.4 provides an explanation of this modelling. We asked IES to undertake additional modelling to align with the policy direction for dispatch mode and include our best available estimates of uptake of dispatch mode.

104 Submission to the draft determination, Ergon and Energex p. 2.

Box 4: IES sensitivity modelling for different participation scenarios

There is material uncertainty regarding the uptake of dispatch mode and we therefore had IES take a probabilistic approach to modelling the benefits. IES models a high, medium and low participation scenario and then gives them weights based on the likelihood of them eventuating. This provides a weighted benefit which the Commission primarily considers for its NEO assessment.

This involved:

- modelling impacts of the rule from November 2026, to align with expected implementation date for the draft rule. We note that under the final rule, dispatch mode will commence in May 2027, 6 months later than the modelling. We do not consider that this delay will significantly reduce the overall benefits and have not sought to model with this later commencement date.
- modelling three different participation rate sensitivities: low, medium and high, see further below
- updating the modelled value of emissions reductions to use the energy ministers' agreed interim values (NSW Treasury figures were used in the February paper as the energy ministers had not released theirs yet).[1]

In addition, we asked IES to:

- Determine the probabilistic NPV from dispatch mode based on different weights for the likelihood of the different participation scenarios. We provided IES with weights based on the likelihood of the scenarios eventuating.
- Identify the relationship between participation and benefits.

We wanted IES to test a range of sensitivities:

- Low participation scenario — This assumes no additional incentives are provided to participants beyond access to existing markets such as regulation FCAS. Regulation FCAS is assumed to drive aggregated batteries (<5 MW) to participate in our new framework. However, the amount of participation remains low.
- Medium participation scenario — This assumes that upfront incentives are provided to early participants (either through the Commonwealth's capacity investment scheme, trial funding from ARENA, or the incentive mechanism in the final rule; see appendix B.1). We also assume that future regulatory change will give VSRPs preferential network or market access.
- High participation scenario — This assumes a take-up rate supported by ongoing substantial incentives. These could be access to other markets (for example, capacity), preferential network access (for example, flexible export limits), or an enduring incentive scheme.

Source: AEMC and IES
Note: 1 - AEMC, How the national energy objectives shape our decisions, 28 March 2024.

4.2.2 Creating a new incentive mechanism will contribute to the NEO

The Commission has explicitly considered and assessed the impact of the incentive mechanism for VSRPs against the NEO.

The incentive mechanism has been designed with a cap on total incentive payments of $50m (plus any funding received from external sources). After deducting any external funding, these payments to VSRPs would be recovered by AEMO through market participants, primarily retailers, and ultimately, customers. The final rule also ensures that customers retain a benefit greater than the cost of providing this incentive. We do this by requiring AEMO to pay less than the estimated benefits from VSR participation. This means that even in the years that the payments are made, consumers still benefit from participation.

We have taken into account the implementation costs and effect on likely participation of the incentive scheme in our quantitative assessment. However, we do not include the $50m of incentive payments from consumers to participants in dispatch mode in this assessment. This is because (similar to the FCAS and energy prices) this is a wealth transfer from consumers to participants, not an efficiency loss.

Our analysis against the relevant assessment criteria is outlined below.

Promotes security, reliability and lower emissions at the lowest possible cost

As outlined above, participation in dispatch mode promotes the security and reliability of the power system by ensuring more accurate demand forecasting and efficient operation of the NEM. However, without an incentive mechanism, participation is likely to be low because of limited direct participant benefits and high upfront costs. The final rule includes an incentive mechanism, as a more preferable rule, to drive higher participation in dispatch by VSRPs. Increased participation will result in significant benefits to the market.

Balances implementation cost and complexity against the benefits

AEMO estimated a cost of $5m (+/- 40%) to establish, administer and report on the incentive mechanism.[105] Our final rule on the incentive mechanism balances the costs of implementation against the benefits. It does this by providing AEMO with flexibility in how it operates the tender process. Through this we are minimising the potential implementation costs and complexity associated with providing funding. As noted above, the benefits that it is expected to provide from increased participation in dispatch mode are an order of magnitude greater than the costs.

Given the significant benefits from increased participation in dispatch mode, we consider that the benefits identified outweigh the costs of providing this additional incentive mechanism. The implementation costs for AEMO to run the scheme are necessary in order to realise the benefits. The Commission therefore considers the incentive mechanism is likely to be in the long-term interest of consumers.

4.2.3 Creating a new monitoring and reporting framework will contribute to the NEO

The Commission has qualitatively assessed the costs and benefits from introducing a monitoring and reporting framework for unscheduled price-responsive resources. We consider that the identified benefits of the monitoring and reporting rule will outweigh the costs, and that the monitoring and reporting rule would better contribute to the NEO than the other options. Therefore, introducing the monitoring and reporting framework is likely to be in the long-term interest of consumers.

We do not consider detailed cost estimates are required to reach this conclusion because the cost of the framework is unlikely to be material. Our analysis against the relevant assessment criteria is outlined below.

The final rule is resilient and future proof

The main benefits from the monitoring and reporting approach in the final rule are that it will assist the market bodies to decide if and when changes are needed to AEMO's forecasting methods. This will include determining if structural changes to the way that forecasting is done in

105 AEMO submission to the draft determination, pp. 6-7.

the NEM are needed (for example, placing some forecasting responsibility on retailers). We consider that this approach will result in timely and effective reforms being made to improve demand forecasting in the NEM in the future. This has the potential to materially increase allocative, productive and dynamic efficiency in the long run. Compared to the alternative of AEMO's proposal, the alternative market model and no rule, this rule provides the most resilience.

Improves efficiency of investment and operations

The final rule provides increased transparency on deviations between forecast and actual demand and measures taken to account for unscheduled price-responsive resources. If this is successful it would improve signals to the market for their investment and operations.

All market participants and consumers would benefit from increased information sharing and more efficient operation of the market.

Balances implementation cost and complexity against the benefits

The final rule has been developed with the aim of minimising costs for market participants while maximising benefits to the market. By developing a more preferable final rule we have sought to reduce the costs of implementing a potentially more expensive and complex solution.

Market bodies are the most impacted stakeholders as they are required to gather data, assess and report on the different factors identified. The final rule extends AEMO's and the AER's functions in these areas. We expect that this would require additional resources from both bodies. However, we consider that the functions enshrined in the final rule are largely similar to functions that AEMO and the AER are likely to undertake in-house over time regardless of the final rule. This is because the market bodies will likely focus an increasing amount of resources to address the issues associated with the growing amount of unscheduled price-responsive resources. The increase in costs as a result of that being done formally and publicly is unlikely to be material.

A Dispatch mode allows for easier participation in central dispatch

The Commission's reasons for introducing a 'dispatch mode' in the NEM are set out in Section 3.2. This appendix details how the framework operates and is structured as follows:

- an overview of how participants will be able to aggregate resources and participate in central dispatch (appendix A.1)
- design details for how VSRs will be treated in central dispatch (appendix A.2)
- the flexibility offered to VSRs through being able to deactivate and hibernate (appendix A.3)
- how DNSPs will consult with VSRPs on FELs (appendix A.4)
- a worked example (appendix A.5)
- our implementation timeline (appendix A.6).

The Commission has made minor changes to dispatch mode between draft and final rules in response to stakeholder feedback. The most important of the changes between draft and final are:

- increased flexibility in the operation of the deactivated and hibernation mechanisms
- a requirement on DNSPs to consult with VSRPs when designing FELs.

A.1 Participants will be able to aggregate resources and participate in central dispatch

The final rule allows participants to nominate a qualifying resource as a VSR, which can participate in central dispatch processes.[106] Participants can also apply for multiple qualifying resources to be nominated as a VSR and participate in central dispatch as if they were a single resource, if approved by AEMO.[107] The final rule builds from the dispatch mode proposed in AEMO's rule change request, incorporating stakeholder feedback throughout our process.[108]

The key design elements of VSRs are explained further in Box 5 below.

Box 5: Voluntarily Scheduled Resources (VSR)

The Commission's final rule allows participants to nominate multiple or a singular qualifying resource as a VSR and participate in central dispatch.

The underlying connection point classification for these resources does not change. That is, if a retailer (Market Customer) aggregates several of its market connection points, these will still be market connection points but will also be part of the VSR.

A participant who has nominated a VSR will be referred to as a voluntarily scheduled resource provider (VSRP) with respect to this VSR. However, they will also retain their existing registration category, for example, IRP or Market Customer, and any existing obligations under the rules for the connection points in their VSR.

Note: The rule change request proposed establishing a LSU; when comparing the final determination and rule to the request, VSR is a similar concept to an LSU.

106 See clause 3.10A.1(b) of the final rule.

107 See clause 3.8.3(a3) of the final rule.

108 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 14.

A.2 We have utilised the existing bi-directional unit design

In integrating VSRs into central dispatch, we have utilised several design elements from the BDU design. Using the BDU design provides flexibility for how VSRs can operate in central dispatch, allowing bids for both generation and load.

The BDU was established in the Commission's final rule for *Integrating Energy Storage Systems into the NEM* (IESS). Further information on the BDU design can be found in Appendix A.3.2 of the Commission's final determination for IESS and should be read in conjunction with this section.[109]

A.2.1 Our rule allows aggregated resources to operate like other scheduled resources

Where a VSRP aggregates several qualifying resources as a VSR, they will be treated as if they were one dispatchable resource. This aggregated VSR would operate similarly to a scheduled BDU in market systems, explained further in appendix A.2.3.

Box 6: Aggregated resources in central dispatch

Appendix A.1 outlines that participants can aggregate qualifying resources together to participate as if they are a single resource, if approved by AEMO. When aggregated, the term VSR would apply to the aggregation as a whole and not the individual qualifying resources within the aggregation.

Where aggregation is approved by AEMO, it is the responsibility of the VSRP to ensure the net performance of the resources in the VSR matches its dispatch obligations. AEMO may also impose conditions on aggregations.

In the following sections, the term VSR applies to the aggregation as a whole and not the individual resources within it unless otherwise specified.

To nominate a qualifying resource as a VSR, Market Participants may be registered as an IRP, Market Customer or Generator under the existing participant registration framework in Chapter 2 of the NER. The final rule establishes the new definition of VSRP, to assist in clarifying participants who have established a VSR in the rules.[110]

A participant is able to nominate or aggregate qualifying resources under the following classifications as a VSR:[111]

- a market generating unit that is a non-scheduled generating unit
- a market bidirectional unit that is a non-scheduled bidirectional unit
- a market connection point that is non-scheduled load
- one or more small generating units or small bidirectional units (or any combination) at a small resource connection point classified as a market connection point.

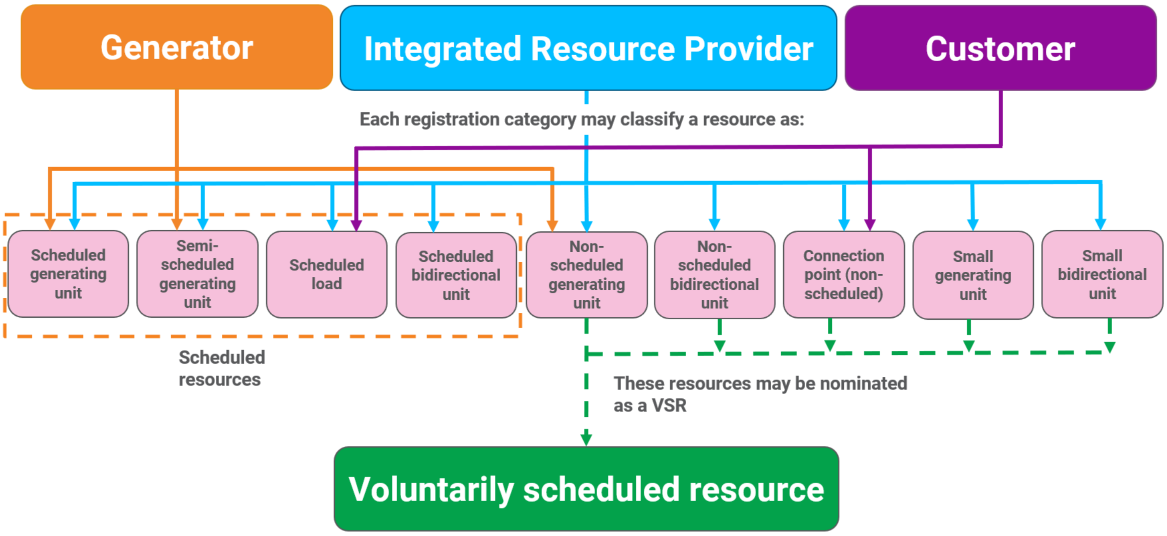
This is outlined in Figure A.1 below.

109 The IESS final determination is available here.

110 See chapter 10 of the final rule.

111 See clause 3.10A.1(a) of the final rule.

Figure A.1: Classifications eligible to be nominated as a VSR



Source: AEMC
Note: Generator, Integrated Resource Provider and Customer refer to the Chapter 2 registration categories. Not all Chapter 2 registration categories have been shown here.

An example of each of these is outlined in Table A.1 below.

Table A.1: Qualifying resources that can be nominated as a VSR

Participant registration	Label	Resource/classification	Example of resource type
IRP or Market Customer	Market Customer	End user connection point (non-scheduled load), classified by a Market Customer as a market connection point	Large users, VPPs, aggregated demand response portfolio
IRP or Generator	Non-Scheduled Generator	Non-scheduled generating unit: Non-exempt generating unit with nameplate rating <30 MW	20 MW diesel generator, not exempt
IRP	Non-Scheduled IRP	Non-scheduled BDU: Non-exempt BDU with nameplate rating <5 MW	3 MW battery in a registered hybrid system
	Small Resource Aggregator	Small resource connection point: small generating unit and/or small BDU (on its own connection point) classified by an IRP (Small Resource Aggregator) as a market connection point	Exempt 1 MW battery on its own connection point Exempt 2 MW cogeneration plant on its own connection point

Source: AEMO, Rule change request — Scheduled Lite Mechanism in the National Electricity Market, p. 22.

Market participants will apply to AEMO to nominate their qualifying resource as a VSR or to nominate two or more qualifying resources to be aggregated as a VSR.[112] In applying to AEMO to nominate a VSR, the participant must:[113]

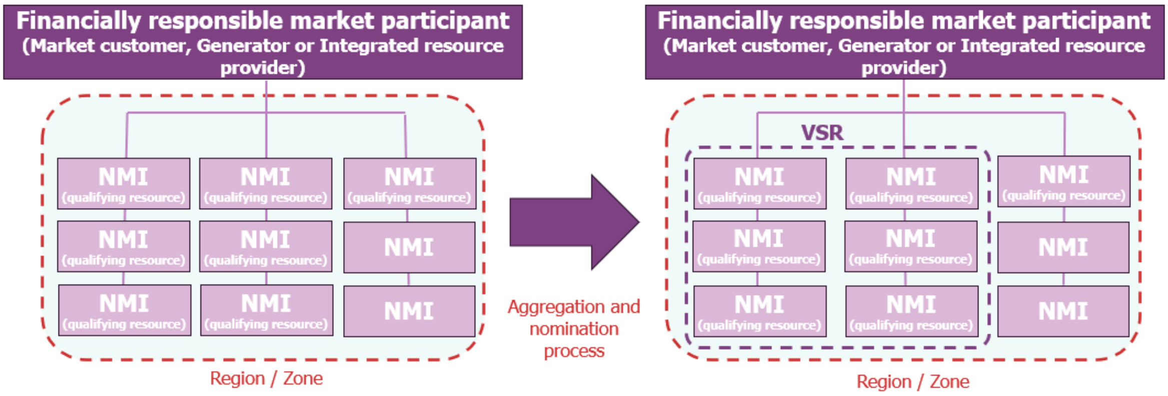
- identify the NMI and market connection point associated with the qualifying resource
- demonstrate how the qualifying resource meets the requirements set by AEMO in the voluntarily scheduled resources guideline (VSR guideline).

If aggregating two or more qualifying resources together the following conditions must be fulfilled:[114]

- each qualifying resource must be connected within a single region and operated by a single person in their capacity as a VSRP
- power system security must not be materially affected by the aggregation
- each qualifying resource in the aggregation satisfies the requirements to be a VSR
- any other requirement for aggregation outlined in the VSR guideline.

A simplified diagram of this process is provided below:

Figure A.2: VSR aggregation and nomination process



Source: AEMC
Note: The FRMP chooses which qualifying resources (NMIs) within the same region (and zone) to nominate as a VSR. Including whether to aggregate them to be treated as if they were one resource for the purposes of dispatch.

The VSR will receive a dispatchable unit identifier (DUID) and be represented in market systems by this DUID.[115]

The VSRP will be the FRMP for the resource(s) it is nominating or aggregating as a VSR. Where the VSRP ceases to be the FRMP, such as if a customer changes retailer, the VSRP is required to immediately notify AEMO.[116] The qualifying resource would then cease to be a VSR.[117] VSRPs must notify AEMO as soon as practicable and no later than 10 business days if their qualifying resource forming a VSR ceases to meet the applicable requirements.[118] This mirrors existing requirements for ancillary services units that cease to meet the requirements for classification.[119]

112 See clause 3.10A.1(b) of the final rule.

113 See clause 3.10A.1(c) of the final rule.

114 See clause 3.8.3(b5) of the final rule.

115 To avoid doubt, where a VSR comprises aggregated resources, the DUID would refer to the aggregated VSR and not each individual resource within the aggregation.

116 See clause 3.10A.1(m)(1) of the final rule.

117 See clause 3.10A.1(n) of the final rule.
Where part of an aggregation, the qualifying resource that the VSRP is no longer the FRMP for would cease to be part of the VSR.

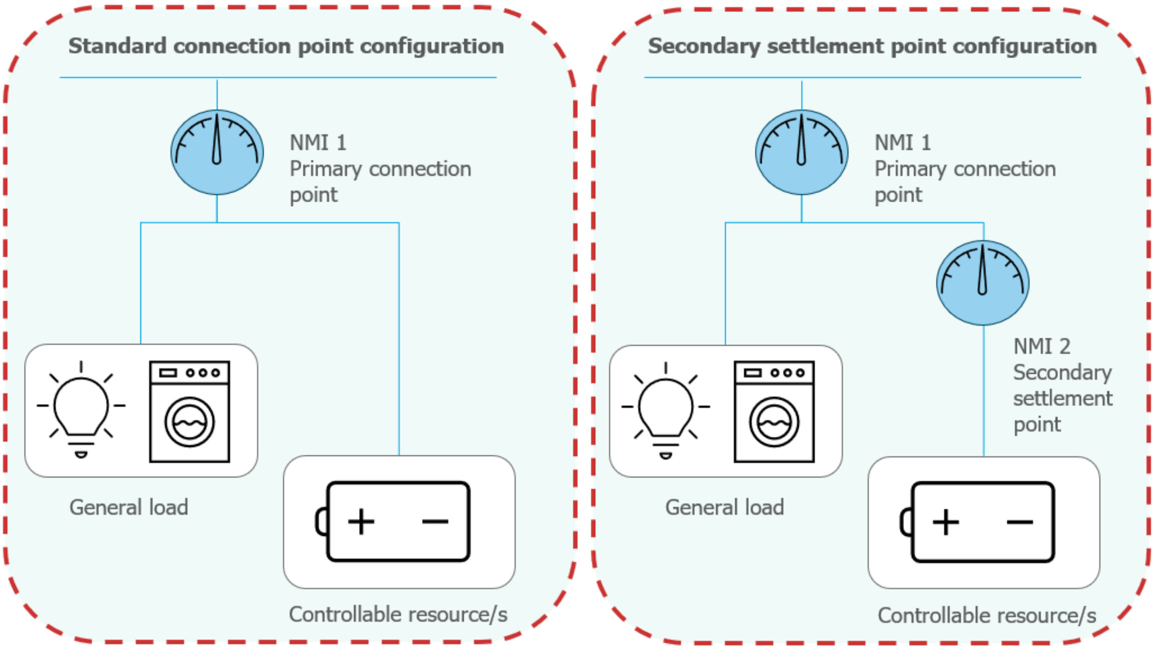
118 See clause 3.10A.1(m)(2) of the final rule.

VSRPs may aggregate resources at standard connection points, secondary settlement points or a mixture of the two.[120] If a VSRP nominates a resource at a secondary settlement point as a VSR, the VSRP would bid and be dispatched for the response from the second settlement point/s only.

The Commission's determination for *Unlocking CER Benefits Through Flexible Trading* provides an option for establishing a second settlement point.[121] This allows flexible resources to be separately metered, and provided to market settlement systems, from the rest of the load at the primary connection point.

Figure A.3 shows a potential configuration of a VSR using a second settlement point.

Figure A.3: Comparison of standard versus secondary settlement point configuration



Source: AEMC

The above diagram is a simplified version of a possible use case for secondary connection points. Consumers have the flexibility to use secondary settlement points in a configuration that works best for them. For instance, households with rooftop solar can still use the output for self-consumption and will not be paying to use their own generation. This is because subtractive settlement arrangements apply between the primary connection point and secondary settlement point(s).[122]

The location of controllable resources in the metering configuration would impact whether the VSRP needs to incorporate their output in their bids and subsequent dispatch. For example, in the figure above, a VSRP for the standard connection point configuration on the left would need to account for both the general load and the controllable resource in its bids. In the configuration on the right, if NMI 2 was nominated as a VSR, the VSRP would only need to account for the controllable resources behind that NMI in its bids.

119 See clause 2.3D.2(e) of the NER.

120 VSRPs may also nominate resources at embedded network child connection points, as long as they are an on-market connection point.

121 AEMC, Unlocking CER benefits through flexible trading, Rule determination, 15 August 2024, p. iv.

122 AEMC, Unlocking CER benefits through flexible trading, Rule determination, 15 August 2024, p. 36.

Zonal aggregation

Participants can aggregate qualifying resources provided that each is within the same zone, with the zones to be defined by AEMO in the VSR guideline.[123] These zones would be fixed for the first three years of dispatch mode's operation.[124] AEMO would have discretion in deciding what zones are appropriate for VSRs in the guideline process, which could include retaining a regional approach.[125] AEMO has proposed that the aggregation process, including the zonal requirements, would be managed mainly through the existing portfolio management processes.[126]

Stakeholders noted that the decision on VSR zones will impact participation.[127] CEC highlighted that even with regional zones, it will be challenging currently to aggregate resources to the proposed 5MW threshold. Origin suggested that zones must stay at the current load forecasting boundaries for a minimum amount of time, proposing the first three years.

A change from the draft rule is that the final rule specifies that the VSR zones determined in establishing the first VSR guideline will be fixed for the first three years of dispatch mode operation.[128] The process for subsequent changes to VSR zones will be outlined through the VSR guideline as well.[129] This provides participants with certainty around where they are able to aggregate when first choosing to participate, and stability in the future.

We have not required the initial setting of zones to follow the current load forecasting boundaries. In setting the VSR zones, both initially and in any subsequent revisions, AEMO must consider the principles outlined in appendix A.2.4.[130] The principles aim to ensure that zones are set at a level that encourages participation, while ensuring AEMO can operate the system effectively. AEMO will also have the ability to disaggregate a VSR within a zone subject to the requirements and processes outlined in the VSR guideline.[131]

A.2.2 We have balanced requirements between the rules and Guidelines

In establishing dispatch mode, we have carefully considered whether requirements should be defined in the rules or in AEMO guidelines. Our final rule defines obligations for participating in central dispatch, with technical details for how VSRs should participate to be defined by AEMO in the new VSR guideline.

