Addendum to the Draft 2022 ISP

March 2022

For the National Electricity Market

Important notice

Purpose

AEMO publishes this Addendum to the Draft 2022 Integrated System Plan (ISP) pursuant to National Electricity Rules (NER) 5.22.13. The addendum provides additional information on how key inputs and assumptions contribute to the Draft 2022 Integrated System Plan (ISP) outcomes.

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Version control

Version	Release date	Changes
1.0	11/3/2022	Initial release.

Contents

1. Introduction

In 2020, reforms to the National Electricity Rules (NER) and the National Electricity Law (NEL) converted AEMO's *Integrated System Plan* (ISP) into an actionable strategic plan. As part of this, the Australian Energy Regulator (AER) is required to review the transparency of the Draft ISP[1]. The role of the AER's transparency review process is to assess the adequacy of AEMO's explanations of the derivation of key inputs and assumptions, and how key inputs and assumptions contributed to AEMO's Draft 2022 ISP outcomes.

Overall, the AER's *Transparency Review of AEMO Draft 2022 Integrated System Plan*[2] ("Transparency Review Report") concluded that "*AEMO has adequately explained the majority of its inputs and assumptions, and how they contribute to the draft ISP outcomes*".

In addition to this overall finding, the Transparency Review Report considered that there were some aspects of the Draft 2022 ISP where AEMO should better explain how key inputs and assumptions contribute to the Draft 2022 ISP outcomes, and required AEMO to consult on the following topics:

- Thermal coal plant retirements – see Section 2.
- Victoria – New South Wales Interconnector (VNI) West and HumeLink decision rules – see Section 3.
- Marinus Link timing – see Section 4.
- *Low Gas Price* sensitivity – see Section 5.

1.1 Invitation for written submissions

AEMO has been consulting with stakeholders on the content of the Draft 2022 ISP.

AEMO is opening a new consultation to enable stakeholders to provide submissions on the content of this Addendum. Written submissions should be provided in PDF form, to AEMO's ISP@aemo.com.au mailbox, by 28 March 2022.

1.2 Process to develop the 2022 ISP

This document is published to support the Draft 2022 ISP[3].

Figure 1 below provides a visual representation of this process, including both the elements of the regulatory framework (in blue, red and green boxes) and the activities undertaken by AEMO and stakeholders (in white boxes).

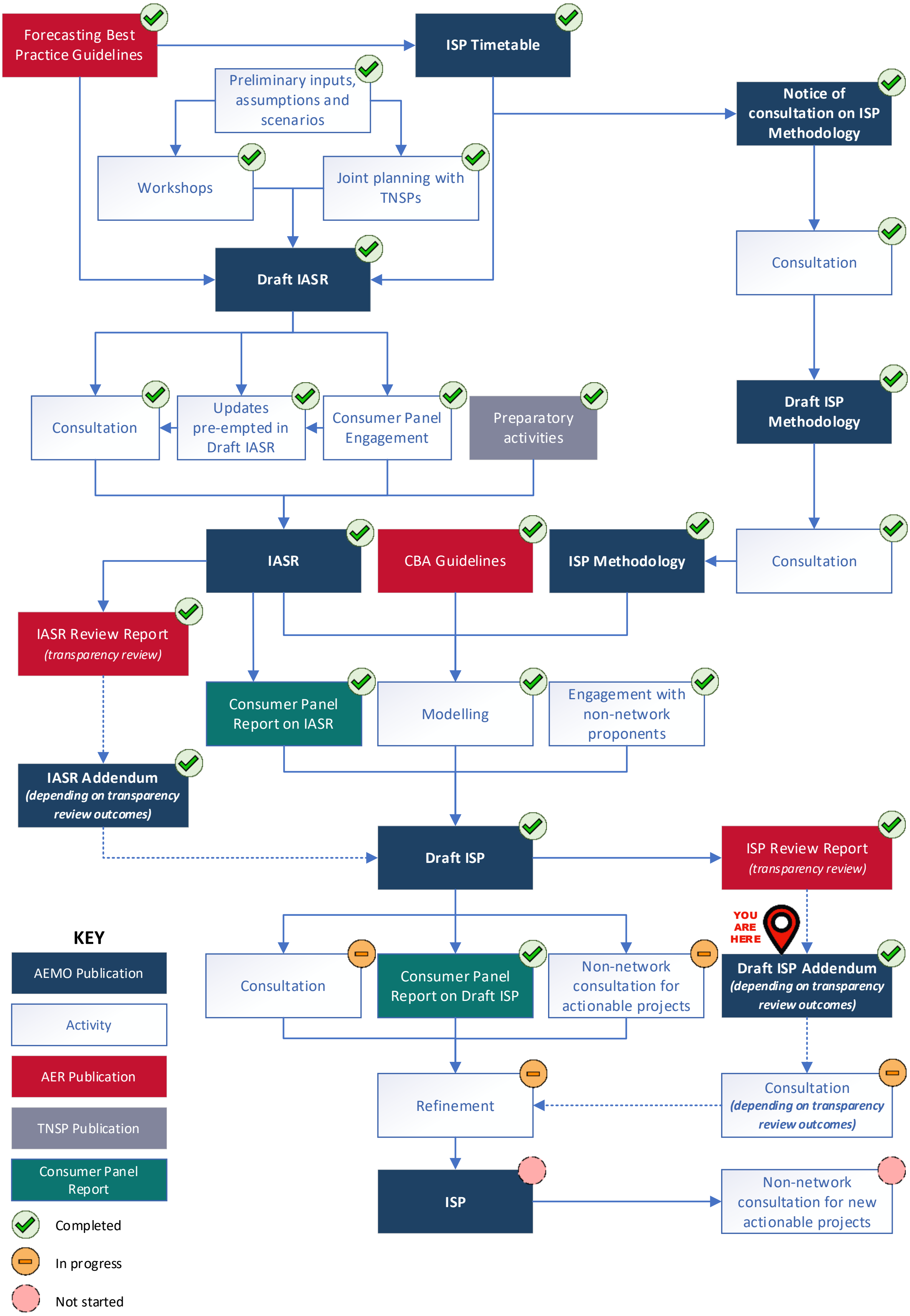
The remainder of this document provides explanations and seeks feedback on topics identified in the Transparency Review Report.

