2022-23 AEMO Budget and Fees

Introduction

AEMO is an independent, not-for-profit public company limited by guarantee, owned jointly by energy industry members and the Commonwealth, New South Wales, Queensland, South Australian, Tasmanian, Victorian, Western Australian and Australian Capital Territory governments.

This document sets out AEMO's proposed budget and fees for 2022-23.

It is the product of extensive and challenging engagement with AEMO's industry and government members.

Commencing 18 months ago, AEMO established a Finance Consultation Committee (FCC) to share its proposed organisational priorities and the resulting draft budget and financial position. All agendas and minutes of FCC meetings are publicly available (https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/financial-consultation-committee).

In the last 12 months, AEMO requested Boston Consulting Group to benchmark its costs against other system operators. BCG presented this work to the FCC which found that AEMO's costs were low relative to peers, though digital costs appeared higher than necessary. In addition, BCG found that some central functions such as finance were materially under-resourced at AEMO.

As the energy transition has accelerated, and following many years of significant underinvestment, both AEMO's capital costs and operating expenses have increased steadily. AEMO's fees have not increased at the same rate over time, and consequently, a substantial operating deficit has opened in the Core NEM functions.

To improve the efficiency of AEMO, we are implementing a broad package of organisational improvements, including realigning our operating model to provide greater clarity and accountability; transforming the way AEMO governs, funds, and executes reform delivery; investing in models, tools, and processes to manage increased complexity in core activities; and reducing cost in digital 'run-the-business' activities. To keep costs down, AEMO has taken, and is continuing to implement, actions to identify, quantify and reduce costs and drive operational efficiencies.

In collaboration with members of the FCC, AEMO has co-designed and adopted a set of financial principles to guide all future budgets. These principles include:

- Demonstrating efficiency and net benefits of decision making;
- Neither over, nor under recovering costs of AEMO functions;
- New investment programs require an accepted funding pathway before proceeding;
- Debt to assets ratio to remain under 100%; and
- Liquidity Ratio to remain above 50%.

For 2022-23, AEMO has developed its budget and fees earlier in the year to enable its inclusion into the Default Market Offers within relevant jurisdictions and to provide earlier input to its members for their planning processes.

A financially sustainable and stable AEMO is critical to helping Australia navigate this once-in-a-generation energy transition – ensuring the delivery of safe, affordable, and reliable energy today and into the future. As a not-for-profit company, it is essential AEMO operates efficiently and effectively.

Just as AEMO does not generate profit, it cannot sustain ongoing deficits. Accumulated deficits must be recovered while AEMO continues to invest in core operations, and its people, to ensure the safe, reliable, and affordable energy system Australians expect.

Following deep industry engagement, AEMO is proposing to recover the NEM Core accumulated operating deficit over three years.

Looking forward, AEMO has an extensive reform implementation agenda to deliver to ensure Australia's systems and markets are fit for purpose in the changing, and more complex, energy future. This includes implementing the recommendations of the Energy Security Board, to countering the threat posed by nefarious cyber actors who seek to disrupt Australia's energy systems, to enabling a transition to low-cost renewable energy at one of the fastest rates in the world.

The Corporate Plan sets out the priorities AEMO intends to undertake, following member feedback, so that members, participants, and the public can be clear about the value AEMO brings to this once in a generation energy transition. Members and stakeholders want us to simplify the way we work, become more efficient and effective, empower individuals to make the right decisions, and ensure we have clear lines of accountability.

AEMO will continue to use debt financing for capital projects, amortising the cost over the life of the particular asset. This model allows participants to progressively contribute to necessary capital projects through tariffs and fees over the life of the assets.

Notwithstanding the recovery of accumulated operating deficits, AEMO's overall debt is forecast to increase, reflecting the continued investment in reforms for the benefit of consumers to enable the energy transition.

AEMO is conscious of its costs for end consumers as well as the companies who immediately pay AEMO's fees. We have worked to ensure that the price caps in the market include the three-year recovery trajectory of AEMO's operating deficit.

Contents

1. Budget

Financial year 2022-23 will be a major year of reform and change for AEMO, and the Budget reflects that. The reform program which has delivered key capabilities such as the 5 Minute Settlement/Global Settlement (5MS/GS) in 2021-22, continues to ramp up. 2022-23 will see significant new and continuing reform activity, including NEM 2025 and WEM Reform, a new Engineering Framework, Connections Reform and Tools, as well as a major series of projects as part of AEMO's role as Victorian Transmission Network Service Provider.

At the same time, AEMO needs to strengthen its organisational capabilities, so it is strongly placed to lead the energy transition into the future. A review undertaken by the Boston Consulting Group (BCG) benchmarked AEMO against other system operators globally. BCG found AEMO's costs were at the low end of international peers, and with some functions significantly underfunded.

The 2022-23 Budget reflects the scale of this reform and change activity through increases in operating costs and capital expenditure, even while AEMO continues to drive efficiencies across its business. The Budget provides for a range of improvements from operational power system tools and capabilities, through developing a Future State IT architecture and strengthening of cyber security arrangements to refining business models and system support for corporate functions in response to the BCG findings. Fee and Tariff Revenue is increased to reflect the increased cost, with a particular uplift in NEM Core fees to offset higher expenditures in 2022-23 and start recovery of the large accumulated deficit, in line with AEMO's financial principles.

In consultation with the Finance Consultation Committee and other stakeholders AEMO has developed a set of financial principles to guide the development of the budget. Financial principles include demonstrating efficiency and cost-effective delivery, fully recovering operating expenditures across entities (i.e., not for profit and not for loss), ensuring new investment programs have an accepted funding pathway prior to proceeding, and transparent ringfencing of participant and member funds by function.

In July 2022, AEMO will publish its annual Corporate Plan that will detail the activities, priorities, and key performance indicators for AEMO for the financial year.