We consider that this approach is best because it:

- Clearly defines the obligations for VSRPs and leverages the Commission's previous work through IESS. This will create certainty for market participants as the NER provides stability and familiarity through the application of existing regulations. See appendix A.2.3 and appendix A.2.5.
- Empowers AEMO to outline the technical details for participation, which it is best placed to do. This allows AEMO to update these details more regularly than if they were placed in the rules and allow them to be tailored to the requirements of participants utilising aggregated small resources. These details are outlined in appendix A.2.4.

123 See clause 3.10A.3(c) of the final rule.
See Section B.1.1 of the consultation paper for further information on the zonal requirement.

124 See cause 11.180.5 of the final rule.

125 See clause 3.10A.3(c) of the final rule.

126 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, pp. 92-93.

127 Submissions to the draft determination, Origin, p. 4, CEC, p. 7.

128 See clause 11.180.5 of the final rule.

129 See clause 3.10A.3(c)(5) of the final rule.

130 See clause 3.10A.3(d) of the final rule.

131 See clauses 3.8.3(b6) and 3.10A.3(b)(2) of the final rule.

Stakeholders broadly agreed with this approach during our technical working groups.[132]

A.2.3 The final rule incorporates VSRs into the existing rules for central dispatch operations

The requirements for how VSRs operate in central dispatch are defined in our final rule and broadly follow a similar process for scheduled BDUs. At a high level, the final rule sets out central dispatch obligations for VSRPs across:

- bidding
- dispatch
- non-conformance process
- PASA
- data requirements.

VSRs (other than hibernated VSRs) are defined as a scheduled resource in the rules and are subject to the provisions that apply to scheduled resources, except as described in this appendix and the final rule.[133] The obligations for deactivated and hibernated VSRs are outlined in appendix A.3.

Bidding

For each VSR, the VSRP will bid in its willingness to generate or consume energy in 20 price quantity pairs, 10 each for generation and load. The bidding process for a VSR is the same as the arrangements for scheduled BDU, including:[134]

- Bids may be for resources that include generation, load and bi-directional resources. They, therefore, may contain up to 20 price and volume bands.
- Bids would include all components applicable to other scheduled resources. This includes, for example, price-volume pairs, maximum availability and a ramp-up and down rate. See appendix A.2.5 for further information about ramp rates for VSRs.
- Bids must reflect the physical capability of the VSR, such that the unit can respond to a dispatch target in the required time frames.
- VSRPs must supply AEMO with bid validation data.
- Bids and rebids submitted for a VSR must not be false or misleading.

Where secondary settlement point/s are used, described in appendix A.1, only the response from the resource at the secondary settlement point would be bid in.

VSRs may also participate in the regulation and contingency FCAS markets, provided they comply with their relevant technical requirements, see appendix B.4.2. The bidding process for these markets would be the same as for scheduled BDUs.[135]

Consistent with the existing bidding process, the minimum incremental bid quantity would be 1 MW.

SA Water suggested that dispatch mode should facilitate non-integer MW unit participation, similar to feedback received in our consultation paper.[136] AGL and AEMO recommended maintaining the existing 1 MW bidding increment.[137] AEMO outlined that changing this could

132 AEMC, TWG Minutes #5, 17 April 2024, p. 2.

133 See chapter 10 of the final rule.

134 See Clauses 3.8.6, 3.8.22A and Schedule 3.1 of the final rule.

135 See clause 3.8.7A of the NER.

136 SA Water, submission to the draft determination, p. 1.
Submissions to the consultation paper, Grids, p. 8, Sonnen, p. 5, SwitchDin, p. 5.

impact NEMDE processing times and would require costly system upgrades, including monitoring requirements for FCAS participation.

The Commission acknowledges that the 1 MW bid limit may limit some participation, however this would only occur when aggregations are small. Taking into account the complexity of changing the bidding increment, we consider that the integer MW bidding increment should be maintained. Participants and AEMO can consider how to enable and encourage the participation of smaller aggregations through the technical details established in the VSR guideline, such as the conformance requirements for small aggregations.

Dispatch

VSRs will be incorporated into the existing NEM dispatch process, including co-optimisation between energy and FCAS dispatch. Dispatch instructions will be generated every five minutes, consistent with the NEM spot market and issued to each DUID.

The VSRP will receive a single bi-directional dispatch instruction representing the net flow to be achieved by the VSR with respect to its DUID.[138] This dispatch instruction would be positive where the VSR is being dispatched to discharge, and negative where it is being dispatched to charge. The VSRP would also obtain an enablement for each FCAS service where relevant.

VSRPs will be required to comply with dispatch instructions in the same as any other FRMP for a scheduled resource.[139] The AER will use its discretion in assessing any instances of non-compliance with the rules, such as whether any non-compliance was due to non-static distribution network limits that the VSRP was unable to account for.

In the example of an aggregated VSR, if the VSRP receives a dispatch instruction to generate 10MW, the VSRP must ensure that the sum of all flows across the aggregated NMIs in the VSR is equal to 10MW at the end of the dispatch interval. In doing this, some NMIs may be consuming power while others are generating. For the purposes of complying with dispatch instructions, it does not matter what each individual VSR is doing as long as the net response matches the dispatch instruction.

EUAA suggested the arrangements for net output for C&I sites be clarified.[140] For a large C&I site with multiple connection points or secondary settlement points, they may participate at the site level with all or only some of their connection points. Dispatch obligations would only apply to the NMIs they choose to participate with.

Non-conformance process

VSRs will have their conformance with dispatch instructions monitored by AEMO against a set of criteria developed through the VSR guideline.[141] See appendix A.2.4 for further information. Where a VSR fails to respond to a dispatch instruction within a tolerable time and accuracy, as determined by AEMO, the VSR:[142]

- would be declared and identified as non-conforming
- cannot be used as the basis for setting spot prices.

137 Submissions to the draft determination, AEMO, p. 9, AGL, p. 3.
138 See clause 4.9.2(a) of the final rule.
139 See clause 4.9.8(g) of the final rule.
140 EUAA, submission to the draft determination, p. 4.
141 See clause 3.10A.3(b)(5)(iv) of the final rule.
142 See clause 3.8.23B(b) of the final rule.

AEMO must advise the VSRP that the VSR is non-conforming and request a reason for this. AEMO may also request that the VSRP submit modified parameters for the VSR based on this non-conformance.[143]

AEMO may also require the VSRP to limit the available capacity of the VSR for as long as the VSR is non-conforming.[144] The VSR would continue to be declared non-conforming until AEMO is satisfied that the VSR would respond to future dispatch requirements as required.[145]

Where a VSR continues to be non-conforming, after a reasonable period, AEMO must prepare a report describing this non-conformance and forward it to the VSRP and the AER.[146] The AER assesses compliance with the rules separately from the conformance process, and may investigate instances of non-conformance to assess whether the VSRP was compliant with the rules.

Non-conforming VSRs can be deactivated or hibernated; see appendix A.3 for more information.

PASA

VSRPs will be subject to the same ST PASA requirements for VSRs as other scheduled resources. For example, over the 7-day ST PASA horizon, the VSRP needs to provide for each VSR:[147]

- available capacity for each trading interval
- PASA availability for each trading interval
- if applicable, projected daily energy availability.

PASA is the principal method of indicating a forecast of electricity system reliability to the NEM. As VSRs will be participating in central dispatch, having information about their availability in ST PASA ensures that AEMO can adequately manage the power system.

VSRPs will not need to submit MT PASA information for their VSR. We consider that requiring VSRPs to provide the forecast availability of their VSR for the next three years would be onerous and not meaningfully benefit the market or AEMO. This is because VSRs will likely be dynamic in their operation and their information would not be best suited to the MT PASA process. Removing this obligation would also reduce barriers for participants to participate in dispatch mode.

VSRPs need to provide DSP information for their VSR(s).[148] AEMO would use the DSP information in its longer-term planning processes. This approach is consistent with the Commission's decision for WDRUs.[149]

Data requirements

Each qualifying resource in a VSR would be required to have appropriate remote monitoring equipment necessary for AEMO to discharge its market and power system security functions.[150] AEMO has discretion on the form of these requirements, which will be outlined in the VSR guideline.[151] This discretion also covers the use of supervisory control and data acquisition (SCADA) lite for transmitting and receiving data, as suggested by EnergyAustralia.[152]

143 See clause 3.8.23B(c) of the final rule.
144 See clause 3.8.23B(e) of the final rule.
145 See clause 3.8.23B(d) of the final rule.
146 See Clause 3.8.23B(g) of the final rule.
147 See clause 3.7.3 of the final rule.
148 See clause 3.7D(a)(3) of the final rule.
149 AEMC, Wholesale demand response mechanism, Rule determination, 11 June 2020, p. 20.
150 See clause 4.11.1(d) of the final rule.
151 See clause 3.10A.3(b)(5)(ii) of the final rule.
152 EnergyAustralia, submission to the draft determination, p. 5.

A.2.4 A new AEMO guideline will outline technical requirements for participation

AEMO will define the required technical details for how VSRs participate in central dispatch through a new VSR guideline. This rule change provides a pathway for currently unscheduled resources to participate in central dispatch, which can comprise various different types of technology which may have different speeds of technological advancement.

The Commission recognises that AEMO is best placed to consult on and make the decisions on the technical requirements for VSRs. Empowering AEMO to define the technical details of participating through a guideline also allows these details to be updated more quickly to account for technological advancements than if they were in the rules.

Our final rule requires the VSR guideline to include:[153]

- processes for nominating a qualifying resource as a VSR and aggregating qualifying resources
- a requirement that VSRPs must be the FRMP at the connection point for the VSR
- processes for participants to test the individual or aggregated capability of their resources to participate in central dispatch before formally nominating these resources as a VSR
- operational requirements of VSRs including:
  - the types of data to be provided by a VSRP to AEMO and by AEMO back to the VSRP
  - telemetry and communication requirements for VSRs
  - minimum threshold for nameplate or combined nameplate rating for nominating a VSR
  - VSR conformance criteria
  - acceptable types of metering installations for participating connection points.
- processes for:
  - VSRPs to share data with DNSPs or TNSPs
  - the disclosure of data collected by AEMO from VSRPs to DNSPs or TNSPs, including obligations for confidential data
- processes for VSRPs requesting to deactivate or hibernate a VSR and the process for reactivating and resuming operation in central dispatch
- any requirements for information to be provided by deactivated or hibernated VSRs
- any other information AEMO considers reasonably necessary.

The VSR guideline has been expanded since the draft rule to account for stakeholder feedback outlining that the guideline should:[154]

- reflect the confidential data provisions in the NER and provide guidance on the use or reproduction of data
- allow for VSR data to be shared with DNSPs
- include data sharing with TNSPs to account for a VSR connected to the transmission network

We have not included any new prescribed data sharing arrangements, as suggested by Ausgrid and SAPN.[155] We consider that DNSPs and AEMO can use their existing data sharing arrangements for VSRP data where needed. As VSRs grow, the Commission will consider whether new prescribed data sharing arrangements are warranted.

153 See clause 3.10A.3(b) of the final rule.

154 Submissions to the draft determination, Ergon and Energex, p. 2, Ausgrid, pp. 2-3, AEMO, p. 8.

155 Submissions to the draft determination, Ausgrid, pp. 2-3, SAPN, pp. 2 and 6.

The CEC and Origin raised concerns with the minimum size of VSRs being 5MW, as proposed by AEMO in its rule change request.[156] We maintain that the minimum size of VSRs is an operational consideration for AEMO and best consulted on by AEMO with industry in developing the VSR guideline.

The VSR guideline will also outline the zonal aggregation requirements for VSRs, including:[157]

- a methodology for determining zones in which VSRs can be aggregated, including applicable loss factors for VSRs
- requirements and conditions for VSRPs when aggregating VSRs
- necessary guidance for VSRPs on the process for aggregating VSRs to relevant zones
- any relevant validation process for AEMO
- guidance for VSRPs on the process and timing for changes to the VSR zones, including minimum lead times for when changes would take effect.

AEMO must follow the Rules consultation procedures in developing the guideline.[158] To ensure that the guidelines are fit for purpose after VSRs have entered the market, AEMO will be required to review these guidelines three years after the commencement of the rule.[159]

Outside of the required review, AEMO may also choose to review this guideline when it considers changes are required.[160]

Principles when creating and amending the guideline

In developing the new guideline, AEMO will need to make decisions on the cost of facilitating VSRs, as well as the technical requirements for VSRs. These decisions are likely to impact the level of participation in VSRs, as outlined below.

In developing and amending the VSR guideline, AEMO must:[161]

- Seek to minimise the total cost of facilitating the rule change, by balancing the cost to participants in operating a VSR and AEMO's costs of facilitating VSRs.
  - For example, through consultation AEMO may choose to develop a more expensive technical solution if it means this expense would significantly reduce costs for participants.
- Facilitate the ease of participation in central dispatch by VSRs and apply restrictions on VSRs only to the extent reasonably necessary for AEMO to manage power system security and reliability.
  - For example, balance the benefits from greater participation with lower technical requirements and the benefits from greater technical requirements with lower participation. This would also allow AEMO to apply different technical requirements based on the size of the VSR. For instance a 150 MW VSR may require different technical requirements than a 10 MW VSR.
  - This principle would also apply to AEMO determining zonal requirements for participation. For example, AEMO must balance the benefits from less strict zonal requirements, such as regional, with the need for VSRs to be in zones that accurately reflect the power system.

156 Submissions to the draft determination; Origin, pp. 3-4, CEC, p. 4.
157 See clause 3.10A.3(c) of the final rule.
158 See Rule 8.9 of the NER.
159 See clause 11.180.3(c) of the final rule.
160 See clause 3.10A.3(e) of the final rule.
161 See clause 3.10A.3(d) of the final rule.

- Have regard to any other matter determined by AEMO, acting reasonably, which must be specified in the VSR guideline.

These principles aim to assist AEMO and stakeholders in balancing these trade-offs, while still giving AEMO flexibility to determine the most appropriate requirements for VSRs. The principles also recognise that VSRs are not the same as large scheduled generators and BDUs, and therefore should not face the same requirements This is important to reflect that:

- Participation in dispatch mode is voluntary. Strict requirements will simply result in low participation and therefore low benefits for consumers.
- Market participants are still learning and developing their capabilities to control aggregated CER and should be given time to develop these capabilities.
- Participation is likely to build up over time. In the early years, the small size of each VSR participating means they are unlikely to have a material impact on power system security and therefore leniency comes at a low risk.

This is explored further below for our decision on VSR conformance criteria.

Origin agreed with the inclusion of these principles but raised that they may be hard to achieve in practice.[162] We recognise that AEMO will have a difficult job in ensuring it has made the right trade-offs when developing the VSR guideline. We strongly encourage stakeholders to engage with AEMO in developing the VSR guideline and note these principles where needed.

Conformance criteria

The conformance of VSRs will be assessed in real-time against criteria developed by AEMO through the VSR guideline.[163] This is consistent with the process for other scheduled units and allows AEMO to easily update the criteria when needed and tailor it the requirements for VSRs.

Red Energy and the AEC suggested that VSR conformance criteria should be defined in the rules, highlighting that lesser obligations for VSRs has the potential to threaten system security and create additional costs for consumers.[164] Red Energy further suggested that the existing bidding rules offer sufficient flexibility for VSRs, by allowing them to amend their bids or offer explanations to AEMO if they cannot follow dispatch instructions.[165] Other stakeholders suggested that if conformance criteria are to be defined in the VSR guideline, it should ensure VSR participation is accurate, creating a level playing field for all scheduled resources.[166]

162 Origin, submission to the draft determination, p 3.

163 See clause 3.10A.3(b)(5)(iv) of the final rule.

164 Submissions to the draft determination, Red Energy, pp. 2-3. AEC, p. 1.

165 Red Energy, submission to the draft determination, p. 3.

166 Submissions to the draft determination, AEC, p. 1. CS Energy, p. 4. Origin Energy, p. 4. Alinta, p. 2.

Box 7: VSR conformance should be set at a level that reflects their impact

The Commission recognises that accurate participation is essential for the efficient operation of central dispatch. However, VSR conformance criteria should be set at a level that does not disproportionately disincentivise participation.

Large scheduled resources are designed around constant spot market operation to a high degree of accuracy. This reflects both:

- the impact they can have on the market and power system
- that their primary reason for operation is to earn revenue in the spot market and when they made their investment cases they knew they would be subject to such requirements.

By contrast VSRs are likely to be comprised to small aggregated resources and, initially, would not materially impact the system. Furthermore, VSRPs will have the option to participate in dispatch, reflecting that the underlying resources are likely to largely have other primary purposes (for example, minimising residential customers' bills) for operation.

If conformance criteria for VSRs are set at the same level as existing scheduled resources, this would likely be disproportionate to their impact and significantly disincentivise participation. This would lead to resources continuing to participate out of market. This will cause the inefficiencies as outlined in section 2.2.3 and lead to an even worse outcome on the power system than had they participated with lower conformance than existing scheduled resources.

Our final rule maintains that AEMO will set the conformance criteria for VSRs, subject to the principles enshrined in the VSR guideline. Allowing conformance to be set at a level that encourages participation and maintains the efficient operation of the market.

The Commission maintains that VSR conformance is best defined in the VSR guideline and determined by AEMO under guidance from the principles outlined above. This is consistent with the conformance process for existing scheduled resources, which have their conformance criteria determined by AEMO through the dispatch operating procedure.[167]

It is important to note that conformance is an operational tool for AEMO to monitor how scheduled resources are performing. VSRPs are still required to comply with dispatch instructions, with instances of non-compliance investigated by the AER. VSRPs are also subject to the same bidding rules as other scheduled resources, as outlined above.

AGL and the CEC suggested that VSRPs should not be accountable for instances of non-conformance due to changes in distribution network limits outside of their control.[168] AEMO may consider how to address these concerns when establishing the conformance criteria in the VSR guideline.

We acknowledge that AEMO will face a complex trade-off in setting conformance criteria to reduce the barriers to entry by aggregated resources and ensuring reliable participation in dispatch. The Commission's guideline principles in appendix A.2.4 aim to guide AEMO and participants in managing this trade-off.

167 AEMO, Dispatch procedure (SO_OP_3705), Section 3, available here.

168 Submissions to the draft determination; AGL, p. 3. CEC, p. 8.

A.2.5 Other requirements that apply to VSRs

AEMO has power to direct active VSRs

AEMO will be able to give directions to active VSRs, and clause 4.8.9 instructions to all VSRs, consistently with existing provisions for other resources. Directions for aggregated VSRs will apply at the aggregated level.

AEMO can issue directions and clause 4.8.9 instructions to maintain or re-establish the power system in a secure, satisfactory, or reliable operating state. Directions may be issued in respect of scheduled resources (which will include VSRs) and clause 4.8.9 instructions may be issued to all Registered Participants (which will include VSRPs in their underlying registration categories, such as generators or IRPs).[169]

EUAA raised concerns that VSRs may be directed based on their technical capability, ignoring operational parameters.[170] For example, a pump may have the technical capability to be directed off, but needs to run for operational requirements.

The existing rules and AEMO procedures require AEMO to contact the participant who may be directed, who in turn can outline any operational concerns or inflexibility.[171] We understand that AEMO would not direct a plant against its operational requirements and would look to update the directions procedures to clarify how this will work for VSRs.

Inactive and hibernated VSRs, described in appendix A.3, are excluded from the directions in clause 4.8.9.[172] VSRs may be inactive for a variety of reasons, including situations where they may not be able to control their VSR. We view being able to direct these resources when inactive or hibernated may be seen as a risk for participants and would act as a disincentive to participate.

The powers in the NER and NEL mean AEMO can issue clause 4.8.9 instructions to inactive or hibernated VSRs. Importantly, AEMO would have this power to issue instructions regardless of whether the resource is nominated as a VSR.

We consider that being subject to directions (while active) would not add any material complexity or pose a significant disincentive to nominate a VSR. As discussed above, VSRs would only be able to be directed for a response they are able to achieve. Furthermore, VSRPs can choose to deactivate or hibernate if they have concerns about being directed in certain circumstances.

We also expect that VSRs would not be directed often in the short term. If they are directed, they would be eligible for compensation under certain conditions.[173] Furthermore, under the ISF final rule, regularly directed participants can request to enter into a contract with AEMO and this has the potential to be a positive for participants.[174]

VSRs will provide state of charge information under the *Enhancing reserve information* rule

Applicable information about the energy availability of VSRs will be published in operational time frames, in line with the Commission's determination for *Enhancing reserve information*.[175] VSRPs with VSRs that are batteries would provide this information for the VSR as a whole, that is at the aggregated level and not for each individual resource that may be aggregated.[176]

169 See clauses 4.8.9(a) and (a1) of the NER.

170 EUAA, submission to the draft determination, p. 4.

171 AEMO, procedures for issue of directions and clause 4.8.9 directions, section 3(c), available here.

172 See clauses 3.10A.2(f)(4) and (l)(2)(ii) of the final rule.

173 See clause 3.15.7 of the NER.

174 AEMC, Improving security frameworks for the energy transition, Rule determination, 28 March 2024, p. 69.

175 AEMC, Enhancing reserve information, Rule determination, 2024, available here.

176 See rule 3.7G of the final rule.

The final rule for *Enhancing reserve information* requires the publication of information on energy availability in the operational time frame, including:

- state of charge (SOC)
- maximum storage capacity.

VSRs are required to provide AEMO with the aggregated actual generation, actual load and actual energy stored as part of their operation. Extending the *Enhancing reserve information* decision to VSRs maintains the signals participants would have on the levels of storage available in operational time frames.

VSRs will be eligible for frequency performance payments but not required to provide mandatory primary frequency response

VSRs are not required to provide mandatory primary frequency response (PFR) but are eligible for FPPs.

The AEMC's final rule for *Clarifying Mandatory Primary Frequency Response Obligations For Bidirectional Units* provided that batteries that are 5 MW or bigger must provide PFR when exporting or importing energy, including when providing a regulation service.[177] We consider that the relative immaturity of smaller distributed resources, which are expected to participate as a VSR, justify their exclusion from providing mandatory PFR.

The AEMC's final rule for *Primary Frequency Response Incentive Arrangements* introduces new FPP arrangements.[178] These incentivise market participants to operate their plant in a way that helps to control power system frequency.

VSRs are defined as an eligible unit and will be able to receive FPP, subject to being able to comply with relevant requirements.[179] See appendix B.4.3 for further details on FPPs.

VSRPs will not be deemed non-compliant with their dispatch instruction when providing a frequency response to power system conditions.[180] VSRPs will however need to inform AEMO of their frequency response settings and require permission from AEMO to change these settings.[181]

VSRs will not be able to be constrained-on

VSRs will not be able to be constrained-on due to network constraints.

Network constraints may cause a scheduled generator, bidirectional unit or WDRU to be constrained-on in accordance with its availability but may not be taken into account in determining the spot price.[182] When constrained-on, participants are not eligible for compensation due to their bid being below the spot price.

Excluding VSRs from being able to be constrained-on is required to recognise that the resources participating may be owned by residential customers. The lack of compensation from being constrained-on can represent a risk to participating as a VSR, as it may impact the value proposition for signing up customer resources.

We acknowledge that the circumstances in which a VSR could be constrained-on are limited and may not materialise. However, removing this risk would decrease the risks of participating as VSR.

177 AEMC, Clarifying mandatory primary frequency response obligations for bidirectional plant, Rule determination, 7 March 2024, p. i.

178 AEMC, Primary frequency response incentive arrangements, Rule determination, 8 September 2022, p. i.

179 See clause 3.15.6AA of the final rule.

180 See clause 4.9.8(a1) of the final rule.

181 See clause 4.9.4(e) of the final rule.
AEMO may set out the process for approving frequency response settings for VSRs through the VSR guideline.

182 See clause 3.9.7 of the NER.

If network constraints do need to be managed using a VSR they may be directed, as outlined above.