[1] NER 5.22.13(a).

[2] At https://www.aer.gov.au/networks-pipelines/performance-reporting/transparency-review-of-aemo-draft-2022-integrated-system-plan.

[3] AEMO. *Draft 2022 ISP*, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

Figure 1 The ISP process



2. Thermal coal plant retirements

Key finding from the Transparency Review Report

“We […] expect AEMO, in an addendum to the draft ISP, to provide further explanations of:

- *How it has derived the assumptions and inputs regarding the profitability of coal plant and how this has contributed to modelled coal plant retirements across each scenario.*
- *How it has derived the inputs and assumptions used to support the conclusion that ‘seasonal mothballing’ of coal plant will not extend the life of this plant in the Progressive Change scenario.*
- *The reasons why intra-day coal plant flexibility has not been modelled.”*

AEMO’s response

AEMO applied two alternative approaches to forecast coal retirements, as explained in this section and in the ISP Methodology. These approaches considered the profitability of generators and/or the impact of emissions reduction objectives in identifying closure timings. As outlined in this section, the revenue adequacy modelling was not a significant driver for generator closure timings.

Thermal generation retirements are challenging to predict, as demonstrated by the latest announcement by Origin Energy[4] on its accelerated retirement of the Eraring Power Station. AEMO applies a scenario analysis framework to accommodate a range of uncertainties, including the timing of potential retirements. Where practical, sensitivity analysis is also often used to identify the risks of variations to key assumptions, as coal retirements are often a material impact to the risks to consumers and the appropriate investments to manage these risks.

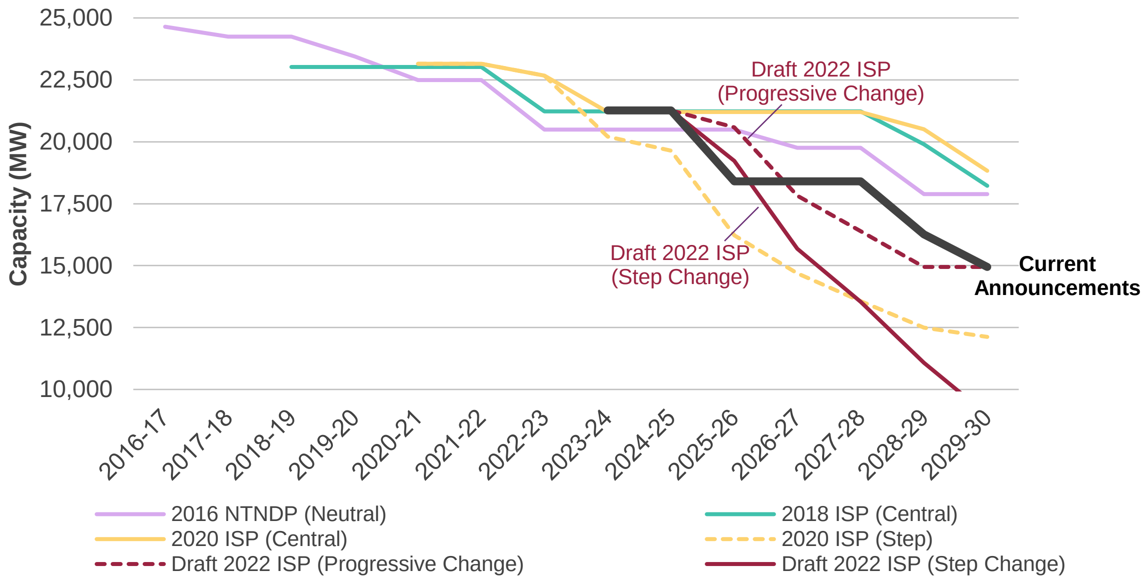
In recent years, the growth in large-scale variable renewable generation (VRE) and distributed energy resources (DER) has put pressure on the market share of incumbent generators.

As demonstrated in Figure 2 below, only the 2020 ISP (with the schedule lying between the *Step Change* and *Central* scenarios) and the Draft 2022 ISP have forecast a scale of coal retirements that is keeping pace with current announcements. Prior to these publications, the ‘central’ planning scenarios did not, in hindsight, sufficiently capture the risks now being observed in terms of the pace of the transformation of the National Electricity Market (NEM).

AEMO therefore considers that the current collection of approaches to model potential coal retirements represent an improved collection of methods to inform the needs of the future power system, and inform the ISP’s optimal development path (ODP).