1.1 Profit and Loss Summary

AEMO Enterprise's 2022-23 Budget[1] (refer Table 1 below) delivers a $22.4m in-year surplus, which reduces the overall accumulated deficit position. The 2022-23 budget comprises of $455.9m total revenue, which is higher by $154.3m or 51% compared with the 2021-22 Budget, and $433.5m of total expenditure, which is an increase of $119.9m on the 2021-22 Budget. The majority of this cost increases reflects investment and enhanced organisational capability to deliver the energy market reform agenda.

[1] The 2022-23 Budget excludes AEMO Services Limited (ASL).

Table 1 AEMO Enterprise 2022-23 summary Surplus and Deficit

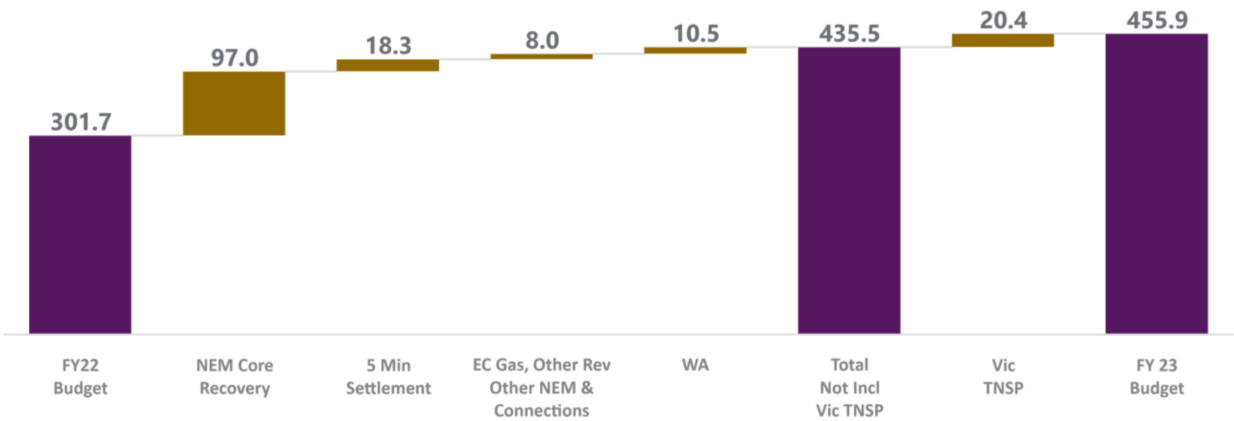
	AEMO (excl. Vic TNSP)			Victorian TNSP			AEMO		
	Budget 2021-22 $'m	Budget 2022-23 $'m	Variance $'m	Budget 2021-22 $'m	Budget 2022-23 $'m	Variance $'m	Budget 2021-22 $'m	Budget 2022-23 $'m	Variance $'m
Fees and Tariffs	255.0	378.5	123.5	-	-	-	255.0	378.5	123.5
TUoS Income	-	-	-	603.0	623.9	20.9	603.0	623.9	20.9
PCF Fees	1.0	0.1	(0.9)	-	-	-	1.0	0.1	(0.9)
Settlement Residue	(0.1)	(0.0)	0.1	43.5	20.0	(23.5)	43.4	20.0	(23.4)
Other Revenue	19.5	30.8	11.3	58.4	66.0	7.6	77.9	96.8	18.9
Network Charges	0.1	-	(0.1)	(678.7)	(663.3)	15.4	(678.7)	(663.3)	15.3
NET REVENUE	275.5	409.3	133.9	26.2	46.6	20.4	301.7	455.9	154.3
Labour	155.6	191.4	35.9	12.7	17.8	5.1	168.3	209.2	41.0
Consulting	10.9	21.1	10.2	10.2	10.7	0.5	21.1	31.8	10.7
IT & Telecommunications	47.4	71.5	24.1	0.0	0.0	0.0	47.4	71.5	24.1
Occupancy	7.7	10.0	2.3	-	-	-	7.7	10.0	2.3
Other Expenses	21.2	29.2	8.0	2.0	3.3	1.3	23.2	32.5	9.3
Depreciation and Amortisation	43.9	69.0	25.1	0.1	0.1	0.0	43.9	69.0	25.1
Financing Costs	2.1	9.4	7.4	-	-	-	2.1	9.4	7.4
Corporate Recovery (TNSP)	(10.7)	(18.0)	(7.3)	10.7	18.0	7.3	0.0	(0.0)	(0.0)
TOTAL OPERATING EXPENDITURE	278.0	383.6	105.7	35.7	49.9	14.2	313.6	433.5	119.9
ANNUAL SURPLUS / (DEFICIT)	(2.5)	25.7	28.2	(9.5)	(3.3)	6.2	(11.9)	22.4	34.4
ACCUMULATED SURPLUS / (DEFICIT)	**(57.0)**	**(47.4)**	**9.6**	**3.5**	**3.6**	**0.1**	**(53.5)**	**(43.9)**	**9.6**

1.1.1 Revenue

AEMO operates over 30 ring-fenced service functions, and revenue comprises fees and tariffs and other revenue sources, which together recover operating expenditure for each of these service functions. Other revenue sources include direct payment from stakeholders for services provided or capabilities built including connecting new renewable energy generators to the grid or providing Jurisdictional services. Fees and Tariffs are the largest source (~80%) of revenue for AEMO. Chart 1 shows the main drivers of revenue growth from 2021-22 to 2022-23.

The 2022-23 Budget of $378.5m Fees and Tariffs Revenue represents a $123.5m year-on-year increase which reflects recovery of higher operating expenditure to support the build of new capabilities, as well as adjustments within segments to return/recover any surplus/deficits.