VSR treatment during supply scarcity events

An issue raised in discussion between AEMO and the Commission between the draft and final determinations was whether AEMO would be required to turn off VSR load before other load in supply scarcity events (for example lack of reserves level 3 (LOR3)). AEMO and the Commission consider this would be undesirable as it would provide a disincentive to participate in dispatch mode. However, upon further investigation, we do not consider this is the case under current rules, and have therefore not made changes to the draft rule to resolve this. Our reasoning is set out below.

Our final rule includes VSRs as scheduled resources, meaning any consumption needs to be bid and dispatched through the market.[183] During supply scarcity events, such as the lead up to load shedding, VSRs that have bid to consume at the price cap will continue to be dispatched. VSRs would still be subject to load shedding, that is have their load interrupted, in the same way as if they were not VSRs.

The rules specify that the central dispatch process operated by AEMO needs to maximise the value of spot trading subject to a variety of factors.[184] One of these factors is the non-scheduled load requirements in each region. As outlined earlier, VSRs will retain their underlying classification from Chapter 2 when nominated as a VSR. This will mean that under this clause VSR load will be considered non-scheduled load, as non-scheduled load is defined as any load which is not classified as scheduled load under Chapter 2.[185]

Despite being considered non-scheduled load in this clause, VSRPs are not exempt from the obligations outlined in appendix A.2.3, such as submitting bids and following dispatch instructions.

The Commission considers that load requirements for VSRs would be any load bid that is within merit order. For instance, a bid to consume 10 MW when the price is less than $1000/MWh:

- would be a load requirement if the price is $150/MWh (i.e. bid to consume is in merit order)
- would not be a load requirement, if the price is $1500/MWh (i.e. bid out of merit order).

In the extreme, any VSR load bid at the price cap would be a load requirement in all instances. This would mean that during supply scarcity, any VSR bids at the price cap must be dispatched, up until the point of load shedding.

We understand that AEMO will consult with industry on how best to achieve this outcome in its systems.

Ramp Rates

VSRPs will provide minimum and maximum ramp rates for the VSR for use in the verification of their offers.[186] AEMO will review the dispatch operating procedure to see whether changes are required to best facilitate VSR ramp rates in central dispatch.[187]

183 See Chapter 10 of the final rule.

184 See clause 3.8.1 of the NER.

185 See chapter 10 of the NER.

186 See clause 3.8.3A(b) of the final rule.

187 See clause 11.180.2(b)(4) of the final rule.

For aggregated VSRs, the aggregated capacity would be used when calculating the minimum ramp rate requirement.[188] This is consistent with our position in the draft rule.[189]

SA Water and AGL noted that ramp rates will be difficult for aggregated portfolios to meet and suggested more flexibility be given to VSRs.[190] AGL suggested there should be a transitional period where VSRPs can test and improve their ramping capabilities.

VSRPs are able to bid in their ramp rates for their VSR, which can take into account any limitations on their ability to ramp. VSRPs may also submit a fixed loading level for the VSR.[191] VSRPs will not be able to submit a dispatch inflexibility profile, consistent with the Commission's previous decision removing the ability for BDUs to use inflexibility profiles.[192]

We recognise that there may be situations where VSRPs may want to use inflexibility profiles or a similar mechanism for their VSRs. In developing the VSR guideline we would encourage stakeholders to outline what mechanisms they would expect to need for VSRs, so these can be implemented through AEMO systems and procedures changes.

We are requiring AEMO to review the dispatch operating procedures, which contain further information on the ramp rate requirements for scheduled resources. In this review AEMO will need to take into account the principles set out in appendix A.2.4. This will allow participants to outline any changes that can be made to ramp rate within this procedure to best accommodate VSRs to increase participation in dispatch.

We also expect that VSRPs will have the opportunity to test the ramping performance of their resources prior to nominating their resources as part of AEMO's testing framework in the VSR guideline.[193]

A.3 The final rule provides flexibility to participants about when they operate in the mechanism

Our final rule includes two options that allow VSRPs to remove a VSR from dispatch obligations. These options recognise the challenges aggregated portfolios may face if required to continually participate in central dispatch.

The two options being introduced are:

- **Deactivation —** allows VSRPs to remove a VSR from most dispatch obligations but still submit bids and send real-time data to AEMO.
- **Hibernate —** allows VSRPs to remove a VSR from all dispatch obligations, including sending bids and real-time information to AEMO.

These options provide a necessary safety net for VSRs and recognise that some resources may only be able to participate over specific periods. This is in contrast to larger scheduled resources which are designed for constant participation and can disconnect from the grid when they encounter an issue in order to resolve it.[194]

188 See clause 3.8.3A(b)(1)(iv) of the final rule.

189 See section A.2.5 of the draft determination for further information.

190 Submissions to the draft determination, SA Water, p. 1. AGL, p. 2.

191 See clause 3.8.19(a) of the final rule.

192 AEMC, Implementing Integrated Energy Storage Systems, Rule determination, 4 May 2023, pp. 7-8.

193 See clause 3.10A.3(b)(4) of the final rule.

194 See section A.3.1 of the draft determination for further information.

We consider that this flexibility is necessary to assist in encouraging participation, as the risks of central dispatch operation can be managed. The need for flexibility was also highlighted by stakeholders to assist overcoming the complexity of participation.[195]

A.3.1 Participants will be able to deactivate their VSRs

VSRPs will be able to deactivate a VSR, removing them from the dispatch process and offering a 'safety net' for participants when they are unable to meet dispatch instructions.[196] There will be no limit on the amount of time a VSR can be deactivated for.

When their VSRs are deactivated, VSRPs will still be subject to most of the requirements outlined in appendix A.2, such as submitting bids and sending real-time information to AEMO. This maintains operational visibility for AEMO and facilitates easy re-entry back into dispatch for the VSRP.

AGL and AEMO outlined that the limit of seven days for deactivating VSRs in the draft rule should be increased, suggesting 30 days.[197] The Commission agrees, and considers that a limit on how long a VSR can deactivate for is not needed as:

- AEMO maintains operational visibility of deactivated VSRs, supporting the operation of the power system.
- VSRPs will incur a cost in needing to send bids and data to AEMO when deactivated. This creates an incentive to move to hibernated status if they will be deactivated for an extended period and do not wish to retain the easier path back to operation by staying inactive.

VSRPs will continue to provide ST PASA information to AEMO for their inactive VSRs, to maintain operational visibility for AEMO. We recognise that information for inactive VSRs will be variable and may not be as accurate as VSRs operating in central dispatch or other scheduled resources. We consider that the current rules drafting, which references best estimates, is flexible enough to cover the information submitted by VSRPs.[198]

Deactivation process

A VSRP may submit a deactivation notice to AEMO, and this notice would apply to each qualifying resource in the VSR. This notice must contain any required information and be submitted per the process outlined by AEMO in the VSR guidelines.[199]

Where a VSRP submits a deactivation notice in accordance with the above then:[200]

- AEMO must record the status of the VSR as inactive
- AEMO may also impose conditions on the inactive VSR which the VSRP must comply with
- AEMO is not required to include dispatch bids from inactive VSRs in central dispatch.

The VSRP will continue to submit bids and data to AEMO but will be exempt from the following regarding their energy bids for inactive VSRs:[201]

- the responsibility to ensure their data in their dispatch bid is correct
- requirements to conform with dispatch instructions, to the extent they receive any from AEMO

195 Submissions to the draft determination; Enel X, p. 2. Energy Australia, p. 5. AGL, pp. 2-3. AEMC, TWG #5 minutes, 17 April 2024.

196 This process is similar to the opt-out process proposed in the rule change request.

197 Submissions to the draft determination; AGL, pp. 2-3. AEMO, p. 4.

198 See clause 3.7.3(h) of the final rule.

199 See clauses 3.10A.2(b)-(c) of the final rule.

200 See clauses 3.10A.2(d)-(e) of the final rule.

201 See clause 3.10A.2(f) of the final rule.

- requirements that bids must not be false and misleading
- the ability to be directed for consumption or generation by AEMO
- the obligation to have personnel available to receive and act upon dispatch instructions
- ensuring that they can comply with their latest dispatch bid.[202]

Inactive VSR bids for contingency FCAS will not be exempt from the above.

VSRPs may submit a reactivation notice at any time to reenter central dispatch, or submit a hibernation notice.[203] As discussed above, there is no limit on the about of time a VSR can be deactivated for.

A reactivation notice must be made in accordance with the VSR guideline and specify a date when they plan to re-enter central dispatch.[204] If a request is made in accordance with the VSR guideline then at the date specified or otherwise determined by AEMO, the VSR will re-enter central dispatch.[205]

A.3.2 Participants will be able to hibernate their VSRs

VSRPs will be able to hibernate a VSR for up to 18 months, and, similar to deactivation, the VSR will be removed from the dispatch process. However, hibernated VSRs (unlike inactive VSRs) will not be considered scheduled resources and as such not be required to follow the obligations of being scheduled.[206]

The hibernation process offers a lower obligation path to keep resources nominated as VSRs over long periods where they do not want to participate in central dispatch. Compared to deactivated VSRs, hibernated VSRs are not required to continue to submit bids or data to AEMO.

As the resource remains nominated as a VSR, this allows an easy path to return to operating in central dispatch, rather than having to de-nominate the VSR. For instance, a participant may only have agreements to manage resources over the summer months and would be hibernated for the remaining months.

Hibernation will be limited to a minimum of 30 days and a maximum of 18 months. The minimum time reflects the complexity AEMO will face in needing to incorporate the resources back into the existing forecasting processes, as it no longer has data on the VSR. The maximum time is aimed at preventing VSRs being nominated and hibernated for indefinite periods of time, without ever planning to re-enter central dispatch.

Hibernation process

A VSRP may submit a hibernation notice to AEMO at any time in respect of a VSR or inactive VSR, and this would apply to each qualifying resource in the VSR.[207] This request must:[208]

- specify the period in which the VSR would be hibernated, from the period of at least 30 days to a maximum of 18 months
- contain any required information and be submitted following the process outlined by AEMO in the VSR guidelines.

202 AEMO may still issue clause 4.8.9 instructions to inactive VSRs.

203 See clauses 3.10A.2(g) and 3.10A.2(j) of the final rule.

204 See clause 3.10A.2(g) of the final rule.

205 The date otherwise determined by AEMO must be made in accordance with the VSR guideline, which can specify the alternate date needs to be agreed by the VSRP.

206 See clause 3.10A.2(l)(2)(ii) of the final rule.

207 See clauses 3.10A.2(j) and 3.10A.2(k)(4) of the final rule.

208 See clause 3.10A.2(k) of the final rule.

Where a VSRP submits a hibernation notice in accordance with the above then the VSR will be considered hibernated and no longer a scheduled resource.[209] While hibernated, AEMO may impose conditions on the VSR in accordance with the VSR guidelines.

To re-enter the central dispatch process, a VSRP must submit a resumption request to AEMO before the end of the maximum 18-month hibernation period.[210] This request will outline when the VSR is to return to dispatch and follow the process contained in the VSR guideline.

Where a VSRP fails to submit a resumption request prior to the end of the 18 period:

- the VSRP ceases to be a VSRP for the hibernated VSR
- each qualifying resource in the hibernated VSR ceases to be a VSR.

A.3.3 Deactivated and hibernated VSRs may still participate in contingency markets

When deactivated or hibernated, VSRs will still be able to offer and be dispatched for market ancillary services, but not regulation FCAS as this requires being scheduled.

This means that inactive or hibernated VSRs can continue to provide contingency FCAS. This in enacted in the final rule by specifying that for market ancillary services, VSRPs will still be required to follow dispatch instructions and will not be excluded from the provisions in appendix A.3.1. Hibernated VSRs are not a scheduled resource, and not excluded from the provisions in appendix A.3.1, meaning they need to follow any applicable ancillary service dispatch instruction. Deactivating or hibernating would not impact a VSR's classification as an ancillary services unit under Chapter 2 of the NER, allowing these resources to provide market ancillary services.[211]

This is a clarification from the draft rule, which merely specified that where deactivated, VSRs would not have obligations to follow any dispatch instruction. The Commission considers that deactivated or hibernated VSRs should continue to be able to provide ancillary services, as being scheduled is not a requirement to deliver these services.

Our final rule gives AEMO discretion on whether to accept bids from deactivated VSRs.[212] This discretion allows AEMO to reject any bid for energy or regulation FCAS from deactivated or hibernated VSRs, but accept bids for the contingency FCAS markets.

A.4 We have introduced new consultation requirements to manage the interactions with distribution limits

Our final rule sets out requirements for DNSPs to consult with VSRPs on the impact of non-static distribution limits on VSRs.[213] This new requirement aims to assist VSRPs in managing central dispatch operation and distribution network limits separately, until enduring regulatory frameworks for non-static distribution limits are developed.

VRSPs will be responsible for ensuring that their bid offers reflect any applicable distribution limits that apply to their VSR.

209 See clause 3.10A.2(l)(2)(ii) of the final rule.

210 See clause 3.10A.2(m) of the final rule.

211 See clause 2.3D.1 of the NER.

212 See clause 3.10A.2(e) of the final rule.

213 See clauses 5A.B.3(a)(6) and 5A.E.3(c)(9) of the final rule.

A.4.1 Distribution network service providers are implementing dynamic limits

DNSPs are investigating FELs as a mechanism to maintain the integrity of the distribution network as customer exports continue to grow. FELs can allow consumers to export more from their resources at times and locations where there is 'spare' unallocated capacity rather than be restricted to (potentially lower) static limits all the time. For a more detailed explanation of FELs see section 1.3 or the draft determination (Appendix A.4.1).

The Commission's position in the draft determination was that VSRPs must ensure that their bids and any subsequent dispatch are within any applicable FEL across their VSR. We also encouraged DNSPs to use their best endeavours to ensure any applicable FEL is communicated to VSRPs as early as possible, with any changes to this FEL communicated at least 30 minutes in advance of the change.

Submissions to the draft determination outlined that distribution limits may be a significant barrier to participating in dispatch mode.[214] Stakeholders suggested that the AEMC further clarify the interaction between FELs and dispatch participation.[215] CS Energy also suggested that an interim framework or a set of principles could be established to manage expectations and assist coordination and compliance with FELs.[216]

CEC and AGL suggested that the AEMC consider exempting a VSR from non-compliance if a FEL is changed on short notice or a DNSP overrides a VSRPs instruction to a device.[217]

A.4.2 We have introduced new consultation requirements for distributors

Our final rule introduces new requirements for DNSPs to consult with VSRPs on how non-static limits can be incorporated into dispatch bids. These requirements apply to both changes in DNSPs' connection policies, and model standing offers that impose non-static limits.[218]

The Commission's final rule strikes an appropriate balance between ensuring that VSRPs can account for distribution limits in dispatch, while not restricting DNSPs in finding appropriate solutions for non-static limits. The final rule maintains that while DNSPs are still developing FELs, it's not feasible to factor in any applicable FEL in dispatch instructions to VSRs. Requiring FELs to be incorporated into dispatch instructions would likely significantly increase the complexity of implementing the mechanism and add delays.

We investigated establishing more prescriptive arrangements for DNSPs and VSRPs, such as distribution limits must be communicated a set number of minutes in advance. However, this would require further work on the roles and responsibilities for distribution networks such as how the network limit is communicated and who it is communicated to. This work is best progressed through a standalone process and may be considered through the DSO work stream.

We consider that the AER can use its discretion in investigating instances of potential non-compliance due to distribution limits. AEMO may also consider these limits when setting conformance criteria in the VSR guideline.

214 Submissions to the draft determination; Origin, p. 4. CEC, p. 8. AGL, p. 3.

215 Submissions to the draft determination, CS Energy p. 3. Ergon and Energex, p. 2. Origin, p. 4.

216 CS Energy, submission to the draft determination, p. 3.

217 Submissions to the draft determination, CEC, p. 8. AGL, p. 3.

218 See clauses 5A.B.3(6) and 5A.E.3(c)(9) of the final rule.

A.4.3 VSRPs will still be responsible for managing distribution limits and dispatch obligations

Consistent with the draft rule, VSRPs will be responsible for ensuring that their bids and any subsequent dispatch are within any applicable FEL across their VSR. This means that the VSRP needs to ensure that each NMI in the VSR (if aggregated) would stay within any applicable FEL imposed by a DNSP at that NMI.

We expect that over the short term, FELs would not pose a significant limit on the operation of price-responsive resources, but this may change over time, requiring their integration with dispatch instructions. As the design and implementation of FELs progresses, AEMO and DNSPs can investigate incorporating FELs into dispatch instructions to VSRs.

A.4.4 Distribution limits should be designed to facilitate VSR participation

While we have not required FELs, or other distribution limits, to be integrated into dispatch instructions, these limits should be designed in a way that facilitates future integration. Our final rule requires consultation between VSRPs and DNSPs, and this should assist DNSPs in considering how this could be achieved.

DNSPs should have the flexibility to deliver a FEL solution that works best for their network. However, the assets being subject to these FELs may, or could in the future, participate as a VSR. As such the Commission expects that when DNSPs are designing the systems and processes for implementing FELs, they allow for future integration with dispatch instructions for VSRs. For example, providing and updating FELs to align with the time frame that allows bids to be adjusted.

Our final rule includes information sharing provisions between AEMO and DNSPs

The VSR guideline will set out data-sharing arrangements between AEMO and DNSPs (see appendix A.2.4). This provision can be used to ensure appropriate data is shared between AEMO and DNSPs when setting distribution limits.[219] This provision may also be used to ensure alignment between AEMO and DNSP systems, such that FELs can be included as part dispatch instructions to VSRs in the future.

A.5 Worked example

The following worked example builds on the example provided to TWG members on March 4th and has been updated to reflect the terminology of the final rule.[220]

In this example, the fictional retailer Ralph Energy has 1,200 households with behind-the-meter batteries with a contract that allows Ralph to control their batteries. The aggregated capacity of these resources is 12 MW/15.5 MWh.

Ralph Energy is registered as a Market Customer and is the FRMP for each customer. Both passive and controllable loads are behind a single NMI, meaning Ralph Energy is responsible for all resources behind the meter at each participating site.

Nomination and aggregation

Each of the 1,200 households would need to meet the requirements to be a qualifying resource and to be aggregated. Ralph Energy would then nominate these NMIs as a VSR, and where approved by AEMO it would receive a DUID. Each NMI would need to be within the same zone

219 This includes TNSPs where relevant.

220 A copy of the slides, as well as the minutes from the TWG, are available on the project page.

specified by AEMO in the VSR guideline. AEMO has proposed that this process would be managed through AEMO's portfolio management functions developed for WDRM.

Data

Ralph Energy would need to provide information about its VSR to AEMO when nominating and in real-time during operation. Specifics on how this data would need to be structured and transmitted to AEMO would be defined by AEMO through the VSR guideline.

A high-level overview of the data requirements is outlined in Table A.2 below.

Table A.2: VSR data requirements

Data	Description	Unit/granularity	VSR implications
Static or standing data	Site data that changes infrequently for each connection point, such as the capacity of the resources and price-responsive capacity.	The VSR guideline would outline specific data requirements.	Every NMI that Ralph wishes to nominate as a VSR must provide this standing data to AEMO.
Availability forecast (PASA)	Aggregated available capacity of generation, load and storage.	MW availability and storage in MWh across the short-term horizon.	Ralph would submit the expected availability of its VSR across the ST PASA horizon.
Bids	Per IESS, a bi-directional offer that includes both generation and load, up to 20 price bands per VSR.	20 price/quantity pairs i.e. $/qty ($/MWh, MW) for each dispatch interval	Ralph would use existing market systems to submit bids to AEMO.
Telemetry/ SCADA	• Aggregated (per VSR) instantaneous period ending measurement of active power flow at NMI. • Aggregated actual generation, actual load and actual energy stored.	Data requirements would be defined in the VSR guideline and power system communication standard.	Ralph would be required to set up appropriate communications to ensure it can provide the necessary data to AEMO

Source: AEMO

Bidding

Ralph Energy bids to charge its aggregated batteries during negative prices and discharge when prices > $300 and nothing at all other times. It would comply with existing bidding rules, such as bidding in good faith.

2 MW of the aggregated battery capacity is reserved to smooth out the passive load and manage unexpected changes to customers' load to comply with dispatch instructions.

These intentions are reflected in the table:

Table A.3: Ralph Energy VSR bidding intention

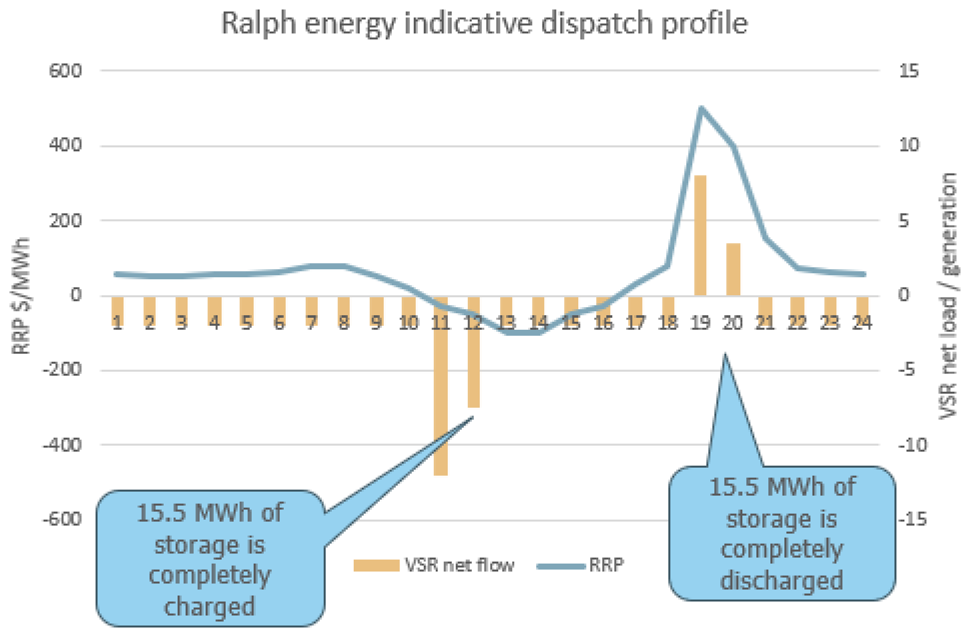
Market price range ($/ MWh)	Ralph Energy intention
<0	Customer batteries: Charge at the maximum rate, for example 10 MW. Assuming all batteries in the fleet have a SOC available to charge. Underlying customer load: no change (2 MW load) Bid intention: -12 MW
0 to $300	Customer batteries: no action. Underlying customer load: no change (2 MW load) Bid intention: -2 MW
Above 300	Customer batteries: Discharge at the maximum rate, for example 10 MW. This assumes all batteries in the fleet have SOC available to discharge. Underlying customer load: no change (2 MW load) Bid intention: +8 MW

Source: AEMC
Note: limitations in the VSRs ability to charge or discharge would need to be reflected in the VSRs bids or rebids.

Dispatch

Ralph Energy's bids are sent to AEMO and incorporated into the central dispatch process (NEMDE). When dispatched, Ralph would receive a single bi-directional dispatch instruction for the VSR. Ralph Energy would then disaggregate the dispatch instruction amongst the NMIs in the VSR and control the batteries to meet the instruction, such as linearly ramping between dispatch targets. An indicative example of Ralph Energy's VSR performance across a trading day is shown in Figure A.4 below.

Figure A.4: Ralph Energy indicative dispatch profile



Source: AEMC
Note: The aggregated battery charge and discharge response to wholesale prices is limited by aggregated capacity of 15.5 MWh. This limitation would need to be reflected by Ralph through its rebids.