[4] “Origin proposes to accelerate exit from coal-fired generation”, 17 February 2022. Available at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

Figure 2 AEMO's forecast coal retirements and the current announced retirement schedule, 2016-17 to 2029-30



NTNDP: National Transmission Network Development Plan

To address the request in the Transparency Review Report for additional explanations of coal plant retirements in the Draft ISP, this section outlines:

- High-level assumptions and approach to identifying retirements due to unprofitability.
- Seasonal mothballing considerations.
- Intra-day flexibility modelling.

Assumptions on coal plant profitability and retirements due to unprofitability

AEMO applied a slightly different approach to coal retirement depending on the scenario, as specified in, and consulted upon, in the 2021 ISP Methodology (Section 2.4.1)[5]:

- Approach 1 – for those scenarios which have periods that are not influenced by an explicit decarbonisation constraint (often referred to as a carbon budget) in the electricity sector, a revenue forecasting and least-cost hybrid retirement approach was taken.
- Approach 2 – where an explicit emissions constraint was implemented, a pure least-cost approach was used.

As defined in the scenario narratives and consulted on in the *Inputs, Assumptions and Scenarios Report*[6] (IASR), some scenarios incorporate carbon budgets that place explicit limits on the emissions intensity of the electricity system. These scenarios therefore incorporate the effects of earlier retirements on the power system to meet climate outcomes, and do not require evaluation of revenue sufficiency to bring forward the timing of generator closures. Emissions reduction limits in these scenarios reflect an efficient emissions-reduction contribution from

[5] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf.

[6] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf.

the electricity system, considering the opportunities for electrification from other sectors. Given this influence, the timing of plant retirements considers the least-cost means[7] to achieve these limits.

Table 1 lists the specific approaches used in each scenario.

Table 1 Retirement approach used for each scenario

Scenario	Approach
Slow Change	Approach 2[8]
Progressive Change	Approach 1
Step Change	Approach 2
Hydrogen Superpower	Approach 2

Approach 1

In Approach 1, expected closure years that apply prior to 2030 may be brought forward from announced closure years by considering the forecast wholesale market profitability of each generator. The consideration of early retirements was limited to the period beyond any NEM or jurisdictional notice of closure requirements. Due to the increased level of uncertainty associated with a changing market share for existing generation portfolios, potential ownership changes and the influence that the changing market may have on participants' bidding behaviour as generator closures occur, this assessment was limited to the period up to 2030.

Forecasts of wholesale prices and generator profitability rely on generation cost and technical assumptions listed in the IASR. For coal units, these include Fixed Operating and Maintenance (O&M), Variable O&M, and fuel costs. These cost assumptions were based on inputs from consultants and were consulted on during the IASR consultation. AEMO also separately shared the inputs with coal station operators, and made minor refinements based on confidential information provided. Based on the information available, AEMO considers the published assumptions represent the best assessment of the cost of operating coal plants until 2030.

Generator market offers (that is, the bids that are submitted to the dispatch process) were calibrated in the model to align with cleared market offers over 12 months in 2020-21, being the most recent full financial year available, and spot market prices were simulated based on dispatch with these bids. AEMO considered that the technical assumptions and market offers within the model were reasonably configured to emulate observed market outcomes, and that the outcomes from the most recent full financial year (2020-21) provide appropriate consideration of current market dynamics.

These bids were kept static for the period assessed, as adjusting bidding strategies to accommodate the uncertainties associated with the evolving market dynamic would rely on additional assumptions about strategic portfolio responses and step away from historical observations of market behaviours. These strategies therefore reflect one possible bidding outcome, and support AEMO's limitation of the assessment to the period up to 2030. AEMO considers that the application of this approach until 2030 remains a robust method, extending current

[7] Least-cost considering the costs that are explicitly incorporated in AEMO's Capacity Outlook modelling. More information on this model is available in the ISP Methodology.

[8] While *Slow Change* does not apply a carbon budget, AEMO considered that Approach 2 was a more suitable method for this scenario, given the modelling complexity associated with Approach 1, and the relatively low weighting (4%) of the scenario. Applying the added complexity of Approach 1 would have been disproportionate to the materiality of the scenario's impact. The retirement outlook from Approach 2 for *Slow Change* was considered consistent with the scenario narrative and insights from other scenarios.

market intelligence of generator bidding, and providing an appropriate method for revenue estimatation of existing generation portfolios for the intended purpose.

Other assumptions which influenced the determination of generator retirements are noted below:

- As noted in the ISP Methodology, the retirement trajectory available in the most recent Consumer Trustee report (the December 2021 *Development Pathways Report*[9], or DPR) was applied as a starting point for a generator retirement trajectory for coal units in New South Wales (in some cases, the DPR forecast retirements earlier than the expected closure dates provided in the IASR, as Figure 3 shows). No subsequent changes to retirement timings were found in applying Approach 1 for New South Wales generators.

Figure 3 Coal retirement in New South Wales (post-Liddell) – as modelled (based on DPR) compared to announced retirements as of July 2021 (IASR) and February 2022.

- Figure 3 above includes recent announcements by Origin Energy and AGL Energy regarding the earlier retirements of the Eraring (2025) and Bayswater power stations (2033), demonstrating that the modelled trajectory is broadly in line with the latest coal retirement announcements, providing an appropriate foundation for the ISP. Yallourn retirement was fixed to 2028-29, based on the agreement reached between Energy Australia and the Victorian Government to deliver an orderly retirement of the power station[10]. No other brown coal units were considered to retire before Yallourn. In Victoria, generators have to give five years notice of closure[11].
- Due to the complexity and long-term nature of the Interconnection and Power Pooling Agreement[12], including its supply arrangements to the Boyne Island Smelter, Gladstone Power Station was not considered for early retirement.