Chart 1: Growth in revenue from 2021-22 to 2022-23, $m



NEM - the majority of the $123.5m year-on-year increase in overall Fees & Tariff Revenue is driven by the NEM Core segment (including +$92.7m of NEM core tariff revenue and +$4.3m in Other NEM core revenue). The 2022-23 NEM Benchmark Fee is 88.5% higher than in 2021-22. There are two main drivers for this change. Firstly, NEM Core expenditure is budgeted to increase by $52.2m compared with 2021-22 due to a significant increase in reform and change activity. Secondly, the NEM Core accumulated deficit is forecast to increase to $103.6m by end of 2021-22. This large deficit is a risk to AEMO's financial health. Following deep industry engagement with stakeholders, AEMO resolved to act in line with AEMO's financial principles and approved a three-year deficit recovery fee pathway from 2022-23 to 2024-25.

The second (2023-24) and third year (2024-25) fee pathway is expected to require a 4.5% increase for both years. In consultation with the Finance Consultation Committee AEMO will determine the final fee increases for these years at end of the prior year through the normal Budget and Fee update process. Similarly, the NEM Core fee pathway beyond 2024-25 will be determined in 2025 in the light of the best information available at that time.

AEMO is very conscious of the magnitude of these deficit recovery fee increases, and of the impact on end consumers as well as the market participants. As part of developing the new NEM Core fee pathway AEMO consulted extensively with members regarding the NEM fee levels and deficit recovery scenarios. Just as AEMO does not generate profit, it cannot sustain ongoing losses. Accumulated deficits must be recovered while AEMO continues to invest in core operations, and its people, to ensure the safe, reliable, and affordable energy system Australians expect.

Secondly, the other main driver of revenue increase in the NEM Segment for 2022-23 is an increase of $18.3m for the 5MS/GS program, which reflects the first full year of operations and recovery of operating costs for this critical new capability.

In East Coast Gas, there is a $3.6m increase in Fees and Tariffs revenue in 2022-23. The increase in fees reflects a net increase in expenditure and the return of accumulated surplus within this segment. The 2022-23 Budget for this segment is set to under-recover current year operating expenditure by $4.9m as part of returning the $27.5m accumulated surplus.

In Western Australia (WA), the 2022-23 Budget includes a $10.5m Fee and Tariff revenue increase reflecting under-recovery in 2021-22 and increased expenditure in 2022-23 to support the energy transition.

In Victorian Transmission Network Service Provider (Vic TNSP) segment, a $20.4m increase is expected which reflects an increase in net revenue for Transmission Use of Service (TUoS). The net revenue increase is primarily driven by increasing negative inter-regional settlements, higher transmission easement tax partially offset by lower network payments and lower return for AusNet services on their regulated assets.

Where required, further detail of each segment's revenue requirement and the associated Fees & Tariffs is presented in section 2 of this document.

1.1.2 OPERATING EXPENDITURE

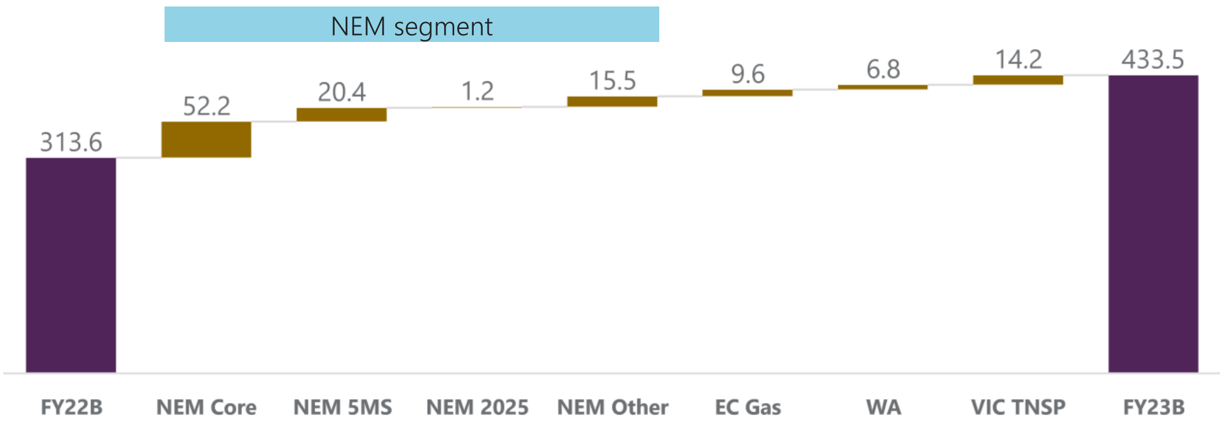
AEMO's 2022-23 Budget total operating expenditure of $433.5m is a $119.9m increase year-on-year, of which $105.7m is for activities excluding Vic TNSP. Of this 38% increase in the overall cost, between half to two thirds is driven by activities to reform the energy market and/or build enhanced capability within AEMO, while ~8% is driven by increases in D&A or borrowing costs. The remaining cost increases (estimated around 2-7%) reflect the additional costs to run the business as we emerge from Covid, including refilling positions vacated, re-expanding travel and training and taking on some additional repairs and maintenance.

By segment, Chart 2 shows the NEM contributes the most to the overall expenditure increase to 2022-23, though all segments have budgeted cost increases reflecting the greater requirements on them to design and build reform capabilities to support the energy transition

- NEM – the $89.3m expenditure increase in the NEM segment is driven primarily by a $52.2m increase in NEM Core, $20.4m increase in the NEM 5MS/GS segment and $1.2M in NEM 2025. The growth in cost in NEM Core includes investment in operational modelling and data management capabilities, support for new/upgraded IT systems, and consulting to support the development of the new Engineering Framework. Increases in NEM 5MS/GS costs are driven by additional cloud storage and software support contracts.

  The $15.5m growth in Other NEM costs includes labour and cloud costs to support the Connections Reform Initiative and the Connections Tool, increases in labour for the National Transmission Planner program and higher D&A for the Distributed Energy Resources (DER) program.