Settlement and conformance

Ralph Energy's VSR would be settled in line with existing market processes. At a high level, Ralph would pay the regional price when its VSR is a net load and the regional price when it is net generation. Ralph will also be paid for any ancillary services it is enabled for, such as regulation FCAS, and receive any applicable frequency performance payments. Ralph's remaining retail customers would be settled normally per the existing arrangements.

The example assumes that the VSR exactly conformed to dispatch instructions. If this did not occur, the VSR would be subject to the process outlined in appendix A.2.3.

A.6 Implementation of VSRs in dispatch will be over 29 months and commence in May 2027

Dispatch mode will begin on 23 May 2027 with the first VSR guideline to be published by 31 December 2025. This commencement date allows greater time for participants to understand the requirements of participating and AEMO greater time to test technical solutions with prospective VSRPs.

Our draft rule proposed a start date of 5 November 2026. CEC and Shell Energy raised that with the large amount of detail in the VSR guideline, participants would have less than 12 months to understand the requirements of dispatch mode before commencement.[221] CEC outlined that additional time would allow participants to work through any issues. AEMO also suggested a longer implementation for dispatch mode so that AEMO and prospective VSRPs can test their

221 Submissions to the draft determination; CEC, p. 8. Shell Energy, p. 2.

technical solutions prior to commencement.[222] The CEC suggested Q1 2027 and AEMO's preference was May 2027 for new commencement dates.

The Commission agrees that greater time to understand and prepare for the requirements of dispatch mode will help to drive participation. In extending the commencement date, we note that AEMO does not make significant system changes over the summer period, so May 2027 was the next available time to implement dispatch mode. The timeline to complete the VSR guidelines is unchanged from the draft, and is required to be complete by 31 December 2025.

The Commission has also considered the need for a post-implementation review of dispatch mode. We consider that performing a post-implementation review is generally best practice given the scope of changes being introduced. We will consider whether a review is required once these amendments have been in operation for an appropriate period of time. If a review is required, we will use our self-initiation review powers to commence this.

222 AEMO, submission to the draft determination, p. 11.

B Additional incentives will help drive participation

Section 3.3 set out the Commission's high-level dispatch mode incentive decisions and reasons for those decisions. This appendix sets out the detailed design of those decisions and is structured as follows:

- the new incentive mechanism (appendix B.1)
- the removal of VSRs from RERT and directions cost recovery (appendix B.2)
- VSR capacity will count as an offset in the RRO (appendix B.3)
- the incentives available to VSRs under the current rules (appendix B.4).

Specifically, the final rule will:

- Introduce a time-limited incentive mechanism to provide early participants with funding to assist participation and building capabilities. This recognises that the other incentives are likely to be insufficient in the short term to attract an efficient level of participation.
- Exclude VSRs from RERT and directions cost recovery.

B.1 A new time-limited incentive mechanism will help to overcome initial barriers to participation

As outlined in section 3.3, there are significant expected benefits to the market from dispatch mode participation, with limited private incentives.

The Commission considers that an incentive scheme in the NER, with dollar and time limits, is in the long-term interests of consumers. The Commission is of the view that a simply designed tender process is the most preferable mechanism to deliver incentives for VSRPs in the NER in the short term.

There are 10 features of this mechanism:

1. incentive payments will be awarded through at least two tender processes between 1 April 2026 and 31 December 2031
2. AEMO will operate the incentive mechanism
3. the objective of the incentive mechanism is to increase dispatch mode participation in the long run, at the lowest cost
4. a per MW price cap will ensure value for money
5. the incentive mechanism will be capped to $50m, but external funding can also be used in addition to this amount
6. operational details will be determined through AEMO procedures
7. resources will only be eligible for one contract for one to three years
8. VSRPs must meet requirements set out in the participation agreements
9. payments will be recovered from Cost Recovery Market Participants and administrative fees from Registered Participants
10. AEMO will publish a report annually and at the end of the incentive period.

There were limited changes between the draft and final rule. Two of these changes were material:

- increasing the per MW payment cap from 50% of the estimated benefits, to less than 100% of the estimated benefits
- allowing external funding to be used with the mechanism.

Furthermore, there were four minor changes:

- bringing forward the commencement date of the incentive mechanism from January 2027 to April 2026
- clarifying the objective of the incentive mechanism
- extending the time for the AER to consider the Contracts and Firmness Guidelines by four months
- clarifying the cost recovery equation.

Key design elements of the mechanism and the reasoning for each of these changes is set out below.

B.1.1 The incentive mechanism will include at least two tenders between April 2026 and December 2031

The final rule provides a time-limited incentive mechanism running between 1 April 2026 and 31 December 2031.[223] It also requires that AEMO run a minimum of two tenders within the period.

Some stakeholders provided comments to the draft determination that the incentives would be hard to remove.[224] We note that the incentive period is defined. A stakeholder would need to submit a new rule change request in order for it to be considered to be extended. The Commission would require new evidence before it would consider a request for an extension to the period, as it currently is. As noted in section 3.3.5, longer-term changes anticipated in the market are expected to drive participation in the absence of the tender process.

The Commission recognises there is also value in allowing AEMO flexibility as to when it runs the tender process. There may be reasons to not run tenders in particular years. For instance, if in one year there is a highly competitive tender process with a variety of resources across all jurisdictions, it may be in the interest of consumers to procure more in that year and defer running the tender process in the following years. The final rule provides AEMO with flexibility as to how often it runs the tender process, but does require a minimum of two tender processes during the incentive period.[225]

Between the draft and final determination, the commencement date of the incentive period was brought forward from January 2027 to April 2026. In its submission, AEMO proposed that the first round of incentives should be awarded well in advance of the commencement of dispatch mode to provide investment certainty for VSRPs and support VSRPs' customer acquisition, technical development and testing.[226] The Commission agrees that there is benefit in allowing the incentive mechanism to commence earlier. Moving the date earlier extends the incentive period by eight months to five years and eight months (noting there is no requirement on AEMO to commence a tender process at the start of the period).

B.1.2 AEMO will operate the incentive mechanism

AEMO will operate the tender process.[227] AEMO has extensive experience in procuring contracts for services, including the RERT, System Restart Ancillary Services, Network Support and Control Ancillary Services, and will enter into transitional services contracts under the *Improving Security Frameworks for the Energy Transition* rule.[228] Additionally, AEMO currently runs a range of auction

223 See clause 3.10B.1 of the final rule, definition of incentive period.

224 Submissions to the draft determination, AEC. p. 2, Ausgrid, p. 3.

225 See clause 3.10B.2 (a) of the final rule.

226 AEMO, submission to the draft determination, p. 6.

227 See clause 3.10B.2(a) of the final rule.

processes, including the Settlement Residue Auctions, the Victorian Distributed Wholesale Gas Market Capacity Credit Auctions and the Day Ahead Auction in the East Coast gas market.

While a tender process will result in some administration and implementation costs to both the mechanism operator and to participants preparing tenders, the Commission considers that AEMO running the tender process will:

- ensure the market benefit is maintained
- target the lowest cost participants to be engaged first
- allow for some flexibility to adjust to market conditions.

B.1.3 The objective of the incentive mechanism is to increase dispatch mode participation in the long run, at the lowest cost

The primary objective of the incentive mechanism is to maximise the benefits to the market from having additional participation of VSRs in dispatch in the long run, whilst minimising the cost of payments made to successful tenderers.[229]

In order to ensure this, the rules provide for a number of considerations that AEMO is to account for in assessing resources for which prospective VSRPs are seeking funding, to meet the VSR incentive principles.[230] Two of these considerations are consequential to the objective of maximising market benefit, specifically:

- **The relative availability of the resource.** Not all resources will have the same characteristics — some resources are seasonal in nature, while others might have a lower capacity factor, yet these resources may still be of benefit to the market if they are scheduled. As such, instead of excluding participants that plan to regularly hibernate from the tender process, the rule requires AEMO to consider the relative availability of the resource when it is considering tenders.
- **The relative price-responsiveness of the resource.** Resources that are able to participate actively in dispatch, changing their consumption or generation on a regular basis in response to normal variations in spot prices, would likely provide greater market benefit than resources that only change their behaviour at the extremes. For example, a battery that responds to changing market conditions each day will likely provide greater market value than a stable load that only changes its behaviour when the wholesale price reaches the market price cap.

The final consideration speaks to the broader intention to build capability across the market, namely:

- **The variety of resource types participating as VSRs.** As noted earlier, one of the key drivers of this incentive mechanism is to build capability across the market in the early years after the VSR option becomes available. As part of this, there is benefit from having a diversity of resource types participating (for example, not just 4 MW batteries). This would assist in building the ability for more diverse resource types to participate as scheduled participants once the incentive scheme ends. Further, having a diversity of resource types in dispatch could have benefits of greater reliability across a range of market conditions, and lead to more competition in dispatch.

228 AEMC, Improving security frameworks for the energy transition, final determination, 28 March 2024.

229 See clause 3.10B.1 of the final rule, definition of *VSR incentive objective*.

230 See clause 3.10B.2(e) of the final rule.

To assist AEMO with these considerations, tender participants must outline their capacity, that is the number of MW (not MWh), region, types of resources and the availability of the resources that would be scheduled for the length of the contract.[231]

There were few submissions on this feature. AEMO noted that the objective may have the unintended consequence of prioritising VSR capacity over VSR capability building.[232] The intention is for AEMO to consider how to prioritise participation in dispatch mode in the long run. This will require a variety of resources and participants to potentially test their capabilities through participation. For the final determination, the definition of VSR incentive objective was amended to include "in the long run" in response to AEMO's submission.

B.1.4 A price cap will ensure value for money

The tender process will have a per MW price cap that AEMO will pay under a participation agreement.[233] Without a price cap, AEMO could be obliged to fund high cost projects, which may outweigh the overall benefit to consumers of having the additional participation in dispatch. As such, the final rule requires AEMO to determine the dollars per MW benefit of having an additional MW of participation in dispatch — that is the point where an incentive payment is at parity with the social benefit that MW generates. The amount that AEMO can pay a participant is then capped below the VSR Benefits. This ensures that consumers would capture the benefits from having the additional participation in dispatch, and should more than offset the cost of paying the incentive payments.

In the draft rule we set the cap at half the VSR benefits. EnergyAustralia proposed making this cap higher or removing it because the mechanism will result in participation in the long run, which consumers will benefit from.[234] The Commission agrees that there is merit to making this more flexible in order to gain more participation, within the overall capped constraint (noted below). Therefore, the final rule increases the per MW payment cap to be less than the VSR benefits. The cap is calculated on the benefits that arise during the incentive period. Participants will likely continue participating in dispatch beyond the incentive period. Therefore, it does not consider longer term value from the participants remaining in dispatch mode. Increasing the cap to less than the benefits will still likely benefit consumers as participation is expected to be lasting.

In terms of calculating the benefits, the final rule explicitly includes the benefits of:[235]

- avoided generation — the reduction in costs from generation that would not need to be dispatched due to the contracted VSR in dispatch
- reduced system security service costs — the cost reduction from having lower FCAS costs from having more VSR scheduled
- reduced RERT costs — reduced costs from having more scheduled capacity where this can reduce RERT activation costs
- avoided emissions — reduced emissions from having additional VSR in dispatch (noting that this would be valued using the value of emissions reduction nominated by energy ministers, as published in our guide on the national energy objectives).[236]

231 See clause 3.10B.2(5)(i) - (v) of the final rule.

232 AEMO, submission to the draft determination, p. 5.

233 See clause 3.10B.2(f) of the final rule.

234 EnergyAustralia, submission to the draft determination, pp. 4-5.

235 See clause 3.10B.1 of the final rule, definition of *VSR Benefits*.

236 AEMC, How the national energy objectives shape our decisions, 28 March 2024.

IES modelled these benefits to support the draft determination. We expect that AEMO would draw on the IES modelling when determining the VSR Benefits in the first instance. Alternatively, if AEMO:

- considers that market conditions have sufficiently changed, or
- is interested in detailed exploration of jurisdictions or sub-regions,

it has the option of conducting new modelling to support a more accurate assessment.

In its submission, AEMO requested further prescription in how it should calculate and determine the price caps.[237] AEMO noted in particular that economic assessments of consumer benefits are typically outside of AEMO's remit, would require non-trivial assumptions and scenarios and time-consuming consultation would likely be needed to mitigate the risks. We have not provided further prescription for a number of reasons:

- we expect that AEMO would use the IES modelling outlined above
- prescription on how to calculate the price cap could reveal the cap and result in potential gaming of offers.

Participation prices will be kept confidential

The price cap would be kept confidential during the incentive period, and only communicated to the AER and the AEMC to inform internal analysis of the incentive program.[238] Keeping the price cap confidential would also assist in keeping offers more accurate and cost reflective, minimising the risk of gaming offers.

The tender process is also closed. A closed, or 'sealed offer' tender process means the price per MW of successful offers is kept confidential. As the tender process would occur at least twice, a closed tender process would assist in developing an efficient level of information asymmetry. Limiting information about the other tender participants, the level of competition in the tender process, and clearing prices would reduce the ability to game the tender process by making offers just below the price cap.

B.1.5 The incentive mechanism will be capped to $50m, but external funding can also be used

The final rule limits the amount of participation payments that can be recovered from Cost Recovery Market Participants to $50m. This sets a boundary on the total amount that can be paid over the incentive period. This will:

- cap the overall payments faced by consumers
- establish market expectations for the incentive mechanism
- assist AEMO in scoping out the number of contracts and tender processes.

There is no single optimal approach in determining the payment cap. Instead, the following information informed our decision:

- **Customer Impact** — One relevant factor is what the 'cost' to end consumers would be for the life of the project. Note that the market benefit requirement of the incentive price cap would ensure these costs are outweighed by cost reductions elsewhere in the market. However, based on around nine million NMIs (roughly equivalent to customers) in the NEM today, adding an additional cost of $1 per customer per year would be equivalent to a $45m payment cap.

237 AEMO, submission to the draft determination, p. 6.

238 See clause 3.10B.2(g) of the final rule.

- **Market Benefit** — Another consideration is to explore the expected market benefit over the five years the tender process would operate. In IES's low uptake scenario, the social benefit from the first five years is around $167m.
- **Participant cost** — A final input is the likely costs to be covered and how many projects could be funded under the tender process. Based on a recent study by GHD for the Commission the upfront costs of a new scheduled generator to set up:[239]
  - forecasting systems range from $5,000-$30,000,
  - generation management system ranges from $90,000-$340,000 and
  - SCADA system ranges from $700,000-$1,000,000 (noting most VSRPs would be expected to use SCADA-lite which would have substantially lower generation management and SCADA costs).

  If it is assumed that on average set up costs are around $250,000- $500,000, then a revenue cap of $50m could fund 100 - 200 participants. EnergyAustralia in its submission noted that these cost ranges seem unrealistic, with potentially material costs to manage aggregated resources.[240] Shine Hub also noted that participants would also need to make significant investments in research and development, including developing price forecasting and bidding systems.[241] CEC stated that there is a level of unknown regarding the expected costs to participants that will only become apparent once AEMO testing has started.[242] We agree with stakeholders that given the novelty for some of these resources' participation, the costs are not fully predictable. Having the incentive mechanism will assist with early participation.

Based on these inputs, the final rule sets the payment cap that can be recovered from Cost Recovery Market Participants to be $50m over the five-year incentive period.[243]

Submissions to the draft determination suggested that an AEMO process could also receive external funding. Alinta proposed external funding could support an AEMO-led tender process.[244] Likewise AEMO in its submission asked for consideration of scenarios where:[245]

- AEMO could increase the cap where it sees a benefit from doing so, for example by seeking additional funding from jurisdictions or other organisations.
- A jurisdiction approaches AEMO to provide a conditional 'top-up' to the cap to incentivise more participation.

We agree that flexibility in allowing additional funding to be channelled through the AEMO incentive mechanism could be beneficial. In response to this we have allowed external funding to be used in addition to (or instead of) the $50m to fund the incentive mechanism.[246]

EnergyAustralia suggested that the total $50m cap be increased, to reflect a greater share of the social benefits.[247] We do not agree with increasing this cap. Retaining the $50m cap provides an appropriate balance between providing incentives and minimising the cost that consumers will ultimately pay. However, we note that through the added flexibility for external funding to be used through this mechanism, there is an ability to increase the amount using external funding.

239 GHD Advisory, Assessment of scheduling costs: Final report, June 2021.
240 EnergyAustralia, submission to the draft determination, p. 4.
241 Shine Hub, submission to the draft determination, p. 1.
242 CEC, submission to the draft determination, p. 4.
243 See clause 3.10B.2(f)(2) of the final rule.
244 Alinta, submission to the draft determination, pp. 1-2.
245 AEMO, submission to the draft determination, p.6.
246 See clause 3.10B.1, external funding definition, and clauses 3.10B.2(j) and 3.10B.3 of the final rule.
247 EnergyAustralia, submission to the draft determination, p.4.

B.1.6 Operational details will be determined through AEMO procedures

The details of the incentive mechanism processes and contract requirements will be set out in AEMO procedures.[248] AEMO must consult with industry to determine the specifics in the procedures. Under the final rule, the procedures are required to cover a range of details including the:[249]

- eligibility criteria for the tender process
- assessment criteria for the tender process
- procedures for conducting the tender process
- timing of the tender process
- offer requirements
- procedures and timetable for participation payments
- requirements of any standard participation agreements, including clarifying the consequences for non-compliance with the agreement.

AEMO would publish this procedure by 1 December 2026, or before the first tender (whichever is earlier), to allow sufficient time for participants to prepare their offers for the first tender process, expected to occur in 2026.[250]

B.1.7 Resources will only be eligible for one contract for one to three years

To align with the objective of maximising participation in dispatch mode and specifically addressing the high set up costs, there will be limits on long and repeated contracts. Contract length will be set at between one and three years.[251] The trade-off is that a single-year contract would only secure the participation of the VSR for a shorter period, while a longer contract could include inflated numbers to cover the risk associated with a longer time period. Introducing a range of one to three years for contract length seeks to assist AEMO in balancing these competing considerations.

Once a contract has been awarded, the resource underwriting the offer would not be eligible to offer into the tender process again.[252] For example, if a FRMP has a NMI that it offers into the tender process and is successful, the FRMP will not be able to submit an offer including that same NMI in a future tender process. As noted above, one of the drivers of the incentive mechanism is to support participants in recovering some of their initial establishment costs through participation payments. By limiting a single contract per resource, participants would be able to provide offers for their establishment costs, with the view of setting their ongoing operational business case to be sustained on the other market incentives.

B.1.8 VSPRs must meet requirements set out in the participation agreement

VSRPs must meet the requirements set out in the participation agreement.[253]

A successful tenderer who does not comply with the participation requirements specified in its contract will face consequences, as detailed in the contract. For example, if a successful tenderer offers to participate in the market year-round with no hibernation periods and then, in practice,

248 See clause 3.10B.2(c)-(f) of the final rule.
249 See clause 3.10B.2(d) of the final rule.
250 See clause 11.182.3(a)(3) of the final rule.
251 See clause 3.10B.2(j)(2) of the final rule.
252 See clause 3.10B.2(d)(1) of the final rule.
253 See clause 3.10B.2(l) of the final rule.

only offers availability for a short period over the year, it will likely be in breach of the contract terms. As such, it will face consequences that could include cancellation of future incentive payments, a requirement to repay part of the payments it has already received, or other penalties. The details of these consequences will be set out in the contract. This is aligned with current practice for other AEMO system service contracts such as RERT.

B.1.9 Payments will be recovered from Cost Recovery Market Participants and administrative costs from Registered Participants

Payments made under contracts between AEMO and successful tenderers will be recovered from Cost Recovery Market Participants based on their share of consumed energy. As Market Customers and other energy consumers would likely be the primary beneficiaries of reduced generation costs, reduced FCAS, and reduced RERT costs, they are the preferred group of participants to recover these costs from.

Recovery of costs will be on a yearly basis to reduce the administrative burden on AEMO.[254] As a result, we understand that AEMO will likely set payments under the contracts to be on a yearly basis, shortly before the costs are recovered. This will ensure that AEMO will not carry debt from making payments throughout the year.

The cost recovery equation was updated between draft and final rules to confirm that the amounts will be recovered across the NEM (not regionally) based on share of energy consumption in a billing week. The adjustment for VSR consumption has been removed because a VSR's consumption does not reflect the benefit that they are providing or how much they are participating in dispatch. It is simpler to recover from all registered participants. The cost recovery provisions also now explicitly require AEMO to account for any external funding that occurred during the year, before recovering any remaining amounts from Cost Recovery Market Participants.[255]

The equation is set out below, and is aligned with other cost recovery approaches present in the rules today:[256]

254 See clause 3.10B.3(3) of the final rule.

255 See clause 3.10B.3(d) of the final rule.

256 See clause 3.10B.3(e) of the final rule.

Figure B.1: Cost recovery equation

$$CRP = \frac{(E \times Net\ Incentive\ Costs)}{\sum E}$$

where:

CRP = the dollar amount payable by a *Cost Recovery Market Participant* in respect of the *financial year*.

E = the sum, in MWh, of the *Cost Recovery Market Participant's adjusted consumed energy* amounts at its *market connection points* in all *regions* over the course of a *billing period* (selected by *AEMO*) in the *financial year*.

$\sum E$ = the sum, in MWh, of all amounts determined as "E" for all *Cost Recovery Market Participants* for the relevant *billing period*.

$Net\ Incentive\ Costs$ = the amount determined under subparagraph (c)(1), less any amounts determined under subparagraph (c)(2). Where *Net Incentive Costs* is a negative number, it is deemed to be zero.

Source: Final rule, clause 3.10B.3(e).

The costs incurred by AEMO to establish and run the incentive mechanism (excluding any administrative costs associated with external funding) would be recovered from Registered Participants through AEMO's usual participant fee processes.[257] The commencement of the incentive mechanism would likely align with AEMO's next participant fee determination process, which would assist in integrating these additional costs.

B.1.10 AEMO will publish a report annually and at the end of the incentive period

AEMO will report on the amounts paid after the first tender process and then annually thereafter.[258]

Within 12 months of the completion of the incentive period, AEMO will publish a report exploring the relative success of the incentive mechanism. This report will cover:[259]

- a summary of the outcomes from the tender processes, including AEMO's opinion of whether the objective of the incentive mechanism was satisfied
- a summary of AEMO's learnings and insights from the incentive mechanism
- an analysis of the participation prices in the incentive mechanism
- an analysis of the types of VSR contracted through the incentive mechanism
- any other information AEMO considers relevant or useful to include.

This report would be a useful input into broader considerations around the future of any VSR incentives moving forward.

257 See clause 3.10B.3(a) of the final rule.

258 See clause 3.10B.4(a) of the final rule.

259 See clause 3.10B.4 of the final rule.

B.2 Participants will be excluded from RERT and directions cost recovery

The Commission's final rule would amend the RERT to exclude a VSRP's adjusted consumed energy from the RERT cost recovery calculation.[260] In doing so, we recognise that by participating in dispatch, a VSRP is delivering a broader social benefit by reducing the size of the RERT event and the corresponding costs.

Participation of VSRPs in dispatch is expected to result in substantial RERT cost savings by reducing the number of times RERT is activated.[261]

When RERT is activated by AEMO, AEMO pays those costs on behalf of consumers which are then recovered from Cost Recovery Market Participants in subsequent billing periods.[262]

Our decision to remove the adjusted consumed energy of VSRs from RERT cost recovery aligns with the Commission's decision to remove the adjusted consumed energy of scheduled bi-directional units from RERT cost calculations.[263] This came into effect through the *National Electricity Amendment (Integrating Energy Storage Systems into the NEM) Rule* 2021.

