Draft
Budget and Fees FY26

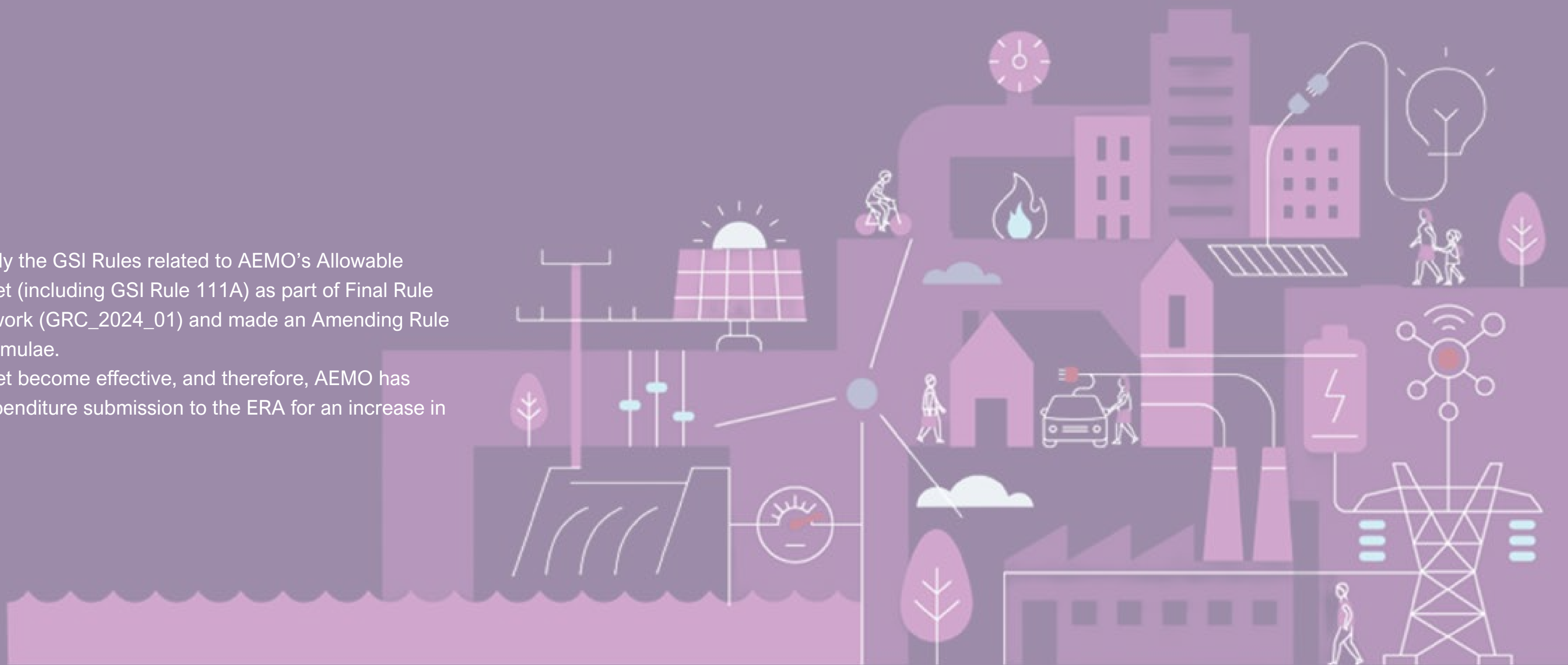
AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

This document sets out AEMO's budgeted revenue requirements and fees for the financial year ending 30 June 2026 (FY26), in accordance with clauses 2.11.3 and S6A.4.2 of the National Electricity Rules, clause 135CF of the National Gas Rules, clauses 1.65 and 2.24 of the Electricity Market Rules (formally the Wholesale Electricity Market Rules) and clauses 111A[1] and 114 of the Gas Services Information Rules.

Included in this document are additional segments which are not funded by market participants via fees. These are included for information, and do not form part of AEMO's public consultation.

The draft FY26 Budget and Fees is presented in nominal Australian dollars, net of goods and services tax and amounts have been rounded to the nearest hundred thousand dollars, unless otherwise stated. Financials are presented consistent with management segments and have been prepared consistent with generally accepted budgeting principles.

[1] The Coordinator has made a final decision to disapply the GSI Rules related to AEMO's Allowable Revenue and Forecast Capital Expenditure and Budget (including GSI Rule 111A) as part of Final Rule Change Report – AEMO's Allowable Revenue Framework (GRC_2024_01) and made an Amending Rule allowing GSI Fees to be increased by an approved formulae.
However, the Coordinator's Amending Rule has not yet become effective, and therefore, AEMO has made an Allowable Revenue and Forecast Capital Expenditure submission to the ERA for an increase in GSI Fees by the approved formulae.



Foreword

AEMO, the Australian Energy Market Operator, independently manages the day-to-day operation of Australia's electricity and gas networks and markets.

AEMO works in the long-term interests of consumers by planning and operating energy systems to ensure that Australians have safe, reliable and affordable energy.

As an independent, not-for-profit company with membership comprising state and territory governments, the Australian Government and energy industry participants, AEMO's work is primarily funded by consumers, via fees paid by market participants.

Today, with Australia's energy systems going through the most fundamental change since the NEM was established, AEMO is being asked to do more. For example, in recent years AEMO has been asked by governments to play a stronger role in ensuring reliability on the east coast gas network, expanding the scope of the Integrated System Plan and to coordinate with industry to prepare for and respond to cyber security incidents.

While some of this work has placed a strain on resources, AEMO's core operating costs have remained stable, reflecting labour and indexing increases but demonstrating our strong focus on prudency and cost management.

Other work the company has been asked to undertake has been provided on a fee for service basis. Our work facilitating investment on behalf of state and federal governments is funded directly through arrangements put in place with the relevant jurisdiction. Similarly, the substantial work AEMO does with proponents and transmission network service providers to enable new energy generation and storage assets to connect to electricity grids, is funded directly by the participant connecting the asset.

AEMO will always prioritise our core operational and planning responsibilities. However, where work is better conducted by government or industry, AEMO has sought to transfer those roles to the most appropriate organisation. An example of this is the upcoming transfer of Victorian transmission network services to the Victorian Government's VicGrid agency.

AEMO's board and management are committed to further improving trust and transparency with industry. We understand that to achieve this must continue to exercise financial discipline through prudency and efficiency.

Improved transparency will be built through a continued focus on engagement. We do this through regular engagement with the Financial Consultation Committee and broad consultation on our annual budgets and fees.

In FY26 we will commence an upgrade to our core digital systems. This program of work is funded by the Australian Government and will enhance energy security and reliability.

AEMO has matured its financial management in recent years, and by the end of FY25 will return to a balanced financial position in our NEM Core financial segment. This follows consultation in 2022 to raise the NEM Core fee and we have been exercising prudency and carefully managing our costs over the three-year period to deliver on our commitment.

Thank you for your interest in AEMO's budget and fees. Your input will help AEMO's work in enabling the energy transition for the benefit of all Australians.

Daniel Westerman
AEMO Chief Executive Officer

Table of contents

1. Our priorities at a glance

In FY26, we will continue to organise our efforts around our four strategic priorities. The initiatives within the four strategic priorities will ensure that we deliver our core obligations and responsibilities, while preparing for the energy systems and markets of the future as the energy transition occurs. This budget and investment program reflects these priorities. The proposed FY26 initiatives are part of a Corporate Plan consultation and will be finalised by the end of June 2025. Current strategic priorities are available in our FY25 Strategic Corporate Plan.

1 Operating today's systems and markets

Operates secure and reliable energy system and markets

- Strengthen operational readiness by modernising technology systems and tools, enhancing operational capabilities and processes to manage emerging power system risks.
- Effectively manage known and emerging power system risks, including improving modelling, streamlining procedures and managing emerging risks.
- Improve cyber preparedness and resilience across AEMO and markets.
- Modernise and uplift AEMO's core digital systems to enhance their effectiveness and reliability.

2 Navigating the energy future

Plans and enables critical infrastructure delivery and market reforms

- Evolve energy system planning advice and reliability outlooks with a focus on CER, gas, and investment signals.
- Plan and report on emerging challenges through delivery of Engineering Roadmap priority actions, and future power system modelling strategy initiatives.
- Onboard and connect new generations efficiently.
- Plan and procure investments through jurisdictional services including tenders.
- Establish a national consumer energy resources (CER) taskforce roadmap, support stage 2 gas reforms, and develop framework for addressing gas supply shortfalls in the East Coast.

3 Engaging our stakeholders

Enhance relationships and trust with governments, industry and consumers

- Work closely with our stakeholder on each of our strategic work programs to build awareness, understanding, confidence and support for the actions needed to effectively and efficiently progress the energy transition
- Continue to build the capability and understanding of energy systems and markets with industry, consumers and governments through our Energy Education program
- Expand the reach and improve the accessibility and effectiveness of AEMO's communication by simplifying language, reaching through the right channels and exploring new ways to communicate.

4 Evolving the way we work

Modernise systems, uplift capabilities and optimise operating model

- Deliver on the commitments in the Reflect Reconciliation Action Plan (Reflect RAP).
- Uplift and enable capabilities for AEMO core and corporate functions, enabled through modern technology and systems.
- Optimise AEMO's operating model by simplifying how we work and implement best practice across AEMO.

Figure 1. A selection of AEMO's proposed FY26 priorities

2. Budget overview

AEMO is a not-for-profit organisation, operating on a full cost-recovery basis. We carry out functions that have been conferred on us under energy laws and rules and have a statutory right to recover our costs for doing so, which are allocated to the market participants or stakeholders who benefit from those services. For the majority of functions AEMO develops a revenue requirement which we consult on and translate to participant fees. AEMO also has additional functions which are subject to other cost recovery mechanisms and oversight.

AEMO's budget reflects the costs associated with the functions and services it provides for each of the segments in which it operates, and the revenue requirements (realised through fees and charges) to fund this work as well as delivering AEMO's corporate priorities and initiatives.

At AEMO, we prioritise strong financial and program governance to ensure financial stability, stakeholder trust and a maintain a strong licence to operate. Our annual budget is one of the ways we provide transparency over our costs.

AEMO's FY26 budget reflects our committed program to deliver on our core functions and responsibilities and our strategic priorities, outlined in the Strategic Corporate Plan. It also reflects the growing complexity of our work and new regulatory responsibilities AEMO has been asked to perform.

The draft budget is shared with AEMO's Financial Consultation Committee (FCC), which considers and provides feedback as AEMO refines its budget, fees and corporate plan priorities.

Stakeholders are also invited to consider the draft budget as part of a broader consultation exercise prior to its finalisation.

2.1. How the budget is developed

AEMO prepares an integrated annual operating and investment budget to outline the work we will deliver in the upcoming year. This is based on the work we will deliver in the year ahead.

The budget is developed by AEMO's Strategic Finance team, working closely with business leaders throughout the organisation. Our goal is to forecast costs as accurately as possible to inform the required fee and revenue requirements for the year ahead. AEMO's Strategy team, Strategic Finance team and Enterprise Program Office collaborate to ensure activities and investments are cost-effective and balanced against broader enterprise priorities. AEMO's executive leadership team and the Board review the draft budget, ensuring alignment to AEMO's priorities, and challenging costs and efficiency.

Using the available information, AEMO's Strategic Finance team produces a draft operating budget for each market segment and an investment plan. The budget adheres to AEMO's financial principles (see below).

- Efficient and cost-effective delivery
- Balanced and sustainable cost recovery
- Clear, ringfenced participant and member funds
- Funding pathways for new investment
- Low tolerance for funding risk on contracted activities
- Debt-to-assets ratio <100%
- Liquidity ratio >50%
- Budget to market participants in a timely way

Figure 2. AEMO's financial principles

AEMO's market segments and fee structures

AEMO's annual budget is comprised of distinct financial segments, which are aligned with our sources of funding. The majority of AEMO's financial segments are funded by fees paid by registered market participants, however, an increasing portion of AEMO's activities are directly funded by state and federal governments and via fee-for-service arrangements.

Financial segments that are funded by market participants have associated fee structures. These fee structures determine how the revenue requirement is divided among different types of registered participants and on what basis the fees are calculated. For example, fees may be allocated based on units such as dollar rate per megawatt hour or dollar rate per National Metering Identifier.

Fee structures typically apply for a period of three to five years, set through a public consultation process. This ensures that our approach is transparent, fair, and takes stakeholder input into account.

AEMO has prepared the budget on the basis that the Vic TNSP transmission planning and associated declared network functions will be transitioned to Vic Grid from 1 July 2025.

Open fee structure consultations

AEMO is currently conducting consultations on the fee structures *Cyber Security Roles and Responsibilities*. This is expected to be implemented on **1 July 2025.**

Separately, AEMO is currently conducting consultations on the fee structures for *NEM* fee structure which is set to take effect on **1 July 2026**. Participants are invited to contribute to the consultations. For more information on the consultations and the processes, please email reformdevelopmentandinsights@aemo.com.au

Separate budget and fee process

While AEMO's overall budget is developed annually there are certain functions and services for which revenue requirements and fees are set at an earlier date or through other processes. These processes are consistent with relevant regulations and the rules governing electricity and gas markets.

The following functions are subject to separate budget and fee setting processes:

- **NEM Core fees for Transmission Network Service Providers,** which AEMO is required to provide by 15 February each year.
- **National Transmission Planning** fees **for Coordinating Network Service Providers**, which AEMO is required to provide by 15 February each year.
- **Budget and fees for Western Australia's (WA) WEM and GSI functions**, which are regulated and subject to their own fee setting processes.
- **Cost recovery activities** associated with services AEMO has been contracted to provide.

Changes from FY25 budget

From FY26 AEMO's budget no longer includes the Vic TNSP segment, as AEMO's transmission planning and associated declared network functions in Victoria will be transferred to Vic Grid from 1 July 2025

2.2. AEMO's market segments

Market fees-funded segments	Segment[2]	Incorporates	Funding source/s	Consultation
	**NEM Core**	Safely, reliably, and securely operating the NEM.	NEM participants via fees.	Budget and fees
	NEM Functions	The operation and evolution of the NEM, including National Transmission Planning (NTP), implementing reforms, facilitating retail market competition, consumer/distribution energy resources integration, cyber security coordination and other functions.	NEM participants via fees.	Budget and Fees
	**East Coast Gas**	The operation and evolution of the East Coast Gas Markets.	East Coast Gas participants via fees.	Budget and fees
	**WA Electricity and Gas**	Safely, reliably, and securely operating the Wholesale Electricity Market (WEM) and perform some functions under the Gas Services Information (GSI) Rules in WA.	WEM participants via fees.	In accordance with WA jurisdictional requirement, set through separate process with Energy Policy WA and Economic Regulation Authority.

Direct funded segments	Segment	Incorporates	Funding source/s	Consultation
	**NEM Connections**	Connections, registrations and onboarding activities in the NEM.	Connecting participants via charges.	Budget and fees. Rates for fee-for-service activities.
	**Other**	Capacity Investment Scheme (CIS), NSW Roadmap, Vic TNSP support and funded upgrade to core systems.	Via contractual or other arrangement with various jurisdictions.	In accordance with jurisdictional requirements.