Chart 2: Growth in expenditure by Segment from 2021-22 to 2022-23, $m



- East Coast Gas – the $9.6m increase in costs reflects additional costs in Vic Wholesale Gas to increase storage from 60TJ to 180TJ, additional D&A and an allocation of support costs.
- WA – key areas for further investment in 2022-23, which contribute to the $6.8m year-on-year expenditure increase, include WEM Reform, WA DER, Systems Management and Gas Services Information.
- Vic TNSP – the $14.2m increase reflects increased labour and consulting to support a range of critical projects including Vic-NSW Interconnector West, REZ Development Plan and Western VIC RIT-Transmission. There is also a small increase to reflect additional Connections Revenue.

By categories of expenditure, the key drivers of the $119.9m overall growth year-on-year are Net Labour ($41.0m), Depreciation and Amortisation ($25.1m), IT & Telecommunications ($24.1m), consulting ($10.7m) and financing cost ($7.4m).

Net Labour – With the acceleration of the energy transition, there is a need for AEMO to expand its workforce to navigate key change activities in areas such as system design, energy reform and operations. This results in an increase of $41.0m to labour costs relative to 2021-22. The 2022-23 budget provides for additional resources in modelling and data management associated with the new Engineering Framework, development of new connections reform initiatives and tools as well as further activities in the National Transmission Planner function. Additionally organisational capability enhancements are required in digital operations, cyber security, and central functions in line with the reform activity.

Depreciation & Amortisation – AEMO's depreciation and amortisation expense reflects the amortisation of its investment in capital projects once they 'go live'. Assets associated with major energy reform programs in the NEM and WEM are progressively going live, as are assets associated with AEMO's digital investment program including replacement of legacy systems.

Key projects impacting the 2022-23 depreciation budget include (update):

- 5MS program, Wholesale Demand Response, DER program, Operational Forecasting Program
- WEM: Market/Regulatory design and Technical/Process design, Reserve Capacity Mechanism, Constraint Management, Generator Performance Standards, DER, Power Systems Operations
- Digital: Corporate Cyber Privileged Access Management, Public Cloud design/build, Delivery Centre, and Application Simplification program

Consulting – the $10.7m year-on-year increase in consulting is driven by the need for technical expert input on a range of new or in-flight programs to strengthen existing operations, or redesign and reform the energy systems; to undertake reviews which are required as part of AEMO's work; and to inform the redesign of corporate function operating models in the light of the BCG benchmark findings.

Increased consulting in the NEM segment includes support for Engineering Framework, Connections Reform Initiative, and the National Transmission Planner, as well as reviews of the Power Systems.

Wider business consulting will cover Cyber Security capabilities and redesign of operating models.

IT & Telecommunications – the $24.1m year-on-year increase in IT & Telecommunications expenditure is due to increases in software support costs (+$3.0m), Cloud costs (+$18.6m) and maintenance costs for both hardware and software ($2.5m)

The majority (75%) of software support costs are in NEM Core, East Coast Gas and Corporate (for AEMO-wide operational and business support systems). The other large contributor to the growth in software support costs for 2022-23 is 5MS/GS (+$1.3m) to support the settlement systems introduced in 2021-22.

5MS/GS is also the key source of Cloud costs ($18.6m in 2022-23) and is driving over 50% of the year-on-year cost increases. The NEM Connection tool initiative is the second main driver of Cloud cost increase in 2022-23, with $1.4m budgeted for this program.

Finance Costs – the $7.4m year-on-year increase in finance costs is primarily due to higher market interest rates combined with a higher average debt position across the two financial years (adjusted for capitalised interest) yields an increased finance costs in Budget 2022-23.

Refer to Appendix A for a detailed Consolidated Profit and Loss Statement.

1.2 Balance Sheet Summary

AEMO Enterprise's 2022-23 Budgeted Balance Sheet position (refer Table 2 below) indicates a negative net assets position of $22.2m. AEMO's negative net asset position is the result of an accumulated operating deficit of $43.9m as at 30 June 2023, primarily driven by historic under recovery of the NEM functions from prior periods.

Table 2 2022-23 Balance Sheet summary

Balance Sheet Summary ($'m)	Budget 2022-23	Notes
Assets		
Cash & Cash Equivalents	198.2	(1)
Other current Assets	144.2	
Non-current Assets	530.7	(2)
Total Assets	873.1	
Liabilities		
Total Current Liabilities	351.9	(3)
Borrowings	529.6	(4)
Other non-current Liabilities	13.9	
Total Liabilities	895.3	
Net Assets	(22.2)	
Equity		
Capital Contribution	7.1	
Participant Compensation Fund Reserve	10.7	See note (2)
Land Reserve	3.9	
Accumulated Surplus/(Deficit)	(43.9)	
Total Equity	(22.2)	

Key points of the AEMO's budgeted financial position as at 30 June 2023, are as follows:

(1) Within the cash and cash equivalents of $198.2m, cash on hand of $15.0m is available on demand for AEMO operational uses. Participant Compensation Funds of $10.7m is held in trust and is held as compensation for scheduling errors. In addition, not available for AEMO operational use, is a cash balance of $172.5m which represents early settlement proceeds and security deposits.

(2) Non-current assets are made up of Intangibles and Property, Plant and Equipment assets which reflect ongoing capital investment net of annual depreciation and asset decommissioning.

(3) Current liabilities include participant security deposits which relate to the NEM and Gas Supply Hub monies held by AEMO on behalf of the registered market customers for prudential requirements.

(4) Borrowings represent debt funding drawn from AEMO's commercial bank facilities. The borrowed funds are utilised to fund net capital investment requirements of 2022-23 budget.

1.3 Cash Flow Summary

AEMO Enterprise's 2022-23 Budgeted Cash Flow summary (refer Table 3 below) indicates a total Cash and Cash equivalents position as at 30 June 2023 of $198.2m which is a forecasted net decrease of $55.9m.