We received limited feedback on this change. Enel X stated that it is unlikely to provide a strong incentive for participation for three reasons:[264]

1. RERT costs are inherently uncertain, meaning it is difficult to justify an investment based on relief from these costs.
2. the benefits do not flow to the market participant, who usually incurs the set-up costs to enable market participation.
3. in theory, participation in dispatch mode should reduce the need for AEMO to activate RERT and so these costs would be expected to reduce over time anyway.

We agree that this change is unlikely to be a significant driver of participation. However, given that the costs to make this change are unlikely to be material, our rule provides for these incentives to participants.

In conversations with AEMO following the draft determination, excluding VSRPs' consumed energy from directions cost recovery was also raised. We agree that this would be aligned with the existing provisions which remove BDU and other scheduled load consumption from directions cost recovery. Our final rule excludes these resources.[265]

Only active VSRs are excluded from RERT and directions cost recovery

For a VSR to be excluded from RERT and directions cost recovery, it must be participating in dispatch. The energy consumed by VSRs that are inactive or hibernating would not be excluded from the calculations under clauses 3.15.8(b) and 3.15.9(e) of the NER and the relevant VSRPs will be subject to those costs.

B.3 VSR capacity counts as an offset in the retailer reliability obligation

The retailer reliability obligation (RRO) aims to support reliability at the lowest cost by requiring retailers to hold a minimum level of wholesale supply contract, with the intention of eliminating forecast reliability gaps before they occur. Where a reliability instrument is made, liable entities

260 See clause 3.15.9 (e) of the final rule.

261 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, June 2024, pp. 12-13.

262 See clause 3.15.9 of the final rule.

263 See clause 3.15.9(e) of the final rule.

264 Enel X, submission to the draft determination, p. 2.

265 Final rule clause 3.15.8(b).

(retailers and other parties that purchase electricity directly from the wholesale energy market) are on notice to enter into sufficient qualifying contracts with generators to cover their share of a 1-in-2 year peak demand forecast. They are also required to report their net contract position (NCP) to the AER.

The final rule, consistent with the draft rule, allows for VSR capacity to offset the relevant FRMP's liable load in the RRO.[266] This is a potential benefit as reducing a liable entity's NCP reduces the amount of additional qualifying contracts that it needs to purchase in the event of these reliability scenarios. Shell Energy's submission to the draft determination highlighted that an offset to a liable entity's liable load for VSR capacity would be an additional incentive to participate in the scheme.[267] SA Water also supported the inclusion of these resources in a Liable entity's NCP.[268]

The materiality of the VSR offset depends on the firmness that is determined for these resources. The AER assesses all NCP against criteria described in the AER's Contracts and Firmness Guidelines.[269] Submissions to the draft determination highlighted the importance of updating these Guidelines. Shell Energy stated that the timing of updates is important as the value of these assets in the development of a liable entity's position would only become evident after publication.[270] SA Water also acknowledged the importance of the update to the AER's Guidelines.[271]

We agree that the Guidelines need to be considered in a timely manner to provide certainty to potential VSR participants. The final rule requires the AER to use the normal consultation processes to update the Contracts and Firmness Guidelines by 30 September 2026.[272] The draft determination proposed that the guidelines were considered by 1 June 2026. However, the AER requested that this be extended by four months, to provide it with flexibility to consider changes for this rule after the amendments associated with the *Retailer reliability obligation exemption for scheduled bi-directional units* rule change.[273] As the extended timeframe still ensures that participants will have clarity on the treatment of resources in the RRO before participating as VSRPs in dispatch, this provides an appropriate balance between implementation considerations and incentivising participation.

We expect that when updating the Guidelines the AER would give consideration to the resources' capabilities from participating in dispatch.[274] Participating as a VSRP requires more control and predictability than unscheduled demand response resources.

266 See clause 4A.E.1(e) of the final rule.
267 Shell Energy, submission to the draft determination pp. 2-3.
268 SA Water, submission to the draft determination, p. 1.
269 See clause 4A.E.1 of the rules.
270 Shell Energy submission to the draft determination pp. 2-3.
271 SA Water, submission to the draft determination, p. 1.
272 See clause 11.180.2(a) of the rules.
273 AER engagement with AEMC staff on 3 December 2024.
274 See clause 4A.E.3(a)(2) of the NER.

B.4 Incentives available to participants under the current rules

Section 2.2.2 sets out that the majority of benefits of participation in dispatch accrue to the market, but there are some direct benefits to participants. This section outlines the existing incentives that exist for dispatch participants and how a VSRP would benefit from these:

- co-optimise energy and FCAS (appendix B.4.1)
- provide regulation FCAS (appendix B.4.2)
- be eligible for frequency performance payments (appendix B.4.3).

B.4.1 Co-optimisation of energy and FCAS would maximise the capabilities of VSRs

The final rule enables VSRs to participate in dispatch. When participating in dispatch, NEMDE will co-optimise VSR energy and FCAS bids, as it does for all scheduled resources. This would maximise the bids of VSRs in FCAS and the wholesale market by enabling their optimal dispatch.

Co-optimisation is the process of trading off between energy dispatch and FCAS enablement to achieve the total lowest cost.[275] NEMDE conducts co-optimisation of energy and FCAS bids for scheduled and semi-scheduled generating units, wholesale demand response units, and scheduled loads.[276]

This incentive would be most beneficial for unscheduled resources currently providing contingency FCAS as joining dispatch will automatically enable co-optimisation.

Eligibility for co-optimisation of energy and FCAS

To be eligible for co-optimisation of energy and FCAS as a VSRP, a FRMP must:

- Nominate a qualifying resource as a VSR and be registered as an ancillary service provider.
- Be participating in the central dispatch process with that VSR. Co-optimisation would not be available for inactive or hibernating VSRs.
- Provide an FCAS trapezium for each VSR.
- Comply with the requirements in the Market Ancillary Services Specifications (MASS) and the NER in regard to the services they will provide.
- Meet technical requirements such as Automatic Generation Control (AGC) if providing regulation FCAS.

In its rule change request, AEMO noted that the technical requirements to enable traditionally unscheduled resources to co-optimise may vary as these resources' capabilities and size evolve.[277]

B.4.2 Participants will benefit through eligibility to bid in regulation FCAS

The final rule enables VSRs to participate in dispatch. When participating in dispatch, VSRs will also be able to bid in regulation FCAS markets, subject to meeting the technical requirements. This aligns VSRs with other scheduled resources currently eligible to provide regulation FCAS and opens a new opportunity for VSRPs to participate in the NEM.

VSRPs providing regulation FCAS will benefit through receiving a settlement payment for each trading interval where they provided FCAS. This payment is calculated by using the relevant

275 AEMO, Guide to Ancillary Services in the National Electricity Market, October 2023, p. 3.

276 AEMO, Guide to Ancillary Services in the National Electricity Market, October 2023, p. 8.

277 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 59.

ancillary services price and the amount of the ancillary service provided in each dispatch interval.[278]

Regulation FCAS corrects supply and demand imbalances in response to minor changes to supply or demand in the NEM.[279] It is controlled centrally by AEMO. The AGC system sends control signals through SCADA every four seconds to participants enabled to deliver regulation FCAS.[280] This alters the output of generation units or the electricity consumption of loads to correct the demand and supply imbalances.

Participation in regulation FCAS requires a resource to be scheduled so that a set point can be determined from which a response can be provided and managed.[281]

AEMO's SCADA Lite initiative will enable a communication stream between AEMO and a VSRP to allow a VSR to provide regulation FCAS. This bidirectional connection will facilitate the exchanging of operational information (telemetry and control), and means a VSR would receive the necessary signals to participate in regulation FCAS.[282]

Eligibility for regulation FCAS

To be eligible to participate in regulation FCAS markets, a VSRP must:

- Be participating in dispatch with the relevant VSR. Regulation FCAS participation would only be available for participating VSRs; not inactive or hibernating ones.
- Classify the plant as an ancillary service.[283]
- Meet technical requirements such as AGC or equivalent functionality. This is necessary to understand the output of a DUID at four-second granularity and for the resource to be able to reach a set point (output target) as requested by AEMO to supply regulation FCAS. The introduction of SCADA Lite will facilitate this.
- Comply with the relevant standards and specifications outlined in the MASS.

B.4.3 Participants can be rewarded through frequency performance payments

Under our final rule, VSR participants would be eligible for FPPs (the FPP arrangements commence before dispatch mode does).[284] The rules on FPPs come into effect in June 2025.[285] This aligns VSRs with other scheduled resources that will be subject to FPP arrangements.

FPPs are a new financial incentive for scheduled resources to provide helpful frequency response into the NEM.[286] Under this scheme, scheduled resources that contribute helpfully to frequency would receive payments from those that make unhelpful contributions.

At this stage, we expect all VSRs participating in dispatch would meet the FPP metering requirements through the requirements to participate as VSRs. However, appropriate metering requirements for FPPs are contained in AEMO procedures and could be subject to future change.[287]

278 AEMO, Settlements guide to ancillary services payment and recovery, June 2024, p. 7.

279 AEMO, Guide to Ancillary Services in the National Electricity Market, October 2023, p. 5.

280 AEMO, Market ancillary service specification, June 2024, p. 13.

281 AEMO, Market ancillary service specification, June 2024, p. 14.

282 AEMO, SCADA Lite, accessed November 2024.

283 See rule 2.3D of the NER.

284 See clause 3.15.6AA of the final rule.

285 AEMC, Primary frequency response incentive arrangements final determination, September 2022.

286 FPPs were introduced under the *National Electricity Amendment (Primary frequency response incentive arrangements) Rule* 2022.

287 AEMO, Frequency Contribution Factors Procedure, February 2024, p. 11.

VSRPs would likely benefit from FPPs, however, we recognise that VSRs may be negatively affected by being subject to FPPs if they do not follow their reference trajectory (or dispatch target trajectory).[288]

Eligibility for FPPs

The final rule includes VSRs as "eligible units" in the FPP provision and so VSRs would automatically be eligible for FPPs, provided they have the correct metering.

288 Reference trajectory is the expected active power output or consumption of an eligible unit or the Residual, see AEMO's Frequency Contribution Factors Procedure, p. 11.

C A new framework to monitor and report on unscheduled price-responsive resources

Section 3.4 provided an overview and described the purpose of the AEMO and the AER reporting functions in the final rule. This appendix sets out the details of this reporting framework for unscheduled price-responsive resources.[289] In particular, it sets out how:

- AEMO reporting will identify issues and increase operational forecasting transparency (appendix C.1)
- the AER reporting will estimate the efficiency implications and costs associated with forecast deviations caused by unscheduled price-responsive resources (appendix C.2)
- our 12-month implementation plan will put the monitoring and reporting framework in place quickly (appendix C.3)
- we will consider if a visibility market model is warranted if reporting reveals an emerging material problem (appendix C.4).

We have only made minor changes between the draft and final rules. Specifically, we have amended the requirement in the draft rule for AEMO to monitor and report on patterns in the use of unscheduled price-responsive resources in response to spot prices. The visibility of the use of unscheduled price-responsive resources is limited. Thus, for reporting purposes, the use of unscheduled price-responsive resources is likely to be derived from deviations between forecast and actual demand, including by accounting for other sources of errors. The final rule reflects this.

No stakeholders submissions to the draft determination commented on the AER's reporting framework specifically. Thus, while we have clarified the level of accuracy implied by the rule, no further changes to the AER's monitoring and reporting framework are required.

C.1 AEMO will transparently identify issues with forecasting unscheduled price-responsive resources

The final rule introduces an AEMO monitoring and reporting framework with two key elements:

1. To monitor and report on the magnitude and impact of unscheduled price-responsive resources on deviations of actual demand from forecast in operational time frames.[290]
2. To publish the actions it takes to improve demand forecasting to account for unscheduled price-responsive resources. As part of this requirement, AEMO will also publish its methods and assumptions for how it considers unscheduled price-responsive resources in its forecasting.[291]

The final rule provides increased transparency on the impact of unscheduled price-responsive resources and how AEMO accounts for these resources in forecasting. Increased transparency of the contribution of unscheduled price-responsive resources to demand forecast deviations and subsequent inefficient market outcomes will be beneficial because:

- **It requires AEMO to transparently identify and seek to remedy issues with its demand forecasting to account for unscheduled price-responsive resources**. We consider that more

289 The reporting framework focuses on improving transparency of the impacts that unscheduled price-responsive resources may have on market outcomes which is a defined term in the final rule. This will not include price-responsive resources that participate in central dispatch.

290 See clauses 3.10C.2(b)-(d) of the final rule.

291 See clauses 3.10C.2(b)(5)-(6) of the final rule.

transparency on how unscheduled price-responsive resources are considered is beneficial, particularly as this is expected to grow and influence market outcomes in the future.

- **It gives market participants a greater understanding of AEMO's operational forecasting**. This will provide participants with valuable insights into the specific drivers of the deviations of actual demand from forecasts in AEMO forecasting. These insights will be especially beneficial if a market-based visibility model is introduced in the future as it could give participants insight into the type of quasi-bids that would improve forecasting and lower their FPP.
- **It provides the AEMC with more information to consider the materiality of unscheduled price-responsive resources on market outcomes**. It will enable the AEMC to consider the inputs that AEMO has used in demand forecasting (such as the DSP information portal), before changing or increasing the regulatory burden on industry.

This is distinct from AEMO's current role in publishing forecast errors for reliability reasons that predominantly relate to planning timeframes (such as the ESOO and ISP). This new focus draws on data to which AEMO already has access, or could request, under NER rules 3.7D and 3.7E.

Our intent is that this will encourage AEMO to make changes where required to its demand forecasting techniques and processes over time. To the extent that AEMO does make changes, this will become evident in the methods and assumptions reporting requirement.

C.1.1 AEMO are to measure the impact of unscheduled price-responsive resources and publish trends annually

AEMO will be required to publish a report on its website on an annual basis within three months of the completion of the financial year. This report will analyse the medium-term implications of the issues it monitors. It will also set out the changes AEMO is making to its forecasts to account for unscheduled price-responsive resources and to reduce deviations from forecasts. An annual reporting requirement will provide industry with a better overall view of how the forecast deviations change between seasons, at different levels of demand, and over time.

The final rule specifies topics that AEMO must cover in its reporting, with a requirement for AEMO to publish a guideline outlining how it will fulfil this reporting requirement.[292] When it develops and amends the guideline, AEMO must consult publicly using the Rules consultation procedures. Input from the AER during this consultation process will be important as AEMO's reporting approach will influence the AER's reporting.

This section sets out the AEMO reporting topics included in the final rule. While the final rule is principles-based and AEMO will determine metrics, the following information guides stakeholders regarding how we have thought about the metrics.

Topic 1A: Summary statistics to identify trends with unscheduled price-responsive resources

AEMO will report on the volumes and types of unscheduled price-responsive resources recorded in the DER register and demand side participation information and their contribution to forecast deviations.[293] We consider this requirement is a more detailed look at a subset of information already included in AEMO's existing annual reporting requirements.[294] The current rules require AEMO to publish volumes of DER generation information and demand-side participation information on an annual basis, without requiring an analysis of how this is changing over time.

292 See clauses 3.10C.2(e)-(f) of the final rule.

293 See clause 3.10C.2(b)(1) of the final rule.

294 See rules 3.7D and 3.7E of the NER, the demand side participation information portal and the DER register.

We have made a minor change between draft and final rules to address feedback provided by AEMO.[295] The final rule has been amended to reflect that direct visibility of unscheduled price-responsive resources is limited. Informed by information gathered through the DER register and the DSPIP, the use of unscheduled price-responsive resources is derived from deviations between forecast and actual demand. The final rule reflects this implementation consideration.

Topic 1B: Deviations between demand forecasts and actual outcomes, and the contribution of unscheduled price-responsive resources to these deviations

AEMO is to report on demand forecast deviations and the reasons for them at a range of price thresholds.[296] For the analysis of forecast deviations, the period of interest is pre-dispatch and dispatch. Pre-dispatch forecasts are prepared up to 36 hours ahead of the dispatch interval. Dispatch forecasts are used to issue dispatch instructions and set spot prices. Given AEMO's different approaches to dispatch and pre-dispatch forecasts, the methodology AEMO may use to fulfil this reporting obligation for those periods could be different.

We note that determining the contribution of unscheduled price-responsive resources to a regional demand forecast deviation will be challenging for AEMO.[297] Electricity demand can deviate from forecasts for a wide range of reasons, such as variations in solar output or price responsiveness, and disentangling the underlying reasons is challenging. For dispatch, this can be especially challenging because the regional demand forecast is currently conducted using persistence forecasting, which means that dispatch forecasts and dispatch instructions are largely determined based on the demand in previous dispatch intervals.

We expect AEMO to use best endeavours to fulfil this reporting requirement. We also expect that AEMO will progressively develop more sophisticated techniques to conduct this analysis over time in proportion to the scale of the problem and their experience. AEMO will also need to consider how to best provide accurate and timely information to the AER (discussed in appendix C.4).

We consider analysis of demand forecast deviations and the reasons for them at certain price thresholds is key to determining patterns of unscheduled price-responsive resources. This is because we anticipate that unscheduled price-responsive resources may respond at very high and very low prices or during different seasons. It is also essential to support the AER's work to determine market impacts. Therefore, as part of developing its reporting guideline with respect to this topic, we expect AEMO to consult with the AER to determine relevant price thresholds and publish them as part of the reporting guidelines.

Topic 1C: Analysis to identify the contribution of deviations from forecast demand to ancillary services costs and frequency performance payments

AEMO is to report on how forecast deviations due to unscheduled price-responsive resources contributed to higher ancillary service costs and frequency performance payments (FPP).[298] We consider an analysis of FCAS is critical to determine whether the inefficiencies associated with not accounting for unscheduled price-responsive resources are increasing. In particular:

- **FPP**. The rules on FPP will take effect in 2025. While not yet in effect, increasing FPP allocations for FRMPs could be a flag for the inefficiencies of not accurately accounting for unscheduled price-responsive resources in regional demand forecasts. While we have given

295 See clause 3.10C.2(b)(1)(ii) of the final rule

296 See clauses 3.10C.2(b)(1)(ii) and 3.10C.2(b)(3)-(4) of the final rule.

297 We consider reporting on ST PASA timeframes is not necessary as ST PASA does not include forecast prices and AEMO does not typically use RERT based on an ST PASA lack of reserve level 2 or 3 (LOR2/3). All other forecasts (MT PASA, Energy Adequacy Assessment Projection (EAAP), ESOO, and ISP) cover planning timeframes, which are not relevant for this rule change.

298 See clause 3.10C.2(b)(2) of the final rule.

AEMO flexibility to determine the specific metrics, we consider it could be useful for AEMO to consider the following.

- The magnitude of FPP due to scheduled vs. unscheduled resources to help determine whether the issue is increasing over time for unscheduled resources.
- The magnitude of the 'noise' and 'flat' components as described in our visibility market model published alongside the final determination.[299] Theoretically, the 'flat' component of FPP would be systematic and predominantly due to unscheduled price-responsive resources. Therefore, analysis and publication of the 'flat' and 'noise' components of FPP could be an effective way to determine if unscheduled price-responsive resources are negatively impacting market outcomes.

- **Regulation FCAS enablement quantities and the utilisation of that enablement**. Our analysis indicates that AEMO may be required to use more regulation FCAS if material dispatch forecast deviations emerge. This is because AEMO would have higher forecast errors and therefore increase the amount of regulation FCAS it enables to manage this uncertainty. AEMO currently does not report on the costs associated with FCAS enablement quantities from not accurately accounting for unscheduled price-responsive resources in dispatch forecasts and therefore using more FCAS than necessary. Similarly, AEMO does not report on how much of the FCAS enablement is used.

Topic 1D: The extent to which accounting for unscheduled price-responsive resources has helped or hindered demand forecasting in operational timeframes

AEMO is required to publish information about how it accounts for unscheduled price-responsive resources in its dispatch and pre-dispatch regional demand forecasts.[300] The purpose of this reporting topic is to increase transparency of how AEMO accounts for unscheduled price-responsive resources in its forecasting. This was an issue raised in stakeholder submissions to both the consultation paper and the draft determination.[301] EUAA in particular commented on the interactions between this framework and AEMO's forecasting. They expressed a concern that the focus on unscheduled price-responsive resources is limiting as forecast deviations arise for a number of reasons, of which price-responsiveness is just one. The Commission notes that both the draft and final rule require AEMO to report on the factors that contribute to the size of the forecast deviation, not just price-responsiveness.

Currently, AEMO is required to describe in general terms how it uses demand side participation information to inform its forecasts.[302] The final rule will increase transparency on how unscheduled price-responsive resources are used in operational time frames and the specific limitations AEMO experiences with that data. The final rule requires AEMO to report on the following issues annually:

- The methodologies AEMO uses to account for unscheduled price-responsive resources in its regional demand forecasting for pre-dispatch and dispatch timeframes.[303]
- Any changes it made to its regional demand forecast methodologies for the pre-dispatch and dispatch timeframes and the level of success of the changes in reducing regional demand forecast deviations associated with unscheduled price-responsive resources.[304] This could

299 Creative Energy Consulting prepared for AEMC, *A Market Design to integrate Demand Response into NEM Pricing and Dispatch*, 25 July 2024.

300 See clause 3.10C.2(b)(7) of the final rule.

301 Submissions to the consultation paper, CS Energy, p. 3, EUAA, p. 3
Submissions to the draft determination, CS Energy, p.2, EUAA, p.3.

302 See rule 3.7D(d) of the NER.

303 See clause 3.10C.2(b)(7)(i) of the final rule.

304 See clause 3.10C.2(b)(6) of the final rule.

also include any changes that AEMO is considering in the future to address demand forecast deviations, particularly deviations due to unscheduled price-responsive resources.

- Any barriers AEMO is experiencing with improvements to regional demand forecasts in operational timeframes.[305]

AEMO must set out how it will meet the above obligations in its unscheduled price-responsive resources reporting guidelines.[306] The Commission's intention is to increase transparency and availability of information and analysis of issues associated with unscheduled price-responsive resources, relating to operational demand forecasting. AEMO remains able to publish more information on its broader forecasting processes if it wishes, as part of this work or separately.

C.1.2 AEMO will publish quarterly statistics

The annual reporting on the four topics outlined above will be central to AEMO's reporting framework. However, an annual approach alone would come with a significant lag to update industry on market outcomes. Therefore, under the final rule AEMO's annual reporting framework is supplemented with the requirement to publish statistics on its website on a quarterly basis.

For each of the above topics discussed in appendix C.1.1, AEMO must, quarterly, publish relevant statistics on its website.[307] AEMO is required to consult with stakeholders as part of developing the reporting guidelines to determine what metrics and format of publication would be most beneficial for industry. The purpose of the quarterly statistics is to provide more regular information to industry and market bodies. In their submission to the draft determination, AEMO outlined that it may take up to two weeks to process, validate and finalise data from the recently concluded quarter.[308] The rule pertaining to the quarterly reporting requirement, however, does not preclude AEMO taking this time each quarter to finalise those processes. As such, this rule remains unchanged from the draft rule.

305 See clause 3.10C.2(b)(7)(ii) of the final rule.

306 See clause 3.10C.2(f) of the final rule.

307 See clauses 3.10C.2(c)-(d) of the final rule.

308 AEMO, submission to draft determination, p. 3.

C.1.3 AEMO proposed other changes to the draft rule that have not been implemented in the final rule

AEMO proposed several other detailed changes to the draft rule in its submission. The Commission has decided for various reasons that these changes should not be implemented in the final rule. They are summarised below.

