28 September 2023

Ms Anna Collyer
Chair
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Electronic Submission – ERC0290

Second Directions paper – Improving security frameworks for the energy transition

Dear Ms Collyer,

Energy Networks Australia (ENA) welcomes the opportunity to provide a submission to the Australian Energy Market Commission (AEMC) on the *Second Directions paper – improving security frameworks for the energy transition*.

ENA represents Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

ENA supports the objective of progressing a system security framework that allows the Australian Energy Market Operator (AEMO) to enable or schedule system security services such as system strength and inertia in operational timeframes. ENA shares the AEMC's long-term goal to co-optimise the provision of security services and energy within the National Electricity Market (NEM), and acknowledges that current limits to engineering knowledge make this impractical in the short-term.

ENA has several key concerns with the proposed Rule design.

TNSPs are not best placed to manage variable system strength payments

ENA strongly disagrees with the AEMC's position that Transmission Network Service Providers (TNSPs) are best placed to manage the risk associated with variable system strength payments, which arise as a result of uncertainty in quantity of enablement and potential wholesale spot price exposure.

A sound principle of regulatory policy design is that risks should be allocated to those parties best-placed to manage those risks. TNSPs are not well placed to manage large and highly unpredictable payments for non-network solutions. ENA considers that AEMO should be responsible for settling contract enablement payments, which is a natural extension of its existing wholesale and ancillary services settlement function and capabilities.

System Strength Service Providers (SSSPs) are currently commencing contract designs for their system strength RIT-Ts. This makes it imperative that AEMO's procurement and enablement guidelines are available early in 2024 to ensure a coordinated and workable framework. It is also imperative that they include clear decision rules for the enablement of contracted security services. ENA members look forward to working collaboratively with

AEMO to develop these enablement guidelines, in parallel with the development of contract specifications.

Cashflow risk and liquidity implications for TNSPs

ENA members have significant concerns about the magnitude and variability of system security service enablement payments for which TNSPs would be liable under the proposed design. These present material financial risks for TNSPs.

To help inform the AEMC, ENA engaged Endgame Economics to quantify the potential system strength payments associated with a wholesale spot price true-up arrangement (make-whole costs) to inform the potential magnitude and variability of cashflows which TNSPs' exposure could be linked to under the proposed design. Key findings were:

- In New South Wales, the average annual make-whole cost for system strength enablement over the period 2025/26 to 2029/30 was forecast to be approximately $224 million, with annual average variability of 19%, and a maximum annual enablement cost of $320 million.
- In Queensland, the average annual cost over the same period was forecast to be $92 million with average annual variability of 27%.
- In South Australia, the average annual cost was forecast to be $32 million with variability of 22%.
- By 2029/30, these annual make-whole costs are anticipated to reach nearly 100% of average annual TNSP operating expenditure allowances in both New South Wales and Queensland.

There are two primary drivers of large and highly variable enablement payments: 1) the quantity of system strength enablement by AEMO, and 2) the potential for generators to seek wholesale spot price linked contracts. ENA members consider that wholesale spot price linkages present material risks from a cashflow and liquidity point of view.

- To manage material cashflow risks, TNSPs may seek to form contracts where the security service providers bear the spot price exposure risk. This is likely to involve inclusion of risk premiums in contracts, and is likely to ultimately be more costly to TNSPs and consumers compared to alternative options.
- Even without wholesale spot price exposure, TNSPs consider that the variability associated with the uncertain quantity of enablement will be sizeable and unpredictable and will have significant implications for TNSP cashflow and liquidity buffers.
- We therefore recommend that AEMO is better placed to manage enablement payments, as per the arrangements proposed in the AEMC's Draft Determination on the Operational Security Mechanism.
- Importantly, all revenue and payments associated with system strength incurred by SSSPs within a financial year will be balanced, with the difference passed through to customers via prescribed transmission charges. There is therefore no double counting associated with AEMO settling variable payments for system strength contracts.

In addition, ENA members do not consider that the proposed drafting provides sufficient timing, alignment or certainty of regulatory cost recovery for non-network options. We would welcome the opportunity to work with the AEMC to explore avenues to provide TNSPs with more certainty, and timeliness of non-network cost recovery.

Attachment 1 explores these cashflow risks and potential solutions in more detail. Further details on Endgame's methodology and modelling results are outlined in ***Attachment 4***.

Inertia framework suggestions

ENA supports the introduction of a more forward-looking inertia framework that encompasses a NEM-wide inertia floor and the alignment of inertia procurement timeframes with those for system strength. However, ENA members have several key concerns:

- The 1 December 2024 timing currently proposed for publishing of inertia requirements by AEMO is not workable and does not provide an opportunity for inertia requirements to be considered as part of system strength RIT-Ts currently underway. ENA considers the best approach would be for timely advice from AEMO (no later than 31 March 2024).
- Transitional arrangements are required to fast-track inertia requirements to enable networks to co-optimise system strength and inertia procurement in the one process. We have outlined a number of suggestions and proposed rule drafting in ***Attachment 3***.
- The proposed penalty provisions for an Inertia Service Provider's failure to meet the relevant allocations, thresholds and standards are disproportionate and have been proposed without explanation or justification. More importantly, the proposed liability is fundamentally at odds with a "reasonable endeavours" obligation on TNSPs. For consistency, the AEMC should have regard to those for system strength.
- Finally, the Second Directions Paper suggests that Inertia Service Providers will have the option to use synthetic inertia to meet the minimum inertia levels with AEMO's approval. ENA members are cautiously optimistic about the potential role of synthetic inertia, and support the future use of synthetic inertia for the minimum level (subject to AEMO's approval). ENA members would also welcome the opportunity to work with AEMO on real-world trials of synthetic inertia solutions to improve power system knowledge.

Further information

ENA provides the following attachments to our submission:

» Attachment 1: Potential solutions to TNSP cashflow concerns
» Attachment 2: Responses to questions raised in the AEMC's submission
» Attachment 3: Drafting suggestions
» Attachment 4: Market modelling results outlining potential volume of enablement payments.

ENA looks forward to further engagement with the AEMC on this rule change to ensure workable arrangements for system strength and inertia are put in place and would welcome the opportunity to review any subsequent changes to the Draft Rule prior to finalisation. ENA will continue to consider Rule drafting suggestions in relation to cost recovery and will provide these to the AEMC in due course.

Should you have any queries on this response please feel free to contact Verity Watson, Head of Transmission, (vwatson@energynetworks.com.au).

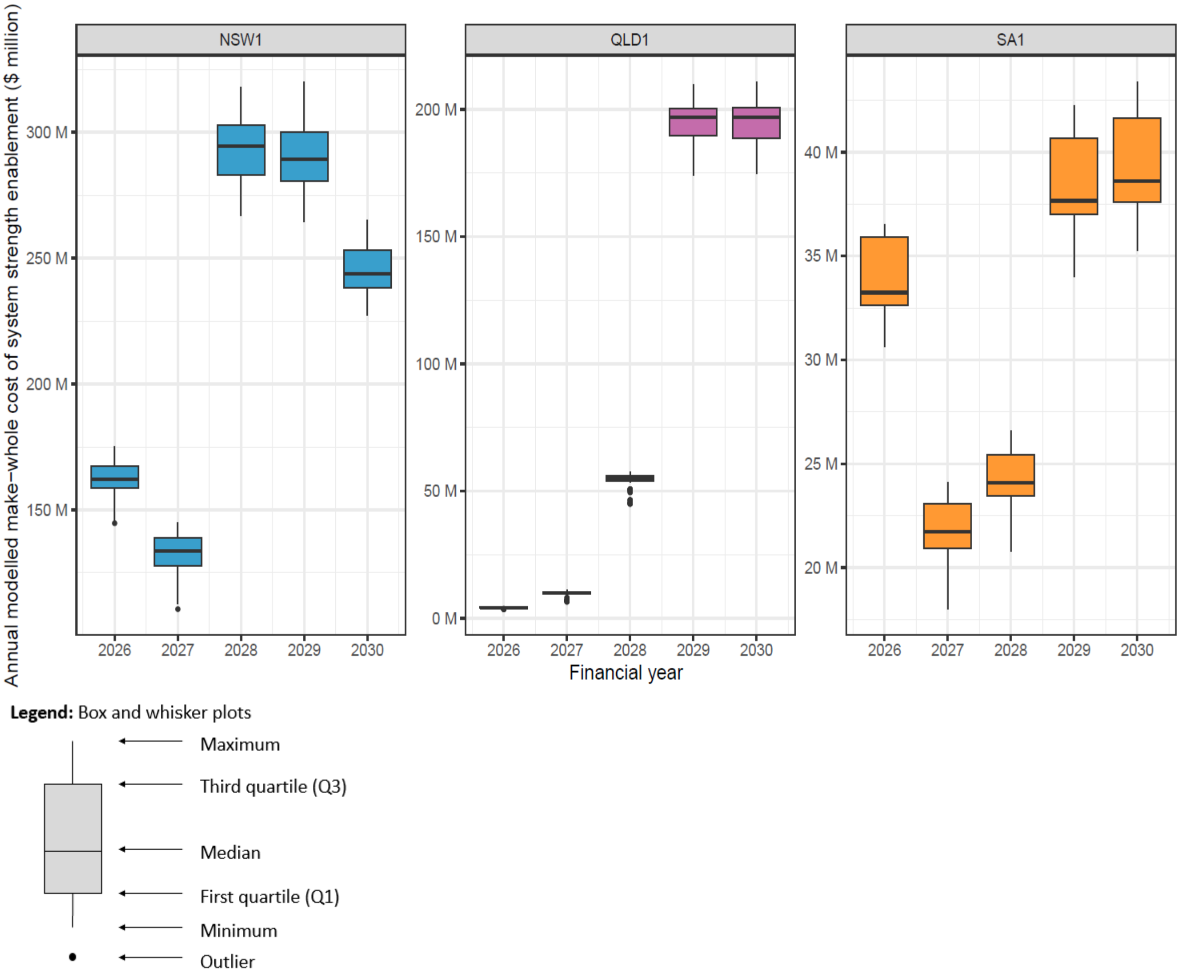
Yours sincerely,

Dominic Adams
General Manager – Networks

Attachment 1 – Potential solutions to cashflow risk for TNSPs

As outlined in our submission and further in ***Attachment 4***, modelling by Endgame Economics indicates that TNSPs may be exposed to very significant and highly variable costs for system strength enablement. The model included a series of 100 simulations of the NEM from FY 2026 to 2030. Figure 1 sets out the range of annual make-whole costs modelled by Endgame.

Figure 1: Modelled annual make-whole system strength costs for Queensland, New South Wales and South Australia, 2025/26 to 2029/30



There are two primary drivers of large and highly variable make-whole payments:

- **Quantity of system strength enablement** which is expected to increase over time, as coal generators retire from the power system. The quantity of enablement is expected to be highly uncertain. The uncertainty is directly linked to generator retirement and commitment decisions. It could also potentially be influenced by perverse incentives for synchronous generators to decommit from the energy market during periods of sustained, predictable periods of negative spot prices (e.g. during spring and autumn) to be called on for system security reasons.

- **Potential for generators to seek wholesale spot price-linked contracts** given the expected higher frequency and increasing depth of negative price periods in the NEM over the five years to 2029/30.

Significant variance in enablement payments could lead to material cashflow issues for TNSPs if true-ups between forecast and actual costs are left to be addressed through the existing network support pass through (NSPT) framework, noting that, at present, no TNSP has a network support allowance to cover these costs. While an appropriate allowance could be added, its absence means that TNSPs are effectively required to 'bank' the total cost of enablement payments for two years.

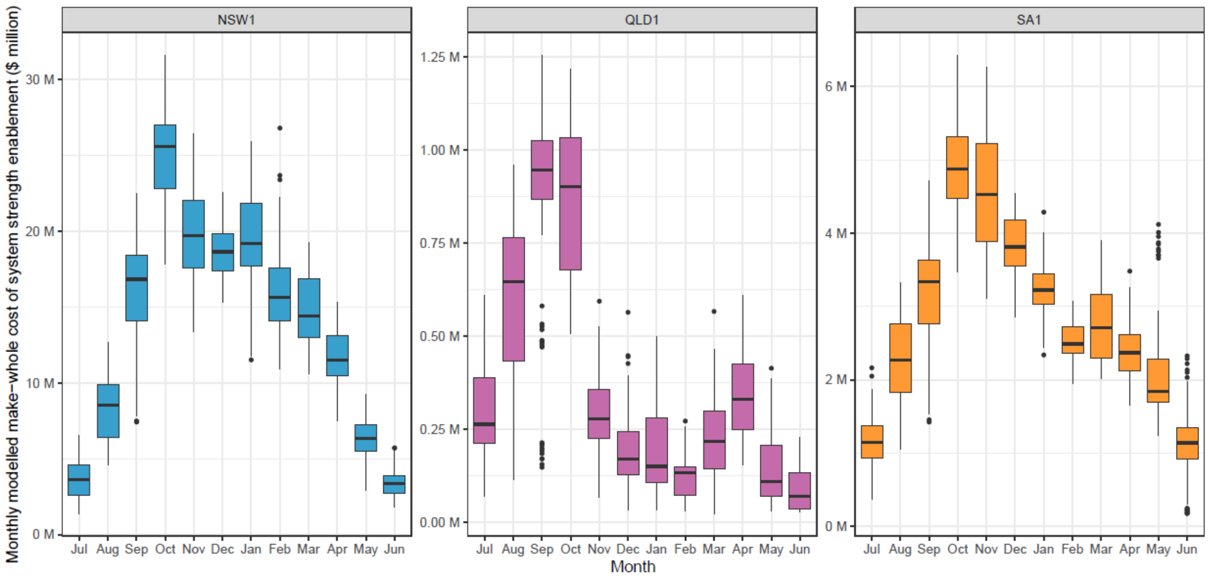
Key risks of the current state:

» **Significant month on month uncertainty:** The recovery of forecast system strength payments through prescribed transmission charges occurs throughout the year via equal monthly instalments. Endgame's modelling indicates that significant month on month variability can be expected in enablement costs associated with a true-up arrangement. Even with an annual forecast that is broadly aligned with actual costs over the course of a year, TNSPs would face material short-term cashflow volatility which could easily exceed ±$10 million in a month for some networks e.g. NSW and Queensland. Figure 2 provides an example of month-on-month variability for 2025/26.

» **Delays to the recovery of costs that could easily exceed 50% of annual opex allowances:** Were TNSPs to forecast based on the average costs presented in the Endgame Economics modelled scenarios, the true-up amount at the end of the year could easily be ±25% of their annual operating expenditure allowances. It must be noted, though, that Endgame's modelling does not attempt to forecast the cost of procuring the contract itself. Experience in South Australia indicates that this could easily double the likely enablement costs compared to the modelled make-whole costs. Such material costs impinge on TNSPs' ability to use their working capital to meet capital, operating and maintenance requirements. The scale of true-ups would significantly increase year-to-year, resulting in increased volatility in prescribed transmission charges to customers (which can be particularly significant for transmission connected customers).

» **Requirement for fixed contracting structures to avoid spot market exposure:** Spot exposure is untenable for TNSPs, who have no experience in hedging spot market risks. This being the case, the AEMC could expect TNSPs to procure contracts that transfer spot price exposure to the provider, which is likely to be a generator with material spot price experience. Combined with the highly concentrated markets in which these transactions will occur, the likely outcome is that generators providing system strength would be able to extract materially higher prices from the relevant markets. Such an approach would increase the total costs to consumers inefficiently.

Figure 2: Modelled monthly system strength make-whole enablement costs for Queensland, New South Wales and South Australia in 2025/26



We see two possible alternative options to reduce cashflow risk to TNSPs from the proposed arrangements, whereby the SSSPs are responsible for variable payments and the NSPT process is used to true-up payments:

- Scenario 1 – TNSPs are responsible for variable payments and Rule 6A.23.3A is amended to enable the true-up of system strength service payments
- Scenario 2 – AEMO settles variable payments through the weekly settlements process (our preferred arrangement)

ENA does not consider the current proposal is appropriate to address cost-recovery concerns, as standard pass-through mechanisms are not well equipped to deal with cost variances of this magnitude. For example, TNSPs would include forecasts of anticipated contract costs when setting prescribed transmission prices on a year-ahead basis. However, the adjustment to correct under/overs has a two-year lag, during which time TNSPs would be required to carry these costs. Additionally, contract costs would also be subject to AER review and approval, but TNSPs wouldn't have this until after contracts are executed. In moving to the revised direction, the AEMC has provided no rationale for the change from the agreed Scenario 2.

Scenario 1 would provide for a true-up for any difference between forecast and actual enablement costs, with any difference being added to (or subtracted from) the annual service revenue requirement for subsequent years. Clause 6A.23.3A provides such a true-up mechanism for system strength revenues (i.e. charges imposed by a SSSP). This framework could potentially be extended to also incorporate any payments made by a TNSP for AEMO-enabled system security services, including system strength service payments or inertia service payments.

However, TNSPs would still be exposed to significant potential month-on-month variability due to the volatility of enablement costs, and therefore still exposed to significant cashflow risk.

Scenario 2 removes the spot market exposure for TNSPs, settling variable payments through AEMO's weekly settlements process. While the magnitude of enablement costs modelled by Endgame is very material to TNSPs, this is only a small additional cost in the scheme of the wholesale market. An additional $348 million per annum (considering 2025/26 to 2029/30 average annual enablement across NSW, Queensland and SA) is only a 3% increase considering the $11.5 billion traded in the NEM in 2020/21.[1]

Importantly, ENA notes that in any of these scenarios, all revenue and payments associated with system strength incurred by SSSPs within a financial year will be balanced, with the difference passed through to customers via common service charges.