Table 3 2022-23 Cash Flow summary

Cash Flow Summary ($'m)	Budget 2022-23
Receipts from customers	433.7
Payments to suppliers and employees	(340.1)
Net Interest and finance costs paid	(9.0)
Net Receipts into the PCF	0.1
Net cashflows from operating activities	84.7
Net Receipt of participant security deposits	8.2
Net Payments for property, plant & equipment	(174.9)
Net cashflows from investing activities	(166.7)
Net Borrowings	27.4
Repayment of lease liabilities	(1.3)
Net cashflows from financing activities	26.1
Net increase/decrease in cash held[2]	(55.9)

[2] Net Increase/decrease in Cash held position is calculated on the 2021-22 forecasted result and not on Budgeted 2021-22 financials.

1.4 Capital Expenditure Summary

AEMO's capital program was developed through a detailed multi-year forecasting process to determine capital priorities to support the strategic objectives in the Corporate Plan. From these four capital programs were identified:

- Reform (excl WEM), including ESB NEM 2025, DER Project Edge, Retail reforms and Gas reforms
- WA Market reforms, including WEM DER
- Operations Tools, including AESC, Forecasting roadmap, Vic Gas Market dispatch system replacement, Operational tools uplift resulting from Operational Tool Roadmap
- Business enablement, including ERP, Cyber security, and Lifecycle capex

For 2022-23, the budget for this net capital expenditure program is $174.9m which is $24.6m (16.4%) higher than 2021-22, with the largest drivers of the year-on-year increase being WEM Reform (+$17.8m) and the investments in Operations Tools (+$15.8m), partly offset by a reduction in other regulatory driven reform programs (-$1.6m) as some projects wind down and reduction in business enablement projects (-$7.3m).

Table 4 provides a summary of the 2022-23 net capital expenditure budget categories.

Table 4 Net Capital program summary

Net Capital Expenditure ($'m)	Budget 2021-22	Budget 2022-23	Variance
Reform Implementation	63.6	62.0	-1.6
WA Market Reform	15.1	32.9	17.8
Operations Tools	20.2	36.0	15.8
Business Enablement (Digital, System, Cyber and other)	51.3	44.0	-7.3
Net Capital Expenditure*	150.3	174.9	24.6

* Net Capital expenditure represents net off $5.1m of Government Grants within 2022-23 Budget.

2. Fees

AEMO's annual revenue requirement, as reflected in its budget, is established to recover operating expenditure for each energy market it operates and the recovery of other services consistent with legislative authority.

Operating on a 'fee for service' and cost recovery basis, the revenue requirement is recovered through fees and charges levied to participants. Each fee is limited to recovering the costs of providing that service. In any year, the revenues collected, and costs incurred, may vary from the levels that were estimated in the budget and reflected in fees. Therefore, the financial budget in a year may include prior year over or under recoveries to adjust for these variances – with the variances referred to as a surplus or deficit.

In Western Australia AEMO's allowable revenue requirement is approved by the Economic Regulation Authority every three years. The current three-year ERA determination on AEMO's allowable revenue and capital expenditure covers the period from 1 July 2022 to 30 June.

In March 2021, informed by stakeholder feedback and internal analysis, AEMO published its:

- Electricity Fees Structures determination detailing the structure of the Participant fees to apply from 1 July 2021 under the National Electricity Rules (NER); and
- Determination regarding the fee structures to apply to gas participant fees from 1 July 2021, having regard to the fee structure principles and National Gas Objective (NGO).

These determinations detail the fee structures to recover AEMO's applicable budget revenue requirements.

This section presents the revenue requirement and fees that will apply from 1 July 2023 for each function.

2.1 National Electricity Market

Purpose of this function

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)

Revenue requirement and fees

The NEM market customer (i.e. Retailers) fee for 2022-23 is $0.7540/MWh (+88.5% on 2021-22). The revenue requirement from wholesale participants (i.e. Generators) for 2022-23 is $63m (+89.2% on 2021-22).

Table 5 NEM revenue requirement and fee

	Budget 2021-22	Budget 2022-23	Variance	Variance
NEM Revenue Requirement ($m)	103.5	195.8	92.3	89.2%
Consumption (GWh)	175,365	176,022	656	0.4%
NEM Fee by Participant type				
Market Customer Fee ($/MWh)	0.4000	0.7540	0.3540	88.5%
Wholesale Participants Revenue Requirement ($m)	33.3	63.0	29.7	89.2%
NEM Benchmark Fee* ($/MWh)	0.5901	1.1122	0.5221	88.5%

* The fee listed above as a benchmark fee is calculated by dividing the total revenue requirement of the NEM functions by the total forecast consumption. The actual fee charged for 2022-23 to Market Customers (i.e. Retailers) is $0.7540/Mwh and revenue requirement from wholesale particpants (i.e. generators) is $63m.

The NEM revenue requirement increase of $92.3m reflects:

- increased operating expenditure of $52.2m driven by the growth in reform and change activity to support the energy transition, including development of a new engineering framework, strengthening of operational tools and capabilities, and enhanced reform planning, system design and digital support capabilities. These changes lead to $10.8m increased labour expenditure (wage escalation and incremental NEM connections roles), $29.0m corporate allocations (capability uplift in the operations team, support functions and power system forecasting), $3.8m increased financing costs due to higher interest rates, and $8.6m in non-labour related expenditure (depreciation & amortisation, IT cloud costs and software support contracts, insurance, and finance charges); and
- increased revenue of $40.1m (representing a budget 2021-22 to Budget 2022-23 movement) to commence recovery (over three years) of the accumulated NEM Core operating deficit. NEM has been under recovering its operating expenditure in recent years resulting in a forecast NEM Core accumulated operating deficit of approximately $103.6m at the end of 2021-22.

The NEM market customers fee increase of 88.5% is lower than the 89.2% revenue requirement increase, due to the 2022-23 impact of the higher GWh forecast consumption.