[2] Refer to Appendix A for a full list of functions included within each segment

2.3. Financial governance and risk management

AEMO's Board is responsible for the overall governance and performance of the company. As an independent system and market operator, we are committed to transparent and accountable financial and risk management.

In carrying out our statutory functions, we have regard to the relevant market objective, such as the National Electricity Objective in the case of the NEM and the National Gas Objective in the case of east coats gas markets.

AEMO has a range of governance mechanisms in place. The roles of each are outlined below.

The Board

The Board oversees AEMO's activities to ensure it meets its responsibilities under relevant laws and rules. The Board monitors the performance and cost-effectiveness of, and risks associated with, AEMO's operations and systems. AEMO's Constitution and Board charter sets out the full role and responsibilities of the Board.

Executive management team

AEMO's executive management team is made up of the CEO and executive general managers for each business division. Executive committees are established around key programs of work and functions. The committees are responsible for overseeing the implementation of strategic initiatives and key programs of work to achieve AEMO's obligations, and to ensure that we are doing so effectively, collaboratively, efficiently and in accordance with our values and compliance obligations.

Finance and Governance team

AEMO's Finance and Governance team is led by the Executive General Manager for Finance and Governance. The team is responsible for establishing, maintaining, and improving AEMO's financial, risk and governance policies, procedures and systems, including financial planning and performance, legal and regulatory obligations, corporate governance standards, and an effective risk and compliance culture. The finance team manages AEMO's finances in line with AEMO's financial principles and budget and publishes a statutory financial report each year.

The Enterprise Program Office provides governance oversight of our investment decision processes and manages performance of inflight programs.

Stakeholders

Stakeholders complement AEMO's governance framework by inputting to our work through many different groups, at different levels of participation. Stakeholder input helps us to do our work more effectively, to implement reforms more seamlessly, and to deliver better outcomes. Our stakeholder engagement groups vary in their focus from strategic input, to sequencing delivery, budget, and expenditure, and to more detailed planning relating to integrating reforms and system changes.

3. Segment budget summaries

3.1. NEM Core

Purpose

Keeping the NEM operating safely, reliably, and securely is AEMO's core work. This includes:

ensuring power system security and reliability.

- markets operation and systems.
- wholesale metering, settlements, and prudential supervision.
- near-term energy forecasting and planning.

Read more about what AEMO does in this segment by referring to Appendix A: Functions within market segments.

Who pays for these services

Registered market participants: market customers, wholesale participants, and Transmission Network Service Providers (TNSPs).

Fee structures that apply

- Electricity Fee Structures: March 2021

Segment health

AEMO has steadily matured its financial management and governance over the past three years, and we are pleased we will achieve full recovery of the NEM core accumulated deficit in FY25 and return to a balanced financial position from FY26, as committed to stakeholders.

Over the last three years we have carefully managed costs. The annual revenue requirement must accurately recover AEMO's costs to safely, reliably, and securely operate the NEM. Essential investments in our operations, operating technology and *Engineering Roadmap* are required to ensure that we can continue to maintain reliable energy supply, while managing the growing complexity and dynamics of the NEM.

Table 1 NEM Core profit and loss summary FY26

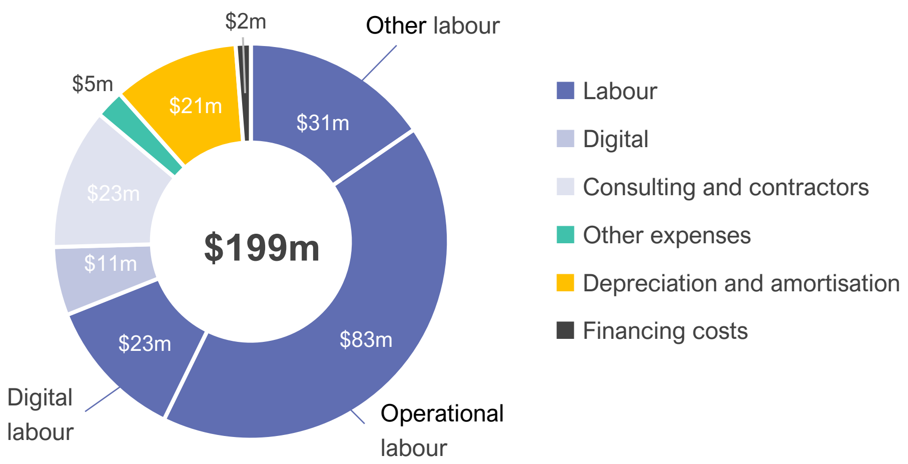
	Budget FY25 $m	Budget FY26 $m	Variance $m	Variance %
Gross revenue	231.5	227.6	(3.9)	(1.7%)
less: Recoverable costs	(15.8)	(0.5)	15.3	(96.7%)
Net revenue requirement	215.7	227.1	11.4	5.3%
Operating costs	210.0	199.3	(10.7)	(5.1%)
less: Recoverable costs	(15.8)	(0.5)	15.3	(96.7%)
Net operating costs	194.2	198.7	4.5	2.3%
Annual surplus/(deficit)	21.5	28.4	6.9	N/A
Accumulated surplus/(deficit)	-	38.5	38.5	N/A

Consists of NEM Core revenue requirement and other revenue

^ Recoverable costs in FY25 included ARENA funding associated with engineering roadmap. Other recoverable costs relate to provision of services for which costs are directly recovered from participants.

NEM Core operating expenditure

Chart 1. Budgeted net operating cost profile for NEM Core FY26 ($m)



Increasing operational complexity

Increasing operational complexity is driving increases in the NEM Core budget in FY26, primarily through labour, digital costs and depreciation and amortisation.

The transformation of the NEM is materially impacting the complexity and volume of work operating it. Day-to-day, AEMO's operations team is maintaining energy reliability and security in the most challenging conditions. Record renewable contributions, record minimum demands, and other new challenges are posing higher operational risks that require more and deeper data analysis and modelling, ongoing risk analysis and planning, procedural revisions and increased resourcing to ensure we are prepared and can respond.

In addition to system changes, the integration of market reforms also drives changes to operating processes and procedures on an ongoing basis.

These changes mean that AEMO needs to invest in appropriate people resources to ensure we can prepare and respond to the changing system and market. We must also fulfil our responsibility to maintain contemporary, reliable, secure digital systems that can respond to our evolving and growing role, changing market conditions and the system and market changes occurring as a result of the transition.

This work is cross-functional and requires the support of our digital, project, program management, governance and corporate teams.

Engineering future energy systems

In FY25 the Australian Renewable Energy Agency (ARENA) continued its 18-month funding to accelerate the activities recommended in AEMO's NEM *Engineering Roadmap to 100% Renewables*. From FY26, the responsibility for funding *Engineering Roadmap* activities transfers fully to AEMO and will be recovered through NEM Core fees. AEMO is committed to a minimum investment of $20.0 million in implementing *Engineering Roadmap* activities in FY26. This reflects our ongoing commitment to identify and remove the obstacles to the power system being able to operate at times of 100% renewable generation.

Modernising business systems

AEMO continues to evolve its corporate system architecture to ensure we can operate efficiently and be flexible and agile to manage the complex system of the future. For example, during FY25 AEMO developed a new enterprise resource planning (ERP) system to streamline procurement, reporting, time sheeting, project and expense management. Costs for this program and others like it will be dispersed to operating costs proportionally to each segment as the systems go into use and will attract software-as-a-service costs for system licenses.

Depreciation, amortisation and financing cost increases reflect delivery of the operational and corporate projects (primarily digital lifecycle projects), which are financed by AEMO in the first instance and are repaid over a period of time through collection of revenue from market participants.

Labour and consulting

Our investment in labour and consulting reflects the need to manage the complexity mentioned above. AEMO uses consultants to provide independent expert advice on best practice.

Our labour inflation is aligned to AEMOs enterprise agreements.

Other expenses

Other expenses in NEM Core primarily reflect costs associated with insurance costs, subscriptions and research data, office accommodation, employee travel, recruitment and training.

Revenue requirement and fees

AEMO will clear the accumulated deficit in NEM Core by the end of FY25, as promised to stakeholders. The revenue requirement for NEM Core for FY26 is $224.8 million, reflecting a continuation of the 4.5% annual increase in the NEM Core benchmark fee, which is lower than the expected 6-8% longer term fee trajectory and small increase in anticipated forecast energy volumes. In the year ahead AEMO will continue to accelerate our operations and engineering activities to ensure we continue to provide secure and reliable energy to Australians.

Refer to 5.1 National Electricity Market (NEM) Core fees for the revenue requirement and associated fees for this segment.

Operating technology program

The transition towards renewable energy, decentralised grids and increasingly complex real-time market dynamics has placed greater demands on AEMO's operational teams and system capabilities.

Managing power system security, responding to critical incidents, and ensuring market stability require more agility, advanced analytics and seamless coordination than ever before. In the past 12 months AEMO's control room operators have experienced an increased number of outages and alarms, and phone calls with transmission network service providers and market participants have risen more than 40 per cent.

At the same time, legacy systems and complex processes are making it harder for AEMO's operations teams to operate efficiently, adding to the strain.

To address these pressures, AEMO is investing in operational technology to enhance efficiency and automation, and ensure critical risks are mitigated. The Operations Technology Program (OTP), launched in 2022, is an ongoing piece of work to address power system risks, the *Engineering Roadmap*, integration of market reforms, and emerging challenges in system operations.

Expected benefits

- Our Real Time Operations (RTO) operators in AEMO's control rooms will see a step change in support, tooling, user interfaces, and system usability and adaptability.
- Modelling and scheduling engineers will be supported by new technology that improves system monitoring and simulation capability, increasing visibility of real-time and forecasted system positions, resulting in better decisions and market outcomes.
- OTP will integrate consumer energy resources (CER) into AEMO's core systems and processes and will create new tools specifically for CER management. This will be a fundamental uplift for incident analysis, problem identification and rectification, and compliance monitoring.
- OTP will also deliver a range of improvements to data management, forecasting, and gas operations while executing our significant foundational projects like the NEM and WEM Energy Management System Upgrade and Short-Term Projected Assessment of System Adequacy (ST PASA) replacement projects.
- Enhancements to the OTP program will introduce structured tracking mechanisms that enable each project to be evaluated on its impact in reducing the likelihood or consequences of potential risk incidents. This approach ensures that every initiative under the OTP contributes to decreasing overall risk ratings by directly addressing key operational challenges and enhancing system resilience.

3.2. NEM Functions

Purpose

AEMO performs several functions and services to support the operation and evolution of the NEM, including:

- National Transmission Planner (NTP)
- 5 Minute Settlements and Global Settlements (5MS/GS)
- trading in Settlements Residue Auction (SRA)
- management of the NEM Reform Program
- facilitation of retail market competition
- provision of a consumer data platform
- planning the integration of Consumer/Distributed Energy Resources into the NEM
- Cyber security roles and responsibilities.

Read more about what AEMO does in this segment by referring to Appendix A: Segment, function, and function purpose.

Who pays for these services

Registered market participants: market customers, wholesale participants and TNSPs.

Fee structures that apply

- Electricity Fee Structures: March 2021
- Structure of Participant Fees for AEMO's NEM2025 Reform: October 2023
- Structure of Participant Fees for the Consumer Data Right Declared NEM Project: June 2023

Segment health

Table 2 NEM Functions profit and loss summary FY26

	Budget FY25 $m	Budget FY26 $m	Variance $m	Variance %
Gross revenue	166.8	220.3	53.5	32.1%
less: Recoverable costs	(1.0)	(1.0)	(0.0)	2.4%
Net revenue requirement	165.8	219.3	53.5	32.2%
Operating costs	168.0	182.1	14.1	8.4%
less: Recoverable costs	(1.0)	(1.0)	(0.0)	2.4%
Net operating costs	167.0	181.1	14.1	8.5%
Annual surplus/(deficit)	(1.2)	38.1	39.3	N/A
Accumulated surplus/(deficit)	(15.8)	20.5	36.3	N/A

*FY25 budget operating costs increased by $4.7m, to incorporate cyber security response market coordination activities into NEM Functions segment.

NEM Functions operating expenditure

Chart 2. Budgeted operating cost profile for NEM Functions FY26 ($m)

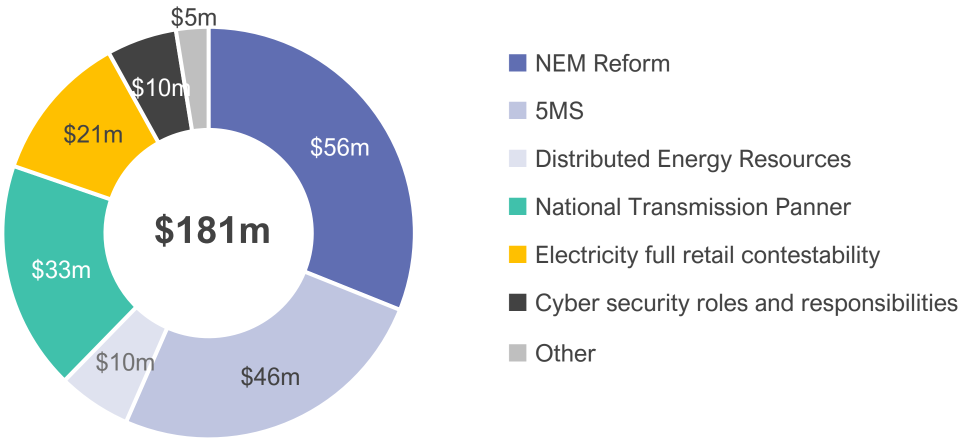
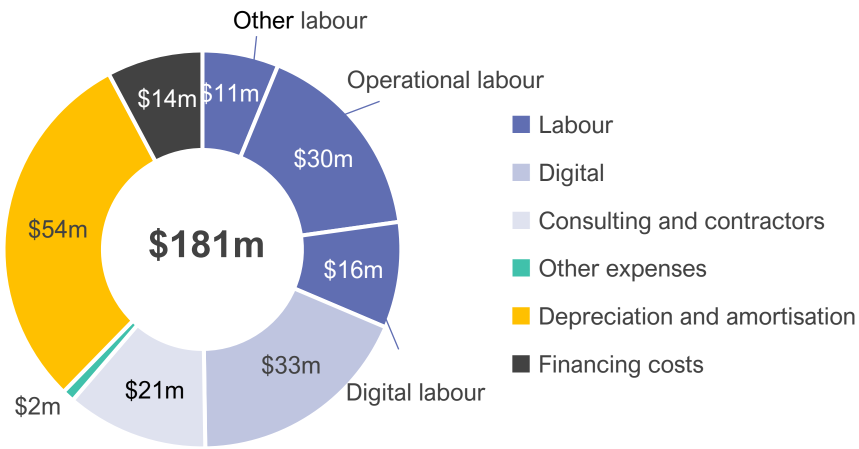


Chart 3. Budgeted operating cost profile by function



NEM market reforms

In line with the NEM Reform Implementation Roadmap, in FY25 AEMO's Reform Program delivered several key projects, including the commencement of non-financial operations of Frequency Performance Payments (FPP) and Retail Market Improvements (Net System Load Profile and Metering Substitutions). The final release for FPP rule commencement and SCADA Lite service operation will be delivered in Q4 FY25.