Cost recovery worked example

A worked example has been included to demonstrate the impact of different cost recovery models on TNSPs. For simplicity, this example deliberately abstracts from any time value of money adjustments. Purely indicative cost assumptions underpinning this numerical illustration are as follows:

Assumptions	**$ million**	**Calculation reference**
Prescribed Common Transmission Services: Annual Service Revenue Requirement plus Non-asset Operating Expenditure	150	a
System Strength Service Payments: Availability Payments	55	b
Forecast System Strength Service Payments: Enablement Payments (ex-ante)	75	c
Actual System Strength Payments: Enablement Payments (ex-post)	101	d
Forecast System Strength Revenue (ex-ante)	5	e
Actual System Strength Revenue (ex-post)	6	f

Worked example:

Costs incurred	**Current state:** SSSP responsible for variable payments, NSPT true-up for payments	**Scenario 1:** SSSP responsible for variable payments, amended 6A.23.3A for true-up process	**Scenario 2:** AEMO settlement of variable payments (Preferred)
Prescribed Common Transmission Services Revenue Requirement (set year ahead)	275 (= a + b + c - e)	275 (= a + b + c - e)	200[3] (= a + b – e)
Amount Settled Through AEMO's Weekly Settlements Process – No holdover	0 (not applicable)	0 (not applicable)	101 (= d)
SSSP Network Support Pass-through Application Amount – Two-year holdover[1]	26 (= d – c)	0 (not required)	0 (not required)
Amount held over for later pricing true-up – One-year holdover[1,2]	-1 (= (e – f))	25 (= (d – c) + (e – f))	-1 (= (e – f))
Total recovery amount from prescribed transmission customers	**300** **(= a + b + d– f)**	**300** **(= a + b + d – f)**	**300** **(= a + b + d – f))**

[1] Before time value of money adjustment

[1] Source AEMO National Electricity Market Fact Sheet 2021

[2] A negative value indicates a reduction in the future payments by prescribed transmission customers
[3] The lower common transmission services revenue in Scenario 2 reflects a lower Maximum Allowed Revenue adjustment

ENA notes that there is an additional option for cost recovery involving the Contingent Project Application (CPA) framework, which could be extended to cover operating expenditure, so that revenues can be adjusted for a forecast operating expenditure cost for non-network contracts. This has not been explored here.

ENA welcomes the opportunity to work with the AEMC on options for cost recovery and variable cost responsibility.

Key assumptions in Endgame analysis

Several key simplifying assumptions were made to support Endgame's analysis within the time period of this consultation.

- Endgame Economics has modelled a single scenario of system strength requirements being met by a combination of synchronous generators (and over time, synchronous condensers). In reality, the quantity of enablement is expected to be highly uncertain and influenced by many factors.
- Endgame Economics has modelled a scenario where TNSPs take on the negative spot price exposure to ensure generators are made whole to their short-run marginal cost. This was studied in the context of AEMC's example in the Second Directions Paper (Table 5.3) where a wholesale spot price true up was done.

Importantly, several key assumptions are understood to be conservative:

- The modelling assumes synchronous generation is meeting the system strength needs, either at the short run marginal cost used in the Integrated System Plan, or at no cost in the case of pumped hydro operating in synchronous mode.
- Only the enablement cost is modelled as a true-up from the Regional Reference Price to an assumed generator short-run marginal cost.
- The fixed set-up and activation costs or any other commercial arrangements are not included.

As such, the cost estimates are anticipated to be very conservative, and the actual commercial costs (and their variability) are likely to be substantially higher.

Attachment 2 - ENA response to Questions

Aligning the inertia framework to system strength & removing the exclusion to procuring inertia network services and system strength in the NSCAS framework

Topic / reference	Comments
Question 1: Do stakeholders support the Commission's proposal to introduce an inertia floor for the mainland NEM?	Yes. ENA recommend that in establishing the forward planning framework for inertia that there should be some consideration of non-credible contingencies, ability to take outages for maintenance etc. in setting the inertia floor.
Question 1: Do stakeholders consider that the allocation of proportions of the floor across the NEM would promote balanced and proactive procurement?	Yes. ENA recommends AEMO publish interim guidance on the NEM wide floor and procurement allocations, by no later than 31 March 2024, to give SSSPs the best chance to consider inertia requirements in the system strength RIT-Ts currently underway.
Question 2: Do stakeholders support the Commission's proposal to require AEMO to project inertia needs for all sub-networks every 10 years?	Yes, AEMO should project 10-year requirements for inertia every year, as per the current system strength framework for all sub networks.
Question 2: Do stakeholders support requiring TNSPs to ensure that sufficient inertia is continuously available to meet the projection three years into the future, to align with the system strength framework?	Yes. ENA supports the alignment of long-term planning requirements for system strength and inertia. We consider these changes will reduce the need for short-term responses. However, we don't agree that the three-year binding requirement is fit for purpose, in the context of RIT-T durations and global supply chain constraints. Delivery of network solutions (e.g. SSSP-owned synchronous condensers) or greenfield non-network solutions (e.g., grid-forming BESS) can take three years for deployment, required after a RIT-T which can take two years to complete (followed by a contingent project application process). ENA considers the shorter the projected planning timeframe requirements for compliance, the more likely network options will be infeasible and non-network solutions will be required to meet the obligations from a largely illiquid market (initially). As the framework progresses, solutions over longer time horizons will enable a mix of options, including network solutions, to figure into the optimal mix. ENA also requests clarity from the AEMC on how it interprets the reasonable endeavours obligations for inertia and system strength provision. ENA considers this should not require procurement of resources at any costs, as this would not be in consumers' interests.

Question 3: Do stakeholders agree with the Commission's proposal for TNSPs to be able to procure synthetic inertia to meet the minimum threshold level?	ENA members are cautiously optimistic about the potential role of synthetic inertia, and support the future use of synthetic inertia for the minimum level (subject to AEMO's approval). ENA members would welcome the opportunity to work with AEMO on real-world trials of synthetic inertia solutions to improve power system knowledge. At this stage, we consider it would be appropriate for AEMO to define the technical characteristics of the power system that Inertia Service Providers must meet. Similar to the outcome-based arrangements for system strength, Inertia Service Providers would then have the flexibility, subject to AEMO's approval, to determine the appropriate mix of solutions to meet these power system requirements. As AEMO's approval is required, ensuring a timely response from AEMO is important in Rule 5.20B.4A (g).
Question 4: Do stakeholders agree with the Commission's proposed approach to remove the current exclusion on inertia and system strength in the NSCAS framework?	Yes
Question 5: Do stakeholders think a RIT-T exemption should apply to inertia and system strength services where a shortfall arises within 18 months?	The RIT-T exemption period should be at least 24 months to provide greater flexibility for TNSPs to select an approach that best fits the requirements for the provision of system services. For example, this could leverage outcomes from recently completed RIT-Ts, as well as Expression of Interest processes already adopted by some networks. With the short timeframes currently proposed, SSSP/TNSPs have even more limited power to influence the costs of available solutions. We therefore recommend the AEMC clarify that TNSP's obligations to meet shortfall requirements should not be 'meet at all costs' type obligations, which is not in consumers' interests.
"The Commission proposes that the new arrangements for AEMO to project inertia needs for the following 10 years, including the inertia floor, would begin on 1 December 2024." (p44)	ENA support co-optimising system strength and inertia. However, inertia requirements will not be published until 1 December 2024 under the draft Rule. At this point, SSSP RIT-Ts will either be concluded or at PADR stage. ENA considers the best approach would be for timely advice from AEMO (no later than 31 March 2024) to help enable inertia requirements to be considered within SSSPs' system strength RIT-Ts (as best as possible). If the information is not available in early 2024, a separate process to procure inertia requirements would likely involve contracting with a similar pool of non-network assets and could risk higher costs to consumers than an integrated procurement approach. Accelerating this timeline will better meet the AEMC's objective of co-optimising security services from the start.

	ENA suggests that there be some form of transitional arrangements that would allow AEMO to provide indicative inertia floors early in 2024 and for these to be incorporated by SSSPs directly into the PADR or PACR stage of a RIT prior to December 2025. ENA also note that the jurisdictional transmission planner and the TNSP can be different parties. System strength obligations have been placed to date on a single System Strength Service Provider per region. To ensure the full benefits from co-optimising the procurement of system strength and inertia resources can be realised, ENA recommends the AEMC amend the definition of an Inertia Service Provider to align with the SSSP definition.
Question 6: Do stakeholders agree with the proposed commencement arrangements?	No. ENA believe transitional arrangements in Chapter 11 should be introduced to fast-track of inertia requirements to enable networks to co-optimise system strength and inertia procurement in the one process. For example: » AEMO being able to publish a draft inertia-floor requirement for each inertia sub-network by at least 31 March 2024 (although December 2023 would be preferable) » SSSPs (or TNSPs) being permitted to adopt the draft inertia requirement as if it were final for the purposes of the current system strength RIT-T and cost recovery processes (and therefore to use this for the PADR or PACR; the draft requirement would be assumed to be needed by 2027, in line with the timings in the Rule change) » SSSPs (or TNSPs) being permitted to expand the scope of the current system strength RIT-T (in particular the identified need) from the PADR or PACR stage to explicitly cover meeting this inertia requirement, as well as the system strength requirement (on the basis that enabling these requirements to be considered together will lower overall costs to customers, the potential inertia solutions are inseparable from system strength solutions and therefore no additional technologies would be expected and that this would avoid a separate RIT-T process for the inertia requirement) ENA suggest this would allow a more streamlined RIT approach and more efficient use of internal resources and the external consultation and procurement processes.
Question 6: Are there extra factors that the Commission should consider in transitioning to the new inertia arrangements?	ENA notes that, to date, obligations have been placed on a single SSSP per region. However, in Victoria the jurisdictional transmission planner and the TNSP are different parties. To ensure the full benefits from co-optimising the procurement of system strength and inertia resources can be realised, ENA recommends the AEMC amend the definition of an Inertia Service Provider to align with the SSSP definition.

	ENA is concerned that the proposed Tier 1 penalty provisions for an Inertia Service Provider's failure to meet the relevant allocations, thresholds and standards are disproportionate and have been proposed without explanation or justification. More importantly, ENA considers that the AEMC's proposed liability is fundamentally at odds with a "reasonable endeavours" obligation on TNSPs. For consistency, the AEMC should have regard to those for system strength.

Creating a new transitional non-market ancillary services (NMAS) framework for AEMO to procure security services necessary for the energy transition

Topic / reference	Comments
Question 7: Do stakeholders agree on the need for a transitional services framework?	Yes
Question 7: What are stakeholders' thoughts on the design of the transitional services framework?	ENA recognise that the energy system is rapidly changing, and there are, and will be power system challenges that are not yet fully understood (or known yet). ENA support providing the flexibility for AEMO to decide and declare the need for transitional NMAS services. There is a risk that a new transitional NMAS frame could blur roles and responsibilities for the procurement of system security services between TNSPs and AEMO, particularly where the assets providing transitional services also provide inertia, system strength and NSCAS. We therefore support the AEMC's proposed approach to ensure AEMO only procures services under the new transitional NMAS framework that could not be procured under other frameworks.
Question 8: Do stakeholders agree that a sunset clause is required?	Yes
Question 8: Is a 10-year expiry an appropriate timeframe?	Yes

Empowering AEMO to enable security services with a whole-of-NEM perspective

Topic / reference	Comments
Question 9: Do stakeholders support the Commission's proposal to place the responsibility of enabling inertia and	Yes. ENA believe that AEMO is the party best able to manage the risks associated with system security enablement, and is best able to ensure costs for consumers are minimised.

system strength contracts on AEMO, with an ability to enable NSCAS and transitional services if it is beneficial?	
Scheduling vs enablement	For avoidance of doubt, ENA recommends the AEMC specify what enablement refers to in the Final Determination and whether scheduling and enablement can be used interchangeably. ENA also request the AEMC clarify whether AEMO is undertaking the necessary forecasting and assessment of gaps for the minimum levels of system security.
Settlement of enablement costs *Simplified example of AEMO enablement of system security (Table 5.2 and 5.3)*	ENA suggests the AEMC clarify whether the netting off of wholesale market revenues, as described in Tables 5.2 and 5.3, is required as part of the settlement process.
Here, the Commission's proposed enablement principles would mean that although some participants may be displaced, the overall effect on the spot market would be much more minimal due to the static costs of enabling contracts and the fact that enablement is not based on forecast energy or ancillary service prices. (p80)	The Directions Paper suggests, though does not explicitly state, that AEMO would consider the cost of enabling contracts as static, and that enablement would not be based on forecast energy or ancillary service prices. ENA note that the draft rule does not explicitly require the cost of enabling contracts to be static. ENA seeks clarity on whether AEMO can (if it is deemed reasonable and if contracts are structured in that way) consider forecast energy or ancillary service prices in their enablement decision making. ENA understand that: » Gas generators may want to link their prices to wholesale gas prices; » Prices from grid forming batteries may consider the opportunity cost associated with having to reserve headroom to provide stable voltage waveform support. » Generators with slow start and ramp times may wish to be enabled for longer durations to best manage their asset.
Question 9: Are there any issues with split contracting and enablement responsibilities between TNSPs and AEMO that have not been outlined above?	ENA do not see the split of contracting and enablement as a cause for concern. However, ENA considers that TNSPs are not best placed to carry the responsibility for the payment of variable, spot price exposed system security contract costs. The AEMC has provided no rationale why they have altered the earlier decision that these should flow through AEMO's market settlement processes. A sound principle of regulatory policy design is that risks should be allocated to those parties which are best able to wear and mitigate those risks. The AEMC has not demonstrated why TNSPs are better able to wear the financial and cashflow risk associated with the enablement payments, and indeed, we consider this risk would likely be better allocated to AEMO given its market settlement function.

	While TNSPs are able to forecast system strength payment, and recover that forecast via prescribed transmission charges, under current arrangements, there is a two-year lag to recover difference between forecast and actual system strength payments through network support pass through application. Our primary concern is that TNSPs don't have large liquidity buffers to appropriately manage volatile, wholesale spot price linked contract prices, and that TNSPs could be exposed to possibly serious cashflow risks, potentially for several years until cost recovery processes catch up. ENA considers the risk of high cashflow variability is accentuated because: » Synchronous generators may be required to run during periods of negative spot prices, which will grow more common as the penetration of renewables increase; » Non-network synchronous condensers may be required to run at times of high or extreme wholesale prices; » Grid forming batteries may need to reserve headroom (both in charging and discharging) in order to provide stable voltage waveform support. This means that fees that battery proponents would be expected to recover would be tied to the opportunity cost of not charging (at negative prices) or not discharging (at high prices). » There is typically high difficulty in predicting spot market outcomes, and therefore difficulty in accurately forecasting spot market exposures. This challenge is likely to increase with the rapid transition. ENA considers AEMO is best placed to settle variable payments, as per the design of the original OSM. ENA notes if SSSPs are required to make enablement payments, then SSSPs are likely to structure contracts to reduce their wholesale spot price exposure and manage cashflow risks. Under the October 2021 system strength Rule change, system strength revenues and system strength payments are subject to different true-up approaches. ENA considers the more extended timeframes to address system strength payment true-ups may add to cashflow risks for SSSPs. ENA suggests the AEMC explore approaches that achieve greater consistency between the true-up mechanisms for system strength payments and revenues that result in a closer alignment of cashflows. Specifically, ENA recommends the AEMC assess two options for reform. » The CPA framework could be extended to cover opex, so that revenues can be adjusted for a forecast opex cost for non-network contracts.

	» Rule 6A.23.3A could be amended to enable the system strength revenue true-up process to also apply to system strength payments. Attachment 1 sets out our preferred approach to enablement payments.
Question 10: Do stakeholders support that the Commission's proposed levels for enablement, including the enablement of system strength contracts to levels above the minimum requirement only if it would result in an overall increase in dispatched IBR?	Yes. ENA understands the AEMC's intended approach is to support the dispatch of large-scale solar and wind generation resources that require system security services to operate, rather than resources that could supply system security needs (such as a grid-forming battery). However the rule should consider the fact that when a grid forming battery (GFB) is enabled to provide system strength, it does not dispatch energy, but it may need to reserve headroom (i.e. withdraw capacity from the energy and FCAS markets) which may have the same effect as dispatching energy. Consider a GFM BESS that, if not enabled for system strength, would be charging at 100MW. If enabled for system strength, but it has to reserve headroom such that is only able to charge at 60MW, i.e. scheduled load is reduced by 40MW which has the same impact as dispatching 40MW of energy (and may displace 40MW of IBR from being dispatched elsewhere).It is not clear if this 40MW reduction in scheduled load would be considered as "energy that is dispatched by that enablement" under the draft rule. ENA also note that inverter-based resources includes inverter based loads, i.e. batteries dispatched to charge. E.g. if enabling a system strength service supports dispatch of 50MW of wind and 50MW of grid-forming batteries to charge, the "total increase in inverter based resources" would be 100MW (despite the fact that only 50MW of this is renewable generation). We query whether this is the intent.
Question 11: Do stakeholders consider the proposed enablement principles to be appropriate and adequate?	ENA note that the overarching reason for moving away from the original OSM was that it was *"too costly and complex to implement"* and that the *"commission considers that a focus on simplicity and flexibility, rather than complex mechanisms for operational procurement, could result in greater benefits and less costs for consumers".* Some generators, including coal generators and biomass, may require more than 12 hours to perform cold (or warm) starts. Therefore, this requirement would effectively rule out these generators from being enabled if they were not already generating power. This approach would also depart from the technology neutrality principles adopted elsewhere in the system security frameworks. ENA considers the AEMC's preference for AEMO to enable contracts specifically for their contracted purpose adds unwarranted complexity to the enablement process. Furthermore, this approach may undermine some of the benefits that SSSPs could seek

	through co-optimising the provision of system strength and inertia resources through RIT-Ts currently underway. ENA considers that the enablement principles (no more than 12 hours ahead), coupled with the enablement levels (projecting IBR based on pre-dispatch bids, forecasts of projected IBR, ST PASA, effect of network constraints and operational demand) will require an extremely sophisticated and complex scheduling engine, akin to the original OSM (but without the ability for uncontracted proponents to bid in). ENA also considers that the industry's technical understanding of the dynamic requirements of IBRs for stable voltage waveform is not well established. As in, at this stage we believe the AEMC's enablement principles are too onerous. ENA queries whether the AEMC should give AEMO the flexibility to make further simplification as appropriate, at least for several years following 2 December 2025.
Question 12: Do stakeholders support the Commission's proposal for AEMO to: • publish an enablement guideline • provide daily information about the type, frequency and cost of enabled contracts • publish an annual enablement report?	ENA support the commission's proposal for AEMO to provide this level of information. *Enablement Guideline* However, the Directions Paper states that *"AEMO would need to produce an enablement guideline and set up enablement systems and/or processes by this date [being 2 December 2025]".* ENA consider it unworkable that AEMO would produce enablement guidelines by 2 December 2025. TNSPs are currently undertaking RIT-Ts and are seeking to run procurement activities, including the design of contracts, in parallel. AEMC, TNSPs and AEMO must work in collaboration to ensure that by the end of 2023 (or early 2024 at the latest), a workable arrangement is in place so that TNSPs can negotiate contracts that contain enablement requirements (and associated payment terms) during 2024 and 2025. The decision rules AEMO use for enablement will need to be clear, including the interactions of the various services, so that SSSPs can make appropriate forecasts of costs they are responsible for when they set prescribed transmission prices. These principles could be articulated within the rule change, or more preferably in a standalone document published by AEMO during the rule development process (which can be subsequently updated). If not, the rules could state transitional arrangements (lasting several years beyond December 2025) where TNSPs' proposed contracts should be deemed to be consistent

	with enablement procedures to be developed (in the future) by AEMO and grandfathered for the term of the contract. *Daily cost information to SSSP/TNSP* If the SSSPs/TNSPs are responsible for the costs of enablement then AEMO will need to advise which contracts were used, how much and when so that the enablement costs are clear to each party on a daily or weekly basis. As discussed earlier, this should include any calculations related to netting off arrangements against wholesale spot market revenues (if this is mandated as a settlement requirement). ***Published cost reports and annual reports*** The level of information disclosure needs to provide consumers with confidence about costs they will face. However, the extent of disclosure should be such that the publicly supplied information should not allow details of TNSP-led contracts to be inferred. Publication of identifiable information could risk participation of non-network options in the current system strength RIT-T and future procurement activities. In turn, this could result in higher costs to consumers. ENA recommends that the Rules and any AEMO guidelines/reports take this into account when choosing the amount of information to disclose.
When AEMO 'enables' a contract, it would instruct the unit to either commit in the energy market by bidding at the market floor, by applying a must-run constraint in NEMDE, or through some other means as AEMO sees fit. The proposed draft rule does not specify how AEMO would instruct enabled units to be online for the relevant trading intervals. (p79, footnote 124)	AEMO's enablement procedures should consider how to keep batteries charged when the over-constrained dispatch price exceeds the market price cap for extended periods (e.g. during administered pricing, or market suspensions). Under these conditions batteries would be unable to charge, and may run completely flat due to self-discharge and auxiliary loads, and would then be unable to provide any system security services. This rule change and the Operating Reserve Market rules which are looking to provide a status of charge should be considered together to ensure they are complementary. ENA also note that enablement does not necessarily involve committing in the energy market and/or earning energy revenue. e.g. » For batteries, enablement may require them to decommit, i.e. withdraw capacity from the energy and FCAS markets, and maintain an energy buffer » Hydro units can choose to run in generating, pumping, or synchronous condenser mode » Synchronous condensers, if run only when enabled, would be an unscheduled load