The consumption forecast increase in 2022-23 compared with the prior year budget, reflects the combined impacts of updated demand driven by post covid market expansion and weather modelling offset by changes in renewable generation and storage.

Refer to table 31 for the components of the NEM fee.

2.2 Full Retail Contestability (FRC) Electricity

Purpose of this function

To facilitate retail market competition in the east coast and southern states of Australia by managing and supporting:

- Data for settlement purposes
- Customer transfers
- Business to business processes
- Market procedure changes

Revenue requirement and fees

The FRC Electricity fee for 2022-23 is $0.02519 per connection point per week (-2.8%).

Table 6 FRC revenue requirement and fee

	Budget 2021-22	Budget 2022-23	Variance	Variance
FRC Revenue Requirement ($m)	14.2	13.9	-0.3	-1.8%
Connection Points (Million)	10.5	10.6	0.1	1.0%
FRC Fees ($ per connection point per week)	0.02592	0.02519	-0.0007	-2.8%

The FRC revenue requirement decrease of $0.3m primarily reflects prior year over-recovery of costs returned to consumers. The underlying costs of the function (excluding enterprise allocations) were broadly unchanged from 2021-22. This results in a 2.8% fee decrease in 2022-23.

2.3 5MS/GS Compliance (5MS) and IT Upgrade

Purpose of this function

To recover the consolidated costs of the Five-Minute and Global Settlement rule changes and upgrades to related legacy IT systems for the National Electricity Market.

Revenue requirement and fees

The benchmark 5MS fee for 2022-23 is $0.2451/MWh.

Table 7 5MS revenue requirement and fee

	Budget 2021-22	Budget 2022-23	Variance	Variance
5MS Revenue Requirement ($m)	24.8	43.1	18.3	73.7%
Consumption (GWh)	175,365	176,022	656	0.4%
5MS Benchmark Fee ($/MWh)	0.1417	0.2451	0.1035	73.0%

The 2022-23 5MS revenue requirement increase of $18.3m reflects:

- an operating expenditure increase of $20.4m driven primarily by higher technology costs including cloud related and support costs ($11.5m), depreciation & amortisation ($6.9m), labour ($1.2m), and other expenses ($0.8m); and
- a return of budgeted accumulated surplus of $2.1m.

The $0.2451 5MS Benchmark Fee reflects the 2022-23 budget revenue requirement being passed through to NEM participants.

Refer to table 31 for the components of the 5MS fee.

2.4 Distributed Energy Resources Integration Program (DER)

Purpose of this function

From 1 July 2021 a new fee category was applied to recover the consolidated costs of the Integration of DER into the National Electricity Market.

Revenue requirement and fees

The benchmark DER fee for 2022-23 is $0.02977/MWh.

Table 8 DER revenue requirement

	Budget 2021-22	Budget 2022-23	Variance	Variance
DER Revenue Requirement ($m)	5.7	5.2	-0.5	-8.8%
Consumption (GWh)	175,365	176,022	656	0.4%
DER Benchmark Fee ($/MWh)	0.03278	0.02977	-0.00301	-9.2%

The DER revenue requirement decrease of $0.5m reflects:

- an operating expenditure increase of $3.3m consisting of depreciation & amortisation mostly of software and licence costs ($2.8m), cloud storage costs ($0.4m), labour ($0.2m), and other expenses ($0.4m); and
- an under-recovery of $2.8M factored into 2022-23 budget year to smooth pricing over a four-year period.

The $0.02977 DER Benchmark Fee reflects the revenue requirement being passed through to NEM participants.

Refer to table 31 for the components of the DER fee.

2.5 National Transmission Planner (NTP)

Purpose of this function

Delivering an actionable Integrated System Plan (ISP).

Revenue requirement

The 2022-23 NTP revenue requirement reflects a 14.6% decrease on the 2021-22 Budget.

Table 9 National Transmission Planner revenue requirement

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue requirement ($m)	23.0	19.6	-3.4	-14.6%

The NTP revenue requirement decrease of $3.4m reflects

- an operating expenditure increase of -$2.2m consisting of labour and consulting (-$0.6m), corporate recover (-$1.1m), IT & telecommunications (-$0.5m); fully offset by
- return of $5.6m of budgeted accumulated surplus from 2021-22.

2.6 Victorian Transmission Network Service Provider (TNSP)

Purpose of this function

The provision of shared transmission network services to users of the Victorian Declared Transmission System (DTS) including the planning of future requirements and procuring of augmentations in the DTS.

Revenue requirement

TNSP Transmission Use of Systems (TUoS) fees are predominately influenced by network charges billed by the Victorian electricity transmission network owners and by estimates of settlement residue receipts.

The 2022-23 TUoS charges revenue requirement is $623.9m reflecting a 3.5% increase on the 2021-22 Budget.

Table 10 Victorian Transmission Network Service Provider revenue requirement

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue requirement ($m)	603.0	623.9	20.9	3.5%

Key drivers of the increased TUoS charges are:

- $23.3m due to increasing negative inter-regional settlement residues arising due to counter-price flows on the Victoria to New South Wales interconnector, lower estimated Settlement Residue Auction proceeds, and lower settlement residue income for the Victorian region as a result of lower estimated spot prices.
- $16.8m relating to higher transmission easement land tax.
- Offsetting the increase is a $19.2m reduction in expenses mainly relating to a combination of lower network payments, lower return for AusNet Services on their regulated assets and a lower charge to the Victorian jurisdiction for the use of the network in other jurisdictions.

The shared transmission network services prices apply for the financial year 1 July 2022 to 30 June 2023 and comprise of locational charges, non-locational charges and common service charges.

2.7 Western Australia Wholesale Electricity Market (WEM)

Purpose of this function

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

Revenue requirement and fees

The WEM indicative benchmark fee is $1.1559/MWh reflecting an increase of 29.3% in 2022-23.