A number of projects are in flight during FY25, including the ST PASA Procedure and Recall Period Project, Enhancing Reserve Information Project, which are due to be completed in FY26.

National Transmission Planning

In its role as the national transmission planner, AEMO undertakes the forecasting, modelling and planning required to support the energy industry and government to make cost-effective and coordinated energy investment that delivers energy to consumers at least cost.

This work culminates in a suite of plans and reports that AEMO produces for use by industry, government, and consumers. Chief of these is AEMO's biennial *Integrated System Plan* (ISP), which provides a whole-of-system blueprint for developing future energy infrastructure, identifying the most cost-effective approach to meet system needs over time, and triggering investment in strategic transmission infrastructure that is robust, justified, and coordinated.

AEMO's revenue requirement for performing its NTP role in FY26 is $35.2 million, which is an increase from $30.4 million in FY25. This increase reflects:

- the estimated costs of the work required to develop the 2026 ISP, which has an expanded scope, as endorsed by the Energy and Climate Change Ministerial Council (ECMC) in March 2024.
- recovery of some costs incurred by AEMO in FY25 for preparing the 2026 ISP, which were not fully recovered in FY25.

- the estimated costs of meeting new Australian Energy Market Commission rules (rule ERC0395 and rule ERC0396) in the development of the ISP, including integration of the impact of gas supply on electricity requirements and improving consideration of demand-side factors that can influence the identification of the optimal development pathway.
- additional costs for preparing the new annual Enhanced Locational Information report, a deliverable of an ECMC requirement to provide participants in the NEM with better information on the optimal location for new investments to inform decisions about where to locate projects in the NEM.

Digital costs, labour costs (including a proportion of central support function roles) and consulting costs are also included. Wage and consumer price index increases have been applied to these costs.

Cyber security roles and responsibilities

On 12 December 2024, the AEMC published a final determination and final rule to formalise and clarify AEMO's cyber security coordination responsibilities in the National Electricity Rules (NER) to enable AEMO and the energy industry to prepare for and respond to cyber security incidents[3]

These responsibilities include:

- planning and coordinating the NEM-wide response to cyber incidents.
- supporting industry preparedness and uplift.
- examining risks and providing advice to government and industry.
- distributing critical cyber security information to industry participants.

For FY26, AEMO proposed a $14.7 million revenue requirement, accounting for costs to perform the function in the budget year as well as addressing the cost incurred in FY25 but not recovered.

AEMO is consulting on the fee structure for this function and anticipated publication of final determination by 30 June 2025. For this reason, we will share the applicable fees in the final release of this document.

3 AEMO is engaging with the Commonwealth and state and territory jurisdictions on establishing equivalent cyber related roles and responsibilities across the gas and WA wholesale electricity markets and these would be subject to separate and distinct consultations.

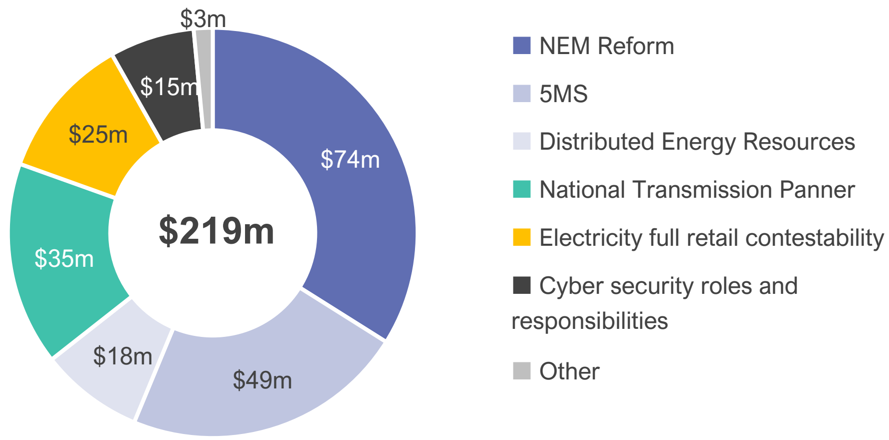
Revenue requirement and fees

The segment net revenue requirement is proposed to increase by $53.5 million in FY26, to account for the following:

- year one cost recovery from the security roles and responsibilities function ($14.7 million)
- Distributed Energy Resource ($11.9 million) and NEM2025 ($10.6m million) revenue requirements to reflect full operational cost and recover prior period deficits. As planned and previously communicated to market participants, NEM2025 recovery of accumulated deficit commenced in FY25 over a two-year period
- 5MS revenue requirement ($6.7m) following return of accumulated surplus in FY25 and a reflection of operational costs, and
- increase in NTP revenue requirement ($4.9 million) as FY25 fees included only a portion of the anticipated costs for the potential increased scope of the ISP.

Refer to 5.2 NEM Functions fees for the revenue requirement and associated fees for this segment.

Chart 4. Budgeted revenue profile by function



MITE(Y) helpful changes at AEMO

In 2022, AEMO identified a subset of critical initiatives as prerequisites to support the effective implementation of many upcoming reforms.

These initiatives, known as the Market Interface Technology Enhancements (MITE) aim to uplift core market interfacing technologies to create a more secure, efficient and streamlined digital interface between AEMO and market participants.

Given the complex and inter-dependant nature of these platforms in underpinning reforms, a collaborative approach is fundamental. AEMO and industry agreed that a foundational uplift – rather than piecemeal, incremental changes would be the most effective and efficient way to implement these essential platform upgrades.

These foundational capabilities can then be leveraged across all markets and fuels, which results in more cost-effective operations for AEMO and industry. MITE consists of three core initiatives:

Industry Data Exchange (IDX), a unified mechanism to authenticate and authorise external identity and entitlements when accessing AEMO services, consolidating and improving overall cyber security controls.

Identity and Access Management (IDAM), a unified data exchange mechanism to support the secure and efficient exchange of data between AEMO and participants that supports existing services, new services required by NEM Reforms and can extend to other energy markets.

Portal Consolidation (PC), an entry point to AEMO's externally facing web presence, with consistent identity, UI standards, help access and menu navigation. Initially this will support the new web pages being developed for IDAM and IDX, and 6 (out of 16) of AEMO's legacy web hosted services will be migrated to it.

By modernising these systems, AEMO can ensure a stronger digital foundation for the NEM and WEM, whilst supporting current market needs and preparing for future reforms.

Industry collaboration at its core

AEMO has worked closely with stakeholders to assess the costs, benefits and design options associated with these projects, ensuring the solutions address industry needs and are appropriately scoped for delivery.

Since 2023, collaboration has involved:

- 1,000+ hours of workshops and technical discussions to shape the program
- continuous engagement with market participants to provide for deliverability and benefits to industry and end consumers.
- industry endorsement of the MITE business case at the NEM Reform Executive Forum in March 2024.

Through this approach, we have developed the foundational capabilities in IDAM, IDX and PC now, while enabling further industry engagement on the transition of legacy business services to IDX.

AEMO recognises and thanks all stakeholders for their invaluable contributions. Continued collaboration will be key as we refine plans and move toward implementation.

3.3. East Coast Gas

Purpose

AEMO performs several functions relating to the East Coast Gas markets, including:

- operating the Victorian Declared Wholesale Gas Market (DWGM) and Declared Transmission System
- operating the Short-Term Trading Market (STTM)
- operating the Gas Supply Hub (GSH), and day ahead auctions (DAA), and Capacity Trading Platform (CTP)
- facilitating retail market competition
- developing the Gas Statement of Opportunities (GSOO)
- administering change proposals for the Operational Transportation Service (OTS) Code
- monitoring and managing East Coast Gas System (ECGS) supply adequacy and operating the Gas Bulletin Board (GBB).

Read more about what AEMO does in this segment by referring to Appendix A: Functions within market segments.

Who pays for these services

Participants in this segment include wholesale market participants in the DWGM and STTM, trading participants and auction participants, retail market participants, and gas bulletin board production facility operators.

Fee structures that apply

- Structure of Gas Participant Fees: December 2023
- GSH Exchange Fees: March 2019

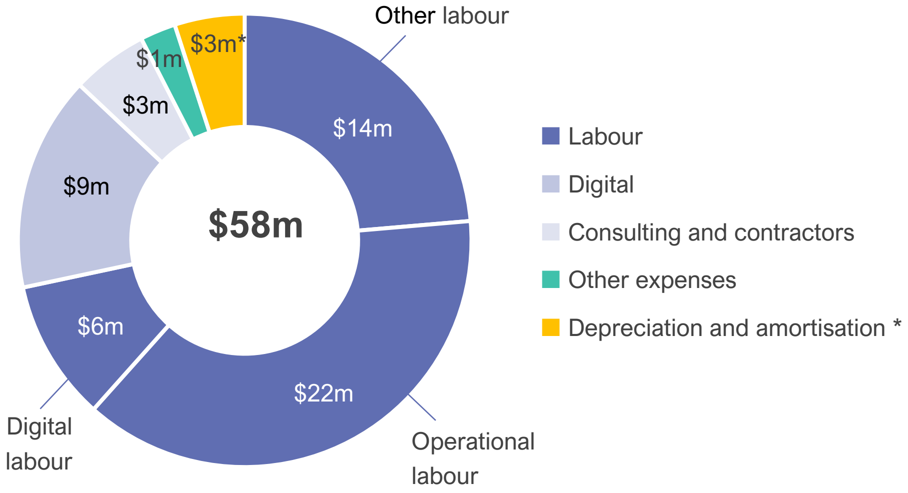
Segment health

Table 3 East Coast Gas profit and loss summary FY26

	Budget FY25 $m	Budget FY26 $m	Variance $m	Variance %
Gross revenue	55.1	60.6	5.5	9.9%
less: Recoverable costs	(8.3)	(10.9)	(2.6)	31.9%
Net revenue requirement	46.8	49.6	2.8	6.0%
Operating costs	59.5	69.4	9.9	16.6%
less: Recoverable costs	(8.3)	(10.9)	(2.6)	31.9%
Net operating costs	51.2	58.4	7.2	14.1%
Annual surplus/(deficit)	(4.4)	(8.8)	(4.4)	N/A
Accumulated surplus/(deficit)	54.1	45.1	(9.0)	N/A

East Coast Gas operating expenditure

Chart 5. Budgeted operating cost profile for East Coast Gas FY26



*Depreciation and Amortisation is shown net of financing income earned on accumulated surplus at the start of FY26 and interest earned on market participant fund associated with settlements.

In FY26, East Coast Gas segment costs increase by $7.2 million compared to FY25, predominantly related to labour, technology costs, depreciation and amortisation.

Declared Wholesale Gas Market (DWGM)

The Victorian DWGM functions drives the largest costs in this segment ($30 million or 54% in FY26). In the budget, AEMO are returning a portion of the accumulated surplus with this function over a period to provide price smoothing effect.

Gas reforms

In August 2022, Energy Ministers agreed to make a range of reforms to support a more secure, resilient and flexible east coast gas market. These actions are designed to enable AEMO to better manage gas supply adequacy and reliability risks to minimise, as far as practicable, the hazards and risks to safety of the public and customers arising from gas supply.

AEMO anticipates making further investment towards stage 2 gas reforms, subject to discussion with the Australian Energy Market Commission (AEMC) and consultation with market participants.

Revenue requirement and fees

Refer to 5.3 East Coast Gas fees for the revenue requirement and associated fees for this segment.

Going green with gas

Gas remains critical to supporting the electricity sector, as Australia transitions to net zero. Flexible gas-powered electricity generation will enable higher rates of renewables and support electricity reliability as Australia's coal-fired power stations retire.

AEMO's annual *Gas Statement of Opportunities* report routinely signals the urgent need for new investment in gas supply to meet demand from homes and businesses, and for gas-powered electricity generation.

In August 2021, Australia's state and federal energy ministers agreed that the national gas regulatory framework be reviewed and extended to accommodate hydrogen, biomethane and other renewable gases. This agreement triggered a number of important reviews of the frameworks that enable the energy markets.

Jurisdictional officials reviewed the National Gas Law (NGL), National Energy Retail Law and National Energy Retail Regulations, the Australian Energy Market Commission (AEMC) reviewed the arrangements in the National Gas Rules (NGR) for hydrogen and renewable gases, and AEMO assessed its market procedures for the east coast gas markets to determine what changes would need to be made to accommodate renewable gases.

In March 2024, the AEMC finalised the National Gas Amendment (Other Gases) rule changes providing regulatory certainty that supports investment in renewable gases, like hydrogen and biomethane, and which will support emissions reductions in east coast gas networks.

Since then, AEMO has been working to enliven these reforms informed by feedback from four separate consultations with stakeholders. Stage 1 of the reform was implemented in May 2024, enabling Victoria's gas market to integrate renewable gases. Stage 2 of the reform, completed in March 2025, extended to Queensland, New South Wales, the ACT, and South Australia.

With these changes now complete, renewable gases are now officially recognised in the gas regulations for the entire East Coast Gas system.

The changes provide gas producers and retailers new opportunities to invest in a more diverse and future-ready energy market, taking Australia another step closer to a cleaner and more resilient energy system.

A number of green gas projects are already planned and in delivery.

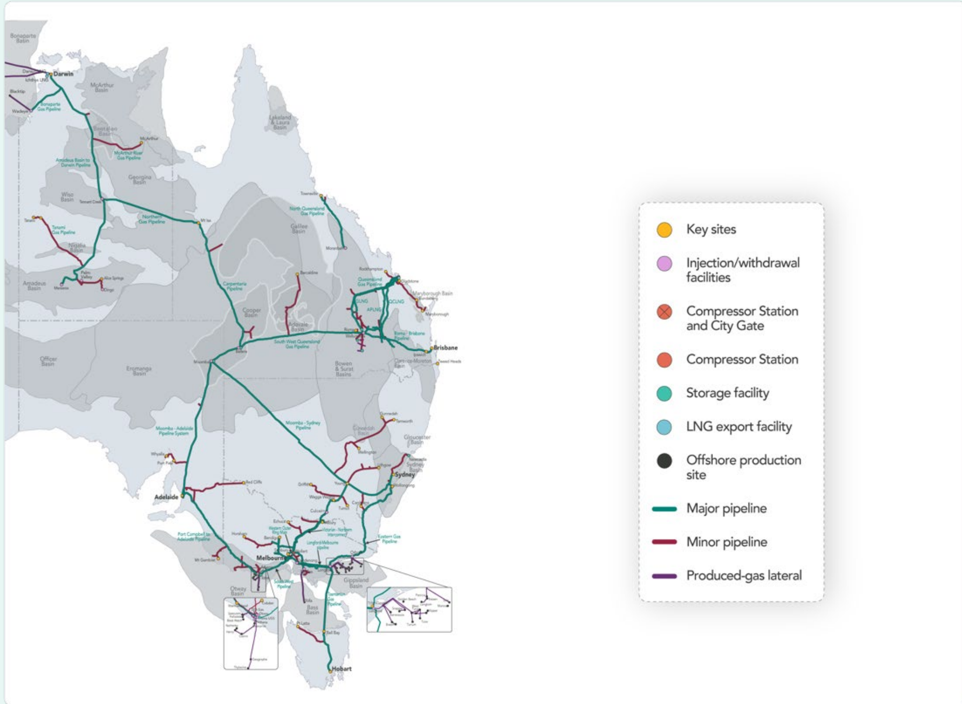


Figure 3. East Coast Gas System

3.4. WA: Electricity and Gas

Purpose

AEMO performs a range of functions for the Western Australia (WA) Wholesale Electricity Market (WEM):

- **market operations:** operating and settling the Reserve Capacity Mechanism and managing the buying and selling of electricity in the Real-Time Market - a gross pool dispatch mechanism for energy and Essential System Services (ESS), and Short-Term Energy Market
- **power system operations**: maintaining the South West Interconnected System (SWIS) in a secure and reliable state, working alongside the network operator (Western Power) and generation facility owners
- **connections and registration**: processing applications for participation, and for the registration, de-registration, transfer, and ESS accreditation of Facilities.
- **procurement:** procuring supplementary capacity, as required, and sufficient ESS to meet the ESS Standards, including via NCESS or the Supplementary Essential System Service Mechanism (SESSM), where needed
- **reform delivery:** managing the WA Reform Program and integration of Distributed Energy Resources (DER) to market mechanisms through the ongoing work on the DER Roadmap.