Improving directions transparency and compensation

Topic / reference	Comments
Question 13: Do stakeholders support the Commission's proposal to adopt the market suspension compensation framework and apply it to directions compensation?	ENA support the ability of AEMO to make directions as a necessary backstop framework. Whilst supportive of the proposed quarterly reporting, ENA suggests that the changes to compensation are worthy of a more comprehensive review and there is still significant work to undertake on the security framework aspects.
Question 14: Do stakeholders agree with the proposal to include annual updates to the schedule of benchmark values for the proposed new directions compensation framework, noting this would also apply to the market suspension framework?	As above.
Question 15: Do stakeholders consider that an estimate of the value of storage should form part of the automatic compensation payable to directed hydro plants and batteries? If so, should a proxy value, such as a relevant gas benchmark value based on the capacity factor of the storage system, be used? Should an alternative approach to estimating the value of storage be adopted for batteries?	As above.
Question 16: Do stakeholders support the Commission's proposal to require AEMO to publish market notices when issuing directions that indicate information about the direction and why it is needed?	Yes
Do stakeholders support the Commission's proposal to replace the existing directions reporting requirements with a quarterly reporting requirement? Is the information that would be included in quarterly direction reports useful (or not) to stakeholders?	Yes, ENA support quarterly directions reporting. As per our response to Question 12, ENA recommends that the Rules and any AEMO reports take potential unintended consequences into account when choosing the amount of information to disclose.

Attachment 3 – Proposed drafting

Proposed drafting	Explanation
Proposed amendment to cl 5.20.4 (align definition of Inertia Service Provider with that of a System Strength Service Provider): (a) The Inertia Service Provider for an inertia sub-network is: (1) the Transmission Network Service Provider for the inertia sub-network; or (2) if there is more than one Transmission Network Service Provider for the inertia sub-network:~~,~~ (i) the jurisdictional planning body for the participating jurisdiction in which the inertia sub-network is located~~.~~, if that entity is also a Transmission Network Service Provider; or (ii) otherwise, the Co-ordinating Network Service Provider for the region in which the inertia sub-network is located.	Consistent with the AEMC's intent of aligning the inertia and system strength frameworks to support coordinated investment, we propose to align the definition of the Inertia Service Provider with the definition of System Strength Service Provider. This will allow for co-optimisation of inertia and system strength requirements.
Proposed amendment to 6A.22.1: For the purposes of this Part J, the *aggregate annual revenue requirement (AARR)* for *prescribed transmission services* provided by a *Transmission Network Service Provider*, is the maximum allowed revenue referred to in clause 6A.3.1 adjusted: (1) in accordance with clause 6A.3.2; (2) by subtracting: (i) the operating and maintenance costs expected to be incurred in the provision of *prescribed common transmission services*; and (ii) expected *system strength service payments*; and (iii) expected *inertia service payments*; and (3) by any allocation as agreed between *Transmission Network Service Providers* in accordance with clause 6A.29.3. Amendment to 6A.23.3(h):	A relatively simple amendment is proposed, to treat expected inertia service payments in the same way as expected system strength service payments for the purposes of TNSP pricing. Aligning the treatment of these two types of system security service payment is consistent with the AEMC's stated intent of aligning the two frameworks.

Proposed drafting	Explanation
(h) The *annual service revenue requirement* for *prescribed common transmission services* is to be adjusted by adding the operating and maintenance costs incurred in the provision of those services, ~~and~~ *system strength service payments* <u>and *inertia service payments*</u> (to the extent that those costs or payments were subtracted from the *maximum allowed revenue* in accordance with clause 6A.22.1)	
Proposed transitional provision for publication of initial inertia requirements: **11.###.1 Publication of initial procedures and inertia requirements** (a) By 31 March 2024, *AEMO* must amend and publish the *inertia requirements methodology* under clause 5.20.4 to take into account the Amending Rule. (b) By 31 March 2024, *AEMO* must publish an update to its most recent *Inertia Report* under clause 5.20.5, including the *inertia requirements* that *AEMO* has determined in accordance with new clause 5.20B.2. (c) *AEMO* must develop and publish the initial *System Security Services Procedures* for the purposes of cl 4.4A.6 no later than 31 March 2024. (d) *AEMO* must develop and publish the initial *inertia network service specification* for the purposes of cl 5.20B.4A no later than 31 March 2024.	This transitional rule is intended to provide TNSPs with early notice of inertia requirements so that these can be factored into investment decisions, procurement processes and associated RIT-Ts. This reflects the AEMC's intent that the rules allow TNSPs to more efficiently coordinate system strength and inertia needs when considering network or non-network solutions. It is proposed that the first System Security Services Procedures and the first inertia network service specification, which will include details around the enablement process and types of inertia services that may be enabled, be published by 31 March 2024. As per the Draft Rule, AEMO will need to comply with the *Rules consultation procedures* in developing these documents.
11.###.2 Application of inertia requirements to RIT-T processes commenced prior to 31 March 2024 (a) If, as at 31 March 2024 a *RIT-T proponent* has commenced the *regulatory investment test for transmission* under rule 5.16 but has not published a project assessment conclusions report, the *RIT-T proponent* may, but is not required to, take into account the *inertia requirements* published under clause 11.###.1 when assessing credible options to meet the *identified need*. For this purpose, the RIT-T proponent may amend its description of the *identified need* to include meeting the published *inertia requirements*. (b) For the avoidance of doubt, where a *RIT-T proponent* chooses to take	This transitional provision is intended to allow TNSPs to co-optimise investment to meet system strength and inertia requirements as soon as the initial inertia requirements are published – including through RIT-T processes that have commenced prior to AEMO's publication of those requirements. A TNSP that is part way through a RIT-T process will be able to take into account the new inertia requirements, without having to restart the RIT-T process. For example, if a TNSP is part way through a RIT-T process for installation of synchronous condensers to address system strength requirements, once the inertia requirements are published it may decide to augment the preferred option to address the broader need

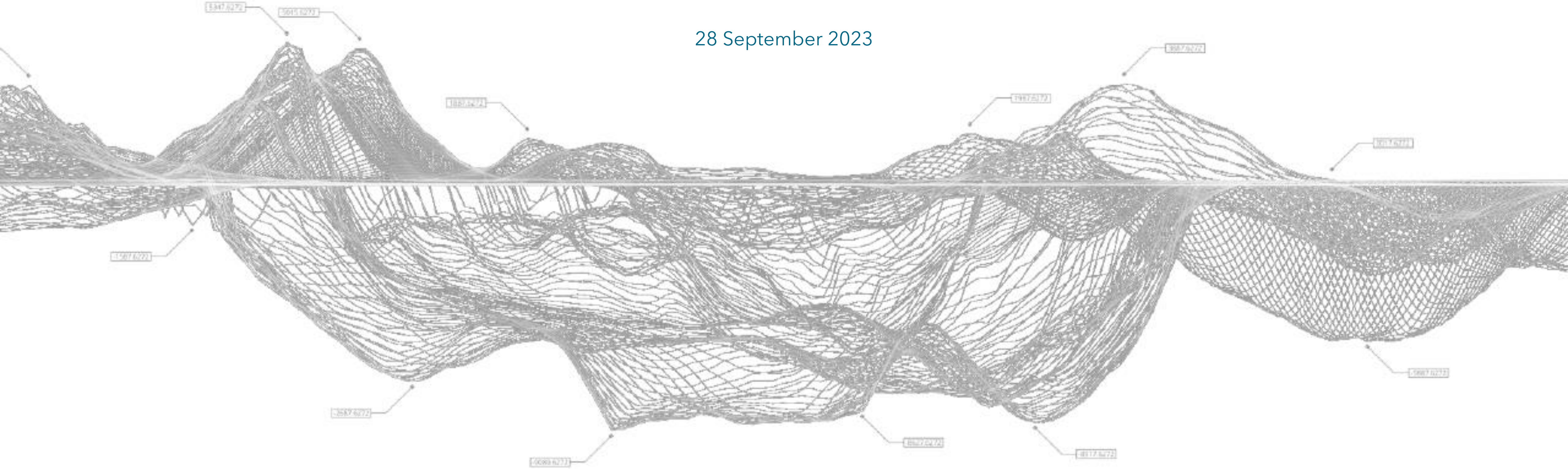
Proposed drafting	Explanation
into account the *inertia requirements* published under clause 11.###.1, it is not required to recommence the *regulatory investment test for transmission*	(including both the system strength and inertia requirements) - e.g. by adding a flywheel.

Attachment 4: Market modelling results outlining potential volume of enablement payments

Modelling make-whole costs for system strength enablement

Final report for Energy Networks Australia

28 September 2023



Contents

We are seeking to estimate make-whole costs of system strength enablement

Under the system strength framework, a subset of Transmission Network Service Providers (TNSPs) called System Strength Service Providers (SSSPs) are required to procure the minimum and efficient level of system strength (the system strength standard). SSSPs are required to meet this either through investment in network assets (e.g. synchronous condensers) or by contracting with providers of system strength services (e.g. synchronous generators).

If SSSPs contract for system strength services with non-network assets, this can expose SSSPs to volatile contract payments due to volatility in wholesale spot prices. Where SSSP's forecast of contractual payments differ from actual payments this creates a cash flow risk for SSSPs.

In this context, Energy Networks Australia has engaged Endgame Economics to undertake quantitative analysis to estimate the level and variability in cash flows under system strength contracts over time.

The scope of this engagement is limited to estimating variable "make-whole" costs only based on the difference between spot price revenues and the short-run marginal cost of enabled resources. The analysis does not encompass start costs or availability payments. We also do not consider market power or commercial realities which may be important factors in contractual negotiations.

In addition, we are taking the total system strength enablement requirement as given in each financial year based on the difference between the efficient level of system strength and the amount provided by generation in AEMO and Endgame dispatch modelling. In practice, synchronous generators may bid unavailable, particularly during low price periods, which would increase the system strength enablement requirement.

Taking these factors into account, we consider that our estimate of make-whole costs is a conservative estimate of the level and variability of actual costs of system strength enablement.

This report sets out our approach and key findings.

What is the level and variability of make-whole costs of system strength enablement over time?

Modelled wholesale prices suggest that the level and variability of make-whole costs of system strength enablement is increasing over time due to increasing system strength enablement requirement and more frequent low spot prices.

Variability in make-whole costs varies by quantity and price

- We have modelled make-whole costs as the difference between spot price revenue and short-run marginal cost of enabled resources for system strength enablement.
- This is a conservative approach that may understate the level and variability of true costs to a network of contracting with system strength providers.
- In practice, the system strength enablement requirement may change due to: bidding behaviour of synchronous units; availability payments for system strength providers; commercial considerations and potentially market power of system strength providers.
- There are two sources of variation in our modelled make-whole costs:
  1. The quantity of the system strength requirement
  2. The level and volatility in spot prices

1. The quantity of system strength enablement is increasing over time

- The requirement to meet the system strength requirement is increasing over time due to lower generation from synchronous units and an increase in variable renewable energy (VRE) generation.
- The overall system strength enablement requirement to reach the efficient level for QLD, NSW and SA is assumed to be fixed in each financial year. It is calculated as the difference between the efficient level and the level provided by synchronous unit generation in AEMO and Endgame modelling.
- In reality, bidding behaviour from synchronous units may increase the required level of system strength enablement.

2. There is a greater frequency of low and negative prices across the NEM over time

- We modelled 100 simulations of the NEM over the period FY 2026 – 30 across different reference years, demand levels and outage traces.
- Increasing entry of VRE leads to lower spot prices over time. There is a greater frequency and depth of negative spot prices over time.
- Variability is seasonal with a greater proportion of negative prices occurring over shoulder and summer months, driving greater make-whole costs of system strength enablement in these months.

We have modelled make-whole payments as the difference between spot price revenue and the short-run marginal costs of enabled resources

Modelling approach

- Our objective is to estimate the level and variability in make-whole payments for enabled system strength resources.
- Make-whole payments are calculated for the the period FY 2026 – FY 2030. Costs are calculated as the difference between spot price revenue and the short-run marginal cost of enabled resources:

*Make-whole costs[1] = Enabled generation (MWh) * (RRP - SRMC)*

- Enabled generation is determined as the difference between the efficient system strength quantity in each region and the generator dispatch quantity under AEMO (from the 2022 System Strength Report) and Endgame modelling.
- Where spot prices are greater than SRMC the make-whole payment is calculated as zero.
- Wholesale prices are taken from Endgame Economics' wholesale price modelling based on 100 simulations of the system (with different demand, reference year and forced outage traces).
- System strength shortfall is assumed to align with the lowest prices in 4-hour blocks in the region for that financial year. For e.g. if a unit is required for 5% of the year it is assumed to be the lowest 5% of 4-hour price blocks in that region for that year.
- The overall system strength enablement requirement to reach the efficient level for QLD, NSW and SA is assumed to be fixed in each financial year as the difference between the efficient level and the level provided by dispatch in AEMO and Endgame modelling. (i.e. we do not account for strategic behaviour from synchronous generators).
- The results are then aggregated by month and by year for each simulation providing a distribution of modelled costs over time.
- Negative wholesale prices have been calibrated to historical price outcomes to capture dynamics in very low spot price bands (e.g. $-1,000 to $-100/MWh).