Table 11 WEM revenue requirement and Fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	30.8	41.9	11.1	35.9%
Consumption (GWh)	17,078	17,950	872	5.1%
WEM Fees				
WEM Market Operator fee ($/MWh)	0.3800	0.4913	0.111	29.3%
WEM System Management fee ($/MWh)	0.5140	0.6646	0.151	29.3%
WEM fee ($/MWh)	0.8940	1.1559	0.262	29.3%
WEM fee (indicative benchmark) * ($/MWh)	1.7880	2.3118	0.524	29.3%

* The fee listed above is a benchmark fee calculated by dividing the total cost of the WEM functions by the total forecast consumption. The actual fee charged to both Market Customers and Generators is $0.4913/MWh and 0.6646/MWh for the Market Operations and System Management functions respectively.

The increase in the WEM Revenue Requirement of $11.1m reflects:

- an operating expenditure increase of $6.0m reflecting growth in activity around WEM Reform and consisting of net labour and consulting ($4.7m) and financing costs ($1.5m) partially offset by net reduction in other cost categories ($0.2M); and
- $5.1m increase in revenue to recoup deficit from prior period.

Other notes

The current three-year ERA determination on AEMO's allowable revenue and capital expenditure covers the period from 1 July 2022 to 30 June 2025.

2.8 Declared Wholesale Gas Market (DWGM)

Purpose of this function

To enable competitive dynamic trading based on injections and withdrawals from the transmission system that links producers, major users, and retailers

This market provides the following broad services:

- Gas system security, market operations and systems
- Gas system reliability and planning
- Wholesale metering and settlements
- Prudential management

Revenue requirement and fees

The 2022-23 DWGM revenue requirement is $27.9m reflecting a $3.4m (13.7%) increase on the 2021-22 Budget.

Table 12 DWGM revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	24.5	27.9	3.4	13.7%
Gas consumption (TJ)	239,675	244,409	4,734	2.0%
Distribution Meters (Avg)	1,086	1,084	-2	-0.2%
DWGM Variable Fees				
Energy tariff ($/GJ)	0.0994	0.1107	0.0113	11.4%
Distribution Meter ($/day per meter)	1.565	1.329	-0.236	-15.1%
PCF Fee ($/GJ)	0.0000	0.0000	0.0000	0.0%
Initial Registration Fees ($ / registration)				
Market Participant - Retailer	20,570	21,084	514	2.5%
Market Participant - Trader	20,570	21,084	514	2.5%
Market Participant - Distribution Customer	19,970	20,469	499	2.5%

The DWGM revenue requirement increase of $3.4m largely reflects:

- an operating expenditure increase in the 2022-23 Budget of approximately $4.2m consisting of labour ($0.6m), IT and telecommunications ($0.8m), enterprise recoveries ($1.9m) and other expenses ($0.9m); partially offset by
- $0.8m return of accumulated surplus.

Energy tariff

The energy tariff fee increases by 11.4% to $ 0.11071 /GJ in 2022-23 reflecting the increase in the revenue requirement partially offset by increase in energy consumption of 2.0% in 2022-23.

Distribution Meter fee

The Distribution Meter fee is paid by each market participant connected to a Declared Distribution System, or whose customers are connected to a Declared Distribution System, at a connection point which there is an interval metering installation.

The Distribution Meter fee relates to metering data services and is to decrease by 15.1% to $1.329 per meter per day in 2022-23.

Participant Compensation Fund (PCF) fee is not required to be charged in 2022-23, as the current level of DWGM PCF funds being held meets the Rules requirement.

Initial Registration Fees

Registration fees increase by 2.5% compared to 2021-22 reflecting cost inflation.

DWGM Energy Consumption

The budgeted consumption for 2022-23 is based on data used in the March 2022 Gas Statement of Opportunities (GSOO) updated to reflect the current outlook.

Table 13 DWGM energy consumption

TJ	Budget 2021-22	Forecast* 2021-22	Budget 2022-23
Domestic	133,135	130,195	130,956
Industrial	63,090	64,123	64,870
Export	40,517	47,079	40,708
GPG	2,933	6,698	7,875
Total	239,675	248,095	244,409
		+3.6%	+2.0%

* Forecast annual 2022-23 consumption as at March 2022.

2.9 Short Term Trading Market (STTM)

Purpose of this function

To enable a wholesale market gas balancing mechanism at the gas hubs – Sydney, Adelaide, and Brisbane. The STTM function provides the following broad services:

- 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

Revenue requirement and fees

The current STTM fee of $0.03762/GJ is to decrease by 10.1% to $0.03382/GJ in 2022-23.

Table 14 STTM revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	5.4	4.7	-0.6	-11.1%
Gas consumption (TJ)	145,642	140,909	-4,733	-3.2%
STTM Variable Fees				
Activity Fee ($/GJ withdrawn)	0.03762	0.03382	-0.0038	-10.1%
PCF Fee – Syd ($/GJ withdrawn per hub per ABN)	Nil	Nil	Nil	0.0%
PCF Fee – Adel ($/GJ withdrawn per hub per ABN)	Nil	Nil	Nil	0.0%
PCF Fee – Bris ($/GJ withdrawn per hub per ABN)	Nil	Nil	Nil	0.0%
Initial Registration Fees ($/Registration)				
STTM User (BRI, ADL, SYD hubs)	20,870	21,392	522	2.5%
STTM Shipper (BRI, ADL, SYD hubs)	20,870	21,392	522	2.5%
STTM Allocation Agent	16,970	17,394	424	2.5%
STTM Pipeline Operator	36,470	37,382	912	2.5%
STTM Distributor	36,170	37,074	904	2.5%
STTM Storage facility Operator	36,470	37,382	912	2.5%
STTM Production Facility Operator	36,470	37,382	912	2.5%

The required revenue decrease of $0.6m (11.1%) reflects return of accumulated surplus funds partially offset by an increase in corporate costs. The 10.1% STTM activity fee decrease reflects the decrease in the revenue requirement in addition to the higher energy forecast consumption in the budget year.