[9] At https://aemo.com.au/about/aemo-services/aemo-services-as-the-consumer-trustee.

[10] See https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station/energy-transition.

[11] See https://earthresources.vic.gov.au/communityand-land-use/key-site-updates/latrobe-valley-coal-mines/rehabilitation.

[12] Australian Competition and Consumer Commission (ACCC) Determination, at https://www.accc.gov.au/system/files/public-registers/documents/D10%2B3621896.pdf.

Approach 2

In Approach 2, AEMO applied a least-cost retirement trajectory that took into account the impact of cumulative emissions, and the influence of the scenario-specific carbon budgets. These retirement outcomes were then validated in the time-sequential modelling, applying a similar bidding approach as applied in Approach 1 to identify if revenues after the carbon-budget triggered retirements were sufficient across the generation portfolio. This assessment observed no large negative profitability outcomes to trigger further or earlier retirements, reflecting that the carbon budget was the dominant driver for retirements in the *Step Change* and *Hydrogen Superpower* scenarios.

Retirements due to unprofitability

Applying Approach 1 in *Progressive Change* identified that only one generator, in Queensland, would be insufficiently profitable, resulting in an earlier closure (bringing forward its retirement three years to 2025-26). The revenue adequacy modelling therefore was not a significant driver for generator closure timings.

As outlined in the ISP Methodology (section 2.4.1), the criteria for early retirement considered whether both the following were met before deciding on an earlier retirement:

- The magnitude of negative returns, relative to the cost of bringing forward any retirement/rehabilitation cost (which is provided in the IASR Workbook, per technology), and
- The duration of consistent negative returns to 2030 or the expected closure year/closure date.

Other retirements beyond 2030 were only brought forward before expected closure years if determined in the capacity outlook modelling, rather than as a result of profitability analysis.

Seasonal mothballing: potential impact on retirement decisions

AEMO's modelling approach to seasonal mothballing was informed by engagement with coal generators, who indicated in general terms the future market circumstances in which economic withdrawal strategies (such as withdrawing units for a period of days or weeks at a time and/or delaying return to service from maintenance) *might* be considered, depending on the long-term technical and commercial viability of adopting such strategies. Based on these one-on-one confidential discussions, AEMO derived a modelling assumption that if forecast conditions led to a high amount of ramping and/or extended operation during low prices, coal power stations might withdraw units for a period of weeks at a time.

In the Draft 2022 ISP, AEMO considered coal seasonal mothballing and how that might affect early retirement decisions in the time-sequential modelling in *Progressive Change* up to 2030. As discussed in Appendix 4 of the Draft 2022 ISP, AEMO conducted a modelled assessment of potential decommitment benefits based on forecast wholesale energy revenue. This assessment applied no additional assumptions or consideration for contract positions or other potential revenue sources, such as frequency control ancillary services (FCAS) markets. In this assessment, if a generator was forecast to experience wholesale energy market losses for the week ahead, and these were greater than the estimated cost of turning off and eventually re-starting a unit, it was assumed that the unit would decommit for that week. The assessment was performed across multiple units in all regions on a rolling weekly basis and assuming stations with higher operating costs were likely to decommit first.

The coal generator costs used to determine these decommitment outcomes were based on the short run marginal costs calculated according to the assumptions in the IASR and the cold-start costs in the 2018 GHD Cost and

Technical Parameter Review[13]. While this review was conducted several years ago, it was at that time reviewed, consulted upon and applied for the 2018 GenCost report, and remains a source for subsequent publications. It remains a credible summary of cold-start costs within AEMO's collection of forecasting assumptions.

The modelling suggested that some coal generators in New South Wales and Queensland would be potentially more profitable in the future turning off during extended periods of low prices. The overall levels of decommitment forecast for these regions (beyond the standard planned and unplanned maintenance) is shown in the Draft 2022 ISP Appendix 4, Figure 21. No seasonal mothballing at any of the brown coal power stations was identified by the modelling using this approach and assumptions.

The revenue sufficiency outlook of each coal station applied the approach outlined above to forecast revenues and costs that considered the potential efficiency improvements of seasonal mothballing. As previously described, AEMO assumed that a station would maintain its operations unless it would be more costly to continue to operate at a loss, than to bring forward the retirement by a year. In these circumstances, if the power station was forecast to consistently sustain losses of this magnitude for the period until 2030, or until its expected closure year/date, then earlier retirement was selected. Volatile returns (such as where losses in one year were balanced by profits in subsequent years) would hold the original retirement schedule firm.

While the modelling showed that seasonal mothballing leads to higher revenues, the change in profitability observed was not sufficient to support a change of the retirement dates up to 2030 determined using Approach 1. In other words, in no case did seasonal mothballing change long-run profitability outcomes by a sufficient degree as to affect the timing of retirements in accordance with the approach in Section 2.4.1 of the ISP Methodology. For the single Queensland generator identified as unprofitable, a seasonal mothballing strategy did not affect this conclusion applying the criteria described previously, although the scale of losses incurred was reduced.