[1] *Note that we present make-whole costs as a positive number in our main results to aid interpretation.*

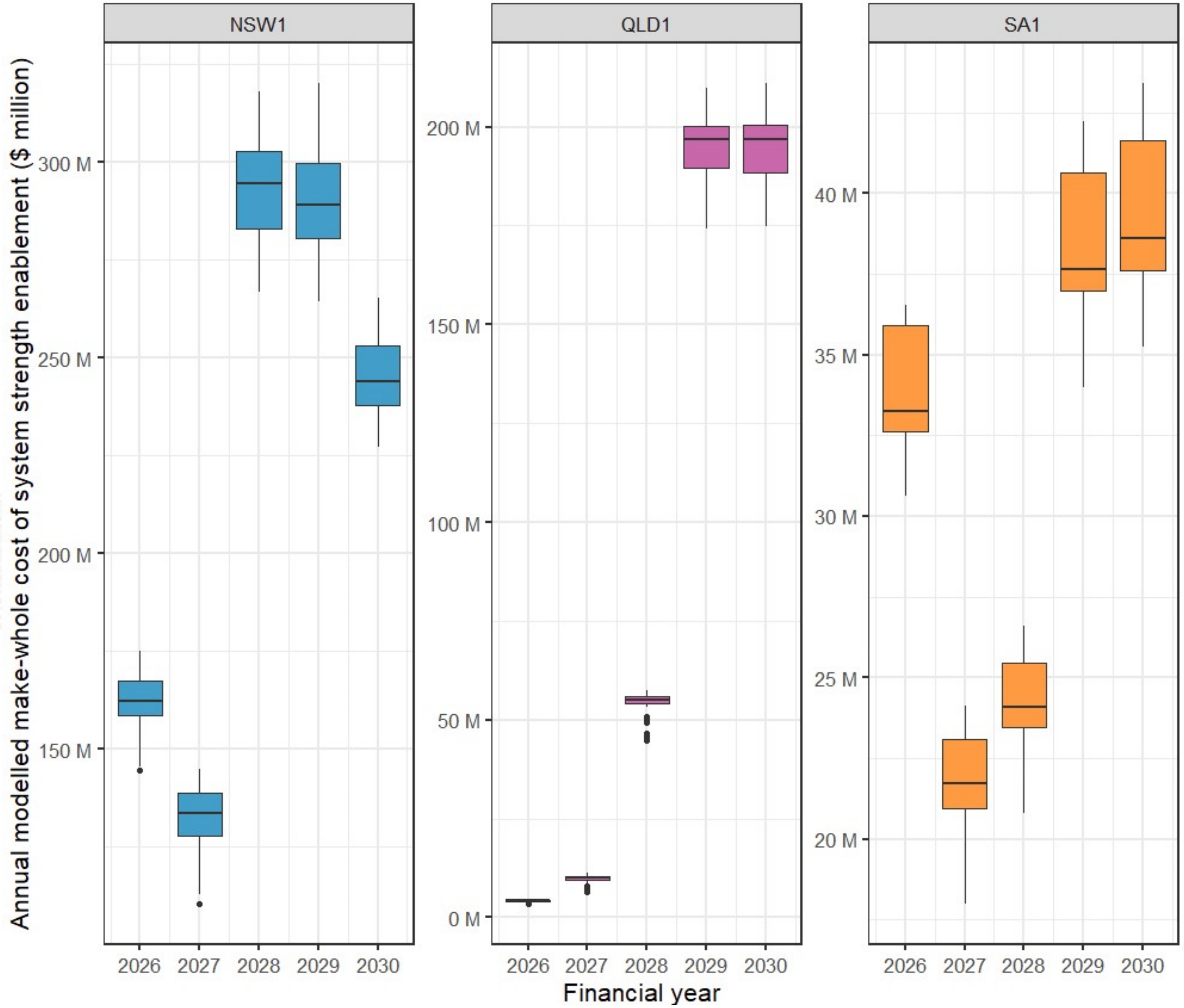
Our modelling assumptions may underestimate true costs

- Estimating make-whole costs necessarily requires a number of simplifying assumptions.
- We set out some key modelling assumptions here noting that they are conservative which likely means that our modelled make-whole cost results are an underestimate of the level and variability of actual system strength contracting costs:

1. We have modelled make-whole costs as the difference between spot price revenues and generator direct costs. This can be thought of as a "make whole payment" – it is what enabled generators would require to break even from being enabled to provide system strength.
2. The total quantity of system strength enablement in each financial year is fixed based on the difference between the efficient level of system strength and the level provided by synchronous resources in AEMO and Endgame modelling. We do not account for behaviour by synchronous resources that results in an increased the system strength requirement (for e.g. by bidding to reduce availability during low price periods).
3. Generator direct costs are based on short-run marginal cost. We have not modelled start-up costs as this would introduce significant complexity and uncertainty. Therefore make-whole costs are likely to be a significant underestimate of actual contracting costs for the SSSP. We have also not included any availability payments but this is likely to impact the *level* rather than the variability in contracting costs.
4. We have not attempted to determine actual system strength contract costs which would depend on negotiation between generators and SSSPs. This is important to note as commercial negotiations would likely increase contracting costs. The risk increases later in the modelling period as a significant proportion of available synchronous units are required late in the modelling period.
5. In NSW, based on industry information, we have assumed that a majority of hydro units provide system strength at zero cost by operating as synchronous condensers. This is unlikely in practice as there is a (small) marginal cost of operating in synchronous condenser mode and the operator of these units will require payment to provide this service. From FY 2028 a large number of hydro units are assumed in NSW which raises the potential for the exercise of market power by these operator(s).

The annual results show variability in costs over time

Annual modelled make-whole cost of system strength enablement ($ millions, real 2023)

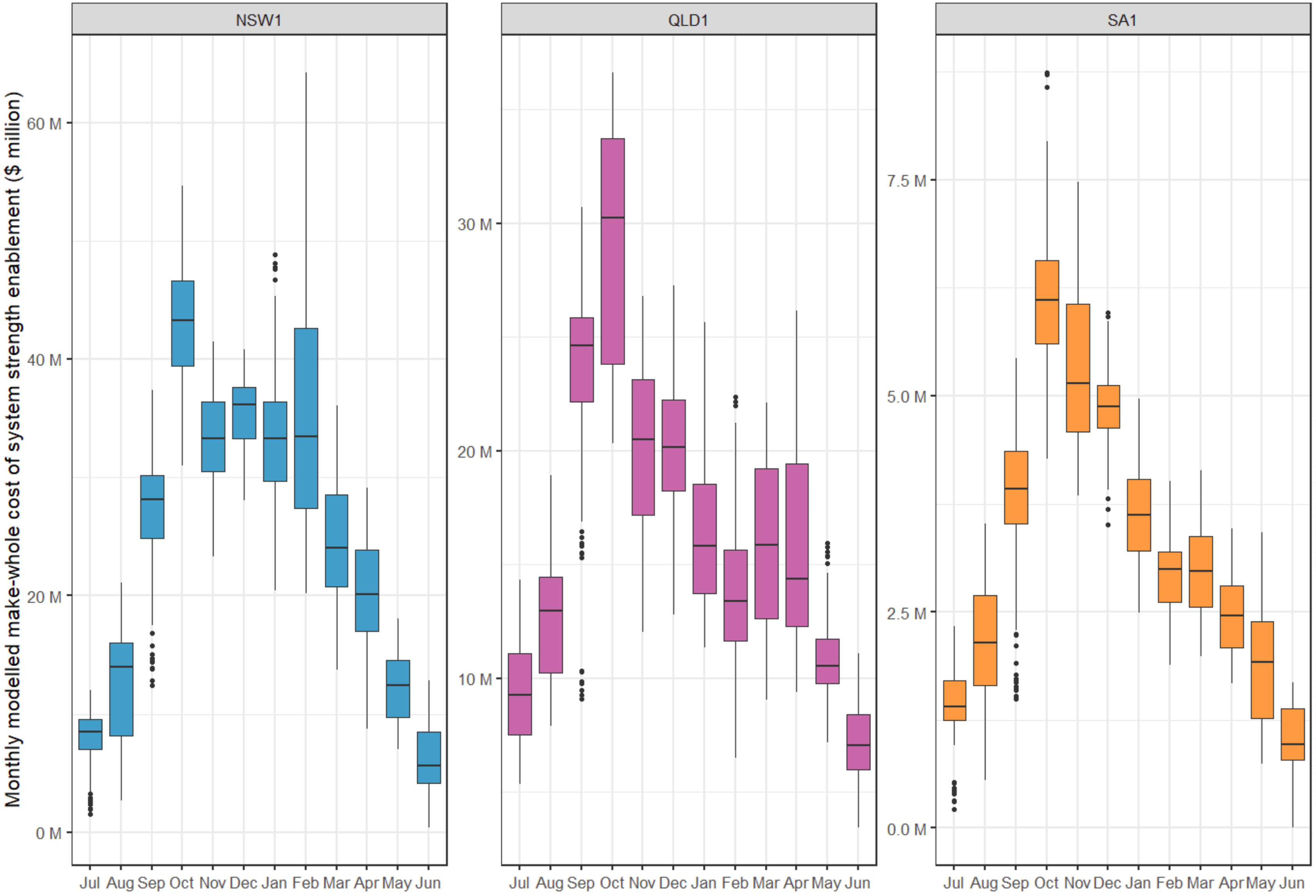


- This chart presents the range of modelled make-whole costs across different simulations by financial year.
- The results show a high degree of variability within and across financial years.
- The difference between years is driven by a combination of increases in the required level of system strength enablement over time and different spot prices.
- The variability *within* years reflects different spot price outcomes under different simulations.
- As we will show in the next slide, the variability at an annual level masks a much greater monthly variability.

Note: scale is automatically set by region to illustrate variability in modelled make-whole costs.

Monthly results show an even greater degree of variability in make-whole costs

Annual modelled make-whole cost of system strength enablement in FY 2029 ($ millions, real 2023)



- This chart presents the range of modelled make-whole costs across different simulations by month in FY 2029.
- The results show a high degree of variability within and across months.
- The variability is driven by different spot price outcomes under different simulations. This changes both the quantity of enablement and the make-whole cost of that enablement within a simulation.

Note: scale is automatically set by region to illustrate variability in modelled make-whole costs.

The annual results show variability in costs over time

QLD modelled make-whole costs ($ millions, real 2023)

Region	FY	Min annual cost	Average annual cost	Max annual cost	St dev annual cost	Range annual cost (max - min)	Range annual cost (% of avg)
QLD1	2026	3.6 m	4.2 m	4.5 m	0.2 m	0.9 m	22.7%
QLD1	2027	6.4 m	9.6 m	11.2 m	1.1 m	4.8 m	49.7%
QLD1	2028	44.9 m	54.0 m	57.5 m	3.4 m	12.6 m	23.4%
QLD1	2029	174.1 m	194.9 m	209.8 m	8.7 m	35.6 m	18.3%
QLD1	2030	174.8 m	194.9 m	210.9 m	8.5 m	36.2 m	18.6%

- The modelled make-whole cost of system strength provision in QLD is generally increasing over time.
- This is due to an increasing requirement for system strength, particularly from FY 2028, and more frequent low and negative prices.
- The range in costs between simulations changes from year to year, creating uncertainty in cash flows.

The annual results show variability in costs over time

NSW modelled make-whole costs ($ millions, real 2023)

Region	FY	Min annual cost	Average annual cost	Max annual cost	St dev annual cost	Range annual cost (max - min)	Range annual cost (% of avg)
NSW1	2026	144.7 m	162.3 m	175.2 m	7.2 m	30.5 m	18.8%
NSW1	2027	110.6 m	132.0 m	145.1 m	8.5 m	34.5 m	26.1%
NSW1	2028	266.8 m	292.9 m	318.0 m	12.3 m	51.2 m	17.5%
NSW1	2029	264.3 m	289.6 m	320.1 m	12.6 m	55.8 m	19.3%
NSW1	2030	227.3 m	245.7 m	265.3 m	9.4 m	38.0 m	15.5%

- The modelled make-whole cost of system strength provision in NSW is generally increasing over time.
- This is due to an increasing requirement for system strength enablement.
- In 2029, the range between the highest and lowest simulation grows to $55.8 million (21% of the average cost).

The annual results show variability in costs over time

SA modelled make-whole costs ($ millions, real 2023)

Region	FY	Min annual cost	Average annual cost	Max annual cost	St dev annual cost	Range annual cost (max - min)	Range annual cost (% of avg)
SA1	2026	30.6 m	33.9 m	36.5 m	1.8 m	5.9 m	17.5%
SA1	2027	18.0 m	21.7 m	24.1 m	1.6 m	6.1 m	28.2%
SA1	2028	20.8 m	24.2 m	26.6 m	1.5 m	5.8 m	23.9%
SA1	2029	34.0 m	38.4 m	42.2 m	2.3 m	8.2 m	21.5%
SA1	2030	35.3 m	39.4 m	43.4 m	2.3 m	8.1 m	20.6%

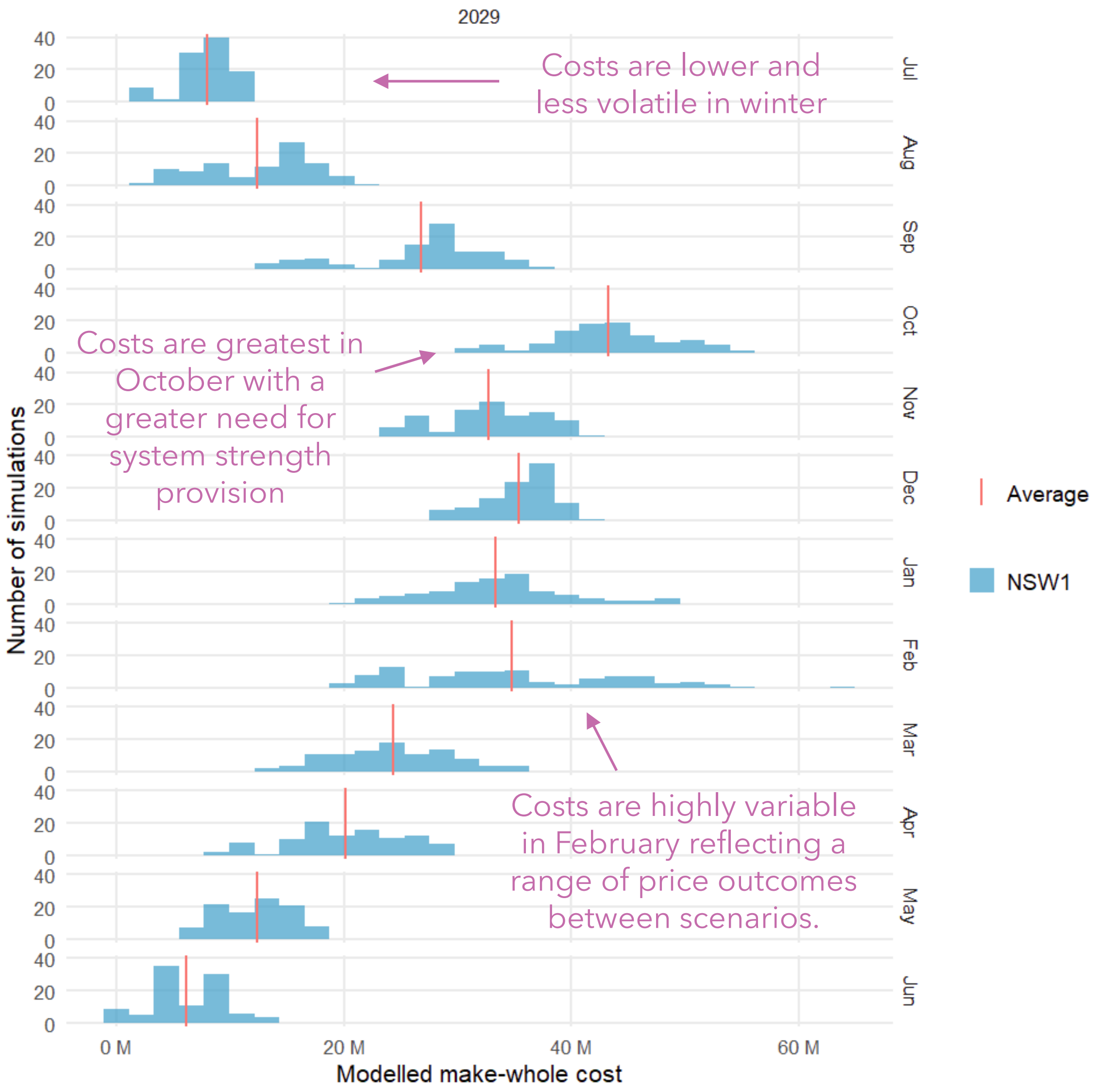
- The modelled make-whole cost of system strength provision in SA is increasing over time.
- This is due to the increasing system strength enablement between FY 2028 and FY 2029 and the increased frequency of low and negative prices.

Monthly results show a greater degree of variability in make-whole costs

- The annual results mask a greater degree of variability within individual months.
- In the following slides we show the distribution of monthly make-whole costs for 100 price simulations across all financial years (FY 2026 – FY 2030).
- These charts show that the level and variability of charges is increasing over time.
- There is also a significant seasonal element. Costs are lowest in winter and highest in spring (usually October).
- This seasonality may pose cash flow risks for networks that contract with non-network system strength providers as the recovery of revenue through transmission prices tends to be evenly spread over the financial year.

Introduction to main results – modelled make-whole costs of system strength provision

NSW modelled make-whole costs in FY 2029 ($ millions, real 2023)



We introduce our main results with an example of NSW for a single modelled year, FY 2029.

This chart shows the distribution of modelled make-whole costs of system strength provision from 100 simulations of prices in NSW in FY 2029.

Modelled make-whole costs are lower and less variable in winter. Modelled make-whole costs are higher and more variable in summer and spring when VRE output is higher, increasing the need for system strength provision.

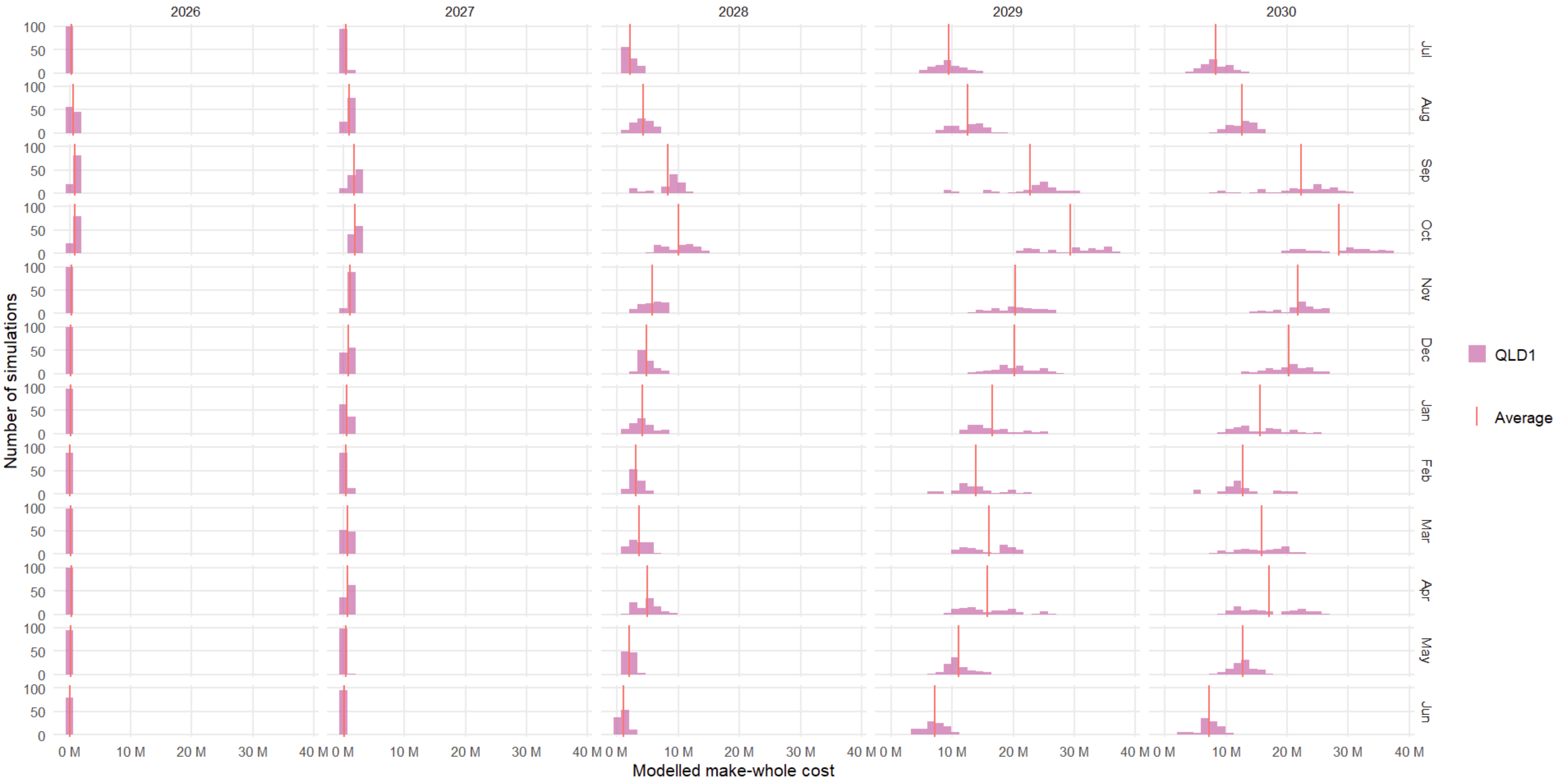
There are two sources of variability in modelled make-whole costs:

1. Spot price revenue
2. Resource run costs (proxied by SRMC)

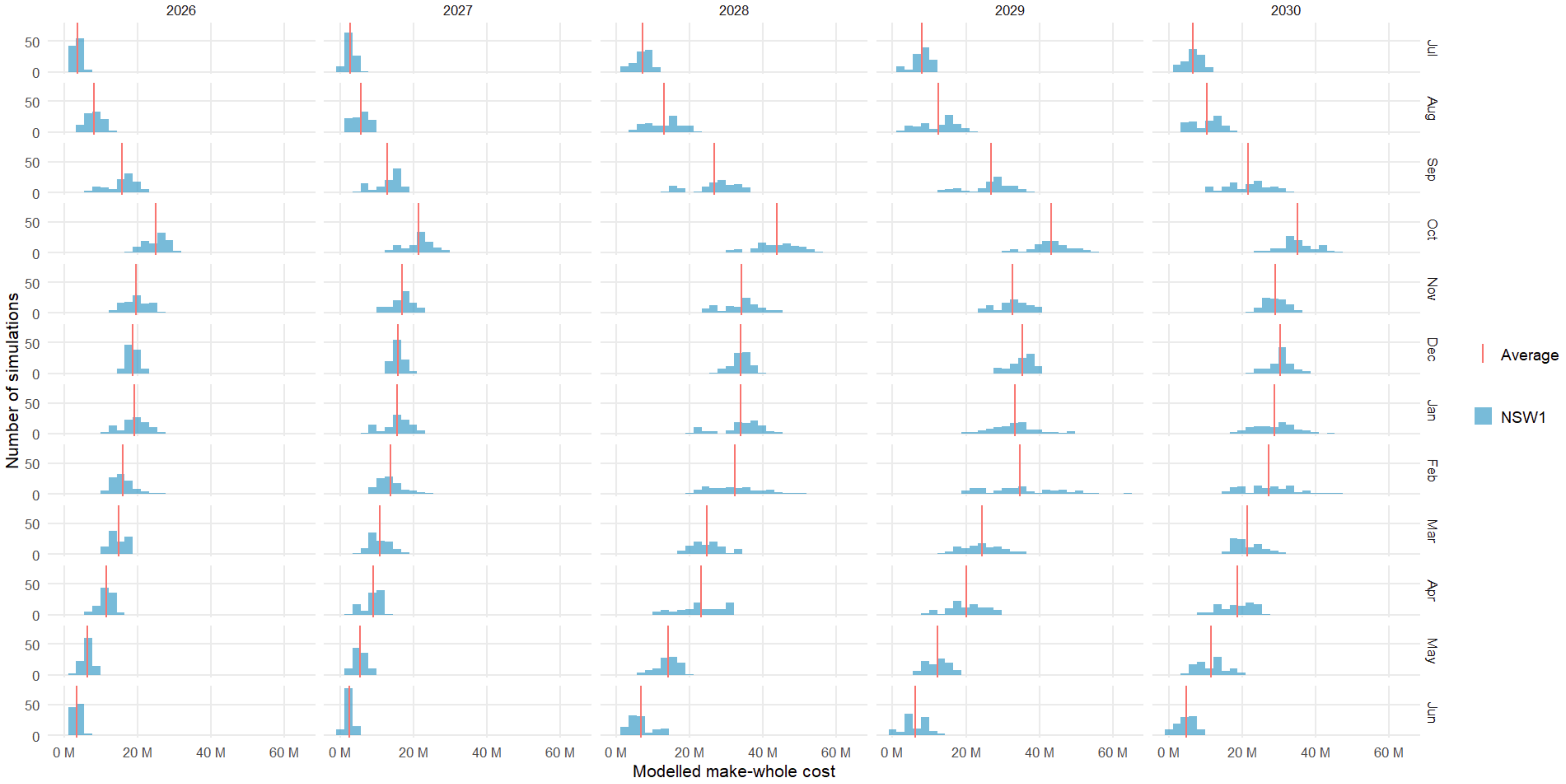
Resource run costs account for the greater share of variability in modelled cost. In the appendix, we decompose the modelled costs into the two sources of variability.

In the following slides we present the modelled make-whole cost results for QLD, NSW and SA across FY 2026 – 2030.

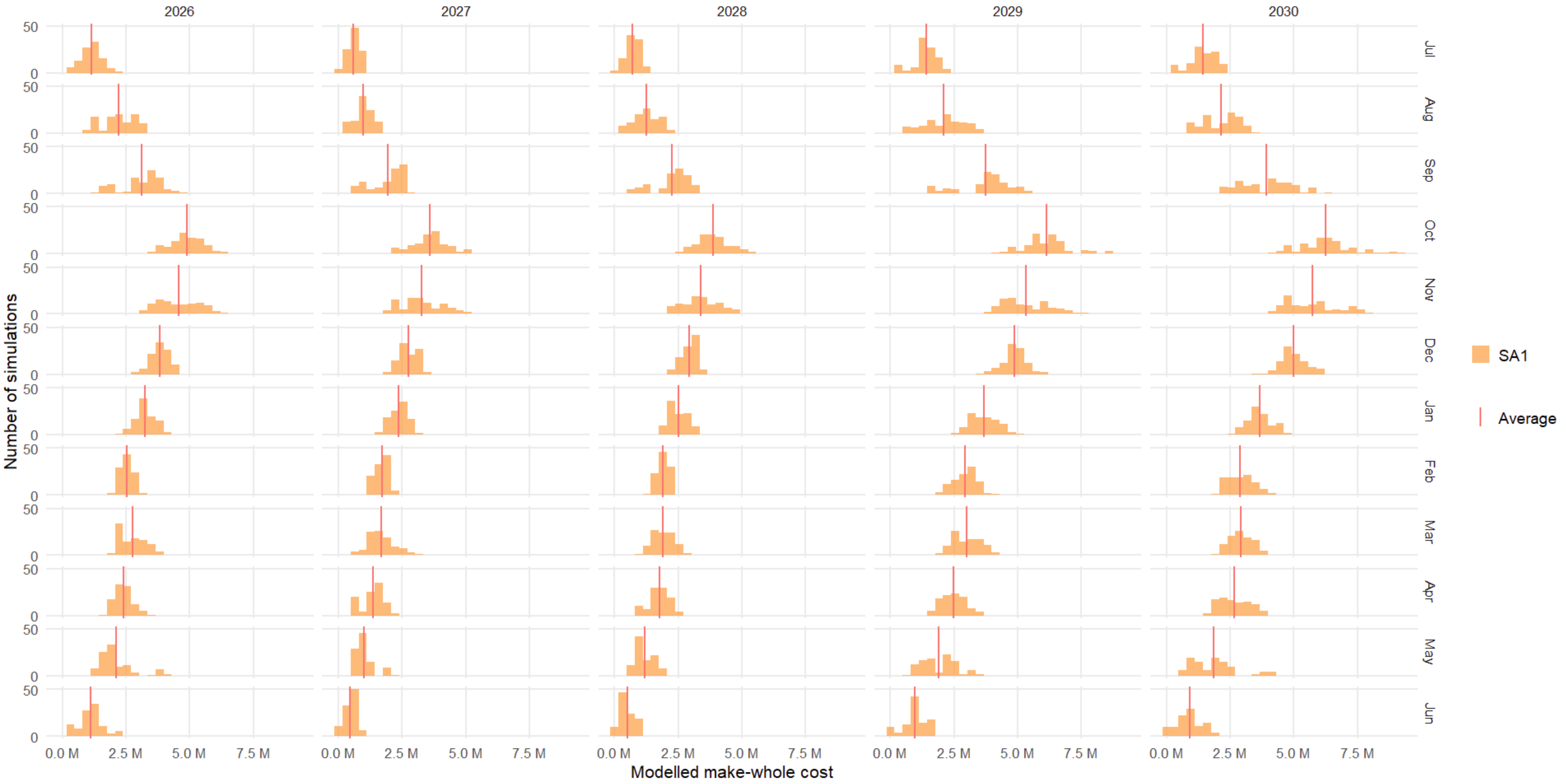
Distribution of monthly modelled make-whole costs by financial year (QLD)



Distribution of monthly modelled make-whole costs by financial year (NSW)



Distribution of monthly modelled make-whole costs by financial year (SA)



There are two sources of variability in make-whole payments

- There are two sources of variability in estimated make-whole payments for system strength enablement:

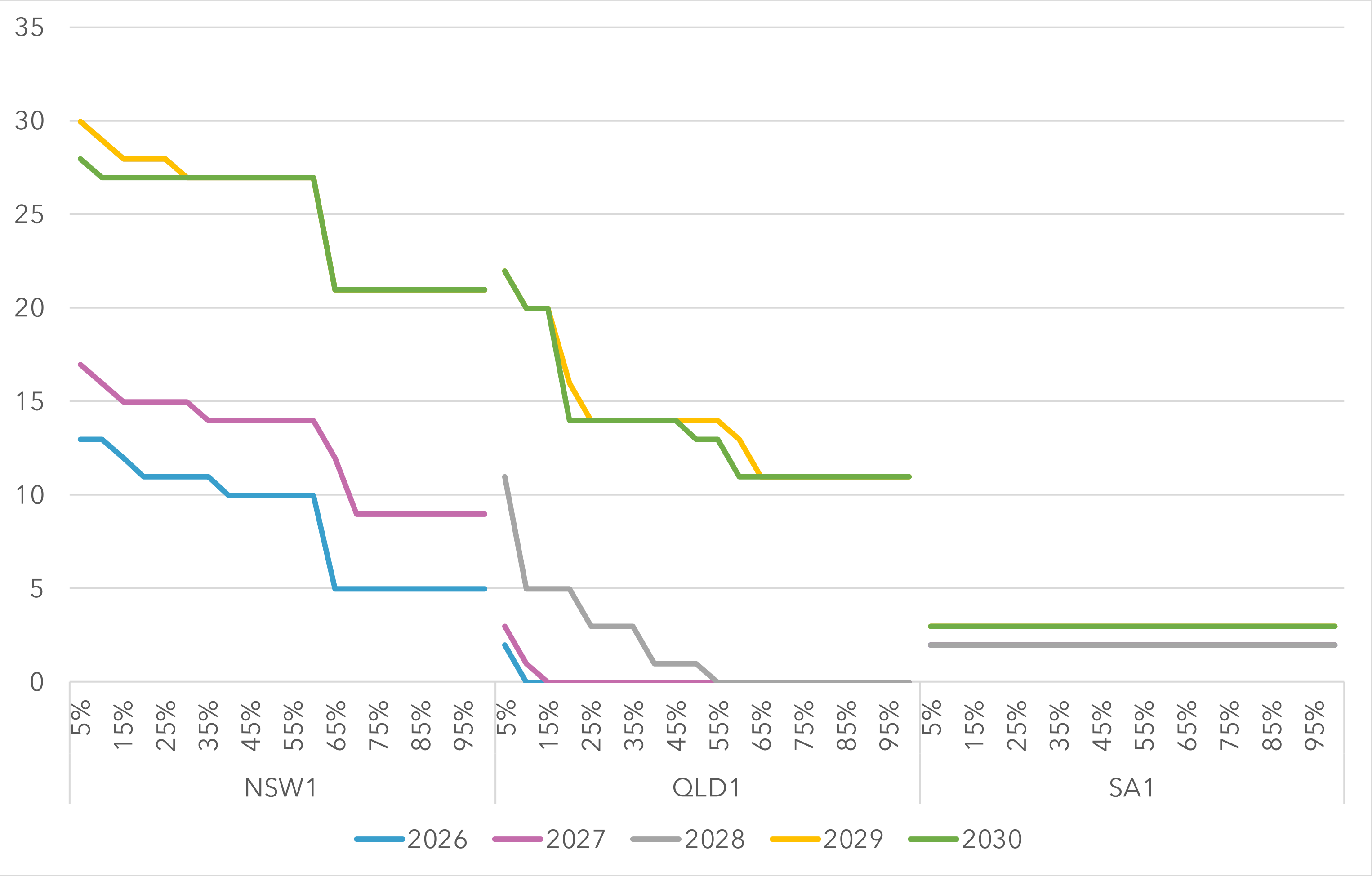
  1. An increasing system strength requirement

  2. More frequent low (and often negative) spot prices

- The following slides illustrate these two sources of variability and the appendix includes a decomposition of the modelled make-whole payments into spot revenue and enabled resource run costs.

Required system strength enablement is one source of variation in make-whole costs over time

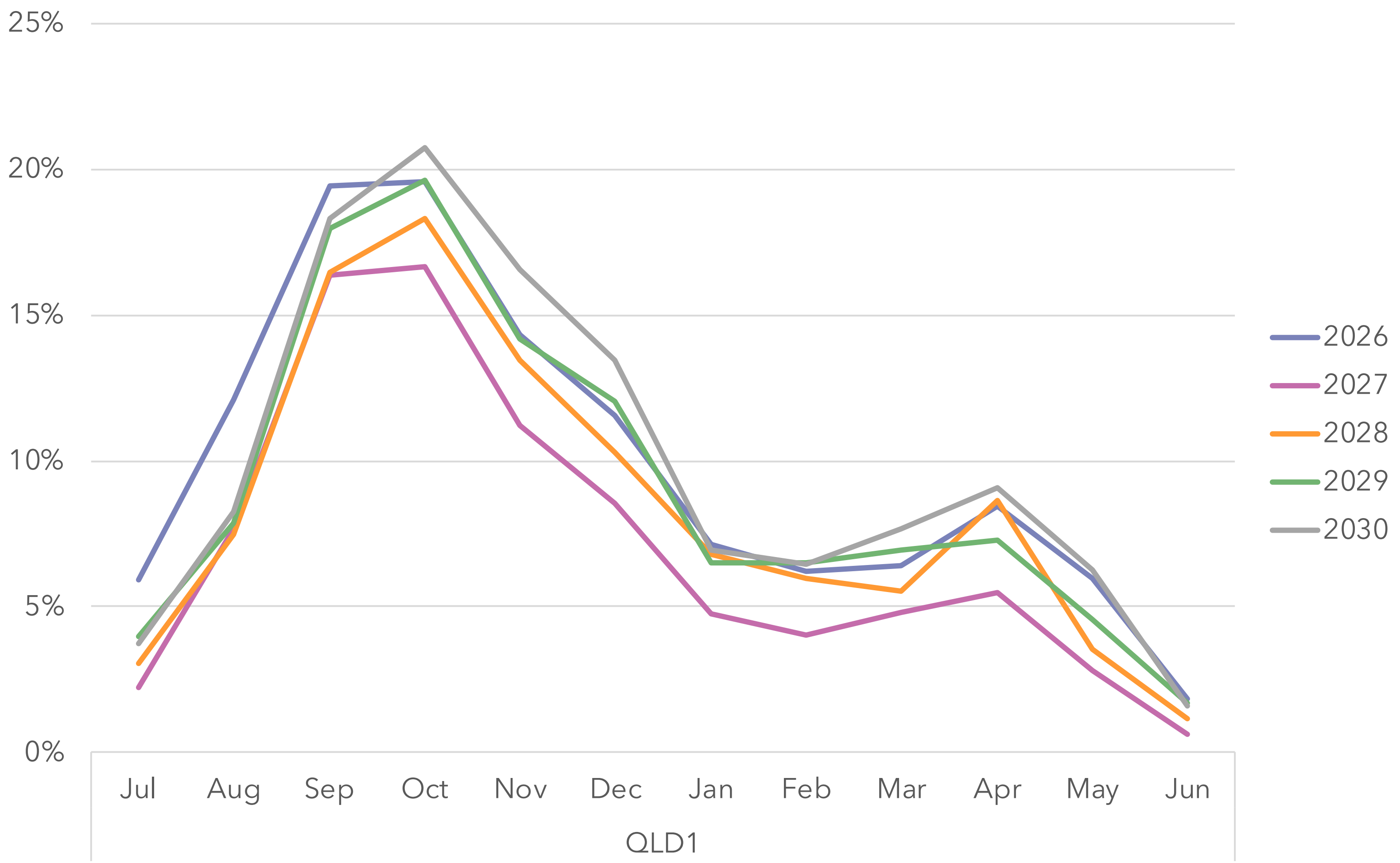
Number of required synchronous units by percentage of the financial year



- This chart shows the required number of synchronous units required to meet the efficient system strength level by percentage of year.
- For e.g. in NSW in FY 2026 13 units are required to be enabled 5% of the time and 5 units are required to be enabled 95% of the time
- Units are assumed to run at minimum generation.
- The mix of units varies by region:
  - QLD – units include coal and gas units
  - NSW – units include coal, gas and hydro units
  - SA – units include gas units only