Table C.1: Proposed changes to the draft rule

Draft Rule	Draft wording	AEMO proposal	Rationale for not implementing
3.10B.2 (b)(1)(iii)	"the approximate contribution of unscheduled price responsive resources to forecast deviations"	"the approximate contribution of unscheduled price responsive resources to forecast deviations **at regional level**"	This final rule has undergone some changes from the draft rule. However, these do not include prescribing that the contribution of unscheduled price-responsive resources to forecast deviations be reported at the regional level. AEMO will devise its own guidelines on reporting this impact, and may choose to specify this analysis will occur at the regional level. Omitting this level of specificity from the rules, however, makes the rule more future-proof. AEMO's forecasting methodology and visibility of price-responsiveness may improve and allow for more granular reporting.
3.10B.2 (b)(2)	"AEMO's best estimate of the impact of unscheduled price responsive resources on forecast deviations in relation to additional amounts paid to: (i) Ancillary Service Providers for additional ancillary services that are enabled; and (ii) Cost Recovery Market Participants for ancillary service transaction payments under clause 3.15.6AA;"	"AEMO's estimate of the impact of unscheduled price responsive resources on forecast deviations in relation to additional amounts paid to: (i) Ancillary Service Providers for additional ancillary services that are enabled; and Cost Recovery Market Participants for payments under clause 3.15.6AA"	The inclusion of the word "best" does not imply the use of excess resources. There is no tangible benefit to softening the obligation. The phrase "ancillary service transaction" has not been removed as cl 3.15.6AA in the PFRI rule does refer to ancillary service transactions.

Draft Rule	Draft wording	AEMO proposal	Rationale for not implementing
3.10B.2 (f)	“The AEMO price responsive reporting guidelines must specify: (1) how AEMO will meet its reporting obligations under paragraph (b); and (2) the information and metrics that AEMO will include in the reporting required pursuant to paragraph (c)”	*AEMO may benefit from the ability to request new information to meeting reporting obligations under this framework*	AEMO already has extensive information gathering powers under DSPIP and ESOO reporting obligations. Stakeholder feedback was that AEMO should utilise this rather than be granted additional powers.
3.10B.2 (e)	“AEMO must develop and publish, and may amend, the AEMO price responsive reporting guidelines in accordance with the Rules consultation procedures”	*AEMO would like to amend the guidelines without full consultation*	AEMO is entitled to enter a separate rule-change proposal to alter the consultation requirements in the rules. Currently, the consultation requirements in the rules are commensurate with the size of the change.

Source: AEMO submission to draft determination

C.2 The AER will estimate efficiency and costs annually

The final rule creates a new reporting requirement for the AER to periodically consider the impact of unscheduled price-responsive resources on efficiency in the wholesale market.[309] This requirement builds upon the AER's current role to monitor and report on effective competition and market efficiency set out in the NEL.[310] The AER is now required to consider the types of inefficient outcomes and costs associated with demand forecast deviations arising due to unscheduled price-responsive resources in the market. The AER is to make recommendations based on its findings.[311]

The AER reporting framework is likely to deliver the following benefits:

- increased transparency of the contribution of unscheduled price-responsive resources to demand forecast deviations and subsequent inefficient market outcomes
- increased transparency on the costs and implications of not accounting for impacts of unscheduled price-responsive resources on market outcomes.

No stakeholders submissions to the draft determination commented specifically on the AER's reporting requirements, except to express broad support for the monitoring and reporting framework as a whole. Thus, changes between draft and final rules are very limited. We have clarified that the AER's reporting of costs associated with unscheduled price-responsive resources should be estimates.

C.2.1 The AER will estimate costs and efficiency implications, and publish a report annually

The AER will be required to report annually, with the report to be published within six months of the end of the relevant year.[312] This reporting function provides a longer term view of the costs and impacts of demand forecast deviations caused by unscheduled price-responsive resources.

The AEMC's benefits modelling revealed that demand forecasting deviations cause a series of inefficient outcomes including inefficient prices and dispatch.[313] Our benefits modelling found there are five key areas where unscheduled price-responsive resources could cause inefficient outcomes, leading to higher costs for all energy consumers, as well as higher emissions.

Under existing processes, AEMO produces a price inelastic demand forecast for every dispatch interval. Figure C.1 demonstrates the outcomes in dispatch costs, prices and security, when unscheduled price-responsive resources respond to prices in a dispatch interval.

309 See rule 3.10C.3 of the final rule.

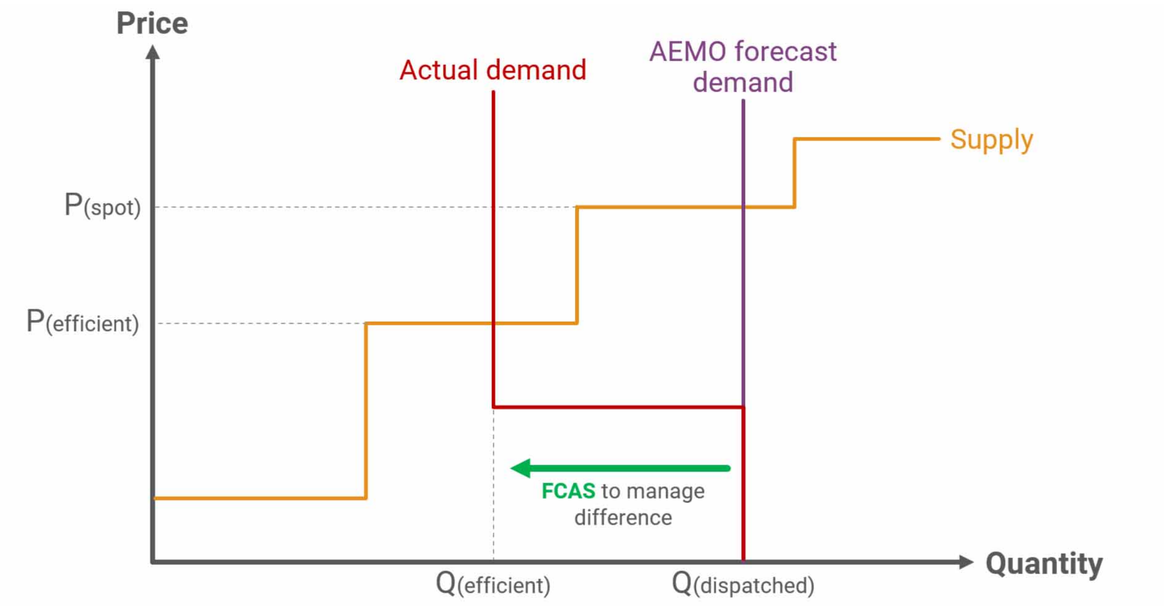
310 NEL Part 3, Division 1A.

311 See clause 3.10C.3(c)(7) of the final rule.

312 See clause 3.10C.3(b) of the final rule.

313 In February 2024, we published IES modelling on the 'size of the prize' with further modelling results published alongside the draft determination.

Figure C.1: Inefficient market outcomes from unscheduled price-responsive resources



Source: AEMC

As AEMO does not know the intentions of these resources, it forecasts demand to require $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of $P_{(spot)}$. However, where there are unscheduled price-responsive resources that will reduce their consumption or increase generation at this price point, actual demand will be $Q_{(efficient)}$ and the efficient price would have been $P_{(efficient)}$. To balance supply with the actual demand level, frequency control ancillary services (FCAS) are required.

IES's modelling demonstrated the following market outcomes:

- inefficiently high spot prices which resulted in scheduled resources being paid more than is necessary
- unnecessary costs were incurred by scheduled resources to meet the forecast demand which was higher than actual outcomes (noting that this category of cost is not entirely separate from the point above)
- market ancillary service costs are incurred to bring supply and demand back into balance
- likely higher than necessary emissions because there is a close correlation between high marginal cost generators and high emissions generators
- RERT use and associated costs, especially in circumstances where demand and supply conditions are particularly tight.

The final rule sets out these five topics for the AER to consider with the requirement for the AER to publish a guideline outlining how it will fulfil this reporting requirement. While the rules are principles-based and the AER will be left to determine metrics, the following sections set out our thinking on how each topic could be considered. We have made minor changes to the relevant draft rules to clarify the level of accuracy this monitoring and reporting framework implies is necessary.[314]

314 See clause 3.10C.3(c) of the final rule

Topic 2A: Inefficient spot prices as a result of regional demand forecast deviations from unscheduled price-responsive resources

The AER will report on the increased amounts paid to scheduled market participants that provide electricity into the wholesale market (generators, IRPs and Demand Response Service Providers (DRSPs)) due to inefficiently high spot prices resulting from demand forecast deviations.[315] To prepare this analysis, the AER could consider the size of the forecast deviation due to unscheduled price-responsive resources and compare that against price sensitivities. This will enable the AER to determine a counterfactual price and quantity which, multiplied together, will identify the higher revenues paid to generators and other relevant market participants from consumers.

Topic 2B: Inefficient costs incurred by scheduled market participants as a result of regional demand forecast deviations

The AER will report on the increased costs incurred by market participants that provide electricity into the wholesale market due to over-dispatch as a result of demand forecast deviations.[316] To prepare this analysis, the AER could consider the individual generating, storage and demand response assets that were issued dispatch instructions because AEMO was unable to account for unscheduled price-responsive resources. The AER could then multiply this inefficient dispatch of certain assets against estimates of their costs.

Topic 2C: Increased market ancillary service requirements as a result of regional demand forecast deviations

The AER will report on the increased market ancillary service requirements and FPP allocations due to demand forecast deviations.[317] To prepare this analysis, the AER could consider the FPP allocations, FCAS enablement and the proportion that is utilised as discussed in AEMO topic 1C in appendix C.1.1.

Topics 2D: Increased emissions as a result of inefficient generation

The AER will report on increased emissions as a result of inefficient dispatch (topic 2B), increased ancillary service requirements (topic 2C), and inefficient RERT use (topic 2E).[318] To prepare this analysis, the AER could consider the emissions intensity of the marginal generator, drawing on the emissions factors published by AEMO under clause 3.13.14. The AER could also apply a standard intensity factor by asset type, and then multiply the tonnes of additional emissions by the agreed value of emissions reductions.[319]

Topic 2E: RERT use and associated costs as a result of inefficient generation use

The AER will report on the increased amounts paid to RERT providers for inefficient RERT use as a result of demand forecast deviations.[320] To prepare this analysis, the AER could consider the size of the forecast deviation due to unscheduled price-responsive resources and compare that against RERT use at the same time (if relevant). If RERT is activated during this time, the AER will need to consider the costs associated with RERT and its impact on the counterfactual demand and price levels. However, unlike the above topics, RERT is triggered based on pre-dispatch rather than dispatch forecasts. Therefore, the AER may consider instances where a dispatch forecast

315 See clause 3.10C.3(c)(1) of the final rule.

316 See clause 3.10C.3(c)(2) of the final rule.

317 See clause 3.10C.3(c)(3) of the final rule.

318 See clause 3.10C.3(c)(5) of the final rule.

319 AEMC, How the national energy objectives shape our decisions, 28 March 2024.

320 See clause 3.10C.3(c)(4) of the final rule.

deviation coincided with RERT use and/or where AEMO used RERT based on a pre-dispatch demand forecast that is materially higher than actual demand.

C.2.2 Relevant data and analysis to support the AER's monitoring and reporting

The reporting framework set out in the final rule outlines some information that the AER will require for its analysis but does not currently have access to. Therefore, the AER will require additional information and analysis from AEMO to fulfil its reporting requirements. We note that the AER currently has general information-gathering powers which it could use to obtain information from AEMO for this purpose. However, for the reporting function to be effective, the AER should be able to easily access the necessary information.[321] The final rule makes explicit that the AER can collect information from AEMO to fulfil this reporting obligation.[322] We understand that the AER could develop an ongoing information request for the timely receipt of information from AEMO.

The AER will likely need to collect information from AEMO on several topics to fulfil the reporting obligation. In particular:

- For energy costs, the AER would require:[323]
  - The contribution of unscheduled price-responsive resources to these forecast deviations (this is set out as one of the metrics AEMO would prepare under its reporting functions).
  - More granular price sensitivities to demand changes. This is a key tool that the AER currently uses to determine drivers of differences between forecast and actual price outcomes.[324] However, if the AER is to understand components of demand forecast deviations, sensitivities smaller than the current levels of plus or minus 50MW in some regions may be needed.
  - Detailed information on unscheduled price-responsive resources from the DSPIP and DER register that AEMO receives on a confidential basis.
- For ancillary services costs,[325] the AER will require information to determine the contribution of unscheduled price-responsive resources to the enablement values of market ancillary services. We understand that this information could be on FPP 'flat' and 'noise' components, as discussed above in Topic 1C.

C.3 There will be a 12-month implementation period for the reporting framework

The implementation schedule included in the final rule for the AER and AEMO monitoring and reporting framework is set out in Figure C.2 below. We consider it is important this reporting framework is in place as soon as practically possible and this has governed our timing requirements. The important elements of this schedule are:[326]

- AEMO publishing its first quarterly statistics following the end of Q3 of the financial year 2025/26 by 1 April 2026.
- AEMO and the AER delivering their first annual reports within three and six months respectively following the end of 2025/26. This means that for the first reporting period, each

321 We consider that the AER should not require any additional information from market participants to fulfil this function.

322 See clause 3.10C.3(e) of the final rule.

323 The AER would report on this under clause 3.10C.3(c)(1) of the final rule.

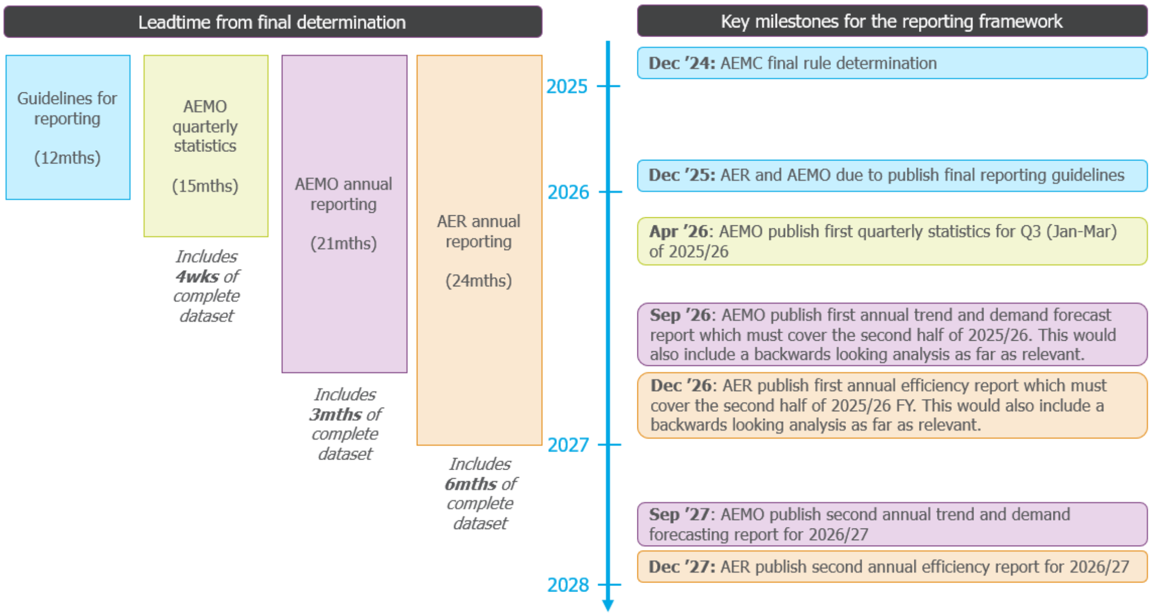
324 AEMO publishes pre-dispatch price sensitivities for each NEM region. See, Pre-Dispatch Sensitivities, March 2021.

325 The AER would report on this under clause 3.10C.3(c)(3) of the final rule.

326 See clause 11.180.4 of the final rule.

body will only have six months of new data (to the extent that AEMO prepares new data/analysis for this function). However, informed by discussions with AEMO and stakeholder feedback, we consider these first reports should also include a backward-looking analysis for the previous three years (to the extent information is available) to form a sufficient baseline and data set.

Figure C.2: Implementation lead time for AEMO and the AER reporting



Source: AEMC

C.4 We will consider whether a market model for the visibility problem is needed in a later review

The AEMC will consider a longer-term regulatory solution in a review if the inefficiencies associated with AEMO's account of unscheduled price-responsive resources become material. The trigger for this review will be informed by the AER's annual reporting, which will include recommendations to be made to the AEMC.

The review should be informed by evidence from AEMO and the AER reports and recommendations. We consider, at this time, there is not sufficient evidence to warrant large regulatory changes or increase burdens on market participants. In the future, should an issue materialise, we could consider the following regulatory approaches which we have consulted on or received stakeholder submissions on throughout this rule change:

- **Whether we should implement a model that enables participants to provide visibility information to AEMO.** Following stakeholder submissions to the consultation paper, we considered an alternative visibility model. This model was designed to enable market participants to provide information to AEMO to be incorporated into dispatch. We published this model in December 2023 and tested it with the TWG and other stakeholders. Following feedback, we refined this visibility market model and have published an amended detailed design alongside this final determination.[327] We consider this model would be fit for purpose should the inefficiencies become material as this would drive incentives for participants to provide accurate information to reduce their frequency performance payments.

- **Whether we should enhance AEMO's information-gathering powers to collect appropriate information from market participants on unscheduled price-responsive resources**. The reporting frameworks by AEMO and the AER should reveal the extent to which AEMO can account for unscheduled price-responsive resources in its forecasting in operational time frames and the way it uses information it currently receives. We received feedback from stakeholders in response to the consultation paper and draft determination that AEMO could more efficiently collect and use information collected in the DSPIP.[328] We will consider the effectiveness of AEMO's information on unscheduled price-responsive resources in the review process. This is because improved reporting will increase transparency and provide evidence of the deficiencies with the current information.

327 Creative Energy Consulting prepared for AEMC, *A Market Design to integrate Demand Response into NEM Pricing and Dispatch*, 25 July 2024.

328 Submissions to the consultation paper, Origin, p. 5, Energy Australia, p. 3, Flow Power, p. 5, submissions to the draft determination, Hydro Tasmania, p. 1, Origin, p. 1.

D Summary of other issues raised in submissions

This appendix sets out the issues raised in this rule change request that we have not addressed in the main body of this document. It also provides our response to each issue.

Table D.1: Summary of other issues raised in submissions on the draft determination

Stakeholder	Issue	Response
Ausgrid, p. 2.	Ausgrid noted that they currently have nine community batteries in operation which will rise to 25 in October 2025. The capacity of these batteries is leased out to offtakers, for example retailers, to operate. Ausgrid questioned what obligations, if any, they would face if the offtake partner chose to use its share of the battery to participate in the scheduling and dispatch procedures facilitated by this rule change.	To nominate a resource as a VSR, the participant would need to be the FRMP at the market connection point. In this example, the offtaker would need to be the FRMP at the market connection point of the community battery. The obligations of participating in dispatch mode apply to the FRMP only. At any market connection point there can only be one FRMP. If there are multiple offtakers at a single site, only the FRMP would be able to participate in dispatch, in relation to the whole battery. However, this may involve coordination with the other offtakers.
EnergyAustralia, pp 5-6.	EnergyAustralia raised concerns about the IES modelling of the benefits: • Benefits are modelled from 1 July 2025, when IPRR will go live later in 2027. • Whether a more recent ISP should have been used.	We did amend the modelling to a later start date. IES undertook two rounds of modelling. The first, size of the prize, is outlined in Chapter 2. In mid 2024, it updated this modelling to understand the sensitivity to different participation rates (chapter 4). As part of this modelling IES changed the modelling start date to November 2026, the expected go live for dispatch mode at the time of the draft rule. We note that dispatch mode will now commence in May 2027. We do not consider that this delay will significantly

Stakeholder	Issue	Response
		reduce the overall benefits because it is a short period and the benefits modeled are lowest in 2027. Given this is immaterial we have not had IES adjust the modeling for it. ISP 2022 was used as the 2024 ISP was not available at the time. However, we note that the 2024 ISP has a higher amount of coordinated CER storage, so the benefits would likely be higher if the 2024 ISP was used.
Shell Energy, p. 2.	Shell Energy raised concerns that the NEM is set to undergo another potentially substantial market redesign through the post-2030 review of the NEM. Shell Energy queried whether this reform would be better integrated into the post-2030 NEM reforms instead.	We do not consider we should delay this rule change to wait for agreement and market re-design because we are not sure when these issues will be resolved or if they will result in market design changes. The Commission considers that solutions need to be put in place now to prepare for the increasing amount of unscheduled price-responsive resources. We also note that dispatch mode is highly resilient and flexible to a variety of potential market design changes.
Enel X, p. 1.	Enel X noted that there will be a suite of tools (such as WDRM and dispatch mode) for different customer and asset types. These tools should be considered as a package and further thought given to how remaining barriers to activating new flexible demand can be removed.	We agree that the different options for FRMPs and their customers could benefit from further explanations on their operation and when each could be beneficial. We will give consideration to how we can support this in 2025.
Erne Energy, p. 4.	If AEMO's concern is that FRMPs are leveraging their customers' CER in a way that is invisible to the market, then a more appropriate response would be to require any FRMP wanting to leverage their customers' CER in the energy market, to have to bid, be scheduled and meet dispatch through the current process, rather than creating an entirely new and unnecessary mechanism.	There is no current mechanism to allow aggregated small and medium resources to participate in central dispatch. The rule change is not specifically aimed at addressing market power issues.

Stakeholder	Issue	Response
	If the concern is the market power of the existing large FRMPs, then this new mechanism does nothing to address the difficulties small and new innovative players might have in accessing the market, even with the flexible trading arrangements rule creating secondary FRMPs (ERC0346). Rather, it just gives the existing large FRMPs a new space in which to exercise their dominance, while earning a new incentive for doing so.	
SAPN, pp. 3-4.	SAPN suggested that to best integrate VSRs into the distribution network and the wider system, the time-horizon of DOEs should align with VSR bids. Such as aligning DOEs with day-ahead bids and pre-dispatch process. This would ensure that all VSR bids provided to AEMO are as accurate as possible, and that efficient pre-dispatch targets and forecast spot prices are generated by AEMO as a result. SAPN and the majority of DNSPs do not produce a 24-hour forecast, which would require an uplift capability to achieve. SAPN also noted that these system uplifts will ultimately be required regardless of the implementation of the Rule Change, in order to best integrate larger traditionally scheduled resources into the network via a flexible connection.	We agree that alignment of the DOE horizon and AEMO's pre-dispatch timeframes would be ideal, as this would ensure all bids reflect the network constraints they may face in operation. However, the Commission does not consider that this rule change should require DNSPs to align the DOE horizon with AEMO's pre-dispatch forecast. DNSPs and AEMO can monitor the impact of DOEs as the size and materiality of VSR participation grows. DNSPs may use these learnings as part of capacity uplift proposals for DOEs in future regulatory resets.
SAPN, pp. 3-4.	Consideration should also be given to the need for alignment on the operational forecasting methodology, inputs and assumptions implemented by AEMO and DNSPs. Alignment on these inputs and assumptions will allow for accurate and consistent operational forecasting between DNSPs and AEMO, in turn allowing for more optimal capacity allocation and dispatch.	AEMO and DNSPs may discuss their inputs, assumptions and methodologies for operational forecasting. The data sharing arrangements introduced through the VSR guideline may be used to align input data sources between DNSPs and AEMO where needed.