AEMO also has several functions under the GSI Rules relevant to WA, which include operating and maintaining the Gas Bulletin Board, administering the registration process for gas market participants and publishing the WA GSOO.

AEMO operates the retail market scheme in WA, providing retail market services to gas industry participants, including procedures governing market operation.

Read more about what AEMO does in this segment by referring to Appendix A: Functions within market segments.

Who pays for these services

Participants in this segment include market participants, shippers, production facility operators, distributors.

Fee structures that apply

- Wholesale Electricity Market Rules – Final Rule Change Report (RC_2024_01)
- Gas Services Information Rules – Final Rule Change Report (GRC_2024_01)
- WA Gas Retail Market Procedures.

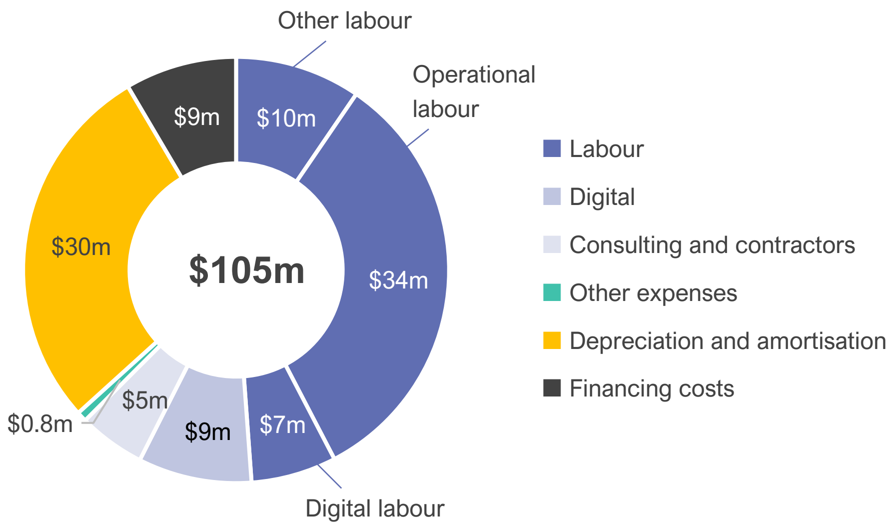
Segment health

Table 4 WA Electricity and Gas profit and loss summary FY26

	Budget FY25 $m	Budget FY26 $m	Variance $m	Variance %
Gross revenue	102.7	102.1	(0.6)	(0.6%)
less: Recoverable costs	-	(0.1)	(0.1)	-
Net revenue requirement	102.7	102.0	(0.7)	(0.6%)
Operating costs	92.8	104.9	12.1	13.1%
less: Recoverable costs	-	(0.1)	(0.1)	-
Net operating costs	92.8	104.9	12.1	13.0%
Annual surplus/(deficit)	9.9	(2.8)	(12.7)	N/A
Accumulated surplus/(deficit)	0.9	(0.6)	(1.5)	N/A

3.5. WA operating expenditure

Chart 6. Budgeted operating cost profile WA Electricity and Gas FY26



General

In WA, AEMO recovers its costs via fees paid by market participants, following an allowable revenue determination by the Economic Regulation Authority (ERA). The current Allowable Revenue (AR) period, AR6, ends on 30 June 2025.

In 2024 AEMO proposed a shift to a revenue framework more suited to a dynamic, shifting energy landscape where AEMO was able to make investments as needed to respond to additional responsibilities and requirements.

Stakeholders who engaged in the consultation on the proposed framework sought an ongoing role for the ERA in assessing AEMO's budgeted costs. Acknowledging the challenges posed by the existing revenue framework and stakeholder feedback, the Coordinator of Energy suspended the Allowable Revenue Framework (ARF), pending its review.

While the ARF Review is underway, for FY26, WEM and GSI fee will be based on the previous Financial Year's WEM Market Fee rate, GSI revenue requirement and WEM Application Fee rate, with 50% adjusted by the annual percentage change in the Wage Price Index (WPI) and the remaining 50% will be adjusted by the annual percentage change in the Consumer Price Index (CPI).

AEMO is committed to continuing transparency and appropriate oversight of its budgets and fees and will continue to engage constructively with all stakeholders to develop an acceptable revenue framework for WA activities.

Visit Energy Policy WA's website for more information. Visit Energy Policy WA's website for more information.

3.6. NEM Connections

Purpose

This segment covers AEMO's connections, registrations and onboarding activities in the NEM, which include:

- assessing and negotiating performance standards to ensure power system security
- providing information on establishing or modifying connections to the transmission and distribution networks in the NEM, including:
  - generating systems
  - customer facilities
- contributing to the assessment of simulation models of power system plant and associated control systems
- commissioning and post-commissioning activities
- registering and onboarding new connecting parties.

Who pays for this service

Connection and registration fees are charged by the connecting/registering market participant.

Fee structures that apply

This is a user-pays function, with fees for service as described in:

- Generator Connection Application Fees (FY25)

As we work with industry to navigate Australia's energy transition, AEMO is committed to ensuring our role in the connection process is responsive, efficient, and predictable for market participants. At the end of February 2025, there were 94 projects in application stage, 105 projects being developed and implemented by proponents (this stage does not involve AEMO), 31 projects in registration (including 10 alterations), and 26 projects in commissioning (including six alterations).

NEM connection and registration tables of fees and rates are included within 5.5 NEM Connections fees.

3.7. Capacity Investment Scheme (CIS)

Purpose

In 2023 the Australian Government engaged AEMO to support the roll-out of the Capacity Investment Scheme (CIS) as an advisor and tender delivery partner, leveraging the capabilities across AEMO Group in energy market design, financial risk management and tender governance and probity. The CIS is designed to attract and accelerate investment in renewable energy infrastructure across Australia to deliver the energy transition.

The Australian Government announced an expansion of the CIS in November 2023. The expanded CIS seeks to incentivise the national deployment of 32 GW of renewable capacity and clean dispatchable capacity by 2030.

AEMO Services is conducting the competitive tender processes that will enable the Commonwealth to determine which projects the scheme should support. Competitive tenders for the expanded CIS are held approximately every six months.

Learn more about AEMO Services' role with the CIS.

Financial information is commercial in confidence.

3.8. NSW Roadmap

Purpose

In 2021, AEMO's subsidiary AEMO Services Limited was appointed by the New South Wales (NSW) Government as the NSW Consumer Trustee, giving it a central role in NSW's energy transition. As the NSW Consumer Trustee, AEMO Services coordinates planning of long-term investment in generation and storage in NSW, designs and conducts competitive tenders to facilitate this investment, undertakes authorisation of Renewable Energy Zone transmission infrastructure, and provides financial risk management and advice. This work is performed in the long-term financial interests of NSW electricity customers.

Learn more about AEMO Services' role as consumer trustee.

Financial information is commercial in confidence.

4. FY26 AEMO group budget summary

4.1. Operating costs by segments

Chart 7. FY26 budgeted net operating costs by segment ($m)

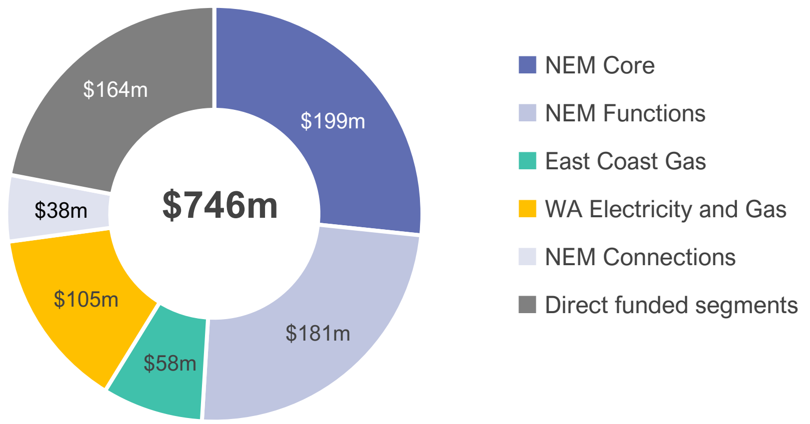
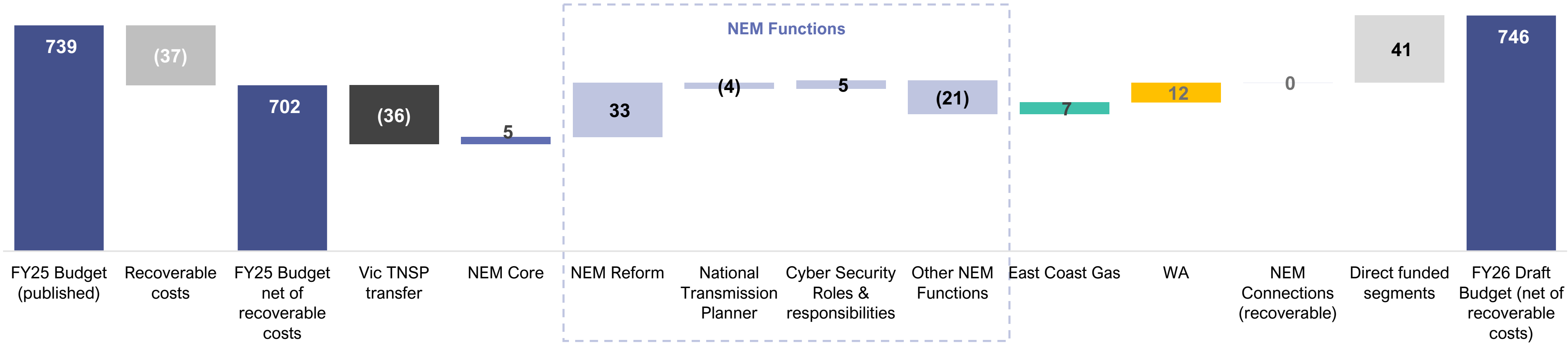


Chart 8. Segment increases in FY26 budgeted net operating costs ($m)

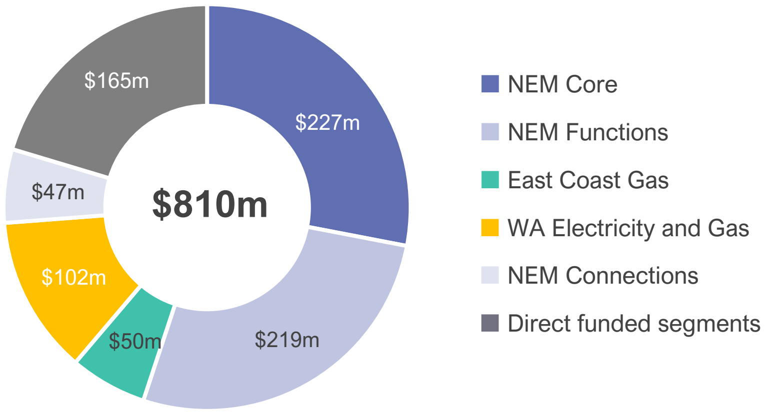


Cost drivers

- **NEM Core:** The underlying costs of operating the energy system and markets and ongoing investment in people, processes and technology, including strategic investment in Engineering Roadmap (previously part funded via an ARENA grant), to prepare for and respond to an increasingly complex operating environment.
- **NEM Functions:** The implementation of market reforms sees capital costs transitioning to operating costs via depreciation and amortisation. Cyber Security roles is a new function commencing 12 December 2024.
- **East Coast Gas:** Costs increases reflect predominantly related to labour, technology costs, depreciation and amortisation.
- **Western Australia:** Costs increases reflect increases in Depreciation and Amortisation (D&A) and Financing costs, technology costs to run WA operations and labour increases aligned to planning the South-West Interconnected System (SWIS) roadmap.
- **Direct funded segments:** Costs for these segments are funded by specific jurisdictional arrangements and relate to facilitating investment in renewable energy and funded upgrade to our core systems.

4.2. Revenue requirements by segments

Chart 9. FY26 budgeted net revenue requirement [operating costs ± surplus/(deficit)] by segment ($m)



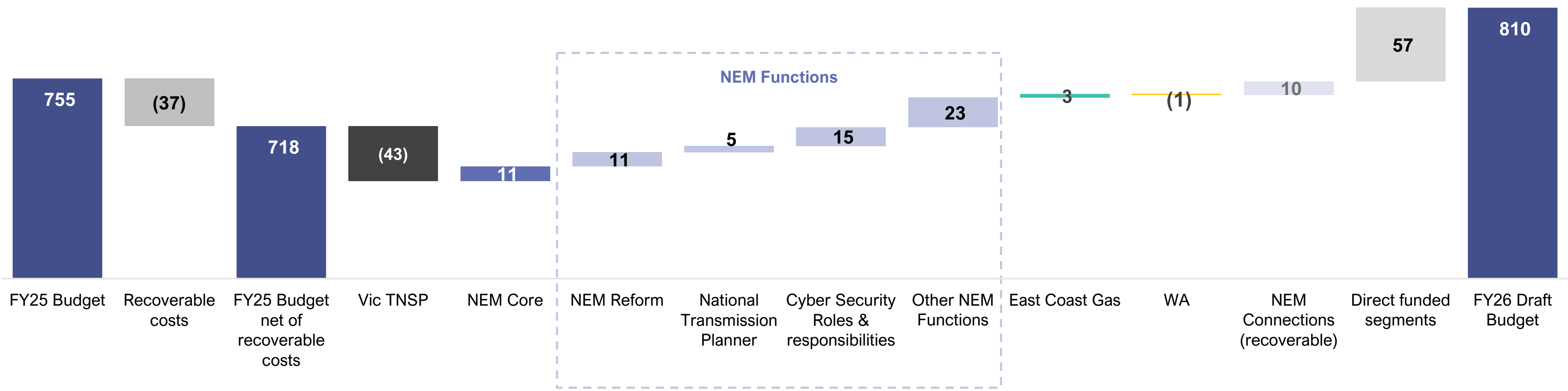
AEMO's annual revenue requirement for a segment may differ from its budgeted operating costs to adjust for a carried forward accumulated surplus or deficit. More information specific to each segment is within the segment summaries.