Price is the other source of variation in make-whole costs

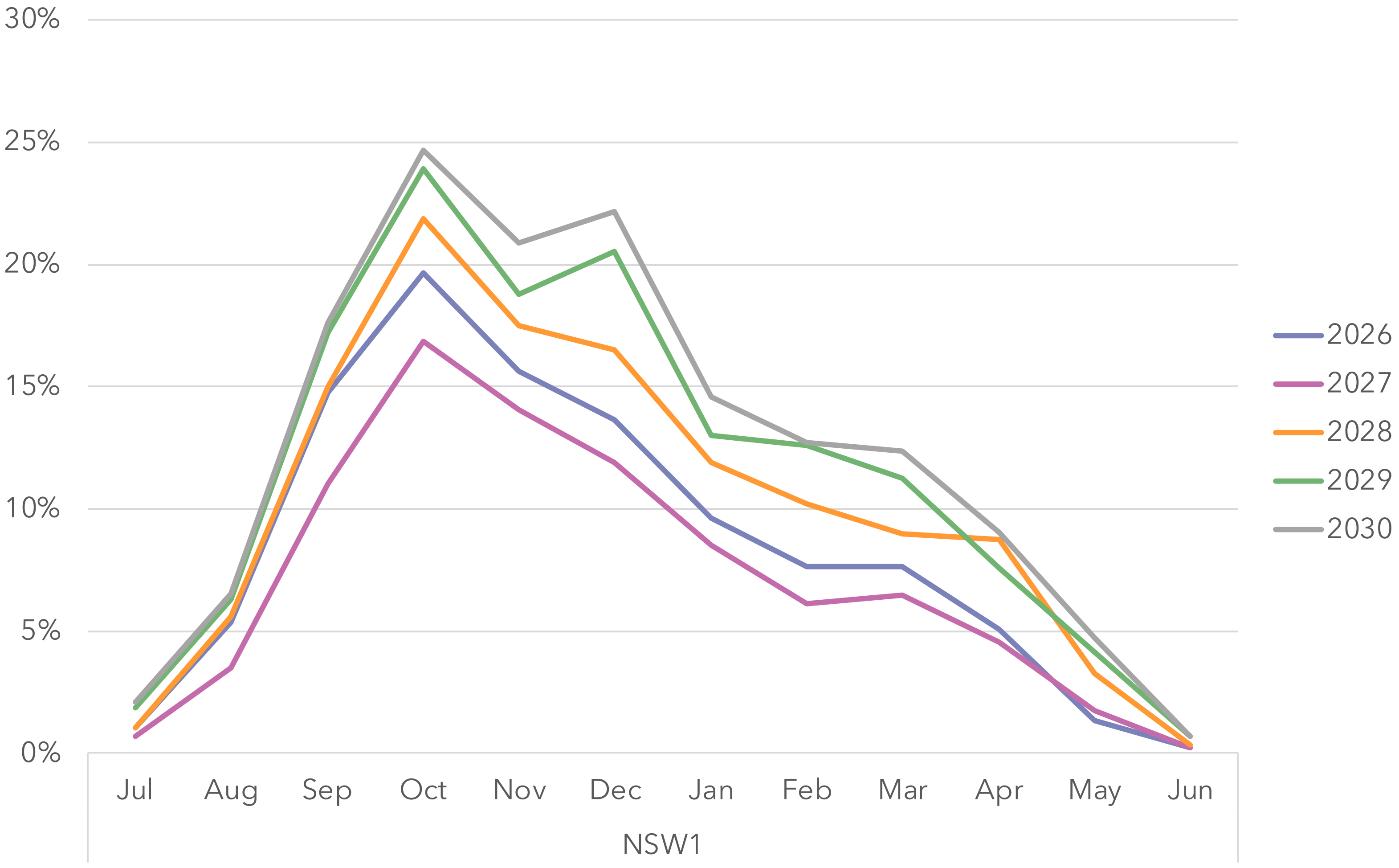
Percentage of negative prices by month in QLD



- The frequency of negative prices hits a minimum in winter when solar output is low.
- Negative price percentage peaks in spring with high VRE output and moderate demand.
- Note that this chart aggregates over 100 simulations in each financial year. The actual frequency and occurrence of negative prices varies across simulations.

Price is the other source of variation in make-whole costs

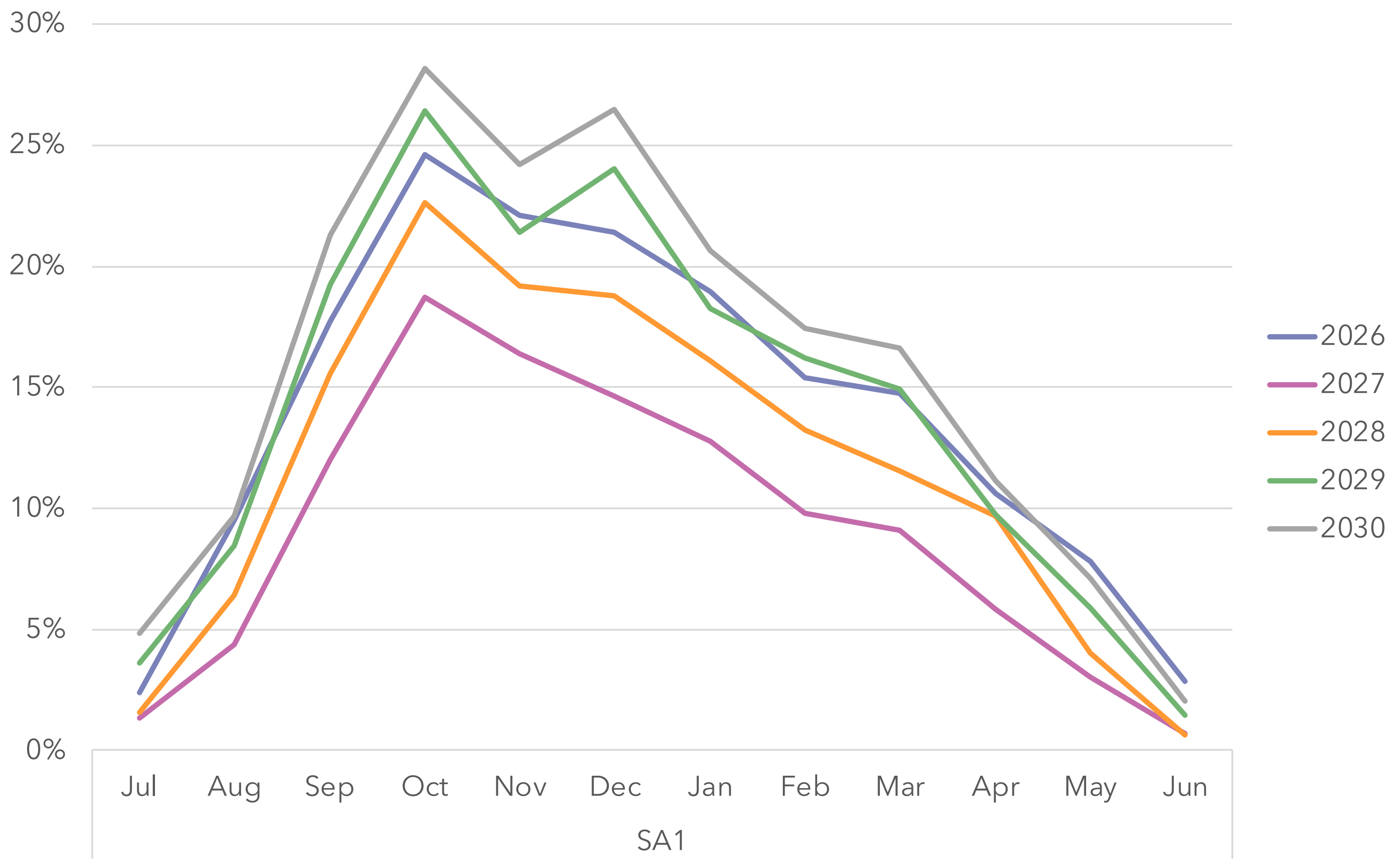
Percentage of negative prices by month in NSW



- The frequency of negative prices hits a minimum in winter when solar output is low.
- Negative price percentage peaks in October with high VRE output and moderate demand.
- The proportion of negative prices generally increases over time as more VRE generation enters the system.

Price is the other source of variation in make-whole costs

Percentage of negative prices by month in SA



- The frequency of negative prices hits a minimum in winter when solar output is low.
- Negative price percentage peaks in October with high VRE output and moderate demand.

The average price earned by enabled resources provides insight into the dynamics

Volume-weighted average price earned by enabled resources ($/MWh)

Region	FY	VWAP earned by enabled resources ($/MWh)
QLD1	2026	-35.85
QLD1	2027	-20.15
QLD1	2028	-5.82
QLD1	2029	21.64
QLD1	2030	21.12
NSW1	2026	23.08
NSW1	2027	29.50
NSW1	2028	31.40
NSW1	2029	26.59
NSW1	2030	29.86
SA1	2026	10.69
SA1	2027	4.30
SA1	2028	8.55
SA1	2029	7.67
SA1	2030	5.20

- Make-whole costs are estimated as the difference between spot revenue and short-run marginal cost of enabled resources.
- This table shows the volume-weighted average price (VWAP) earned by enabled resources across all simulations by financial year.
- There are two offsetting effects:
  1. The number of low and negative prices over time tends to increase with increasing penetration of VRE.
  2. A greater system strength requirement over time tends to increase the average price earned by enabled resources.
- In QLD, effect (2) tends to dominate due to a significant increase in the required system strength enablement after FY 2027.
- In NSW and SA the two effects are largely offsetting one another, i.e. increased occurrence of low and negative prices is offset by increasing system strength enablement.

Conclusion: modelled make-whole payments for system strength enablement are volatile

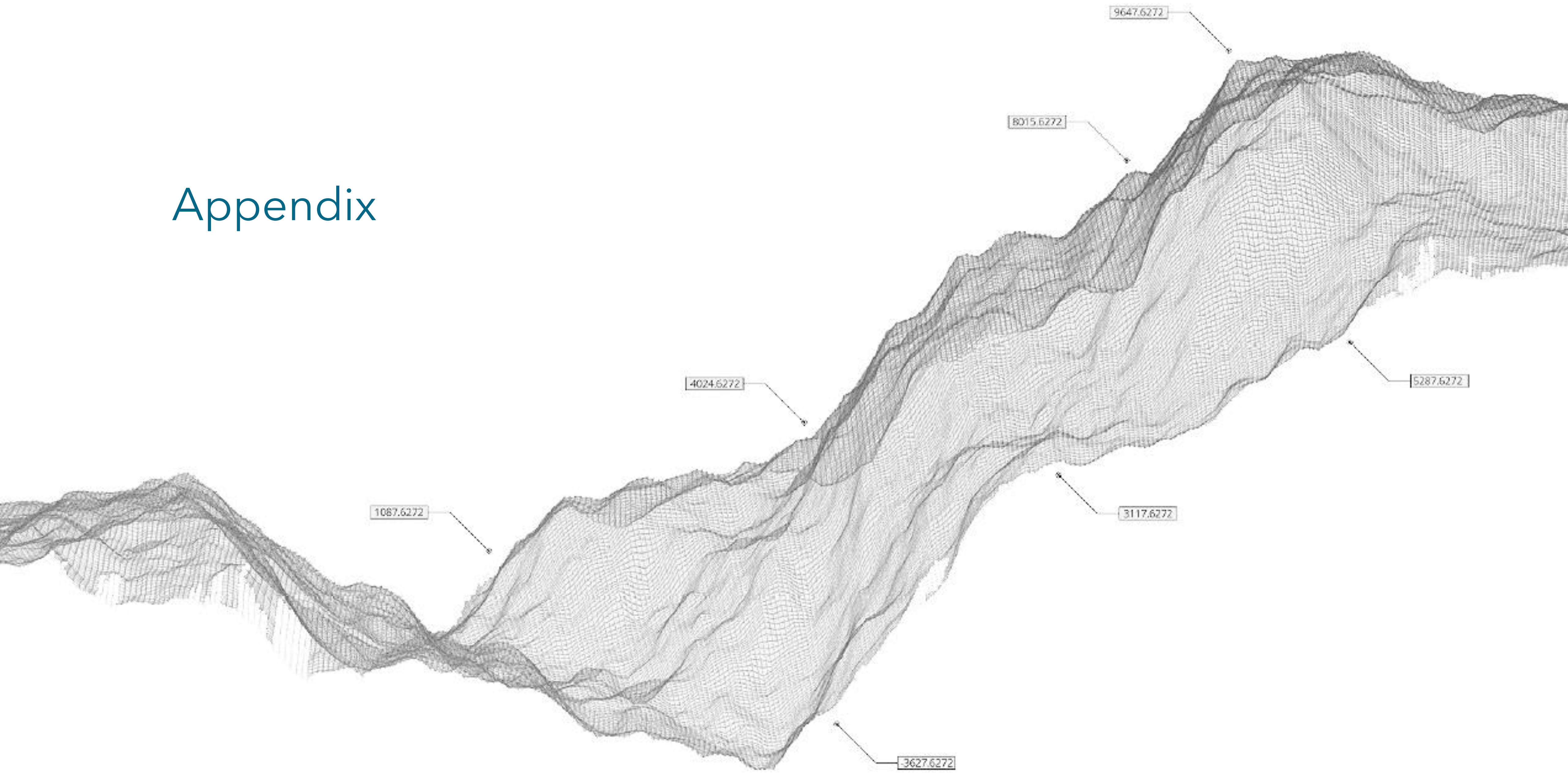
- The level and variability in modelled make-whole costs for system strength providers is increasing over time.

- This is due to two sources of variation:
  - An increasing system strength requirement as VRE generation increases and synchronous generation decreases
  - More frequent low (and often negative) spot prices

- The results suggest that if SSSPs were to contract with non-network system strength providers they may be exposed to cash flow risk.

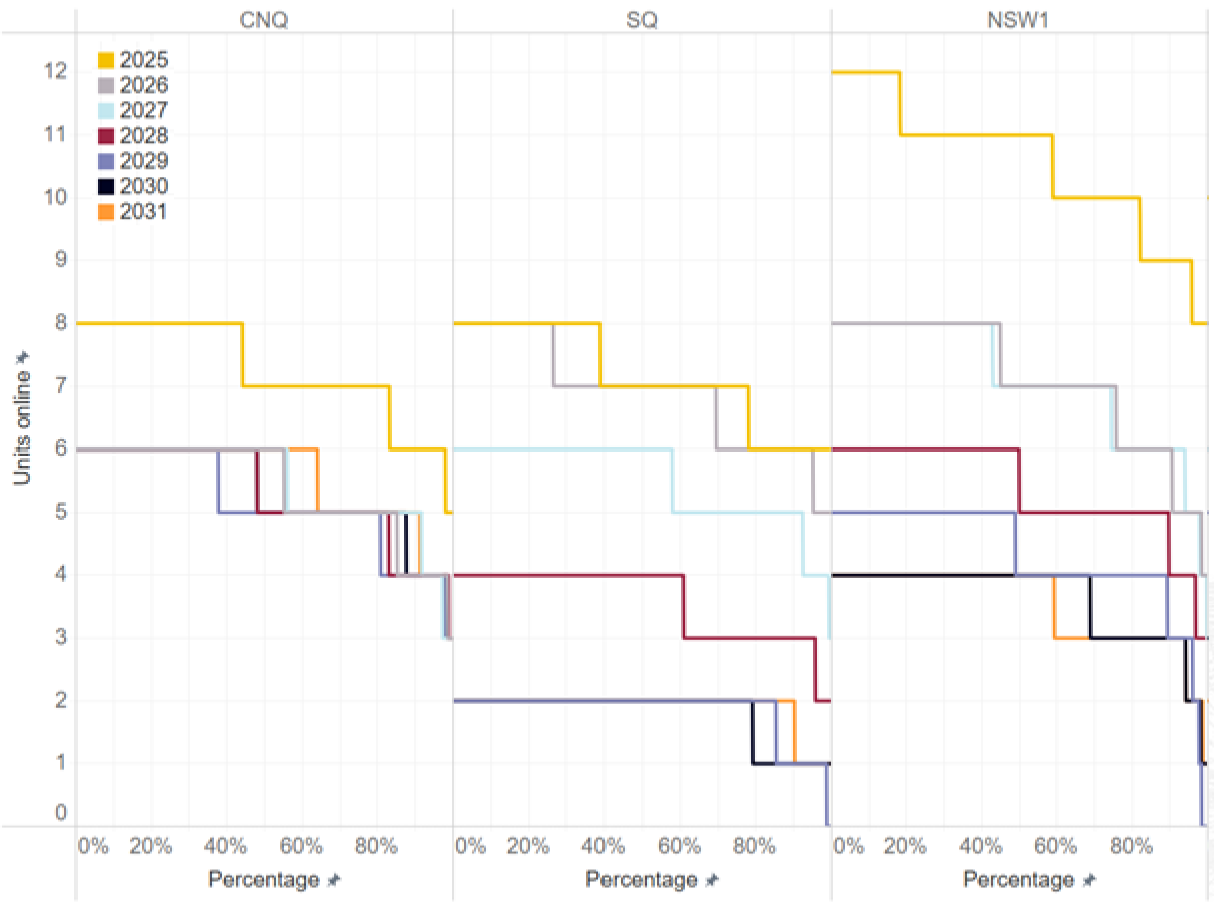
- We have adopted a conservative approach that may understate the true cash flow variability that SSSPs may be exposed to. In practice, economic behaviour by participants may increases the system strength enablement requirement. In addition, availability payments, commercial negotiations and the potential for market power by system strength providers may increase the level and/or variability of costs.