Stakeholder	Issue	Response
SAPN, p. 4.	All generators connected to the SAPN network with an export capacity of less than 200 kVA need to be capable of receiving DOEs via the CSIP-AUS protocol, whilst generators exporting above 200 kVA receive DOEs via a SCADA connection. The current CSIP-AUS implementation deployed by SAPN and several other DNSPs does not allow for a 24-hour control schedule to be provided to a connected generator. Additionally, high voltage connected generators receiving controls via SCADA currently receive only a single control, with most SCADA systems currently unable to send or receive timeseries control schedules. To support the provision of 24-hour DOE forecasts, DNSPs will need to invest in uplifts of their CSIP-AUS and/or SCADA systems. Aligning communication of DOEs between DNSPs would also aid in delivering more efficient connection processes nationally. SAPN recommended that the AEMC and AEMO engage closely with DNSPs to understand current progress on national alignment between DNSPs regarding the implementation of DOEs and consider where further alignment and uplifts may be required to support the requirement of providing 24-hour DOE forecasts to VSRs.	We recognise that DNSPs may need to invest in their systems to efficiently communicate with the wide range of resources connected to their network. We encourage DNSPs to engage with AEMO in developing the VSR guideline and systems for implementing VSRs to see what alignments can be made. The AEMC will follow the implementation of this rule closely. We encourage DNSPs to engage with the Commonwealth's DSO workstream and AEMO's CER data exchange to see whether alignments can be made through these processes as well.
SAPN, pp. 4-5.	SAPN cautioned the AEMC against presuming a future state where distribution limits are implemented via NEMDE. This is because many VSRs are likely to consist of low voltage connected resources, each of which would be receiving a unique site-level DOE from the DNSP.	The intent of the draft and final determinations is for AEMO and DNSPs to consider how distribution limits might be incorporated into dispatch instructions in the future. We consider that the end goal of this process would be to allow VSRPs to bid in their commercial intentions and have any network constraints applied through the dispatch process.

Stakeholder	Issue	Response
	The SA network alone has approximately 77,000 low voltage networks with constraints that would need to be managed, likely requiring a very significant upgrade to NEMDE. SAPN proposed that a more efficient long-term model would be for distribution network limits to be accounted for directly between DNSPs and VSRPs and only the aggregated, post-constrained VSR bids being provided to AEMO and ingested into NEM-DE. We encourage the AEMC to consider future models for dispatch of all distribution connected generators in their DSO roles and responsibilities review via the parallel Electricity pricing for a consumer driven future market review and the delivery of the National CER Roadmap, noting that multiple models may be required when considering the future broad spectrum of scheduled resources.	Similar to the process for existing scheduled resources. This approach does not try to impose a set technical solution for implementing distribution network limits into NEMDE. We agree that integrating the calculation and optimisation of many distribution constraints into NEMDE may be technically challenging. We note that these issues are being considered through the Commonwealth's DSO workstream within the CER roadmap and encourage stakeholders to engage in this process.
SAPN, pp. 6-7.	SAPN strongly recommend that AEMO's VSR Guideline require the MW provision of VSR bid data to DNSPs. Receiving this data will allow DNSPs to better understand, model and forecast the behaviour of unpredictable price responsive resources such as VPPs, large batteries and large flexible loads. Providing more efficient allocation of network capacity under a DOE to these resources. In the absence of this data provision, DNSPs must make assumptions regarding the behaviour of price-responsive resources, with these assumptions typically being conservative and resulting in sub-optimal allocation of network capacity to these resources.	The VSR guideline required under our final rule will set out processes for data sharing between VSRPs and DNSPs or TNSPs. As well as data sharing arrangements for VRSP data collected by AEMO to be shared with DNSPs or TNSPs. These data sharing arrangements do not require data to be shared between the parties, but allow the guideline to set out efficient processes for sharing data where agreed. Existing provisions in the rules and agreements between the parties can be used where there is a need for data. The data sharing arrangements can allow for VSRP bid data to be provided to DNSPs to assist in calculating DOEs. Where aggregated the VSRP bid data would be for the entire

Stakeholder	Issue	Response
	We recommend that VSR bid data be provided to DNSPs at an individual resource level, i.e. at the NMI or SSP level. Aggregate bid data will significantly limit the usefulness of this data in generating site-level DOEs for these resources, potentially resulting in an inefficient allocation of network capacity and hence a reduction in the market benefits the Rule Change seeks to deliver.	aggregation. VRSPs may choose to share more granular data with DNSPs where it exists and would be beneficial for both parties.
SAPN, p. 7.	SAPN recommend that AEMO's VSR Guideline include requirements for the provision of VSR enrolment standing data to DNSPs. This will allow DNSPs to best understand the local network impact of a given VSR's bids, by having a complete mapping of the aggregated VSR down to each individual resource, and hence generate more efficient DOEs for these resources. This standing data should include: • the individual resource identifier, i.e. the connection point NMI • for individual resources that are operated under a SSP, both the SSP and the primary NMI of the site connection point should be provided • the installed export capacity of the individual resource • the FRMP operating the VSR • the markets that the VSR is registered in.	Similar to the response above, the VSR guideline can provide processes for this data to be shared with DNSPs. VSRPs may also choose to share additional data with DNPSs to receive better distribution limits.
SAPN, p. 8.	SAPN raised that some scheduled resources are already connected to the distribution network, with more expected in the future. The current solution for providing dispatch controls to	We would encourage AEMO and DNSPs to investigate more efficient data and control signal paths where there is a need to improve existing systems. Consultation through the development of the VSR guideline

Stakeholder	Issue	Response
	distribution connected scheduled generators in South Australia requires a passthrough of controls from AEMO to the DNSP and in turn the generator, via the TNSP SCADA system. This control pathway has historically incurred additional costs for TNSP SCADA development, with these costs initially borne by the DNSP but ultimately passed on to the connecting generator. We note that this issue is not present in all jurisdictions, with a direct link to AEMO already implemented for some DNSPs. We recommend that AEMO review the suitability of existing communications pathways for dispatch controls where SCADA Lite is not available, engaging closely with DNSPs to reach a cost-effective solution for all parties where one is not already in place.	may assist in investigating appropriate data and control signal arrangements.
AEMO, p. 8.	AEMO considered that the IPRR final rule may require some aspects of the Unlocking CER Benefits rule drafting to be reviewed. In particular, the drafting does not allow for a secondary settlement point to be established where the connection point has a scheduled resource (NER 7.2.6(b)(2)(i)).	The retail customer would need to request their retailer to remove that site from the VSR in order to install an SSP. The retailer could then include the secondary settlement point in a VSR. This could occur under existing processes. If a retail customer is part of a VSR and wishes to install an SSP and their retailer does not agree to go through the above process to install an SSP, the customer may switch retailers to one who does agree.
AEMO, pp. 8-9.	AEMO noted that there will likely be many market procedures that will require minor or administrative change to accommodate the IPRR rule. Proposing a transitional rule to make minor or administrative amendments without following the NER process for amending these. Suggesting that this would provide clarity and lessen the impact on both AEMO and industry.	We consider that the Minor rules consultation procedure, which is an option under the Rules consultation procedures, gives AEMO sufficient flexibility to make minor or administrative changes quickly and easily.[1]

Stakeholder	Issue	Response
	Similar to the transitional for the *Integrating energy storage system into the NEM* rule.	
Geoffrey Houston	Compromises should not be made to achieve net-zero.	Emissions reduction targets are legislated objectives under the NEL and are not in scope for this rule change.
Rainforest Reserves Australia	VPPs cause environmental damage through localised heating, noise pollution and vibrations.	VPPs are a form of aggregation and co-ordination of distributed resources. They do not themselves generate heat, noise or vibration. These concerns are not relevant to the issues addressed in this rule change.
Private Individual	The energy regulatory framework should be reviewed, including cost assessment methodologies. Renewable energy ambitions should be abandoned.	The energy regulatory framework and legislated emissions reduction or renewable energy targets are not in scope for this rule change.

Source: 1 — See clause 8.9.4 of the NER.

E Key features of the final rule

This appendix provides an explanation of the final rule. It is written to assist stakeholders who may be interested in, or affected by, the rule drafting. The final rule has three key elements:

1. **Central dispatch participation by VSRs:** a new framework to integrate price-responsive resources into central dispatch and scheduling processes. When participating in central dispatch in this way, these resources are termed VSRs, which reflects both the voluntary nature of participation and that they are scheduled resources. This framework also includes processes for those VSRs to be temporarily inactive or hibernated for specified periods of time.
2. **VSR incentive mechanism:** is a tender process run by AEMO to incentivise the participation of qualifying resources in central dispatch as scheduled resources by nominating to be a VSR. It does so by awarding participation payments to successful participants. A VSR is not required to participate in the VSR incentive mechanism. However, it may do so in order to receive participation payments that are in addition to any payments receivable (or payable) in the spot market through participation in central dispatch.
3. **AEMO and AER reporting on unscheduled price responsive resources**: new monitoring and reporting requirements on
   a. AEMO in relation to the impacts of unscheduled price responsive resources on forecast deviations in pre-dispatch and dispatch
   b. the AER in relation to the impacts of unscheduled price responsive resources on the efficiency of the market.

The following sections describe the key features of these three elements of the final rule by discussing:

- registration, classification and nomination
- aggregation of VSRs
- the VSR guidelines
- participation of VSRs in central dispatch
- deactivation and hibernation of VSRs
- the VSR incentive mechanism
- reporting obligations on AEMO and AER in relation to non-scheduled price responsive resources.

Each section also provides an explanation of what we have changed between draft and final rule.

E.1 Registration, classification and nomination

Box 8: Key changes between the draft rule and final rule

- The definition of Market Participant has been removed from Chapter 2 of the NER, as it is covered in Chapter 10 and amended by the final rule to include VSRPs.[1]
- There have been small drafting changes to clarify that AEMO's approval to nominate the relevant resource as a VSR means it becomes a scheduled resource despite not being

> classified as a scheduled generating unit, scheduled load or scheduled bidirectional unit in Chapter 2 (and retaining its original classification).[2]

Note: 1 — See Chapter 10 of the final rule for the definition of *Market Participant*. 2 — See clause 3.10A.1(h) of the final rule.

Chapter 2 of the NER specifies the requirements for registration and classification. The categories of registration for different types of participants and the associated classifications are largely based on the characteristics of the plant or equipment, or the activities of the registered participant. The final rule does not change these requirements. The new framework for VSRs can only apply to a person who is already registered under Chapter 2 and has classified its relevant resources in accordance with the relevant requirements.

The final rule enables (but does not require) a person who is already registered as a Generator, Integrated Resource Provider or Market Customer in respect of one of the types of qualifying resources specified in the final rule to apply to AEMO to nominate its qualifying resource as a VSR.[329] A Generator, Integrated Resource Provider or Market Customer who has received approval for nomination of a VSR is called a VSRP.

The resources that are defined to be qualifying resources, and therefore able to be nominated as a VSR, are the following:[330]

- a market generating unit that is a non-scheduled generating unit
- a market bidirectional unit that is a non-scheduled bidirectional unit
- a market connection point that is non-scheduled load
- one or more small generating units or small BDU (or any combination) at a small resource connection point classified as a market connection point in (accordance with clause 2.2.8).

Therefore, qualifying resources are all resources that would otherwise be non-scheduled, but are participating in the market (i.e. resources at a market connection point - which may be a secondary settlement point, introduced in the Unlocking CER Benefits rule change). The effect of nominating a qualifying resource as a VSR is that it becomes a scheduled resource.[331]

Approval of a qualifying resource as a VSR:

- means the Generator, Integrated Resource Provider or Market Customer who nominates their qualifying resource as a VSR (the VSRP) must now comply with the obligations imposed on scheduled resources in relation to the VSR (unless otherwise specified).
- does not change the underlying classification of the qualifying resource as a non-scheduled generating unit, non-scheduled bidirectional unit, non-scheduled load or small resource connection point (as applicable) to be a scheduled generating unit, scheduled bidirectional unit or scheduled load (as applicable) but imposes additional obligations on those qualifying resources as scheduled resources.
- does not affect the underlying classification of that resource as a market generating unit, market bidirectional unit or market connection point (as applicable).[332]

In other words, the final rule does not remove the registration requirement for that Generator, Integrated Resource Provider or Market Customer or change the classification criteria of the

329 See clause 3.10A.1(a)-(b) of the rule.

330 See clause 3.10A.1(a) of the rule.

331 See Chapter 10 of the final rule for the definition of *scheduled resource*.

332 See clause 3.10A.1(h) of the final rule.

qualifying resource. This is why the final rule uses the terminology of 'nomination' and sets out a process in Chapter 3 rather than Chapter 2. The registration and classification approved under Chapter 2 remain in place, while scheduling obligations are layered on top.

The obligations on the Generator, Integrated Resource Provider or Market Customer continue to apply. In addition, the person must comply with the obligations of a VSRP for a VSR.

E.2 Aggregation of VSRs

Box 9: Key changes between draft rule and final rule

Subheadings have been added to clause 3.8.3 for ease of navigation. The drafting has been refined to clarify that qualifying resources may be aggregated to form a VSR (and if so, each individual resource is not required to go through the nomination process before being aggregated).[1]

Note: 1 - See clause 3.8.3 and Chapter 10 of the final rule for the definition of *voluntarily scheduled resource*.

The final rule allows for the aggregation of multiple qualifying resources.[333] The final rule defines 'voluntarily scheduled resource' as either a single qualifying resource, or two or more qualifying resources that have been aggregated in accordance with clause 3.8.3.[334] Therefore, references to VSR throughout the final rule refer to an aggregated VSR where it has been aggregated.

The aggregation process for VSRs aligns with the existing process for aggregation in the NER, which requires AEMO to approve the aggregation of resources or units for the purposes of central dispatch.[335] The final rule requires a VSRP seeking to nominate its resources as VSRs, and who wishes to aggregate those qualifying resources so they are treated as one VSR, to apply to AEMO to do so.[336] In practice, the Commission expects AEMO would be able to undertake the nomination approval under clause 3.10A.1 and the aggregation approval under clause 3.8.3 concurrently.

Where two or more qualifying resources have been aggregated, AEMO can treat those individual resources as one resource for the purposes of central dispatch. This means that the disparate resources are collectively seen as one DUID for the purposes of bidding and dispatch. However, the final rule also allows AEMO to impose conditions on the VSRP, which may include circumstances in which AEMO requires disaggregation, or for reporting obligations to be met by each individual qualifying resource rather than the aggregated VSR.[337]

Where multiple qualifying resources have been aggregated, the aggregated VSR consists of multiple market connection points, each with its own NMI. An example of an aggregated VSR could be the consumer energy resources associated with a number of small customers. Given customers may switch retailers, the VSRP (who would be registered as a Market Customer and be the retailer for those small customers) would need to notify AEMO immediately if a resource no longer forms part of the VSR (for example, because a customer is no longer a customer of the retailer and therefore the Market Customer is not the financially responsible market participant for the market connection point).[338]

333 Sees clause 3.8.3 of the final rule.

334 See Chapter 10 of the final rule for the definition of *voluntarily scheduled resource*.

335 See clause 3.8.3 of the NER.

336 See clause 3.8.3(a3) of the final rule.

337 See clause 3.8.3(b6) and (f1) of the final rule.

338 See clause 3.10A.1(m)(1) of the final rule.

The VSRP also has an obligation to notify AEMO as soon as reasonably practicable, and in any event, within 10 business days of becoming aware that a VSR ceases to be a qualifying resource for any reason.[339] For example, this might occur because the characteristics of the plant or equipment change such that it no longer satisfies the requirements for the underlying classification approved by AEMO under Chapter 2 and it would require a change to its classification. The Commission is recommending that these provisions (3.10A.1(m)(1) and (2)) be classified as Tier 1 civil penalty provisions - see appendix F.5.

E.3 The VSR guidelines

Box 10: Key changes between draft rule and final rule

- The VSR guidelines must include processes for data sharing, collection and disclosure between VSRPs, DNSPs, and TNSPs.[1]
- The factors which AEMO must have regard to when drafting the guidelines have been amended for clarity.[2]
- The date for AEMO's review of the VSR guidelines has moved to 23 May 2030 in the final rule.[3]
- AEMO must not implement any change to a zone in which VSR are able to participate in central dispatch prior to 23 May 2030.[4]

Note: 1 - See clause 3.10A.3(b)(6) of the final rule. 2 - See clause 3.10A.3(d) of the final rule. 3 - See clause 11.180.3(c). 4 - See clause 11.180.5 of the final rule..

E.3.1 Contents of the guidelines

The final rule requires AEMO to make the VSR guidelines.[340] The guidelines must specify a number of matters, including:

- the requirements for nominating qualifying resources as VSRs[341]
- the requirements and processes for aggregation of qualifying resources as VSRs under clause 3.8.3[342]
- how VSRs will participate in central dispatch, including the operational requirements they must be able to comply with[343]
- the processes for VSRPs to share data with DNSPs and/or TNSPss[344]
- the application of zones for participation.[345]

The final rule also specifies that the guidelines must include a requirement that the VSRP whose VSR is approved for nomination must be the FRMP for the market connection point (this includes secondary settlement points) associated with the VSR.[346]

In addition, the guidelines must include a framework for testing the capabilities of qualifying resources prior to nomination.[347] This will enable interested parties to work out whether their

339 See clause 3.10A.1(m)(2) of the final rule.

340 See clause 3.10A.3 of the final rule.

341 See clause 3.10A.3(b)(1) of the final rule.

342 See clause 3.10A.3(b)(2) of the final rule.

343 See clause 3.10A.3(b)(5) of the final rule.

344 See clause 3.10A.3(b)(6) of the final rule.

345 See clause 3.10A.3(c) of the final rule.

346 See clause 3.10A.3(b)(3) of the final rule.

347 See clause 3.10A.3(b)(4) of the final rule.

qualifying resources might be suitable for nomination before formally applying to AEMO under final rule clause 3.10A.1.

E.3.2 AEMO's considerations in developing the guidelines

In developing the guidelines, AEMO:

- must balance costs of participation for VSR in central dispatch with AEMO's costs of facilitating participation by VSRs in central dispatch
- must facilitate ease of participation in central dispatch for VSRs
- may apply restrictions on VSRs in central dispatch only to the extent reasonably necessary for AEMO to manage power system security and reliability
- may have regard to any other matter determined by AEMO, acting reasonably, and which must be specified by AEMO in the VSR guidelines.[348]

E.3.3 Reviewing the guidelines

AEMO must review the guidelines by 23 May 2030, three years after the new VSR provisions take effect, in accordance with the rules consultation procedures. Outside of this review, it is able to review the guidelines as it sees fit from time to time in accordance with the rules consultation procedures.[349]

E.4 Participation of VSRs in central dispatch

Box 11: Key changes between draft and final rule

- DNSPs are required to consult with VSRPs where the model standing offer or a proposed change to a connection policy imposes non-static limitations on Distribution Network Users' maximum capacity of supply into the distribution network.[1] The aim of this change is to ensure that export limits do not change so close to real time that VSRPs are unable to reflect new limits in their dispatch bids.
- In provisions on short term projected assessment of system adequacy (ST PASA), drafting has been clarified and hibernated VSRs have been removed.[2]
- Drafting on ramp rates for VSRs has been clarified.[3]
- References to connection point have been replaced with references to market connection points, to allow for VSRs at secondary settlement points.[4]
- In the provision on enhancing reserve information, VSRs that are bidirectional units have been removed from rule 3.7G(c), but retained in rule 3.7G(a) as part of the definition of "battery", for consistency with the approach to scheduled bidirectional units.
- VSRs have been added to clause 3.8.20(k), for consistency with similar clause 3.8.21(m).
- VSRs have been removed from clause 3.14.5A(h), to remove the requirement for AEMO to include them in its benchmarking for market suspension compensation (given the variety of resources that may become voluntarily scheduled). However, they will still be eligible for compensation as Market Suspension Compensation Claimants.

348 See clause 3.10A.3(d) of the final rule.

349 See clauses 3.10A.3(e) and 11.180.3(c) of the final rule.

- VSRs have been added to clause 3.14.6, so they can be eligible for compensation due to an administered price cap or administered floor price.
- Energy consumed by VSRs (not including inactive or hibernating ones) has been excluded from the share of energy used to determine funding of compensation for directions under clause 3.15.8, in the same way it has been excluded from the funding of contracting for reserves under clause 3.15.9.
- VSRs have been added to clause 3.15.6A(k) on cost recovery for ancillary services, with the effect that they are not assessed as contributing to the need for such services in certain cases.
- A bid validation data table has been added for VSRPs in schedule 3.1.
- The definitions of Affected Load Participant and Affected Participant in chapter 10 have been redrafted for clarity (no changes to policy); VSRPs are included in those terms as they were in the draft rule.

Note: 1 - See clauses 5A.B.3(a)(6) and 5A.E.3(c)(9) of the final rule. 2 - See clause 3.7.3 of the final rule. 3 - See clause 3.8.3A of the final rule. 4 - See for example clauses 3.8.6(h) and 3.15.3(a) of the final rule.

As noted above, under the final rule, VSRs are scheduled resources. The VSRP is also a market participant. Therefore, the obligations placed on scheduled resources and market participants in the NER apply to VSRPs in respect of their VSRs (for example, some VSRPs may be Cost Recovery Market Participants). Many of these obligations in the NER are captured because the final rule amends the Chapter 10 definition of 'scheduled resource' to include VSR. The final rule also amends the definition of 'Market Participant' to include VSRPs for clarity, noting that the entities that are VSRPs will already be included as Market Participants under their Chapter 2 registration as Market Generators, Integrated Resource Providers or Market Customers.

However, some specific changes have also been made to the NER by the final rule to expressly refer to 'voluntarily scheduled resource' where required. Sometimes all scheduled resources have the same obligation in the NER. However, at other times, the obligations are different for different types of units or resources. In the latter case, VSRs are separately identified so that it is clear whether and if so, how, the obligation applies to the VSR.[350]

The most substantial effect of VSRs being scheduled resources is that the VSRP participates in central dispatch by submitting dispatch bids for a VSR,[351] and then conforming to their dispatch instructions for dispatch.[352] Principally, the final rule achieves this by amendments throughout rule 3.8.

The final rule includes a clause that sets out the consequences of a VSRP failing to conform to dispatch instructions in relation to its VSR.[353] This rule does not apply to inactive VSR or hibernated VSR. This is because inactive ones are only required to submit bids into central dispatch (but are not dispatched) and hibernated ones do not participate in central dispatch at all.[354] Inactive and hibernated VSRs are discussed further below.

350 For example, compare clause 3.8.9 of the NER (which is not amended by the final rule because it captures Market Participants which includes VSRPs) and clause 3.8.4 of the final rule (which has been amended by the final rule to refer to VSRs, in the provisions with references to specific types of resources).

351 See clauses 3.8.2 and 3.8.6 of the final rule. This may also include rebids under clause 3.8.22 and 3.8.22A.

352 See clause 3.8.23B of the final rule.

353 See clause 3.8.23B of the final rule.

354 See clause 3.8.23B(a) of the final rule.

VSRs that successfully participate in central dispatch will contribute to the setting of spot prices.[355] However, VSRs will not be able to be constrained on under NER clause 3.9.7.

VSRPs who are successful in the VSR incentive mechanism receive financial payments to incentivise participation in central dispatch (the incentive program is discussed further below).[356] These payments are in addition to any amounts payable or receivable in the spot market.

A VSRP may also receive a direction or clause 4.8.9 instruction from AEMO under NER clause 4.8.9 in relation to its VSR (however, inactive or hibernating VSR are not subject to directions).[357]

Consultation between DNSPs and affected VSRPs is required where the model standing offer or a proposed change to a connection policy imposes non-static limitations on Distribution Network Users' maximum capacity of supply into the distribution network.[358]

E.5 Deactivation and temporary hibernation of VSRs

Box 12: Key changes between the draft rule and final rule

- The approval and request mechanism for deactivation, reactivation and hibernation has been replaced with notices, which can be issued by a VSRP and must be made in accordance with certain requirements and the VSR guidelines.[1]
- Inactive VSRs can now retain that status indefinitely. The VSRP can now choose to reactivate or hibernate its inactive VSR at any time.[2]
- The modifications to certain obligations that apply to a VSRP during which its VSR is inactive have been amended.[3]

Note: 1 - See clause 3.10.A.2 of the final rule. 2 - See clause 3.10A.2(i) of the final rule. 3 - See clause 3.10A.2(f) of the final rule.