On 26 February 2025, the Coordinator of Energy (Coordinator) issued Final Rule Change Reports, capped AEMO's revenue requirement for GSI as well as the WEM fees in FY26 at FY25 levels with indexation, while the WA allowable revenue framework is under reviewed.

Direct funded segments reflect funding received under specific jurisdictional arrangements and relate to facilitating investment in renewable energy and funded upgrade to our core systems.

Chart 9 details the FY26 budgeted revenue requirement (operating costs +/- surplus/deficit) by segment ($m)

Chart 10. Segment increases in FY26 budgeted net revenue requirements ($m)



4.3. FY26 profit and loss summary

AEMO's FY26 budget delivers a $26.5m in-year surplus overall. This reflects a full remediation of the accumulated deficit in NEM Core.

Table 5 provides the consolidated profit and loss summary by expenditure categories and Table 6 provides a summary of the profit and loss by segment.

Key changes between FY25 and FY26 are as follows:

- **Fees and tariff /Other revenue**: Reflects the revenue requirement across various segments as discussed within above sections and governmental funding for specific initiatives.
- **VicTNSP function handover**: This affects the net TUoS/Network charges, other revenue and settlement residue sections of Table 5.
- **Labour expenditure, consulting technology costs**: Increases reflect wage growth and requirements to meet requirements within market funded and direct funded segments.
- **Depreciation and amortisation:** Largely aligned to the FY25 pace of investment program, assets retiring at end of their useful life offset by new investment within various market segments.
- **Financing costs**: Financing costs are consistent between years with active debt management and balance between investment spend and recovery through fees.

Table 5 AEMO Group consolidated* profit and loss summary

	Budget FY25 $m	Budget FY26 $m	Variance $m
Revenue			
Fees and tariffs	538.7	602.8	64.1
Other revenue	208.9	191.1	(17.8)
Net TUoS/ Network charges	(43.9)	-	43.9
Settlement residue	7.1	-	(7.1)
Connections revenue	44.5	39.9	(4.6)
Total revenue	755.4	833.8	78.4
less: Recoverable costs	(37.0)	(23.4)	13.6
Net revenue	718.4	810.4	92.0
Operating expenditure			
Labour expenditure	322.1	365.9	43.7
Consulting and contractors	84.1	124.7	40.6
Digital costs	122.7	103.6	(19.1)
General expenses #	34.6	12.9	(21.7)
Depreciation and amortisation	118.1	119.0	0.9
Financing costs	20.7	19.4	(1.3)
Total net operating expenditure	702.4	745.5	43.1
Annual surplus/(deficit)	16.1	64.9	48.9
Accumulated surplus/(deficit)	29.6	112.8	83.2

*AEMO Group includes the consolidation of AEMO Services Limited and TCV in FY25 only.

FY25 budget included $37m recoverable costs reported within General Expenses category, now reported within Net Revenue. Total expenses reported in FY25 budget was $739.4m including recoverable costs.

Table 6 AEMO Group consolidated profit and loss by segment

	Budget FY25 $m	Budget FY26 $m	Variance $m
NEM Core			
Revenue	215.7	227.1	11.4
Expenditure	194.2	198.7	4.5
Annual surplus/(deficit)	21.5	28.4	6.9
Accumulated surplus/(deficit)	-	38.5	38.5
NEM Functions			
Revenue	165.8	219.3	53.5
Expenditure	167.0	181.1	14.1
Annual surplus/(deficit)	(1.2)	38.1	39.3
Accumulated surplus/(deficit)	(15.8)	20.5	36.3
East Coast Gas			
Revenue	46.8	49.6	2.8
Expenditure	51.2	58.4	7.2
Annual surplus/(deficit)	(4.4)	(8.8)	(4.4)
Accumulated surplus/(deficit)	54.1	45.1	(9.0)
WA Electricity and Gas			
Revenue	102.7	102.0	(0.7)
Expenditure	92.8	104.9	12.1
Annual Surplus/(deficit)	9.9	(2.8)	(12.7)
Accumulated surplus/(deficit)	0.9	(0.6)	(1.5)
NEM Connections			
Revenue	44.5	47.4	2.9
Expenditure	45.6	38.4	(7.2)
Annual surplus/(deficit)	(1.1)	9.0	10.1
Accumulated surplus/(deficit)	1.7	9.5	7.8
Other direct funded entities			
Revenue	143.7	165.0	21.3
Expenditure	151.6	164.0	12.4
Annual surplus/(deficit)	(7.9)	1.0	8.6
Accumulated surplus/(deficit)	(11.3)	(0.2)	11.1

4.4. Investing in Australia's energy future

AEMO is investing across four key programs of work, as we prepare the markets and our operating and business systems for a renewable energy future.

A full list of AEMO's major programs and initiatives is available on our website.

AEMO maintains an integrated delivery plan across investment portfolios, with work prioritised, sequenced and optimised by a Portfolio Leadership Team. Wherever possible AEMO seeks to sequence and bundle reform implementation and solutions to reduce overall cost and impacts on industry. In addition, vendor partnerships and panels enable AEMO to streamline delivery capacity and capability.

AEMO will undertake a major core operating system upgrade, spanning several years. This program will be funded by the Australia government.

Steering committees for each portfolio meet monthly to review delivery and budget.

Major programs of work are also subject to consultation with market participants.

AEMO has set a capital expenditure cap of $180m for FY26. Table 7 provides an estimate of expenditure by portfolio, but allocations will be subject to change as programs of work progress through the integrated investment prioritisation and assessment processes.

Table 7 AEMO's FY26 investment plan

	Budget FY25 $m	Budget FY26 $m	Variance $m	Variance %
Reform delivery (NEM and East Coast Gas)	73.9	85.3	11.4	15.4%
WA program	32.1	32.0	(0.1)	(0.3%)
Designing and modernising market operations systems	48.8	38.6	(10.2)	(20.9%)
Modernising business systems	25.2	24.1	(1.1)	(4.4%)
AEMO capital expenditure	180.0	180.0	0.0	0.0%
Project-related operating costs *	38.6	36.9	(1.7)	(4.4%)
Total investment expenditure #	218.6	216.9	(1.7)	(0.8%)

* Project-related operating costs includes items that are SaaS, feasibility studies and costs that are attributed to be operating in nature during the delivery of the investment program. These costs are captured as operating expenditure in the FY26 budget and fees but are shown in this table to provide a more complete picture of project costs.

Investment to enable a reliable and secure energy transition will be funded by government is commercial in confidence and is not included within the above table.

Table 8 AEMO's investment program for FY26

Key program	NEM and East Coast Gas reforms	Western Australia reforms	Operations technology	Business technology
Relevant market segment/s	NEM Functions and East Coast Gas	WA Electricity and Gas	NEM Core and East Coast Gas	Where the benefit is shared across all market segment, costs are allocated proportionately across all segments.
Scope	Delivery and implementation of reforms, including: • NEM Reform Program initiatives, as outlined in the *NEM Reform Implementation Roadmap* • East Coast Gas reforms • initiatives to enable reforms to be integrated and managed • regulatory reform initiatives outside the scope of the two programs above.	Delivery and implementation of: • a new WA Reform program initiatives to continue supporting the energy transition in Western Australia and improve the effectiveness of the WEM. • Enabling the integration of distributed (or consumer) energy resources and new technologies into the SWIS. • Delivering initiatives to implement critical engineering actions from the SWIS *Engineering Roadmap*.	Upgrades to AEMO's operational digital systems and the integration of new and improved operational processes into digital systems, to ensure the continuity of reliable and secure energy supply in an increasingly complex operating environment.	• Modernisation of AEMO's business systems to ensure they are contemporary and support business efficiency, management and transparency. • Cyber security uplifts to address cyber risks and issues. • Digital lifecycle upgrades to ensure AEMO's business systems remain fit-for-purpose.
Projects in planning and execution in FY26	• Industry Data Exchange (IDX) • Identity and Access Management (IDAM) • Integrating Price Responsive Resources (IPRR) into the NEM • Improving Security Frameworks (ISF) • Metering Services Review (MSR) • Flexible Trading Arrangements (FTA) • Shortening the settlement cycle • Project Energy Connect – Market Integration • Portal consolidation • Gas Retail Initiatives (GRI)	• Enhancements to market operations and system frameworks. • Refinements to the Reserve Capacity Mechanism to ensure sufficient capacity. • Integration of Distributed Energy Resources (DER) to support system security and reliability. • Engineering actions required for operating the power system securely and reliably at times of high renewables contribution. • Strengthening digital infrastructure to enhance critical market systems and support ongoing reforms.	• ST PASA • Real Time Systems • Victorian Gas market dispatch systems • East coast Gas system demand forecasting • Victorian Gas operational systems upgrade • Wide area monitoring systems	• Digital annual lifecycle program • Annual cyber program • Minor works annual program • Other corporate systems

4.5. FY26 balance sheet summary

The AEMO FY26 budget continues to remain in a net asset position, reflecting the accumulated surplus and favourable financial performance against operating budget in FY25 across majority of segments.

Cash and cash equivalents include participant compensation funds which are held for the purposes of providing compensation for scheduling errors, and participant security deposits which protect the market from the risk of participant payment defaults.

Current liabilities include participant security deposit liabilities, which also increased for the reasons noted above for cash and cash equivalents.

Borrowings represent drawn debt from AEMO's commercial bank facilities and Australian Medium-Term Notes. The borrowed funds are used to finance capital investment and working capital requirements. A decrease in budgeted borrowings for FY26 reflects capex underspend in FY25, accumulated surplus across most segments and the transfer of Transmission Company Victoria as part of the Vic TNSP function handover to VicGrid anticipated in July 2025.

Consistent with our financial principles, AEMO is committed to achieving a debt-to-assets ratio of under 100% and maintaining a liquidity ratio above 50%.

Table 9 FY26 AEMO Group consolidated* balance sheet summary

	Budget FY25 $m	Budget FY26 $m	Variance $m
Assets			
Cash and cash equivalents	297.0	353.6	56.6
Other current assets	173.0	188.4	15.4
Non-current assets	721.2	697.1	(24.1)
Total assets	1,191.1	1,239.1	48.0
Liabilities			
Current liabilities	453.2	476.4	23.2
Borrowings (non-current)	642.4	587.0	(55.4)
Other non-current liabilities	35.5	30.2	(5.3)
Total liabilities	1,131.1	1,093.6	(37.5)
Net assets	60.1	145.5	85.4
Equity#			
Capital contribution	7.1	7.1	(0.0)
Participant Compensation Fund reserve	10.4	12.0	1.6
Other reserves	13.0	14.3	1.3
Accumulated surplus/(deficit)[1]	29.6	112.0	82.4
Total equity #	60.1	145.5	85.4
Ratios			
Debt / total assets	53.9%	47.4%	(6.6%)
Current assets / Current liabilities	103.7	114.0%	9.9%

*AEMO Group includes the consolidation of AEMO Services Limited and TCV (FY25 only).

Total equity includes non-controlling interest share of $0.7M (FY25) relating to ASL. AEMO has 70% controlling interest in ASL.

[1] $0.8m has been transfer to PCF and Land reserves

4.6. Capital management

AEMO's capital investments and short-term working capital requirements are facilitated through debt financing, which enables capital costs to be applied over the life of the asset.

Due to extensive market reform driving increased capital investment, AEMO's debt has increased over recent years, with the lower balance in FY26 reflecting the repayment of debt funding the VNI-W investment following its transfer.

AEMO is optimising the risk and cost of its capital structure by:

- ensuring adequate working capital and standby liquidity
- undertaking debt refinancing well in advance of maturity to provide optionality
- seeking to diversify tenor and funding sources, as observed through the recent Australian Medium Term Note issue.

4.7. FY26 cash flow summary

AEMO's FY26 budgeted cash flow is shown in Table 10. The decrease in net cash flows from operating activities is due to higher payments to suppliers and employees, partly offset by increased revenue requirements in all segments, particularly in NEM Core and NEM Functions.

Table 10 Table 10: FY26 AEMO Group consolidated* cash flow summary

	Budget FY25 $m	Budget FY26 $m	Variance $m
Receipts from customers and government grants	705.1	810.4	105.3
Payments to suppliers and employees	(526.4)	(607.1)	(80.7)
Net interest and finance costs paid	(20.7)	(30.2)	(9.5)
Other operating cash flows	0	11.4	11.4
Net cash inflows from operating activities	158.0	184.5	26.5
Net payments for intangible assets and property, plant and equipment	(216.0)	(180.0)	36.0
Net cash outflows from investing activities	(216.0)	(180.0)	36.0
Net borrowings	35.9	40.0	4.1
Net cash inflows from financing activities	35.9	40.0	4.1
Net increase/decrease in cash	(22.1)	44.5	66.6

*AEMO Group includes the consolidation of AEMO Services Limited and TCV (FY25 only).

5. Revenue requirements and fees

The tables in this section present the revenue requirement and fees (excluding any applicable GST) that will apply from 1 July 2025 for each function within each energy market.

5.1. National Electricity Market (NEM) Core fees

The NEM Core benchmark fee is proposed to increase by 4.5% in FY26, consistent with the year-on-year step change in operating expenditure including the funding needs of *Engineering Roadmap*, investment into management of increasing operational risk as the energy transition gains momentum. Forecast consumption is estimated to increase in FY26 by 0.7% which has resulted in a higher revenue requirement for the budget year.

The FY26 budget is based on the *Step Change* scenario from the 2024 NEM *Electricity Statement of Opportunities* (ESOO), updated to reflect the latest assumptions on key inputs including large industrial loads, electrification, electric vehicles, and distributed photovoltaics (PV).

In accordance with the National Electricity Rules, AEMO notified its NEM Core Fees for Transmission Network Service Providers on 15 February 2025. Since notification, AEMO continues to further refine its budget and as a result the proposed TNSP allocation ($27.5 million) is lower compared to notified amount ($28.0 million). Based on current practice, AEMO will continue to invoice TNSPs its notified amount and incorporate the difference as part of true-up in FY27 fees.

Table 11 NEM Core revenue requirement and fees FY26

	Budget FY25	Budget FY26	Variance $	Variance %
NEM revenue requirement $m	213.68	224.81	11.13	5.2%
Consumption (GWh)	175,934	177,124	1,190	0.7%
Connection points (Million)	10.82	11.04	0.22	2.0%
NEM fee by participant type				
Market customer fee ($/MWh)	0.29525	0.30854	0.01329	4.5%
Market customer fees ($ per connection point per week)	0.09228	0.09515	0.00287	3.1%
Wholesale participants allocation $m	83.61	87.97	4.36	5.2%
TNSP allocation $m	26.18	27.54	1.36	5.2%
NEM benchmark fee* $/MWh	1.21455	1.2692	0.05465	4.5%
Participant Compensation# Fund $m	NIL	NIL	NIL	NIL

*The NEM benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.
There is no requirement for the participant compensation fund (PCF) to be collected in FY26. The PCF fee applies to scheduled generators, semi-scheduled generators and scheduled network service providers.