Appendix


9647.6272
8015.6272
4024.6272
5287.6272
1087.6272
3117.6272
-3627.6272

Quantity of system strength enablement based on dispatch

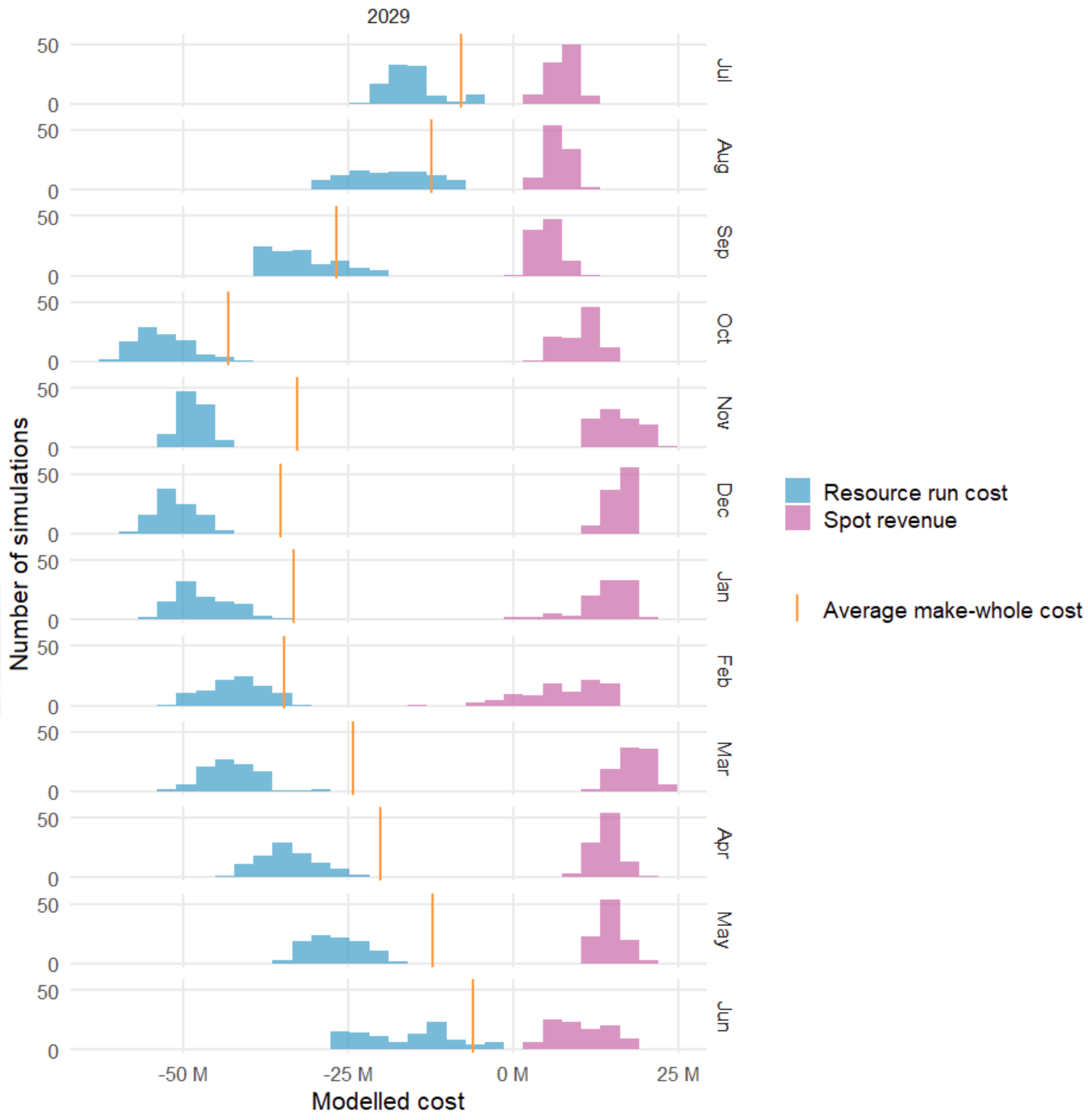
Coal unit duration curves



- The quantity of system strength enablement for each region and financial year is based on the difference between the efficient level and the level of generation from a subset of synchronous units.
- For this purpose we use generation duration curves by financial year from:
  - AEMO 2022 System Strength Report until FY 2028
  - Endgame modelling from FY 2029
- The coal generation duration curve decreases over time.
- This requires increasing enablement for system strength.
- In Queensland this leads to an increasing number of coal and gas units being enabled a greater proportion of the time.
- In NSW it relies on a combination of coal, gas and hydro units being enabled.
- Gas units are assumed in SA.

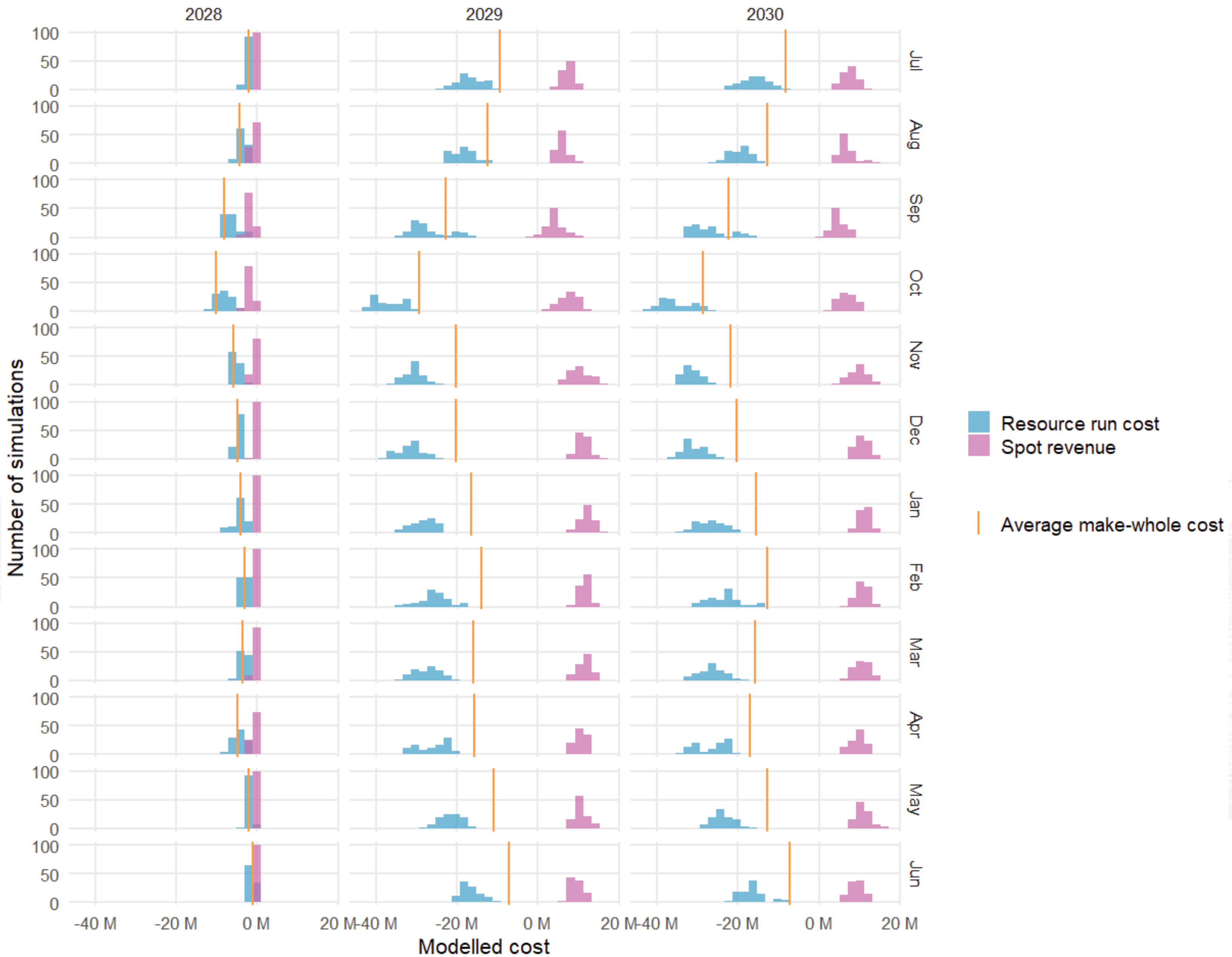
Modelled make-whole costs can be decomposed into spot revenues and resource direct costs

NSW monthly spot revenue and resource run costs (FY 2029)



- The modelled costs for each simulation can be broken down into spot revenue and resource direct costs (proxied by SRMC from the 2023 IASR).
- To clearly illustrate the relationship between the components we have presented costs in net revenue terms i.e. the orange vertical line is presented as the **negative** of the average net modelled make-whole cost presented in the main results.
- The results show that resource run costs are the greater source of variation in net modelled costs. This reflects that the SRMC of enabled resources is generally higher (in absolute terms) than the spot prices earned by these resources during enablement.
- Prices will generally be low (often negative) during periods when system strength enablement is required.

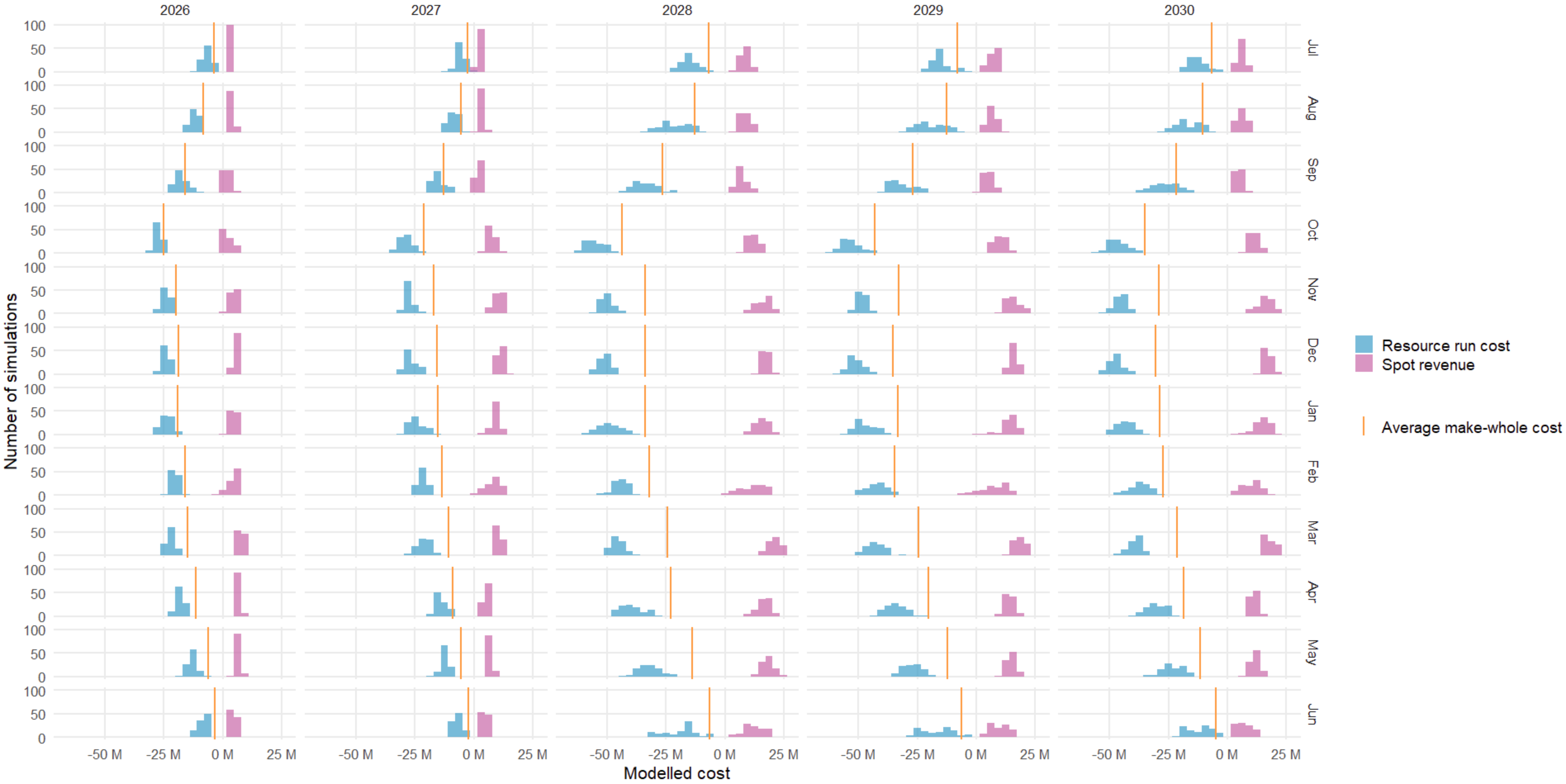
Distribution of spot revenue and resource run costs (QLD)



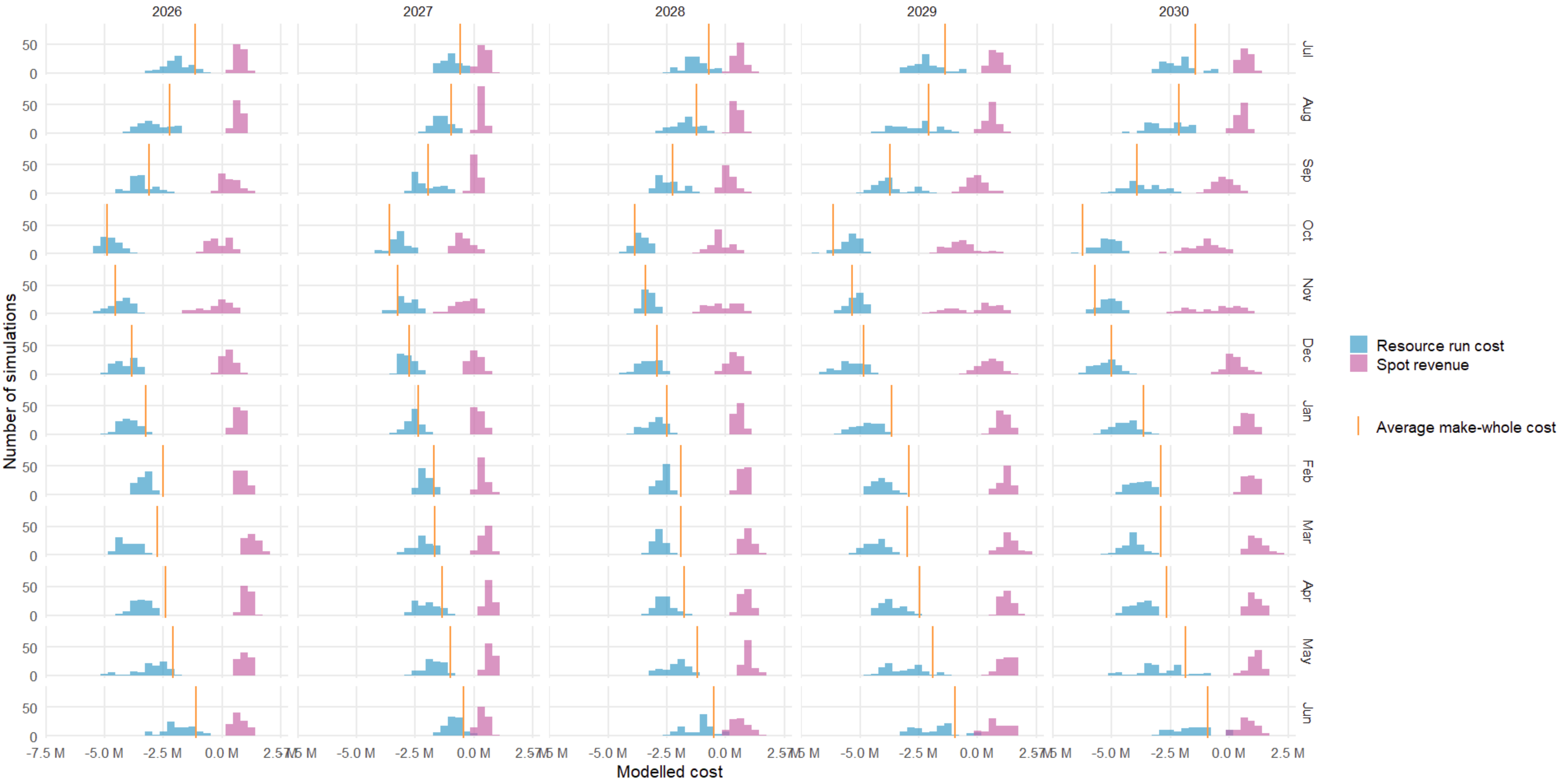
- The results show that resource run costs are a greater source of variability than spot revenues.
- These results are consistent across time and across regions.

Note: FY 2026 and 2027 omitted from QLD due to relatively low variation in costs.

Distribution of spot revenue and resource run costs (NSW)

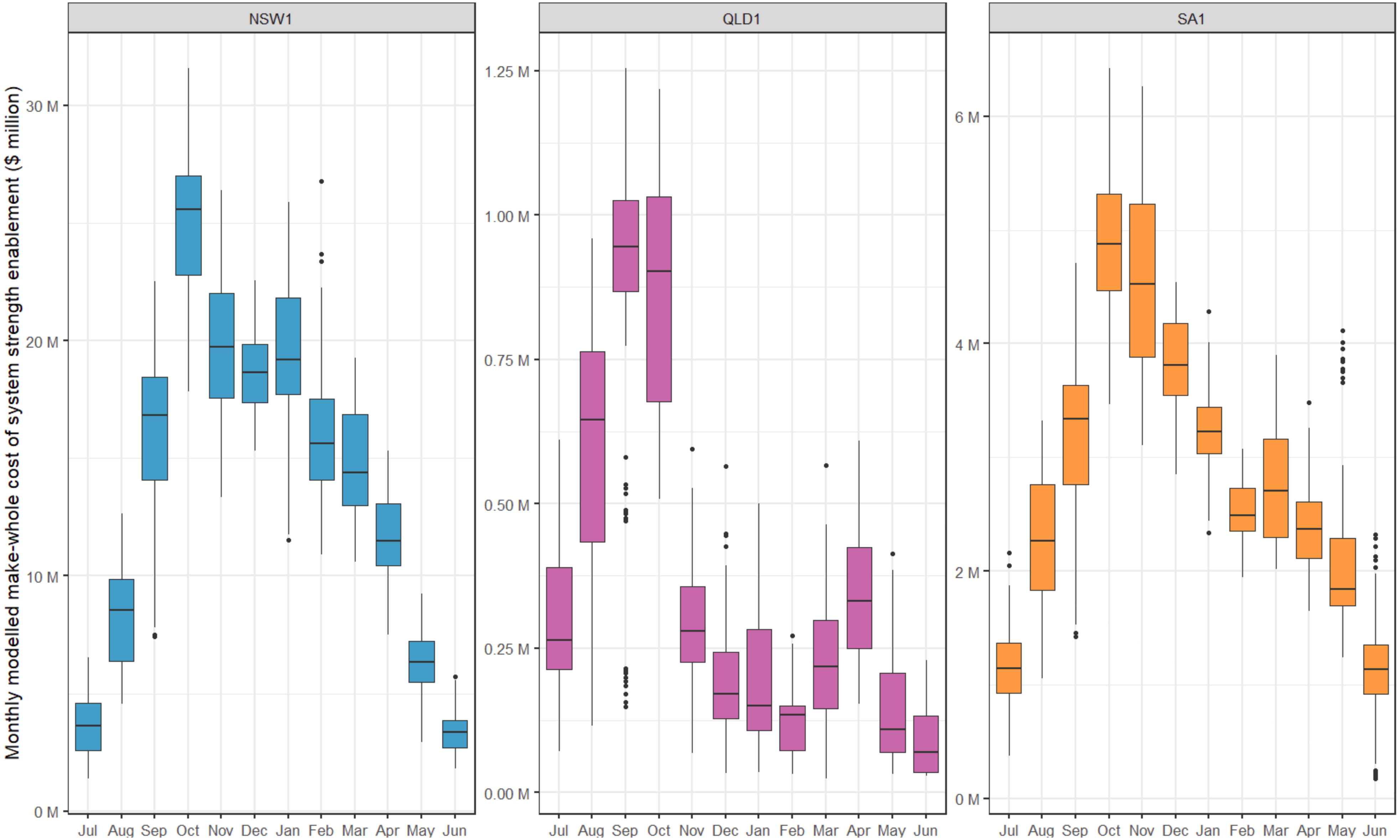


Distribution of spot revenue and resource run costs (SA)