Intra-day flexibility

Intra-day coal plant flexibility was modelled, with coal generators ramping up and down, within the technical limits assumed, depending on the availability of lower-cost alternative generation, and the level of operational demand. That is, if insufficient load exists to warrant the operation of coal generation at maximum loads given the availability of renewable generation, coal generators were forecast to ramp down to lower levels of dispatch, including to minimum operating levels.

Modelling coal unit commitment and optimising short-term decommitment (that is, turning off a unit in the middle of the day and returning it to service to meet the evening peak) is computationally challenging. Furthermore, there is no reliable historical data on which to base these assumptions, given that no coal generator has displayed this type of behaviour in Australia to date on a consistent basis. Confidential one-on-one discussions with coal power station operators suggest that this type of short-term decommitment behaviour is not considered likely in the future, and that generators are still learning how this type of behaviour impacts costs and operations.

Given this uncertainty, AEMO more prudently considered other forms of flexibility which are a) observed and b) being considered by coal power station operators (as indicated in confidential one-on-one discussions) as likely in the future (for example, operating at minimum load for longer periods, higher ramping relative to history, and extended outages such as a delayed return to service from maintenance, called seasonal mothballing).

[13] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/9110715-rep-a-cost-and-technical-parameter-review---rev-4-final.pdf.

Confidential one-on-one discussions with market participants also suggested that intra-day flexibile operation would have reliability implications (particularly for brown coal generators) which were not well known or understood. The discussions also outlined that the wear-and-tear associated with unit start-ups and shutdowns were a factor in considering the viability of economic decommitment strategies.

3. VNI West and HumeLink decision rules

Key finding from the Transparency Review Report

"The draft ISP applies decision rules in relation to both the HumeLink and VNI West actionable projects which state that

- *these projects should proceed to implementation beyond early works unless there is an increase in the likelihood that either:*
  - *material volumes of existing dispatchable capacity are retained in New South Wales (or Victoria and NSW for VNI West); or*
  - *material volumes of new dispatchable capacity are developed in those regions beyond what is assumed in the Step Change scenario.*
- *these projects should not proceed beyond early works if there is a material increase in total project cost (including early works costs), relative to what has been assumed in the Draft ISP.*

[…] AEMO has not explained the circumstances under which this assumption would lead to these projects not progressing to the next stage e.g the increased level of retained capacity or developed capacity above the Step Change scenario."

AEMO's response

The use of decision rules ensures that a project can be delivered when it is needed, with an additional checkpoint before construction. The application of a materiality threshold here provides flexibility such that the latest project costs and benefits can be assessed in the ISP feedback loop. Project staging may also identify cost savings, reduce cost uncertainties, and provide greater consumer confidence in the investment.

The Transparency Review Report expected AEMO to further explain the circumstances (in terms of increased level of retained capacity or additional dispatchable capacity) that would lead to HumeLink and VNI West not progressing to the next development stage.

It is not feasible to provide specificity around the potential array of changed circumstances that may occur in the future which would lead to the decision rules not being met when this is subsequently assessed (for which the timing itself is uncertain). There are many things that could happen that would cause either materiality threshold to be met, with potential new information affecting the assumptions of any individual project, broader generation developments, and/or changes to the levels of electricity demand that the ISP developments are forecast to serve.

AEMO will, however, provide more context on how the framework is to be used. In this section:

- Part 1 covers the 'materiality' threshold regarding dispatchable capacity and project costs in decision rules, and their relation to the feedback loop.
- Part 2 discusses VNI West and its relationship with coal retirements and additional dispatchable capacity.
- Part 3 discusses HumeLink and its relationship with New South Wales coal retirements in particular and additional dispatchable capacity in general.

Part 1: the 'materiality' threshold

The Draft 2022 ISP included in the ODP the staging of the VNI West and HumeLink projects, with proposed decision rules that must continue to be met before the implementation stages for each of these projects are progressed.

AEMO proposed decision rules in the Draft 2022 ISP, considering dispatchable capacity and project costs, to enable project staging where desirable. This approach is intended to provide the flexibility to adapt project delivery to future uncertainties, while continuing to provide consumers with confidence that projects are beneficial before proceeding with the full investment.

The decision rules incorporate a 'materiality' threshold on both dispatchable capacity and project costs. The benefits of these projects decline as dispatchable capacity or project costs increase. A materiality threshold is used rather than a fixed number because the net market benefits are a function of both variables (for example, if dispatchable capacity declines then project costs could increase and still provide the expected market benefit, and vice versa).

Provided the proposed decision rules are met, the ISP feedback loop, which will assess the project as a whole, could be initiated after early works are completed.[14] The feedback loop would assess the materiality thresholds using the inputs and assumptions in the latest ISP, including the latest view on project costs and dispatchable capacity. This approach ensures that:

- the project continues to address the relevant identified need specified in the most recent ISP and aligns with the ODP referred to in the most recent ISP, and
- the cost of the preferred option does not change the status of the actionable ISP project as part of the ODP.

Part 2: VNI West

The Draft 2022 ISP's cost benefit analysis (CBA) found that, in the case of VNI West, staging the project resulted in an overall increase in weighted net market benefits. This is because when taking into account scenario weights, the benefits of being able to progress the project when needed in *Step Change* and *Hydrogen Superpower* exceeded the cost associated with incurring the early works component earlier than it would otherwise have been needed (in *Progressive Change* and *Slow Change*).