Table 12 NEM Core revenue requirement breakdown

Function	Rate $	Recovery basis
NEM unallocated fees (30%)		
Market customers	0.19038	MWh of customer load
Market customers	0.05871	Per connection point per week
NEM allocated fees (70%)		
Market customers	0.11816	MWh of customer load
Market customers	0.03644	Per connection point per week
Wholesale participants	N/A	Daily rate calculated on 2023 capacity/ energy basis
Transmission Network Service Providers	Table 13	Energy consumed for the latest completed financial year

Table 13 Notified NEM Core Transmission Network Service Providers allocation

Function		% allocation of charge	FY26 participant fees ($)	FY25 true-up *	Final FY26 Fees ($)
VIC - AusNet Services	VIC	1.7%	2,653,200	0	2,653,200
TransGrid	NSW	7.4%	11,822,797	0	11,822,797
PowerLink	QLD	6.0%	9,597,647	0	9,597,647
ElectraNet	SA	1.3%	2,030,768	0	2,030,768
TasNetworks	TAS	1.2%	1,903,486	0	1,903,486
Total		17.5%	28,007,898	0	28,007,898

*FY25 true-up is the difference between Draft and Final publication of the AEMO's NEM TNSP fees in February and June 2024.

5.2. NEM Functions fees

Electricity retail market

This revenue requirement includes cost recovery relating to Consumer Data Right (CDR) Reforms.

The proposed FY26 retail market revenue includes a 22.5% increase as part of ongoing effort to normalise revenue after FY23 and FY24, when rates were set lower to return accumulated surplus. This marks the second and final year of the phase adjustment, with full cost recovery expected by the end of the budget year.

Electricity retail market fees apply to market customers with a retail licence.

Table 14 Electricity retail market revenue requirement and fee

	Budget FY25	Budget FY26	Variance $	Variance %
Electricity retail market revenue requirement $m	20.31	24.87	4.56	22.5%
Connection points (Million)	10.82	11.04	0.22	2.0%
Electricity retail market fees ($ per connection point per week)	0.03609	0.04330	0.00721	20.0%

5MS and Global Settlements (GS) compliance (5MS/GS) and IT upgrade

The proposed FY26 5MS/GS/GS revenue requirement includes a 15.8% increase to account for rising operational costs and revenue normalisation, following a lower FY25 rate set to return accumulated surplus.

Table 15 5MS/GS revenue requirement and fee

	Budget FY25	Budget FY26	Variance $	Variance %
5MS/GS revenue requirement $m	42.31	48.99	6.68	15.8%
Consumption (GWh)	175,934	177,124	1,190	0.7%
Connection points (Million)	10.82	11.04	0.22	2.0%
5MS/GS fee by participant type				
Market customer fee ($/MWh)	0.09861	0.11340	0.01479	15.0%
Market customer fees ($ per connection point per week)	0.03082	0.03497	0.00415	13.5%
Wholesale participants allocation $m	7.60	8.82	1.22	16.1%
5MS/GS benchmark fee# ($/MWh)	0.24050	0.27658	0.03608	15.0%

The benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.

Distributed Energy Resources (DER) Integration Program

The proposed FY26 DER revenue requirement includes a 202% increase to full operational costs for the budget year and address a portion of prior year's deficit. As part of FY24 year-end closure and annual accounts process, we identified that costs associated with some DER program projects were not included within the function cost. Although this issue was corrected, the adjustment was not reflected in the FY25 revenue setting, resulting in a deficit that will need to be recovered in FY26.

Table 16 DER revenue requirement

	Budget FY25	Budget FY26	Variance $	Variance %
DER revenue requirement $m	5.91	17.85	11.94	202.0%
Consumption (GWh)	175,934	177,124	1,190	0.7%
Connection points (Million)	10.82	11.04	0.22	2.0%
DER fee by participant type				
Market customer fee ($/MWh)	0.01344	0.04031	0.02687	199.9%
Market customer fees ($ per connection point per week)	0.00420	0.01243	0.00823	196.0%
Wholesale participants allocation $m	1.18	3.57	2.39	202.5%
DER benchmark fee # $/MWh)	0.03359	0.10077	0.06718	200.0%

The fee listed above as a benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.

National Electricity Market (NEM) 2025 Reform Program

The proposed FY26 NEM2025 Reform Program revenue requirement includes a recovery of system establishment cost from go-live date, ongoing cost for the budget year and recovery of the remainder portion of FY24 accumulated deficit. Recovery of the FY24 accumulated deficit has been smoothed over two financial years being FY25 and FY26. As reference, NEM reform participant fee structure is available here. *October 2023 Structure of participant Fees for AEMO's NEM2025 Reform Program*.

Table 17 NEM2025 revenue requirement

	Budget FY25	Budget FY26	Variance $	Variance %
NEM2025 revenue requirement $m	63.48	74.07	10.59	16.7%
Consumption (GWh)	175,934	177,124	1,190	0.7%
Connection points (Million)	10.82	11.04	0.22	2.0%
NEM2025 fee by participant type				
Market customer fee ($/MWh)	0.09679	0.11218	0.01539	15.9%
Market customer fees ($ per connection point per week)	0.05151	0.0589	0.00739	14.3%
Wholesale participants allocation $m	17.46	20.37	2.91	16.7%
NEM2025 benchmark fee # $/MWh)	0.36363	0.41817	0.05454	15.0%

The fee listed above as a benchmark fee is calculated by dividing the total revenue requirement by the total forecast consumption.

National Transmission Planner (NTP)

In line with the NER, AEMO published its *NTP revenue requirement* for FY26 in February 2025. This fee applies to Coordinating Network Service Providers.

Table 18 National transmission planner revenue requirement

	Budget FY25	Budget FY26	Variance $	Variance %
NTP revenue requirement $m	30.35	35.20	4.85	16.0%

Cyber security roles and responsibilities

On 12 December 2024, the AEMC published a final determination and final rule to formalise and clarify AEMO's cyber security coordination responsibilities in the NER to enable AEMO and the energy industry to better prepare for and respond to potential cyber security incidents[4]. These responsibilities include:

- planning and coordinating the NEM-wide response to cyber incidents
- supporting industry preparedness and uplift
- examining risks and providing advice to government and industry
- distributing critical cyber security information to industry participants.

For FY26, AEMO proposed a $14.7 million revenue requirement, accounted for costs to perform the function in the budget year as well as addressed the cost incurred in FY25 but not recovered. The revenue requirement represents costs incurred from 11 Dec 2024 (FY25) and FY26.

AEMO is consulting on its fee structure for this function and anticipated publication of final determination by 30 June 2025. For this reason, we will share the applicable fees in the final release of this document.

Table 19 Cyber security roles and responsibilities revenue requirement

	Budget FY25	Budget FY26	Variance $	Variance %
Cyber security roles and responsibilities revenue requirement $m	NA	14.7	NA	NA

Other budgeted revenue requirements

AEMO also collects revenue to recover the costs of the South Australian planning function, administration of the Settlement Residue Auctions (SRAs) and Consumer Data Platform.

The revenue requirement for South Australian planning for FY26 is set to remain consistent with FY25.

Expenses associated with administration of SRAs are recovered on a cost recovery basis. Budgets and fees are required to be set for three years in advance, with over or under recoveries recovered in subsequent years.

Consumer Data Platform revenue is proposed to decrease in FY26, reflecting cost saving from efficiency gain achieved through the platform amalgamation with CDR.

[4] AEMO is engaging with the Commonwealth and State and Territory jurisdictions on establishing equivalent cyber related roles and responsibilities across the gas and WA wholesale electricity markets and these would be subject to separate and distinct consultations.

Table 20 Other revenue requirement and fees ($m)

	Budget FY25	Budget FY26	Variance $	Variance %
SA planning	1.00	1.00	NIL	NIL
Settlement Residue Auctions	0.78	0.67	(0.11)	(14.1%)
Consumer Data Platform	0.70	0.50	(0.20)	(28.6%)

5.3. East Coast Gas fees

Declared Wholesale Gas Market (DWGM)

The proposed DWGM revenue requirement for FY26 reflects a 10.4% reduction as part of the ongoing phased return of the of accumulated surplus over three years. As a result, the DWGM tariff for FY26 is set 4.9% lower than FY25, driven by both the reduced revenue requirement and a lower consumption forecast for the budget year. The FY26 consumption forecast is based on the *Step Change s*cenario from the 2024 *Gas Statement of Opportunities* (GSOO), updated to reflect changes to forecast assumptions. Final Energy Tariff will be calculated based on the *Step Change s*cenario from the 2025 *Gas Statement of Opportunities* (GSOO).

Distribution meter fee

The distribution meter fee is paid by each market participant connected to a declared distribution system, at a connection point at which there is an interval metering installation.

The distribution meter fee is set to recover the cost relating to metering data services. For FY26, the meter fee is set at $1.55646 per meter per day, which is 0.9% higher than FY25.

Table 21 DWGM revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
DWGM revenue requirement (Energy tariffs) ($m)	11.81	10.58	(1.23)	(10.4%)
Gas consumption (TJ)	213,302	201,074	(12,228)	(5.7%)
Distribution meters (Avg)	1,087	1,086	(1)	(0.1%)
DWGM variable fees				
Energy tariff ($/GJ withdrawn)	0.05535	0.05262	(0.00273)	(4.9%)
Distribution meter ($/day per meter)	1.54196	1.55646	0.0145	0.9%
Participant compensation fund (PCF)	NIL	NIL	NIL	NIL
DLNG Storage recoveries ($m)	8.4	10.95	2.55	30.4%

Table 22 FY25 budget DWGM energy consumption

TJ	Budget FY25	Forecast * FY25	Budget FY26
Residential and commercial	123,352	108,648	118,495
Industrial	59,449	54,617	52,484
Export	29,130	27,062	27,694
GPG	1,371	4,575	2,401
Total	213,302	194,902	201,074
% change	(4.2%)	(8.6%)	(5.7%)

* Forecast annual FY25 consumption as at January 2025.

Short-Term Trading Market (STTM)

Over the past decade, the STTM revenue requirements have been deliberately reduced to return surplus funds. However, starting from FY26, it is proposed to incrementally increase the revenue requirement over the coming years to gradually achieve full cost recovery.

The STTM activity fee includes the STTM Market Operator Service (MOS) allocation fee. Excluding the STTM MOS fees, the activity fee is 20% higher compared to FY25, reflecting increase to revenue requirement and reduction to FY26 forecast consumption. The STTM MOS allocation fee for FY26 is 10.1% higher than FY25, reflecting estimated MOS allocation costs for the year and the recovery of the prior's deficit.

FY26 consumption is forecast to be 3.5% lower compared to FY25 budget, with lower projected consumption for all three STTM hubs, based on the *Step Change* scenario from the 2024 GSOO, updated to reflect changes to forecast assumptions. Final Energy Tariff will be calculated based on the *Step Change* scenario from the 2025 *Gas Statement of Opportunities* (GSOO).

Table 23 STTM revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
STTM revenue requirement $m	2.45	2.84	0.39	15.9%
Gas consumption (TJ)	137,223	132,468	(4,755)	(3.5%)
STTM variable fees ($/GJ withdrawn)				
Activity fee	0.02084	0.02471	0.00387	18.6%
Activity fees (excluding STTM MOS)	0.01785	0.02142	0.00357	20.0%
STTM MOS allocation fee	0.00299	0.00329	0.00030	10.0%
Participant Compensation Fund (PCF)				
PCF fee – Syd ($/GJ withdrawn per hub per ABN)	NIL	NIL	NIL	NIL
PCF fee – Adel ($/GJ withdrawn per hub per ABN)	NIL	NIL	NIL	NIL
PCF fee – Bris ($/GJ withdrawn per hub per ABN)	NIL	NIL	NIL	NIL

Table 24 STTM energy consumption

TJ	Budget FY25	Forecast * FY25	Budget FY26
Adelaide	19,150	19,441	19,851
Brisbane	25,105	22,783	24,423
Sydney	92,969	91,815	88,195
Total	137,223	134,039	132,468
Percentage change		(2.3%)	(3.5%)

* Forecast annual FY25 consumption as at January 2025.

East Coast Gas System (ECGS) Function

The proposed FY26 ECGS function revenue requirement includes a 40% increase, to recover the remaining 50% of system establishment cost, cover ongoing costs for the budget year and address a portion of prior year deficit. It is anticipated that FY27 will return to a full cost recovery model.

Trading Fund and Contribution Rate

Under Part 27, Division 7, Rule 709 of the National Gas Rules, AEMO is required to publish the adjusted trading amount and the contribution rate for trading fund for the new financial year, by 30 June each year.

The adjusted trading amount for the trading fund is calculated using March quarter Consumer Price Index (CPI) of All Groups, weighted average of eight capital cities. For FY26, the trading amount is estimated to be $39,280,492, with an estimated 3% increase applied. This provisional figure will be updated with the actual indexations in the final document.

In determining the contribution rates, AEMO may have regard to a number of factors including the use of the trading fund in affected jurisdictions. Participants are invoiced based on their consumption in each jurisdiction multiplied by the contribution rate. For FY26, the contribution rates determined under NGR 709(3) are $0/GJ for all jurisdictions as no trading costs were incurred in FY25. There will be no invoice issued for FY26.

Table 25 East Coast Gas System Function revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
East Coast Gas Reform revenue requirement $m	3.23	4.52	1.29	39.9%
Gas producers' production (PJ)	1,957	1,920	(37)	(1.9%)
MIRNs basic meters - total (Million)	4.87	4.93	0.06	1.2%
East Coast Gas fees				
Producer fee ($ per GJ)	0.00050	0.00071	0.00021	42.0%
Retailer fee ($ per customer supply point)	0.03865	0.05347	0.01482	38.3%
East Coast Gas Contribution Rates ($/GJ)				
New South Wale and Australia Capital Territory	NIL	NIL	NIL	NIL
Victoria	NIL	NIL	NIL	NIL
Queensland	NIL	NIL	NIL	NIL
South Australia	NIL	NIL	NIL	NIL
Northern Territory	NIL	NIL	NIL	NIL
Tasmania	NIL	NIL	NIL	NIL

Victorian (VIC) retail gas market

The proposed FY26 Victorian retail gas market revenue requirement includes a 31.5% increase as part of ongoing revenue normalisation, following previous years of setting revenue below cost to return prior surplus. A further adjustment is anticipated in FY27 to fully align revenue with the cost of this function.

Table 26 VIC retail gas market revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
VIC retail gas market revenue requirement $m	1.62	2.13	0.51	31.5%
Customer supply points (Million)	2.34	2.37	0.03	1.3%
VIC retail gas market tariff ($ per customer supply point per month)	0.05764	0.07493	0.01729	30.0%

Queensland (QLD) retail gas market

The proposed FY26 revenue requirement includes a 3.9% increase, reflecting wages inflation, partly offset a return of accumulated surplus.