Monthly results for all financial years

Annual modelled make-whole cost of system strength enablement in FY 2026 ($ millions, real 2023)

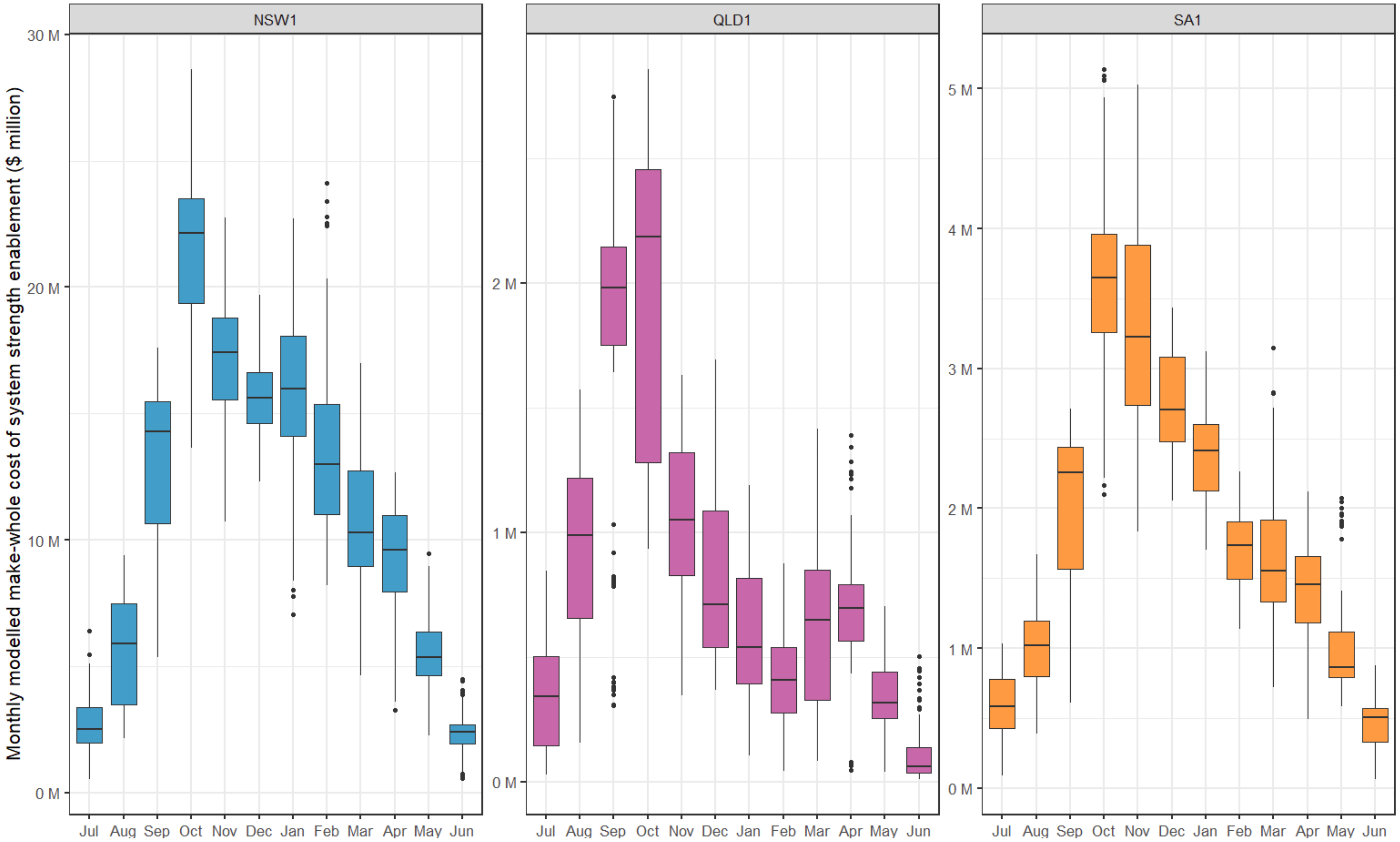


- This chart presents the range of modelled make-whole costs across different simulations by month in FY 2026.
- The results show a high degree of variability within and across months.
- The variability is driven by different spot price outcomes under different simulations. This changes both the quantity of enablement and the make-whole cost of that enablement within a simulation.

Note: scale is automatically set by region to illustrate variability in modelled make-whole costs.

Monthly results for all financial years

Annual modelled make-whole cost of system strength enablement in FY 2027 ($ millions, real 2023)

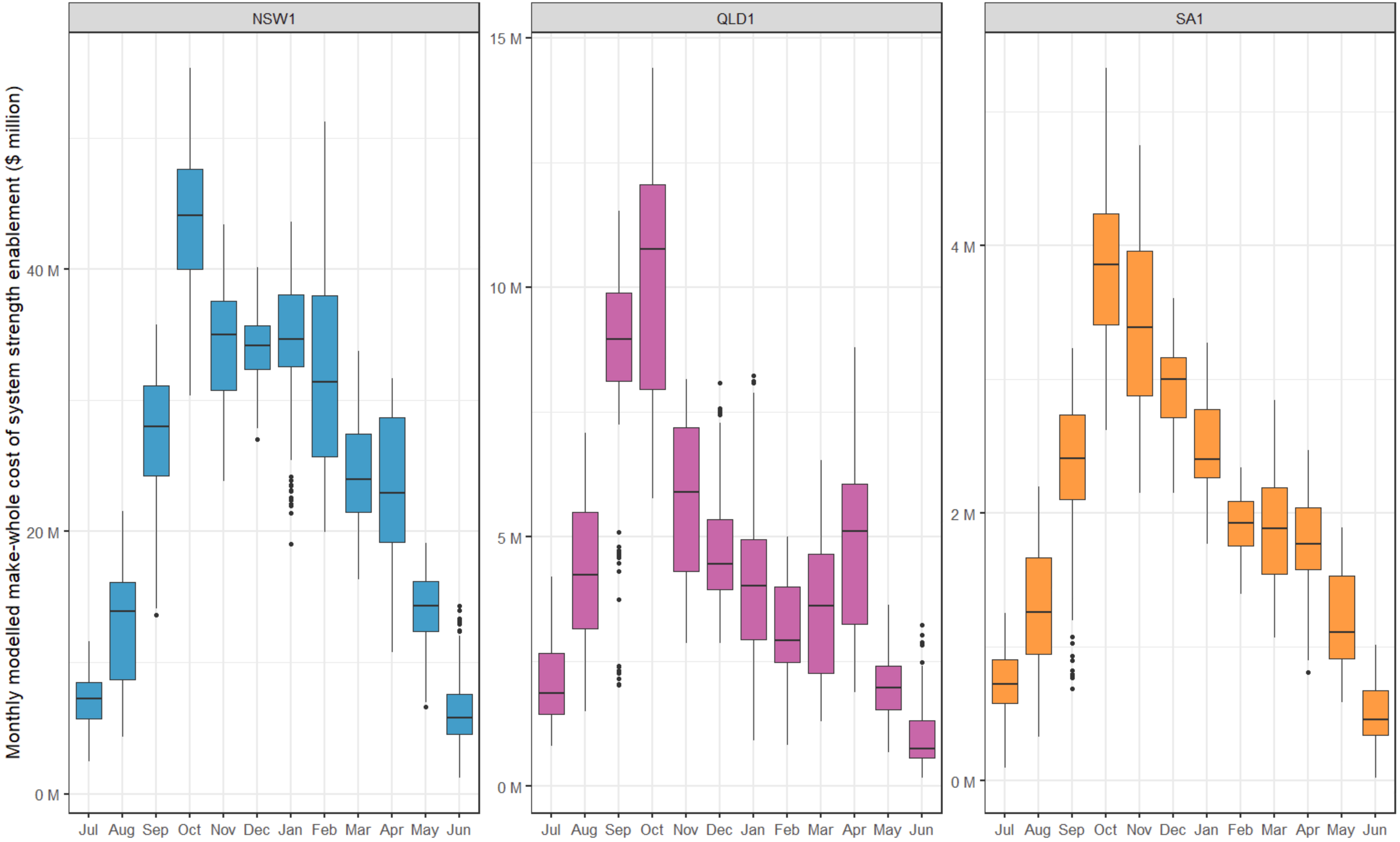


- This chart presents the range of modelled make-whole costs across different simulations by month in FY 2027.
- The results show a high degree of variability within and across months.
- The variability is driven by different spot price outcomes under different simulations. This changes both the quantity of enablement and the make-whole cost of that enablement within a simulation.

Note: scale is automatically set by region to illustrate variability in modelled make-whole costs.

Monthly results for all financial years

Annual modelled make-whole cost of system strength enablement in FY 2028 ($ millions, real 2023)

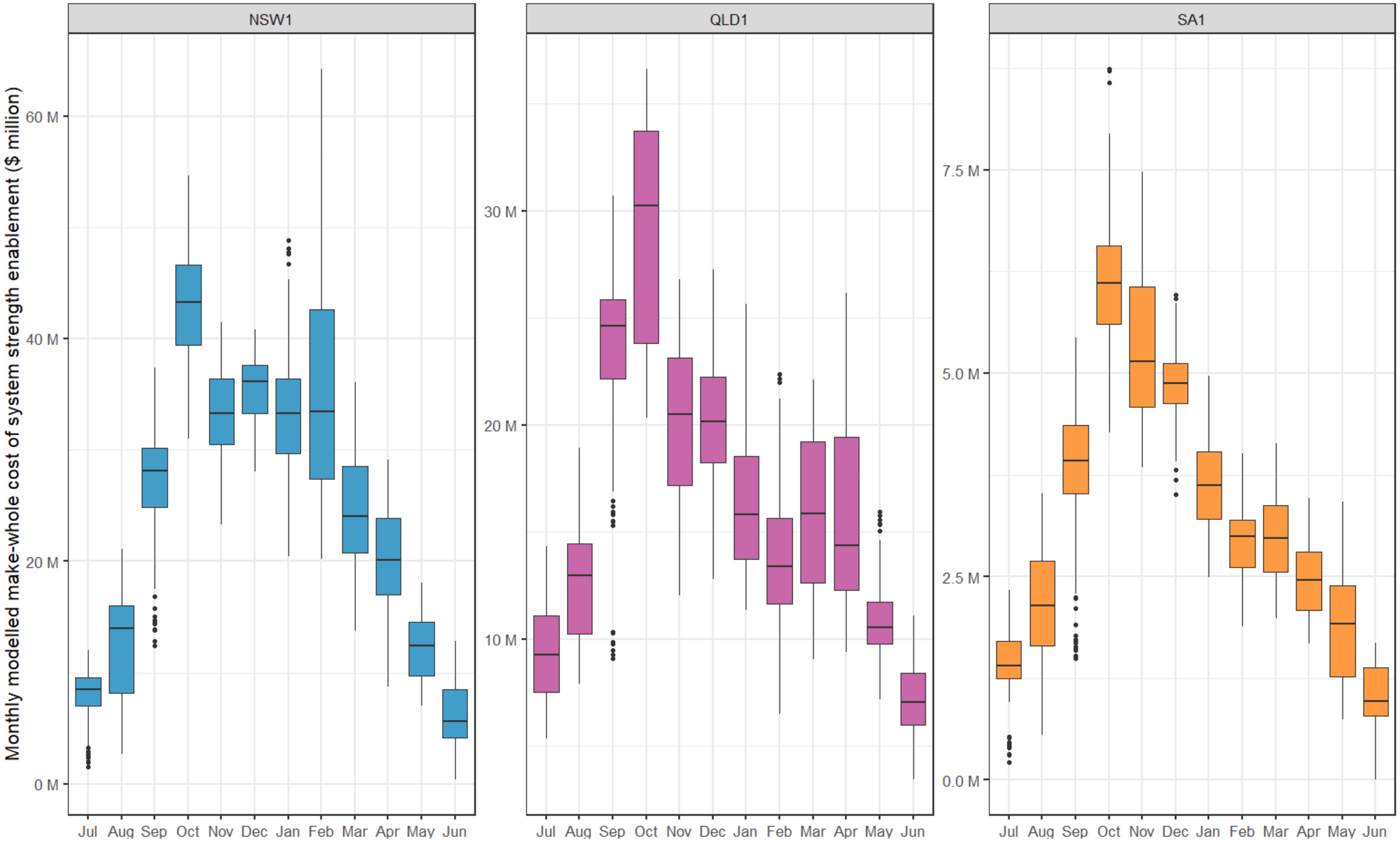


- This chart presents the range of modelled make-whole costs across different simulations by month in FY 2028.
- The results show a high degree of variability within and across months.
- The variability is driven by different spot price outcomes under different simulations. This changes both the quantity of enablement and the make-whole cost of that enablement within a simulation.

Note: scale is automatically set by region to illustrate variability in modelled make-whole costs.

Monthly results for all financial years

Annual modelled make-whole cost of system strength enablement in FY 2029 ($ millions, real 2023)

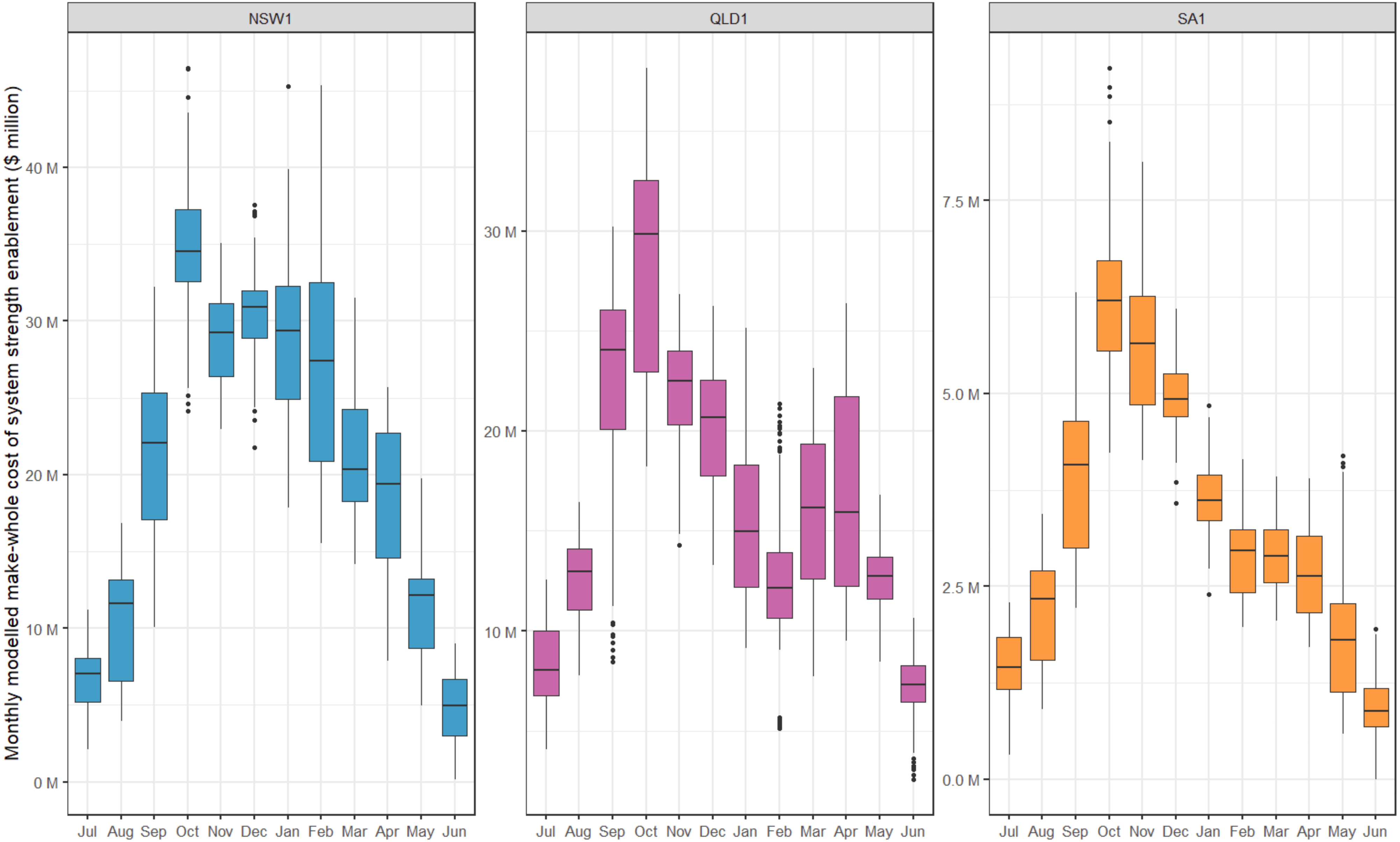


- This chart presents the range of modelled make-whole costs across different simulations by month in FY 2029.
- The results show a high degree of variability within and across months.
- The variability is driven by different spot price outcomes under different simulations. This changes both the quantity of enablement and the make-whole cost of that enablement within a simulation.

Note: scale is automatically set by region to illustrate variability in modelled make-whole costs.

Monthly results for all financial years

Annual modelled make-whole cost of system strength enablement in FY 2030 ($ millions, real 2023)



- This chart presents the range of modelled make-whole costs across different simulations by month in FY 2030.
- The results show a high degree of variability within and across months.
- The variability is driven by different spot price outcomes under different simulations. This changes both the quantity of enablement and the make-whole cost of that enablement within a simulation.

Note: scale is automatically set by region to illustrate variability in modelled make-whole costs.

ENDGAME
ECONOMICS

Experts in the design, development
and application of mathematical models.

www.endgame-economics.com

T: +61 2 9037 0370
M: +61 425 204 793

24.01, 9 Castlereagh St
Sydney NSW 2000

info@endgame-economics.com