In addition, actioning early works on VNI West is forecast to provide greater insurance value to early coal retirements in Victoria, which result in the need for additional firming capacity, or delivery schedule delays (including potential for delay for Marinus Link). In *Step Change*, VNI West is needed from 2031 onwards, when all brown coal in Victoria is assumed to retire (driven by the carbon budget). If retirements in other scenarios were faster than assumed, the value to consumers from early implementation would increase.

If the feedback loop assessment was conducted given assumptions available from the Draft 2022 ISP, as seen in Figure 16 in Appendix 6 of the Draft 2022 ISP, significant firming (provided by storage) would be needed if the VNI West project was not developed, with the majority of that firming dispatchable capacity in Victoria. The interconnector defers the need to install approximately 900 megawatts (MW) of additional dispatchable capacity by 2031-32 in New South Wales and Victoria. Put another way, if an additional 900 MW of dispatchable capacity was built in New South Wales and Victoria by 2031-32 above what is assumed in the model, and all else

[14] Note that AEMO completed a feedback loop assessment of HumeLink early works in January 2022: see https://aemo.com.au/-/media/files/major-publications/isp/2022/isp-feedback-loop-notice-humelink-early-works.pdf.

remained equal (that is, no further early closure announcements, or changes in demand were forecast, and other network investment proceeded as per the ODP) then the optimal timing for VNI West may be delayed. In practice, AEMO expects that a number of inputs and assumptions are likely to change, and that the feedback loop will be used to assess the materiality threshold and confirm whether the project remains aligned with the latest ISP.

Part 3: HumeLink

The CBA in the Draft 2022 ISP also found that in the case of HumeLink any potential slippage of the commissioning schedule of the project, delays in storage development, or faster coal retirements would also result in increased benefits associated with declaring the project as a staged, actionable project.

As discussed in Appendix 6 section A6.5.2, the optimal timing for HumeLink is closely linked with New South Wales coal retirements. The project begins to deliver positive net market benefits from the time at which the fourth New South Wales coal-fired power station (including Liddell) retires.

Figure 18 in that Appendix highlights the increase in dispatchable firm capacity that is needed in the absence of HumeLink in the *Step Change* scenario. With HumeLink developed, nearly 1 gigawatt (GW) of additional dispatchable capacity is avoided across the NEM by 2028-29, particularly in New South Wales and Queensland[15]. In practice, AEMO expects that a number of inputs and assumptions are likely to change, and that the feedback loop will be used to assess the materiality threshold and confirm whether the project remains aligned with the latest ISP.

[15] The level of avoided dispatchable capacity for each project separately may not reliably indicate the level of additional dispatchable capacity required if both projects do not proceed.

4. Marinus Link timing

Key finding from the Transparency Review Report

"The draft ISP states that both MarinusLink cables are actionable projects across all scenarios at some stage between now and the mid-to-late 2030s. In addition, the draft ISP states that:

- *In all scenarios, the second cable is built two years after the first, except the Slow Change scenario which delays the second cable an additional year. When Marinus Link is brought forward as an actionable project, the second cable is sometimes shifted to three years after the first cable in the Progressive Change scenario, depending on the individual CDPs.*

Appendix 6 of the draft ISP states that although the second cable does not necessarily deliver benefits immediately after its construction, the additional $600m cost of delivering the second cable more than three years after the first means that the timely delivery of the second cable is always beneficial. However, AEMO has not provided details as to how these additional costs have been estimated and how the estimated additional costs of $600m after three years of constructing the first cable leads to the conclusion that timely delivery of the second cable is always beneficial across the scenarios."

AEMO's response

The Transparency Review Report raised two key questions for AEMO to expand on in the Draft ISP Addendum. This section outlines the following:

- Part 1: It is cheaper to deliver the second Marinus Link cable within three years of the first cable.
- Part 2: Because of the cost savings and the timing of benefits, it is optimal to deliver the second Marinus Link cable within three years of the first cable in all scenarios.

Part 1 – It is cheaper to deliver the second Marinus Link cable within three years of the first cable

AEMO consulted on Marinus Link costs during the 2021 Transmission Cost Review[16]. This consultation outlined an approach for adopting transmission network service provider (TNSP) estimates from Regulatory Investment Test for Transmission (RIT-T) assessments into the ISP, and also sought feedback on the costs for Marinus Link – including the impact of a delay beyond three years. In the 2021 Transmission Cost Report, AEMO also reviewed components of the Marinus Link estimates demonstrating close alignment with AEMO's transmission cost database. Following an independent review of its cost estimate[17], TasNetworks advised AEMO that the cost is a class 4 estimate with ±15% accuracy.

AEMO has worked closely with TasNetworks to understand the basis of Marinus Link costs, which were subject to consultation in the Project Marinus RIT-T[18] and in AEMO's Transmission Cost Review. The Transparency Review Report notes a saving of $600 million when the second Marinus Link cable is delivered within three years of the first cable. This saving is primarily attributable to the synergies of planning, constructing and delivering the project

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[16] AEMO. *Transmission costs for the 2022 ISP*, at https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

[17] Jacobs. *Project Marinus Cost Estimate Report*, at https://www.marinuslink.com.au/wp-content/uploads/2021/06/Attachment-3-Jacobs-cost-estimate-report.pdf.