Table 27 QLD retail gas market revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
QLD retail gas market revenue requirement $m	1.05	1.10	0.05	4.8%
Customer supply points (Million)	0.24	0.24	0.00	0.0%
QLD retail gas market fee ($ per customer supply point per month)	0.37219	0.38336	0.01117	3.0%

South Australia (SA) retail gas market

The FY26 market fee is proposed to be the same as FY25, with slight increase in the revenue requirement of 1.7%, driven by higher forecast of customer supply points in the budget year.

Table 28 SA retail gas market revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
SA retail gas market revenue requirement $m	1.32	1.34	0.02	1.5%
Customer supply points (Million)	0.50	0.51	0.01	2.0%
South Australia retail gas market fee ($ per customer supply point per month)	0.21910	0.21910	NIL	NIL

New South Wales (NSW) retail gas market

The proposed FY26 revenue requirement includes a 6.3% increase, reflecting wages inflation and higher forecast of customer supply points in the budget year.

Table 29 NSW retail gas market revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
NSW retail gas market revenue requirement $m	2.70	2.87	0.17	6.3%
Customer supply points (Million)	1.79	1.81	0.02	1.1%
NSW retail gas market fee ($ per customer supply point per month)	0.12555	0.13183	0.00628	5.0%

East Coast Gas Statement of Opportunities (GSOO)

In recent years, the GSOO revenue requirement has been consistently set below operational costs. Despite incremental adjustments during this period, revenue levels have remained insufficiently to fully cover expenses. For FY26, it is proposed that the revenue requirement to be adjusted to full cost recovery and address a portion of the prior year's deficit.

Table 30 GSOO revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
GSOO revenue requirement $m	3.13	4.13	1.00	31.9%
Gas producers' production (PJ)	1,957	1,920	(37)	(1.9%)
MIRNs basic meters - total (Million)	4.87	4.93	0.06	1.2%
GSOO fees				
Producer fee ($ per GJ)	0.00048	0.00065	0.00017	35.4%
Retailer fee ($ per customer supply point)	0.03746	0.04884	0.01138	30.4%

Operational Transportation Service (OTS) Code Panel

The proposed revenue requirement for FY26 is set to remain the same as FY25, with the increase in function cost being offset by the return of accumulated surplus.

Table 31 OTS Code Panel revenue requirement and fee

	Budget FY25	Budget FY26	Variance $	Variance %
OTS revenue requirement $m	0.09	0.09	NIL	NIL
OTS Code Panel ($/GJ)	0.00074	0.00074	NIL	NIL

Gas Supply Hub (GSH)

Fees are determined outside of AEMO's budget and fee setting process through a consultation process as set out in the *Gas Supply Hub exchange agreement*.

Table 32 GSH revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
GSH revenue requirement $m	2.05	2.05	NIL	NIL
Gas consumption (TJ)	35,100	35,100	NIL	NIL
Trading participant fees				
Fixed fee - on licence per annum	12,000	12,000	NIL	NIL
Fixed fee - additional licence per annum	12,000	12,000	NIL	NIL
Variable transaction fee - daily product fee ($/GJ)	0.03	0.03	NIL	NIL
Variable transaction fee - weekly product fee ($/GJ)	0.02	0.02	NIL	NIL
Variable transaction fee - monthly product fee ($/GJ)	0.01	0.01	NIL	NIL
Other participant fees				
Reallocation participants - fixed fee per annum	9,000	9,000	NIL	NIL
Viewing participants - fixed fee per annum	3,600	3,600	NIL	NIL

Gas Capacity Trading Platform (CTP)

The fixed and variable fee for CTP is proposed to remain the same as FY25.

Table 33 CTP revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
Fixed fee - on licence per annum (commodity and capacity) ($)	12,000	12,000	NIL	NIL
Fixed fee - on licence per annum (capacity only)	7,000	7,000	NIL	NIL
Trading participant fees				
Variable transportation fee ($/GJ) Daily/ Weekly/ Monthly	0.00345	0.00345	NIL	NIL
Variable compression fee ($/GJ) Daily/ Weekly/ Monthly	0.00345	0.00345	NIL	NIL

Note: the variable transaction fees for CTP includes a fee of $0.00074 relating to OTS Code Panel.

Day Ahead Auction (DAA)

The proposed FY26 revenue requirement includes a 16.1% reduction, reflecting an ongoing return of accumulated surplus. Participant fees, including fees relating to Operational Transportation Service (OTS) Code Panel.

Table 34 DAA revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
DAA revenue requirement $m	1.89	1.59	(0.30)	(16.1%)
Gas consumption (GJ) - transportation	93,750	93,750	NIL	NIL
Gas consumption (GJ) - gas compression	31,250	31,250	NIL	NIL
Trading participant fees				
Other transportation fee ($/GJ)	0.01643	0.01391	(0.00252)	(15.3%)
Compression fee ($/GJ)	0.01415	0.01198	(0.00217)	(15.3%)

Note: the variable transaction fees for DAA includes a fee of $0.00074 relating to OTS Code Panel.

Gas Bulletin Board (GBB)

In FY24m the revenue requirement was set below cost to return prior year surplus. Although the FY25 revenue increase by 5% to account for inflation, it remained below the actual cost for the budget year. For FY26, the requirement has been adjusted to fully cover the budgeted costs. However, a deficit remains from prior years due to revenue falling short of actual costs. This deficit is planned to be gradually recovered by the end of FY28.

Fee increases reflect a reduction in forecast gas production and consumption in FY26.

Table 35 GBB revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
GBB revenue requirement $m	2.57	3.25	0.68	26.4%
Gas producer production (PJ)[1]	1,957	1,920	(37)	(1.9%)
Gas consumption (TJ)	350,525	333,542	(16,983)	(4.8%)
GBB fees				
Producer ($/GJ)	0.00066	0.00085	0.00019	28.8%
Participants in wholesale gas market ($/GJ withdrawn)	0.00367	0.00487	0.00120	32.7%

[1] 2024 GSOO, Table 6 - Forecast of available annual production as provided by gas producers, 2024-28 (PJ)

5.4. Western Australia (WA) fees

WA Wholesale Electricity Market (WEM)

On the 26 February 2025, the Coordinator issued its *Final Rule Change Report – AEMO's Allocable Revenue Framework (RC_2024_01)*. The final decision is to reject Rule Change Proposal RC_2024_01 and make Amending Rules to:

- suspend AEMO's current Allowable Revenue Framework (ARF) until market fees can be set under a new framework.
- continue to apply the current Market Participant Market Fee rate and Application Fees while the ARF Review is progressing.
- for every Financial Year while the ARF Review is underway, 50% of the previous Financial Year's Market Participant Market Fee rate and Application Fees will be adjusted by the annual percentage change in the Wage Price Index (WPI) and the remaining 50% will be adjusted by the annual percentage change in the Consumer Price Index (CPI).

In line with the recent rule change, AEMO has applied an estimated 3% increase to the FY26 fee. This provisional figure will be updated with the actual indexations in the final release in June 2025. Notably, the WEM revenue requirement for FY26 indicates a 1.9% reduction compared to FY25, primarily due to a 3.3% decrease in forecast consumption, which more than offsets the 3% fee increase. The forecast consumption assumption is based on the *expected* scenario from the *2024 WEM Electricity Statement of Opportunities*, updated to reflect changes to forecast assumptions. A loss factor of 1.8% is applied in calculating the FY26 WEM revenue requirement (FY25: 3.3%).

Table 36 WEM revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
WEM revenue requirement $m	99.46	97.61	(1.85)	(1.9%)
Energy consumption (GWh)	18,018	17,422	(596)	(3.3%)
WEM FEES				
WEM fee ($/MWh) #	2.6717	2.75185	0.08015	3.0%
WEM fee (indicative benchmark) * ($/MWh)	5.3435	5.50370	0.16020	3.0%
WEM REGULATOR & COORDINATOR FEES ($/MWh)				
WA Economic Regulation Authority – Regulator fee	0.1792	TBC	TBC	TBC
Energy Policy WA – Coordinator fee	0.0872	TBC	TBC	TBC

WEM fee applies to Market Customers and Generators.

* Benchmark fee reflects the total of WEM fee per MWh for both Market Customers and Generators.

Western Australian Gas Services Information (GSI)

The final rule change decision, "*Final Rule Change Report – AEMO's Allocable Revenue Framework (GRC_2024_01)"* applies the same indexation methodology to GSI, being a provisional 3% increase that will be replaced by actual indexations in the final release in June 2025.

Table 37 GSI revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
GSI revenue requirement ($m)	1.61	1.66	0.05	3.0%
WA Economic Regulation Authority – Regulator fee ($m)	0.15	TBC	TBC	TBC
Energy Policy WA – Coordinator fee ($m)	0.15	TBC	TBC	TBC

Western Australia (WA) retail gas market

The WA retail gas market revenue requirement include annual member fees. For FY26, the revenue is set to increase by 10.8% reflecting cost inflation and revenue normalisation due to FY24 revenue requirement being set lower to return accumulated surplus.

The annual member fee is escalated based on a 2.9% forecast Perth's March quarter Consumer Price Index. This number will be replaced with actual in the final document.

Table 38 WA retail gas market revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
WA retail gas market gas revenue requirement $m	1.61	1.78	0.17	10.6%
Customer supply points (Million)	0.82	0.84	0.02	2.4%
WA FRC gas fees				
WA retail gas market fee ($ per customer supply point per month)	0.13765	0.15142	0.01377	10.0%
Annual fee – member	24,814	25,534	720	2.9%
Annual fee - associate member	4,839	4,979	140	2.9%

Note: associate members are self-contracting users that are partly to the WA Gas Retail Market Agreement. The FY26 annual fees are calculated according to clause 362A(5) of the Retail market Procedures (WA), with forecast CPI being 2.9%.

5.5. NEM Connections fees

AEMO Connections charge out rates

Across the NEM, AEMO assesses and negotiates performance standards for connecting assets to assure the reliable and secure performance of the power system. AEMO also assesses simulation models of power system plant and associated control systems and performs commissioning and post-commissioning activities.

AEMO's brings specialised engineering skills to ensure new connections to the NEM continue to support the safe and secure operations of the system. We are committed to provide an efficient service to the industry. AEMO's rates are reflective of the technical effort and expertise required and are comparable to specialist/skilled external consultant rates. Different roles are required to support the end-to-end connection assessment process. Rates for these roles reflect direct and indirect costs. Fees are charged on a time and material basis and invoiced monthly. Fees are charged to the connecting market participant.

Table 39 AEMO connection charge-out rates FY26

Role	Rate per hour $	Variance %
Analyst/engineer	365	5.8%
Senior	400	5.3%
Principal	445	4.7%
Managers/specialist	515	4.0%
Third party labour[1]	Cost + 15%	
Site visits[2]	Rate per hour (+15% for third-party labour) including travel time, and travel expenses.	
Connections Initiative uplift[3]	$30	

[1] AEMO may engage contractors or consultants or seek specialist advice (e.g. legal advice) in relation to an assessment.
[2] AEMO employees and/or contractors may attend site to oversee testing (in accordance with clause 5.8.5(a) of the NER).
[3] In 2021 AEMO and the Clean Energy Council established the Connections Reform Initiative (CRI) to accelerate the process for assessing and connecting plant to the NEM in an increasingly complex and dynamic environment. Through consultation with stakeholders, a roadmap was developed identifying key improvement workstreams. It was agreed with stakeholders that this work would be funded by connecting participants. A $30/hour fee is applied to AEMO Onboarding and Connections charges.

5.6. Other fees and charges

In addition to the above fees and charges prescribed under the associated rules, AEMO provides a range of services to electricity and gas markets participants which are charged on a fee-for-services (FFS) basis.

Other fees

Table 40 Other fees

	Budget FY25	Budget FY26	Variance $	Variance %
NEMDE queue ($ per application)	17,600	18,450	850	4.8%
Project developer ($ per facility)	11,250	9,500	(1,700)	(15.6%)
Voluntary book build participant accreditation fee ($ per application)	1,000	1,050	50	5%
Additional participant ID ($ per additional ID)	6,500	6,800	300	4.6%

AEMO charge-out rates

From time to time, AEMO provides consulting and other services for which it charges the user. AEMO's charge out rates are determined on the basis of full cost recovery and include direct and indirect costs. Charge out rates for connections assessments attracts a different rate, due to the nature of the work. Refer to section **Error! Reference source not found.** for these rates.

Table 41 AEMO charge-out rates ($ per hour)

	Budget FY25	Budget FY26	Variance $	Variance %
Senior leadership	560	585	25	4.5%
Manager/specialist	470	490	20	4.3%
Principal	370	390	20	5.4%
Senior	340	355	15	4.4%
Analyst/engineer	320	335	15	4.7%
Office	270	285	15	5.6%

Fees schedules of new registrations

On 3 June 2024 a new market participant category of Integrated Resource Provider (IRP) became effective in the NEM. Registration fees for IRPs will be considered through consultation on the NEM participant fee structure in 2025-2026. In the interim, IRP applicants will incur the registration fees relevant to the type of unit they are connecting to the NEM or role they are undertaking. This will be discussed with connecting applicants upon receipt of their application. Existing eligible market participants who wish to transfer to the new application type will not be charged for transferring their registration type.

For FY26, registration fees will continue to be calculated based on assessed effort, consistent with the approach introduced in FY25. While most fees have increased by an average of 5%, primarily due to AEMO's Enterprise Agreement (EA) adjustment and higher employer super contributions, some fees have experienced more substantial changes, reflecting a reassessment of effort level required. The registration fees for each registration type are charged to the appropriate participant. Any third-party costs incurred by AEMO in the process of registering a participant are included within the fees.

For enquiries about registrations please email onboarding@aemo.com.au.

Fees are rounded up to the nearest $50.

Table 42 Fee schedule of new NEM registrations ($ per registration)

Registration type	Budget FY25	Budget FY26	Variance $	Variance %
Scheduled market generator [A]	41,800	46,000	4,200	10%
Semi-scheduled market generator	54,850	61,750	6,900	13%
Non-scheduled market generator	40,100	42,100	2,000	5%
Scheduled non-market generator	31,250	NA		
Semi-scheduled non-market generator	43,300	NA		
Non-scheduled non-market generator	41,950	44,050	2,100	5%
Transfer of registration	29,200	30,650	1,450	5%
Market customer	13,250	13,950	700	5%
Market small generation aggregator	21,750	22,850	1,100	5%
Network service provider	60,800	63,850	3,050	5%
Metering coordinator (MC)	22,450	23,600	1,150	5%
Trader	16,300	17,150	850	5%
Reallocator	14,950	12,600	(2,350)	(16%)
Intending participant	11,250	9,500	(1,750)	(16%)
Exemption from registration	10,200	10,750	550	5%
Frequency control ancillary services				
Classification of generating units as frequency control ancillary services (FCAS) generating units [B]	13,600	14,300	700	5%
Classification of load as frequency control ancillary services load – new ancillary services or classify load in a new region [C]	13,600	14,300	700	5%
Amendment of an existing load classification, and/or aggregating further load to an existing load classification for frequency control ancillary services purposes	5,800	6,100	300	5%
Wholesale demand response				
Registration as demand response service provider	20,250	21,300	1,050	5%
Classification of load as wholesale demand response unit – new wholesale demand response unit or classify load in a new region or load forecasting area [D]	12,650	13,300	650	5%
Amendment of the relevant plant associated with its existing load classification, and/or aggregating further load to its existing load classification for wholesale demand response unit	2,550	2,700	150	6%
Aggregation of existing load already classified as wholesale demand response unit	2,550	2,700	150	6%
Disbursement charges				

Registration type	Budget FY25	Budget FY26	Variance $	Variance %
Disbursement charge – additional energy conversion model – semi scheduled market generator	6,050	6,400	350	6%
Disbursement charge – additional energy conversion model – non-scheduled market generator	3,050	3,250	200	7%
Stand-alone power system				
New participant as a market stand-alone power system resource provider (MSRP)	13,850	14,550	700	5%
Existing market participant registering as a market stand-alone power system resource provider (MSRP)	9,100	9,550	450	5%

A. Each category of Generator in this table includes applications made by persons intending to act as intermediaries.
B. This fee is additional to the fee required to register as a Generator.
C. This fee is additional to the fee required to register as a Market Customer or Demand Response Service Provider.
D. This fee is additional to the fee required to register as a Demand Response Service Provider.