Process of becoming an inactive or hibernated VSR

The final rule sets out a framework for VSRP to be able to deactivate or temporarily hibernate a VSR.[359] A VSRP may submit a deactivation notice (to become an inactive VSR)[360] or a hibernation notice (to become a hibernated VSR)[361] to AEMO in accordance with the requirements specified in clause 3.10A.2 of the final rule.

Deactivation applies from the time set by a VSRP in a deactivation notice and applies indefinitely, unless the VSRP submits a reactivation notice or a hibernation notice.[362] While inactive, the VSRP has limited participation in central dispatch during that period, in that it must provide dispatch bids but it will not be required to follow dispatch instructions. In contrast, hibernation applies for periods between 30 days and 18 months,[363] and during that period the VSRP ceases to participate in central dispatch altogether.[364]

355 See clause 3.9.1(a)(3) of the final rule.
356 See rule 3.10B of the final rule.
357 See clause 4.8.9 of the NER.
358 See clause 5A.B.3(a)(6) and 5A.E.3(c)(9) of the final rule.
359 See clause 3.10A.2 of the final rule
360 See clause 3.10A.2(b) of the final rule
361 See clause 3.10A.2(j) of the final rule
362 See clause 3.10A.2(i) of the final rule.
363 See clause 3.10A.2(k) of the final rule and clause 3.10A.2(a) of the final rule for the definition of *maximum hibernation period*.
364 See clause 3.10A.2(l) of the final rule.

AEMO will specify the information required to be included in the notices as well as the process for submitting notices in the VSR guidelines.[365] In a deactivation notice, the VSRP does not need to propose a deactivation period.[366] In contrast, in a hibernation notice, the VSRP must specify a proposed hibernation period.[367]

A hibernated VSR will continue to have that status until:

- the VSRP submits a resumption notice to remove its status as hibernated, in which case it becomes a scheduled resource again; or
- the VSRP submits a notice to withdraw the nomination as a VSR, or the maximum hibernation period ends. In this case, the resource ceases to be a VSR, and will only be subject to the obligations applying due to its existing classification as a generating unit, bidirectional unit or market connection point under Chapter 2.[368]

Impacts of becoming an inactive or hibernated VSR

Under this framework, the person whose VSR is approved as an inactive or hibernated VSR remains a VSRP. However, the obligations that apply to that person in respect of that resource are reduced.

Final rule clauses 3.10A.2(f) and 3.10A.2(l)(2)(ii) outline the modifications that apply to a VSRP while its VSR is an inactive or hibernated VSR. More specifically:

- an inactive VSR remains a scheduled resource (and is still required to submit dispatch bids) but is not required to conform to its dispatch instructions[369]
- clauses 3.8.8, 3.8.23B, 3.8.22A, 4.8.9 (in relation to directions), 4.9.2 and 4.9.8 do not apply to an inactive VSR[370]
- a hibernated VSR is not a scheduled resource and none of the requirements applying to scheduled resources apply to a VSRP in respect of the hibernated VSR[371]
- because the VSRP retains its underlying registration as a Generator, Integrated Resource Provider or Market Customer, the VSRP must continue to comply with the obligations that apply to a Generator, Integrated Resource Provider or Market Customer in respect of the relevant qualifying resource.

Clause 3.8.2B in the final rule outlines the requirement on a VSRP to participate in central dispatch and how this is varied when the VSR is recorded as an inactive or hibernated VSR.

E.6 The VSR incentive mechanism

Box 13: Key changes between the draft rule and final rule

- The clause numbering has changed such that the incentive mechanism is now contained in a separate rule 3.10B, rather than grouped with the VSRs provision in clause 3.10A.[1]

365 See clauses 3.10A.2(c) and 3.10A.2(k) of the final rule.
366 See clause 3.10A.2(c) of the final rule.
367 See clause 3.10A.2(k) of the final rule.
368 See clause 3.10A.2(p) of the final rule.
369 See clauses 3.10A.1(i)(1) and 3.10A.2(d)(3) of the final rule.
370 See clause 3.10A.2(f) of the final rule.
371 See clause 3.10A.1(i)(2) and 3.10A.2(l)(2)(ii) of the final rule.

- The incentive period has changed such that it is now between 1 April 2026 and 31 December 2031.[2]
- The incentive mechanism has been amended to allow external bodies other than AEMO to provide funding, grants or other financial support to meet part or all of AEMO's costs of implementing a VSR incentive mechanism, including to meet any participation payments.[3] This is referred to as "external funding" and will not be included in cost recovery calculations.[4]
- The incentive MW price cap has been increased from half the VSR benefits, to any amount less than the VSR benefits.[5]
- In the cost recovery calculation, energy consumed by VSRPs is no longer excluded, the share of energy is determined over a billing week rather than over the whole year, and the calculation is done across the NEM rather than regionally.[6]

Note: 1 - See rule 3.10.B of the final rule. 2 - See clause 3.10B.1 of the final rule for the definition of *incentive period*. 3 - See clause 3.10.B.1 of the final rule for the definition of *external funding*. 4 - See clauses 3.10B.3(c) to (e) of the final rule. 5 - See clause 3.10B.1, definition of incentive MW price cap, in the final rule. 6 - See clause 3.10B.3(e) of the final rule.

Outline of the VSR incentive mechanism

The final rule introduces a VSR incentive mechanism to incentivise the participation of qualifying resources in central dispatch as scheduled resources by nominating to be a VSR. It does so by awarding participation payments to successful participants. These payments are additional to any payments receivable (or payable) in the spot market.

The mechanism only operates during the incentive period, which is a limited period from 1 April 2026 until 31 December 2031.[372] During the incentive period, AEMO must conduct at least two tender processes to determine which participants will receive participation payments.[373]

Details will be set out in an AEMO procedure

AEMO must develop VSR incentive procedures, which must specify a range of matters, including:[374]

- the criteria for participating in the mechanism, which must include a prohibition on participation by a VSRP who already has been, or is a party to a VSR participation agreement for a particular VSR
- any further requirements for VSR incentive mechanism participants to satisfy in order to receive external funding
- the procedures for conducting the incentive mechanism and timing of each tender process
- the requirements for offers submitted by participants
- the assessment criteria and methodology AEMO will use to select successful participants
- the procedures and timetable for settling participation payments
- requirements for the VSR participation agreement.

Eligibility and participation agreements

372 See clause 3.10B.1 of the final rule for the definition of incentive period.

373 See clause 3.10B.2(a) of the final rule.

374 See clause 3.10B.2(c)-(e) of the final rule.

In order to be eligible to participate in the VSR incentive mechanism, a participant must be a VSRP, or someone who is not yet a VSRP but intends to be if it is successful in the mechanism (an intending VSRP).[375]

If successful, the VSRP must enter into a contract (a VSR participation agreement) under which AEMO pays the VSRP a participation payment, and the VSRP participates in central dispatch in accordance with the terms of the agreement and any requirements specified in the VSR incentive procedures.[376]

Incentive objective and VSR benefits

The VSR incentive mechanism must be structured and run by AEMO in a way that achieves the VSR incentive objective, which is to maximise VSR benefits in the long run by incentivising market participants with qualifying resources to nominate those resources as VSRs, while minimising the cost of facilitating participation through participant payments.[377]

The VSR benefits are the expected benefits to consumers (as a whole) of VSRs participating in central dispatch, including where the participation results in reduced system security services costs, avoided generation, avoided emissions and reduced RERT costs.[378]

Incentive MW price cap and overall cap

The price paid to a successful VSR incentive mechanism participant (the participation price) must not exceed the incentive MW price cap. The price cap is a price (in $/MW) determined by AEMO that must be less than the VSR benefits (calculated in $/MW) that AEMO expects will accrue from successful VSR incentive program participants participating in central dispatch, in relation to a particular VSR tender process.[379]

AEMO must determine the incentive MW price cap for each NEM region before commencing each VSR tender process and must notify the amount to the AER and AEMC.[380] All three market bodies must keep the incentive MW price cap confidential during the incentive period.[381]

Therefore, no one successful participant can be paid (per MW) more than the incentive MW price cap under a VSR participation agreement.[382]

In addition to the incentive MW price cap, the aggregate of all payments made under all VSR participation agreements (i.e. participation payments) must not exceed a total amount of $50 million plus the value of all external funding (if any).

How the costs of the incentive mechanism will be recovered

There are two main types of costs arising from the introduction of the VSR incentive mechanism:

- AEMO's costs and expenses incurred in establishing, administering and conducting the VSR incentive mechanism, and
- the amounts payable as participation payments under VSR participation agreements.[383]

375 See clause 3.10B.1 of the final rule for the definition of Intending VSRP.

376 See clause 3.10B.2(i) of the final rule.

377 See clause 3.10B.1 of the final rule for definition of *VSR incentive objective* and clause 3.10B.2(e) of the final rule.

378 See clause 3.10B.1 of the final rule for definition of VSR Benefits.

379 See clauses 3.10B.1 and 3.10B.2(f) of the final rule.

380 See clause 3.10B.2(g) of the final rule.

381 See clause 3.10B.2(h) of the final rule.

382 See clause 3.10B.2(j)(3) of the final rule.

383 See clause 3.10B.3(b) of the final rule

The final rule requires AEMO to recover the first type of costs from all Registered Participants as part of the fees imposed in accordance with rule 2.11 (i.e. participant fees).[384]

For the second type of costs, the final rule sets out a cost recovery framework.[385] These amounts are to be recovered from cost recovery market participants (which may include VSRPs) in accordance with the formula specified in the final rule.

AEMO must determine the amounts of participation payments in respect of the previous financial year, less any external funding received in that year, within 40 business days of the completion of that financial year and then allocate that amount between cost recovery market participants based on their share of energy consumed during a billing week.[386] The amount for each participant is then included in the next preliminary statement provided to that participant. This links these payments to the settlement processes in Chapter 3 of the NER.

AEMO will report annually and after the end of the incentive period

Following the completion of the first VSR tender process, and annually thereafter, AEMO must publish the aggregate amount of all participation payments payable in each financial year under all VSR participation agreements. This obligation continues for every financial year in which there is an amount payable under a VSR participation agreement.[387] This means that the reporting of payments could extend beyond the incentive period because VSR participation agreements entered into at the end of the incentive period may nonetheless continue until the expiry of their term, which could be up to three years.[388]

Following the completion of the incentive period, AEMO must publish a report within 12 months that includes a summary of the outcomes from the VSR incentive mechanism, an analysis of the participation prices paid to participants under the VSR participation agreements, as well as an analysis of the types of VSRs contracted under those agreements.[389]

E.7 Reporting obligations on AEMO and AER in relation to unscheduled price responsive resources

Box 14: Key changes between the draft rule and final rule

- In AEMO's report on statistics and trends relating to unscheduled price responsive resources, two sub-topics on forecast deviations have been combined into one.[1]
- While the topics the AER is required to report on have not changed, it has been clarified that the AER's report will provide estimates of the five areas of costs that may arise from the impact of unscheduled price responsive resources on forecast deviations.[1]

Note: 1 - See clause 3.10C.2(b)(1) of the final rule. 2 - See clause 3.10C.3(c) of the final rule.

The final rule introduces a reporting function on AEMO and the AER to report on the impact that unscheduled price responsive resources have on forecast deviations. Forecast deviations are the difference between forecast load for a particular trading interval developed for pre-dispatch and dispatch, and the actual load during that trading interval. Unscheduled price responsive resources

384 See clause 3.10B.3(a).

385 See clauses 3.10B.3(c) to (e) of the final rule.

386 See clauses 3.10B.3(c), (e) and (f) of the final rule.

387 See clause 3.10B.4 of the final rule.

388 See clause 3.10B.2(j)(2) of the final rule.

389 See clause 3.10B.4(b) of the final rule.

refer to resources that are not a scheduled resource, are capable of changing output or consumption depending on changes in forecast or actual spot prices. They include hibernated VSRs, but not other voluntarily scheduled resources.[390]

AEMO's reporting functions

The final rule requires AEMO to report on the impact that unscheduled price-responsive resources have on forecast deviations, and the resulting market outcomes.[391] The product of this reporting is two things: an annual report, and quarterly data produced as a source of information that is updated at least quarterly.

By 30 September each year, AEMO must publish a report that covers the previous financial year. The report must include AEMO's analysis of the statistics and trends of:

- the volumes and types of unscheduled price-responsive resources reported by Registered Participants, using the DER register information and demand side participation information[392]
- patterns in forecast deviations, including to the extent identifiable, the approximate contribution of unscheduled price-responsive resources to those deviations, in response to forecast and actual spot prices.[393]

The report must also include AEMO's best estimate of:

- the impacts of unscheduled price-responsive resources on the load forecast used by AEMO for pre-dispatch and dispatch, including in comparison with outcomes published in previous reports[394]
- the impact of unscheduled price-responsive resources on forecast deviations in relation to additional amounts paid to ancillary service providers for the additional ancillary services enabled and to cost recovery market participants for the ancillary service transaction payments made.[395]

The report must include AEMO's identification of additional information or inputs required to improve or account for unscheduled price-responsive resources in load forecasts.[396]

The report must include AEMO's description of:

- any actions taken by AEMO to reduce forecast deviations by accounting for unscheduled price-responsive resources, where those actions have resulted in improved market outcomes[397]
- the methodologies used by AEMO to consider and manage the impacts of unscheduled price-responsive resources on load forecasts for pre-dispatch and dispatch[398]
- any barriers to AEMO using those methodologies to improve forecasting.[399]

The annual report must also be supported by a source of information that presents the information and metrics specified by AEMO in its reporting guidelines. The source of information

390 See definitions in clause 3.10C.1 of the final rule.
391 See clause 3.10C.2 of the final rule.
392 See clause 3.10C.2(b)(1)(i) of the final rule.
393 See clause 3.10C.2(b)(1)(ii) of the final rule.
394 See clause 3.10C.2(b)(4) of the final rule
395 See clause 3.10C.2(b)(2) of the final rule.
396 See clause 3.10C.2(b)(5) of the final rule.
397 See clause 3.10C.2(b)(6) of the final rule
398 See clause 3.10C.2(b)(7)(i) of the final rule.
399 See clause 3.10C.2(b)(7)(ii) of the final rule.

must be updated when new information becomes available and at least once each calendar quarter.[400] This source could be in the form of a webpage that can be readily updated and accessed by interested parties.

The AER's reporting functions

The final rule also requires the AER to publish a report by 31 December each year that covers the previous financial year.[401] The objective is to provide transparency on the impacts of unscheduled price responsive resources on efficient market outcomes to inform future market reform.[402] The monitoring and reporting framework established by the final rule is part of the AER's existing wholesale market monitoring and reporting functions under section 18C of the NEL.

The AER's report must analyse the impact of unscheduled price responsive resources on forecast deviations, and the consequential impacts on the efficiency of the market, including estimates in relation to:[403]

- additional amounts paid to Generators, Integrated Resource Providers and Demand Response Service Providers for different quantities and prices of electricity and wholesale demand response that are dispatched
- additional amounts paid to Ancillary Service Providers for additional market ancillary services that are enabled
- additional amounts paid to Cost Recovery Market Participants for ancillary service transaction payments under clause 3.15.6AA
- additional amounts paid to Registered Participants for RERT for scheduled reserves that are dispatched and unscheduled reserves that are activated
- additional emissions resulting from the relative increases referred to for the previous items.

The report must also identify the trends and outcomes on the efficiency of the market as a result of those matters when compared to previous financial years and the AER's recommendations for how to improve the efficiency of the market in respect of those matters.[404]

The AER may request AEMO to provide information to the AER if it considers it reasonably necessary to satisfy its reporting obligations, including confidential information that AEMO has received from registered participants, and AEMO must comply with any such request from the AER.[405]

The final rule requires both AEMO and the AER to prepare and publish price responsive resource reporting guidelines, which specify how each will meet their respective reporting obligations.[406]

400 See clauses 3.10C.2(c) and (d) of the final rule.

401 This means it covers the same financial year reporting period as AEMO's report, but it is published three months after AEMO's report, which allows the AER to consider AEMO's report in preparing its own report.

402 See clauses 3.10C.3(a) and (b) of the final rule.

403 See clause 3.10C.3(c) of the final rule.

404 See clause 3.10C.3(c) of the final rule.

405 See clauses 3.10C.3(e) and (f) of the final rule.

406 See clauses 3.10C.2(e) and (f) and clauses 3.10C.3(g) and (h) of the final rule.

F Legal requirements to make a rule

This appendix sets out the relevant legal requirements under the NEL for the Commission to make a final rule determination.

F.1 Final rule determination and more preferable final rule

In accordance with sections 102, 102A and 103 of the NEL, the Commission has made this final rule determination for a more preferable final electricity rule, and no final retail rule, in relation to the rule proposed by the proponent.

The Commission's reasons for making this final rule determination are set out in chapter four.

A copy of the more preferable final electricity rule is attached to and published with this final determination. Its key features are described in Appendix E.

F.2 Power to make the final electricity rule

The Commission is satisfied that the more preferable final electricity rule falls within the subject matter about which the Commission may make rules.

The more preferable final rule falls within section 34 of the NEL as it relates to regulating the activities of persons (including Registered participants) participating in the national electricity market.[407]

F.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the more preferable final rule
- the rule change request
- submissions received during consultation on the consultation paper and the draft determination
- stakeholder input received at the public forums held on 19 February and 27 August 2024, and in technical working group meetings held over the period February to May 2024
- the ways in which the more preferable final rule will or is likely to contribute to the achievement of the NEO
- whether any consequential changes to the NERR were required
- the application of the more preferable final electricity rule to the Northern Territory.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[408]

407 NEL section 34(1)(a)(iii).

408 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy.

F.4 Making electricity rules in the Northern Territory

F.4.1 Application of the final rule to the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[409] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

As the final rule amends some chapters of the NER that apply in the Northern Territory, the Commission has considered how the rule should apply to the Northern Territory according to the following questions:

- Should the NEO test include the Northern Territory electricity systems? Yes. For this rule change request, the Commission's final determination is that the reference to the "national electricity system" in the NEO includes the local electricity systems in the Northern Territory. See appendix F.4.2 for the relevant test.
- Should the rule be different in the Northern Territory? No. For this rule change request, the Commission's final determination is to make a uniform rule for the NEM and the Northern Territory. The key aspects of the final rule would have no effect in the Northern Territory as chapters 3 and 4 of the NER do not apply in the Northern Territory. However, this does not necessitate making a differential rule. See appendix F.4.3 for the relevant test.

F.4.2 Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[410]

1. the national electricity system
2. one or more, or all, of the local electricity systems[411]
3. all of the electricity systems referred to above.

F.4.3 Test for differential rule

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[412] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity systems, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

409 The *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015* (**NT Act**). The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations 2016.

410 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

411 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

412 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[413]

F.5 Civil penalty provisions and conduct provisions

The Commission cannot create new civil penalty provisions or conduct provisions. However, it may recommend to energy ministers that new or existing provisions of the NER be classified as civil penalty provisions or conduct provisions.

The NEL sets out a three-tier penalty structure for civil penalty provisions in the NEL and the NER.[414] A Decision Matrix and Concepts Table,[415] approved by Energy Ministers, provide a decision-making framework that the Commission applies, in consultation with the AER, when assessing whether to recommend that provisions of the NER should be classified as civil penalty provisions, and if so, under which tier.

The final rule includes three new provisions in the NER which the Commission will recommend that the energy ministers classify as civil penalty provisions, as set out below. The Commission has consulted with the AER on these recommendations, and the AER supports these decisions.

Table F.1: NER civil penalty provision recommendations

Clause	Description of clause	Proposed classification	Reason
3.10A.1(l)	This clause requires Voluntarily Scheduled Resource Providers to comply with any terms and conditions imposed by AEMO in respect of their voluntarily scheduled resource.	Tier 1	Failure to comply with terms and conditions imposed by AEMO may affect AEMO's ability to plan and operate the power system efficiently. This Tiering is also consistent with similar CPPs in Chapter 2 of the NER.
3.10A.1(m)	This clause requires Voluntarily Scheduled Resource Providers to notify AEMO: (1) immediately if the Voluntarily Scheduled Resource Provider ceases to be the financially responsible Market Participant for a qualifying resource forming part of a voluntarily scheduled resource; or (2) as soon as practicable, and in any event, no later than 10 business days	Tier 1	Failure to comply with these notification requirements may negatively impact the relevant customer and the energy market. This Tiering is also consistent with similar CPPs in Chapter 2 of the NER.

413 Clause 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

414 Further information about civil penalties is available here.

415 The Decision Matrix and Concepts Table is available here

Clause	Description of clause	Proposed classification	Reason
	after becoming aware that a voluntarily scheduled resource ceases to be a qualifying resource.		
4.9.8(g)	This clause requires Voluntarily Scheduled Resource Providers to be able to comply with their latest dispatch bid.	Tier 1	Failure to be able to comply with dispatch bids may affect the efficient operation of the power system. This Tiering is also consistent with similar CPPs within clause 4.9.8.

Where the final rule amends provisions that are currently classified as civil penalty provisions, the Commission will not recommend any changes to the classification of those provisions.

The final rule does not amend any provisions currently classified as conduct provisions, and the Commission will not recommend that any new provisions introduced by the final rule be classified as conduct provisions.

Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AGC	Automatic Generation Control
BDU	Bi-directional unit
Commission	See AEMC
CER	Consumer energy resource
CIS	Capacity investment Scheme
C&I	Commercial and industrial
CPP	Civil Penalty Provision
CSIP-Aus	Common Smart Inverter Profile - Aus
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DER	Distributed energy resources
DNSP	Distribution network system provider
DOE	Distribution operating envelope
DRSP	Demand Response Service Provider
DSO	Distribution system operator
DSP	Demand side participation
DSPIP	Demand side participation information portal
DUID	Dispatchable unit identifier
EAAP	Energy Adequacy Assessment Projection
ESOO	Electricity statement of opportunity
ESB	Energy Security Board
EV	Electric vehicle
FCAS	Frequency control ancillary services
FEL	Flexible export limits
FPP	Frequency performance payments
FRMP	Financially responsible market participant
HLIA	High-level implementation assessment
ICCP	Inter-control centre communications protocol
IES	Intelligent energy systems
IESS	Integrated Energy Storage Systems rule change
IRP	Integrated resource provider
ISP	Integrated system plan
LOR	Lack of reserve
LIL	Large industrial load
LSU	Light scheduling unit
MASS	Market Ancillary Services Specifications

MCE	Ministerial Council of Energy
MT PASA	Medium term projected assessment of system adequacy
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NCP	Net Contract Position
NMI	National metering identifier
NPV	Net Present Value
NSP	Network service provider
PASA	Projected assessment of system adequacy
PFR	Primary Frequency Response
RERT	Reliability and Emergency Reserve Trader
RRO	Retailer Reliability Obligation
SCADA	Supervisory Control and Data Acquisition
SOC	State of Charge
SRA	Small resource aggregator
ST PASA	Short term Projected assessment of system adequacy
TWG	Technical working group
V2G	Vehicle to grid
VPP	Virtual power plant
VSR	Voluntarily scheduled resource
VSRP	Voluntarily scheduled resource provider
WDRM	Wholesale demand response mechanism