[18] TasNetworks. *Project Marinus RIT-T*, at https://www.marinuslink.com.au/rit-t-process/.

as one standalone project (as outlined in the Project Marinus Project Assessment Conclusions Report [PACR][19]). TasNetworks has indicated that the cost savings are attributable to:

- **Synergies in progressing design, approvals and community engagement** – the Marinus Link project needs to seek at least 15 major environmental approvals from three different jurisdictions (Victoria, Tasmania and Commonwealth). Each approval typically requires commencement of construction within two to three years of the permit being granted. This work involves community engagement, land-use planning, detailed technical system studies, economic analysis, project management (legal, tendering, safety) and financial activities (project financing, debt and equity raising). Undertaking these approvals once rather than twice presents a significant cost saving.
- **Economies-of-scale discount when negotiating with suppliers** – major suppliers (converter station and cable) have indicated that Marinus Link may be eligible for volume discounts if orders are placed for components as one standalone project with the two stages being delivered within 2-3 years of each other.
- **Construction efficiencies** – a range of cost savings occur when construction activities of both stages can be coordinated as one project. This is particularly relevant where specialised equipment and crew needs to be mobilised. This includes:
  - Undertaking horizontal directional drilling for shore crossings at the Tasmanian and Victorian coasts.
  - Common civil works activities such as access tracks, fencing and land remediation.
  - Project management and supervision in extending the project delivering timeline.
  - Trenching activities for the entire 90 km of the underground Victorian corridor.
  - The impacts and timeline of land remediation after construction activities are completed.
  - Mobilisation of the construction workforce (specialised cable-laying and converter station crew).

Part 2 – Because of the cost savings and the timing of benefits, it is optimal to deliver the second Marinus Link cable within three years of the first cable in all scenarios

In the *Step Change* and *Hydrogen Superpower* scenarios, the second cable begins to deliver positive annual net market benefits less than four years after the first cable is commissioned. Delaying the second cable beyond three years after the first would therefore mean that these benefits are foregone, as well as incurring the additional $600 million of capital cost.

Figure 4 below highlights this for *Step Change*, with net market benefits becoming positive in 2030-31, three years after the first cable. Delaying the second cable would increase the cost by $600 million and miss the opportunity to accumulate market benefits.

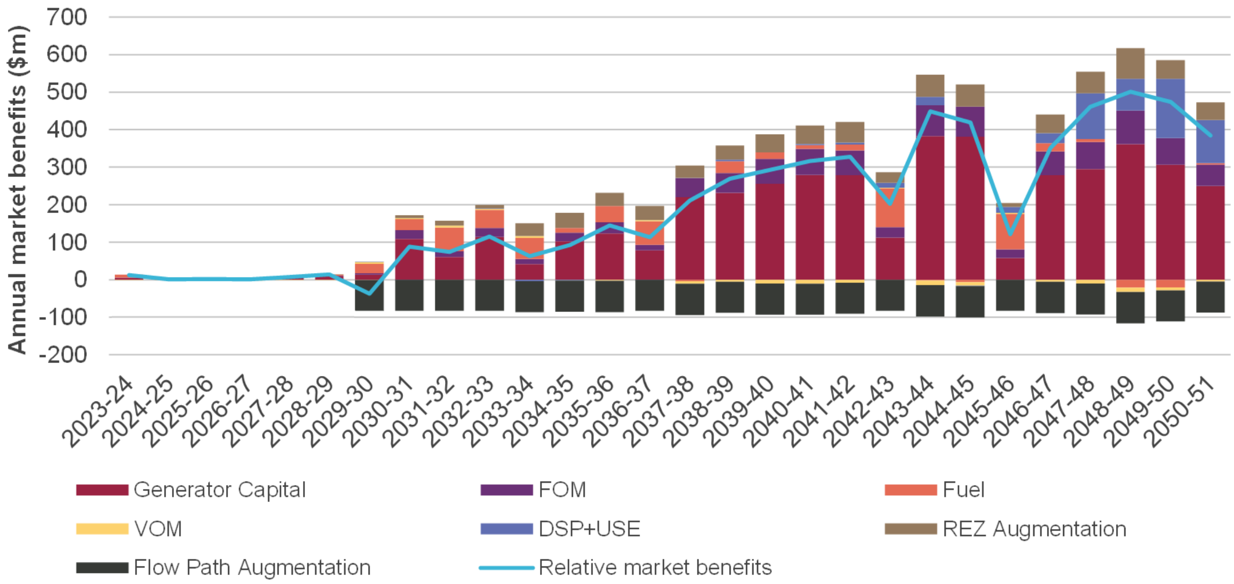
In *Progressive Change* and *Slow Change*, the second cable does not deliver positive annual net market benefits until 2032-33 and 2038-39 respectively. Figure 5 presents the relative market benefits associated with the second cable in *Slow Change*.

Rather than delivering the second cable within three years of the first cable, the second cable could be delivered when it begins to deliver positive annual benefits in 2038-39. However, delaying the second cable in *Slow Change* to 2038-39 (at an additional $600 million increase in project capital costs) results in around $50 million reduction

[19] At https://www.marinuslink.com.au/wp-content/uploads/2021/06/Project-Marinus-RIT-T-PACR.pdf.