Table 43 Fee schedule of new WA WEM registrations ($ per registration)

Application type	Budget FY25	Budget FY26	Variance $	Variance %
Rule participant registration application fee	2,800	2,884	84	3%
Facility registration application fee	5,150	5,305	155	3%
Facility transfer application fee	2,800	2,884	84	3%
Conditional certification of reserved capacity	1,450	1,494	44	3%
Resubmission - application for early certified reserved capacity	12,700	13,081	381	3%
Consumption deviation application reassessment application fee for non-temperature dependent loads and for relevant demand (Clause 4.26.2CC and 4.28.9B of the WEM Rules)	650	670	20	3%

Note: Rule Participant De-registration and Facility De-registration will remain at zero.
In line with the recent rule change, AEMO has applied an estimated 3% increase to the FY26 fee. This provisional figure will be updated with the actual indexations in the final release in June 2025.

Table 44 Fee schedule of new power of choice accreditations ($ per application)

Application type	Budget FY25	Budget FY26
Initial deposit – embedded network manager	2,000	2,000
Initial deposit – metering data providers	5,000	5,000
Initial deposit – metering providers	5,000	5,000
Incremental charge rate per hour	Per Table 41 AEMO charge-out rates ($ per hour)	

Table 45 Fee schedule of new gas registrations

Fees are rounded to the nearest $50.

Market	Application type	Budget FY25 $	Budget FY26 $	Variance $	Variance %
Victoria Retail Gas	Market participant - retailer	33,300	35,000	1,700	5%
	Market participant - other	19,700	20,700	1,000	5%
QLD Retail Gas	Retailer	33,300	35,000	1,700	5%
	Self-contracting user	32,600	34,250	1,650	5%
SA Retail Gas	Retailer	40,850	42,900	2,050	5%
	Self-contracting user	39,450	41,450	2,000	5%
NSW Retail Gas	Retailer	35,000	36,750	1,750	5%
	Self-contracting user	34,650	36,400	1,750	5%
WA Retail Gas	WA retail gas - member	15,382	15,828	446	3%
	WA retail gas - associate member	3,075	3,164	89	3%
DWGM	Market participant - retailer	23,100	24,250	1,150	5%
	Market participant - trader	23,100	24,250	1,150	5%
	Market participant - distribution customer	22,450	23,600	1,150	5%
STTM	STTM user	21,400	22,500	1,100	5%
	STTM shipper	21,400	22,500	1,100	5%
Pipeline Capacity	Part 24 facility operator	24,800	26,050	1,250	5%
	Day ahead auction – auction participant	21,750	22,850	1,100	5%

Note: the above registration fees are per registration per registrable capacity, which is per registration.

Table 46 Registration fees to be provided on a quoted basis for each new Registered participant, including those listed below

Market	
DWGM	Market participant - producer
	Market participant - transmission customer
	Market participant - storage provider
	Market participant - blend processing provider
	Participant - declared transmission system service provider
	Participant - interconnected transmission pipeline service provider
	Participant - distributor
	Participant - producer
	Participant - distribution connected facility operator
	Participant - blend processing provider
	Participant - storage provider
	Participant - transmission customer
Retail - NSW/ACT	Network Operator
Retail - Qld	Distributor
Retail - SA	Network Operator
	Network Operator - Mildura region
	Transmission system operator
Retail - Vic	Distributor
	Transmission System Service Provider

Note: Market participant – blend processing provider, distribution connected facility operator and blend processing provider are new Registered participant categories introduced in the National Gas Amendments (Other Gases) Rule 2024 and the National Gas Amendment (DWGM distribution connected facilities) Rule 2022 No. 3

Energy Consumers Australia (ECA)

In January 2015, Energy Consumers Australia (ECA) was established by the Council of Australian Governments (COAG) Energy Council with the focus on national electricity market matters of strategic importance for energy consumers, in particular residential and small business consumers. AEMO is required to collect funding from market participants in the NEM and gas markets on ECA's behalf to fund its program of work, however, AEMO is not responsible for setting ECA's budget. In FY26, ECA has budgeted to collect $15.28m (FY25: $10.31m).

The electricity ECA fee for FY26 is $0.02058 per connection point for small customer per week, a 53.2% increase compared with FY25, reflecting an increase in funding requirements (43%) and a recovery of forecast deficit. This fee is applicable to Market Customers.

The gas ECA fee for FY26 is $0.06251 per customer supply point per month, 33.6% higher than FY25. The fee increase is driven by an increase in funding requirement (43%) and a recovery of forecast deficit. This fee applies to each retail gas market participant participating in the registrable capacity of market participant – retailer in Victoria or retailer in NSW/ACT, QLD and SA.

Table 47 ECA revenue requirement and fees

	Budget FY25	Budget FY26	Variance $	Variance %
Electricity				
Revenue requirement ($m)	7.47	11.58	4.11	55.0%
Electricity retail market - connection points for small customers	10.70	10.82	0.12	1.1%
Electricity ($/connection point for small customers a week)	0.01343	0.02058	0.00715	53.2%
Gas				
Revenue requirement ($m)	2.74	3.70	0.96	35.0%
MIRNs basic meters - total (Million)	4.87	4.93	0.06	1.2%
Gas ($/customer supply point per month)	0.04679	0.06251	0.01572	33.6%

For enquiries relating to the ECA funding requirement, please contact Director, Strategy and Corporate c/o info@energyconsumersaustralia.com.au

Appendix A. Functions within market segments

Table 48 Functions within market segments

Function	Summary of responsibilities[5]
NEM Core	
NEM Core	**AEMO is responsible for managing:** • power system security and reliability • market operations and systems • wholesale metering, settlements, and prudential supervision • longer-term energy forecasting and planning services (for the eastern and southern Australian states).
NEM functions	
Electricity retail markets	AEMO is responsible for facilitating retail market competition in the east coast and southern states of Australia by managing and supporting: • support retail market functions and customer transfers • manage data for settlement purposes. • implement market procedure changes. • business to business processes.
5-minute settlements (5MS/GS)	AEMO is responsible for operating and maintaining systems and procedures necessary for financial settlement of the national electricity market at five-minute intervals.
Distributed Energy Resources (DER) program	AEMO is responsible for understanding and integrating high levels of DER into the Australian power system to ensure a smooth transition from a one-way energy supply chain – starting with large-scale generation units to consumers – to a decentralised, two-way energy system.
National Transmission Planner	AEMO is responsible for delivering an actionable Integrated System Plan (ISP).
SA Planning / South Australian Advisory Functions (SAAF)	AEMO is responsible for preparing a collection of independent reports and publishing them for the South Australian jurisdiction under Section 50B of the National Electricity Law. Under these provisions, the South Australian Government may also request AEMO to undertake additional advisory functions for the South Australian Declared Power System.
Settlements Residue Auction Administration	AEMO is responsible for conducting Settlements Residue Auctions including: • building, updating and maintaining the auction platform • facilitate the settlement residue auction process • Manage the Settlements Residue Committee
Consumer Data Platform (CDP)	AEMO is responsible for providing a data access service to government-operated energy comparison websites.
NEM Reform program	AEMO is responsible for managing the implementation of the Energy Security Board's post-2025 electricity market design, including: • resource adequacy mechanisms • essential system services and ahead scheduling • integration of DER and flexible demand • transmission and access.
Cyber Security Roles and Responsibilities	AEMO's responsibilities include coordination and support of cyber security preparedness, response and recovery as well as the four following cyber security functions • planning and coordinating the NEM-wide response to cyber incidents

[5] For further detailed information, please see the relevant legislation and governing rules or agreement

Function	Summary of responsibilities[5]
	• supporting industry preparedness and uplift • examining risks and providing advice to government and industry • distributing critical cyber security information to industry participants.
East Coast Gas Functions	
Declared Wholesale Gas Market (DWGM)	The DWGM enables competitive dynamic trading based on injections and withdrawals from the Victorian Declared Transmission System, which links producers, major users, and retailers. AEMO is responsible for: • gas system security, market operations and systems • gas system reliability and planning • wholesale metering and settlements • prudential management.
Short-Term Trading Market (STTM)	The STTM is a market-based wholesale gas balancing mechanism at defined gas hubs (Sydney, Adelaide, and Brisbane). AEMO is responsible for: • market operations and systems • Market Operator Service (MOS) – recovery of the pipeline operators' service costs in relation to the STTM and recovers this from participants • wholesale metering and settlements • prudential management.
East Coast Gas System (ECGS)	The ECGS functions bestow AEMO with the responsibilities for monitoring, signalling and responding to risks or threats to the adequacy and reliability of gas supply in the ECGS. Stage 1 of these functions was implemented for winter 2023 and these functions will be further enhanced with longer term enduring solutions through the delivery of Stage 2. AEMO has been providing input into Stage 2, which will be progressed as a series of rule changes through the AEMC. For more information on ECGS reforms, please click here.
Gas retail markets	AEMO is responsible for providing the services and infrastructure to allow gas consumers to choose their retailer while also providing the business-to-business interactions to support efficient operation of the market. This includes: • supporting retail market functions and customer transfers • managing data for settlement purposes • implementing market procedure changes • operating the central IT systems that facilitate retail market services. • (Operated in Victoria, Queensland, South Australia, New South Wales, and Western Australia).
Gas Statement of Opportunities (GSOO)	AEMO is responsible for consulting, developing and reporting on annual gas consumption and maximum gas demand, and for reporting on the adequacy of central and eastern Australian gas markets to supply forecast demand over a 20-year outlook period.
Gas Supply Hub (GSH)	The GSH provides a centralised trading, settlement and clearing facility through an online portal, and enables generators, users, producers and retailers to manage their daily and future gas requirements. AEMO centrally settles transactions, manages prudential requirements, and provides reports to assist participants to manage their portfolio and gas delivery obligations.
Capacity Trading Platform (CTP)	AEMO is responsible for the maintain and operating the CTP, which facilitates the trading of pipeline capacity, including: • settlement and prudential management of capacity transactions. • exchange transaction information with facility operators to facilitate the delivery of capacity transactions. • update STTM contract rights and DWGM accreditations in accordance with transactions in integrated products.
Day Ahead Auctions (DAA)	AEMO is responsible for facilitating DAAs, which includes: • managing and maintaining the auction platform to allocate capacity to shippers • settlement and prudential management of auction transactions • providing auction results to facility operators to facilitate the delivery of auction transactions

Function	Summary of responsibilities[5]
	• updating DWGM accreditations, in accordance with transactions to a DWGM interface point.
Operational Transportation Service (OTS) Code Panel	AEMO is responsible for assessing, consulting and preparing proposals to amend the Operational Transportation Service Code.
Gas Bulletin Board (GBB)	The GBB facilitates improved decision-making and trading in gas commodity and pipeline capacity, through the provision of readily accessible and up-to-date gas system and market information. AEMO is responsible for capacity outlooks, nominations and forecasts, actual flows, line pack adequacy and additional information for maintenance planning.
WA Electricity and Gas Functions	
Wholesale Electricity Market (WEM)	AEMO is responsible for managing: • power system security and reliability • market operations and systems • wholesale metering, settlements, and prudential supervision • preparing for and implementing the WA Government's WEM and Constrained Access Reforms • longer-term energy forecasting and planning services.
Gas Services Information (GSI)	AEMO is responsible for operating the Gas Bulletin Board (WA) and developing the WA Gas Statement of Opportunities in accordance with the Gas Services Information (GSI) Rules and relevant GSI Procedures. This includes: • providing an information website hub to provide flow information on gas, transmission, storage, emergency management with supply disruptions, and demand in WA • developing an annual planning document providing medium to long-term outlook of WA gas supply and demand and transmission and storage capacity.
Gas retail markets	Refer to gas retail markets, in East Coast Gas, above.

Appendix B. Glossary

Term	Definition
5MS/ GS	5 Minutes Settlement and Global Settlements
ACT	Australia Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator Limited
ASL	AEMO Services Limited
CEO	Chief Executive Officer
CDP	Consumer Data Platform
CIS	Capacity Investment Scheme
CPI	Consumer Price Index
CTP	Capacity Trading Platform
D&A	Depreciation and Amortisation
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DLNG	Dandenong liquefied natural gas
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ECA	Energy Consumers Australia
ECGS	East Coast Gas System
ECMC	Energy and Climate Change Ministerial Council
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
FCAS	Fast Frequency Ancillary Services
FCC	Finance Consultation Committee
FPP	Frequency Performance Payments
FRAC	Finance, Risk and Audit Committee
FRC	Full Retail Contestability
FY23	Financial Year 1 July 2022 to 30 June 2023
FY24	Financial Year 1 July 2023 to 30 June 2024
FY25	Financial Year 1 July 2024 to 30 June 2025
FY26	Financial Year 1 July 2025 to 30 June 2026
GBB	Gas Bulletin Board
GJ	Gigajoule
GPG	Gas Powered Generation
GSI	Gas Services Information
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GWh	Gigawatt-hour
IDAM	Identity and Access Management

Term	Definition
IDX	Industry Data Exchange
ISP	Integrated System Plan
MITE	Market Interface Technology Enhancements
MOS	Market Operator Service
MSRP	Market Resource Provider
MWh	Megawatt-hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEL	National Electricity Law
NER	National Electricity Rules
NGO	National Gas objective
NGR	National Gas Rules
NMI	National Meter Identifier
NSW	New South Wales
NTP	National Transmission Planner
OTP	Operations Technology Program
OTS	Operational Transportation Service
PC	Portal Consolidation
PCF	Participant Compensation Fund
PJ	Petajoule
PV	Photovoltaic
QLD	Queensland
RTO	Real Time Operations
REZ	Renewable Energy Zone
PJ	Petajoule
SA	South Australia
SRA	Settlement Residue Auction
STTM	Short Term Trading Market
SWIS	South-West Interconnected System
TCV	Transmission Company Victoria
TJ	Terajoule
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of System
VIC	Victoria
WA	Western Australia
WEM	Wholesale Electricity Market

Australian Energy Market Operator Limited

ABN 94 072 010 327

www.aemo.com.au