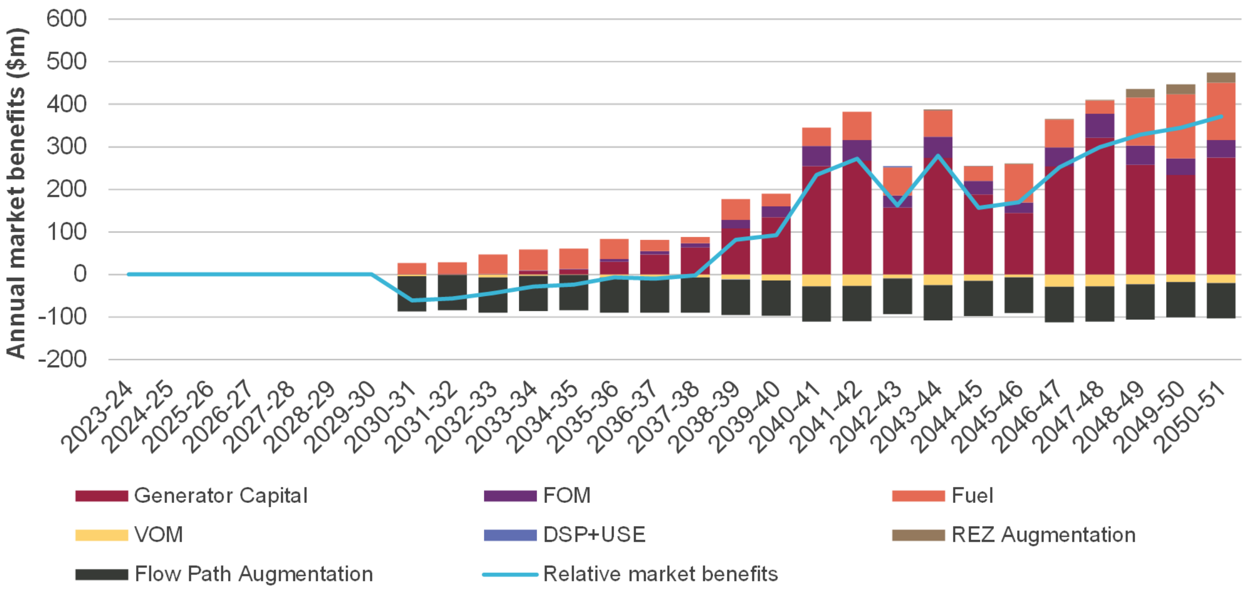
in net market benefits, compared to delivery of the second cable in 2030-31. In *Progressive Change*, delivery of the second cable in 2032-33 results in a reduction of net market benefits of around $230 million. In other words, consumers are better off if the cable can be delivered more cheaply, but a little too early, than just in time, but at a $600 million higher cost.

Figure 4 Relative market benefits associated with Marinus Link's second cable in *Step Change*



Positive values represent an increase in annual net market benefits following the installation of the second Marinus Link cable.

Figure 5 Relative market benefits associated with Marinus Link's second cable in *Slow Change*



Positive values represent an increase in annual net market benefits following the installation of the second Marinus Link cable.

In summary, although the second Marinus Link cable does not always deliver benefits immediately after its construction, the additional $600 million capital cost associated with a delay of more than three years results in the second cable being beneficial within three years of the first cable in all scenarios.

5. *Low Gas Price* sensitivity

Key finding from the Transparency Review Report

"The draft ISP has tested the resilience of the ODP to lower gas prices and states that the ranking of the higher ranked candidate development plans was unchanged. However, in undertaking this sensitivity analysis, in estimating the weighted net benefits across scenarios AEMO has not applied the lower gas price sensitivity in the Hydrogen Superpower and Slow Change scenarios.

We expect AEMO to provide further explanation in an addendum to the draft ISP, of why the low gas price sensitivity has not been applied across all scenarios."

AEMO's response

The Draft 2022 ISP contained an assessment of the impact of lower gas prices across a selection of Candidate Development Paths (CDPs) in the CBA. The subset of CDPs tested was selected due to their importance in determining whether some major projects – Marinus Link, VNI West and HumeLink – ought to be part of the ODP. These projects were selected due to avoided fuel costs representing a material source of their benefits.

Under time constraints to deliver the Draft 2022 ISP, AEMO applied the sensitivity to a limited number of scenarios, given the intended purpose of the sensitivity – to test the robustness of CDPs. Ultimately the sensitivity was only applied to *Step Change* and *Progressive Change*, because

- Following the industry stakeholders' Delphi Panel convened by AEMO, *Slow Change* was allocated a weight of only 4% in the CBA. Furthermore, this scenario has the least amount of gas generation over the period to 2050. Given it has both the lowest scenario weight and lowest volume of gas generation across the scenario collection, it was considered that it would have a more limited impact on the CBA, and that other scenarios should be prioritised.
- Gas generation in the *Hydrogen Superpower* is also lower than in *Step Change* and *Progressive Change* over the period to 2050, given the tighter climate change targets and greater prominence of hydrogen gas turbines. Additionally, this scenario also accounted for just 17% of scenario weighting, and therefore again other scenarios were prioritised.

By applying the *Low Gas Price* sensitivity to *Step Change* and *Progressive Change* (scenarios with relatively greater gas consumption than *Slow Change* and *Hydrogen Superpower*), 79% of the weighted results were influenced by low gas prices. The detailed results of the lower gas price sensitivities (provided in Appendix 6) show that lower gas prices reduce the net market benefits of all CDPs tested, but importantly, do not change the rankings of the higher ranked CDPs. This outcome is similarly expected in the *Slow Change* and *Hydrogen Superpower* scenarios, particularly given that gas generation in those scenarios is lower than that in *Step Change* and *Progressive Change*.