The STTM energy consumption forecast is based on data used in the March 2022 GSOO, updated to reflect the current outlook.

Table 15 STTM energy consumption

TJ	Budget 2021-22	Forecast* 2021-22	Budget 2022-23
Adelaide	21,426	18,906	18,534
Brisbane	33,511	33,707	33,356
Sydney	90,705	88,310	89,019
Total	145,642	140,923	140,909
		-3.2%	-3.2%

* Forecast annual 2021-22 consumption as at March 2022.

The Participant Compensation Fund fee is not required to be charged in 2022-23, as the current level of STTM PCF funds being held meets the Rules requirement.

Registration Fees

Registration fees are increasing by 2.5% compared to 2021-22 reflecting cost inflation.

2.10 FRC Gas Markets

Purpose of these functions

To provide 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.

The following broad services are provided:

- Support retail market functions and customer transfers
- Manage data for settlement purposes
- Implement market procedure changes
- Operate the central IT systems that facilitate retail market services

(Operated in Victoria, Queensland, South Australia, New South Wales, and Western Australia)

2.10.1 Victorian FRC Gas

Revenue requirement and fees

The revenue requirement is little changed year-on-year.

The current Victorian FRC Gas fee is $0.05965 per customer supply point/month. As a result of the 2022-23 Budget increase in customer supply points the fee is to decrease to $0.05650 (down 5.3%) in 2022-23.

Registration fees applicable to Victorian FRC Gas have been disaggregated and increased in line with general cost increases and inflation.

Table 16 Vic FRC gas revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	1.74	1.68	-0.06	-3.6%
Monthly average customer Supply points (Million)	2.26	2.29	0.04	1.6%
Vic Gas Fees				
FRC Gas Tariff ($ per customer supply point per month)	0.05965	0.05650	-0.0032	-5.3%
Initial Registration Fee ($ per participant retailer)	20,157	20,661	504	2.5%
Initial Registration Fee ($ per non-retailer participant)	20,157	20,661	504	2.5%

2.10.2 Queensland FRC Gas

Revenue requirement and fees

The 2022-23 revenue requirement has increased 15.1% due to an increase in directly identifiable support costs.

The current Queensland FRC Gas fee is $0.2637 per customer supply point/month. This fee is to increase to $0.2863 in 2022-23.

Registration fees applicable to Queensland FRC Gas have been disaggregated and increased in line with general cost increases and inflation.

Table 17 Qld FRC gas revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	0.75	0.86	0.11	15.1%
Monthly average customer Supply points (Million)	0.23	0.24	0.00	1.5%
Qld Gas Fees				
FRC fee ($ per customer supply point per month)	0.2637	0.2863	0.0225	8.5%
Registration Fee ($ per participant retailer)	18,035	18,486	451	2.5%
Registration Fee ($ per non-retailer participant)	18,035	18,486	451	2.5%

2.10.3 South Australia FRC Gas

Revenue requirement and fees

The revenue requirement has increased 6.6% due mainly to labour and IT systems expenditure.

The current South Australian FRC Gas fee is $0.2034 per customer supply point/month. This fee is to increase to $0.2191 (up 7.7%) in 2022-23.

Registration fees applicable to South Australian FRC Gas have been disaggregated and increased in line with general cost increases and inflation.

Table 18 SA FRC gas revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	1.27	1.35	0.08	6.6%
Monthly average customer Supply points (Million)	0.49	0.49	0.00	0.6%
SA Gas Fees				
FRC fee ($ per customer supply point per month)	0.2034	0.2191	0.0156	7.7%
Registration Fee ($ per participant retailer)	16,974	17,399	424	2.5%
Registration Fee ($ per non-retailer participant)	16,974	17,399	424	2.5%

2.10.4 New South Wales FRC Gas

Revenue requirement and fees

The revenue requirement has increased 3.2% year-on-year. This is driven by a decline in depreciation and amortisation off-set by increased labour and other expenditure.

The current New South Wales (including Australian Capital Territory) FRC Gas fee is $0.1377 per customer supply point/month. This fee is to increase to $0.1395 (up 1.3%), offsetting the budgeted growth in the number of customer supply points.

Table 19 NSW FRC gas revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	2.9	2.99	0.1	3.2%
Monthly average customer Supply points (Million)	1.75	1.79	0.034	1.9%
NSW Gas Fees				
FRC fee ($ per customer supply point per month)	0.1377	0.1395	0.0018	1.3%
Registration Fee ($ per participant retailer)	20,157	20,661	504	2.5%
Registration Fee ($ per non-retailer participant)	20,357	20,866	509	2.5%

2.10.5 Western Australia FRC Gas

Revenue requirement and fees

The 2022-23 revenue requirement is budgeted to increase by 4.4% due to increased labour and IT system costs, partially offset by a reduction in depreciation and amortisation, and a progressive return of accumulated surplus to members.

The fee for 2022-23 is to increase by 2.6% to $0.1229.

Table 20 Western Australia FRC gas revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	1.40	1.46	0.1	4.4%
WA Gas Fees				
FRC fee ($ per customer supply point per month)	0.1197	0.1229	0.0031	2.6%
Initial Registration Fee – member	13,565	13,904	339	2.5%
Initial Registration Fee – associate member	2,712	2,780	68	2.5%
Annual Fee – Member	20,849	22,434	1585	7.6%
Annual Fee – Associated Member	4,066	4,375	309	7.6%

Note: associate members are self-contracting users that are party to the WA Gas Retail Market Agreement. The 2022-23 registration and annual fees are calculated according to clause 362A(5) of the Retail Market Procedures (WA).

2.11 Eastern and South Eastern Gas Statement of Opportunity (GSOO)

Purpose of this function

To report the supply adequacy of eastern and south-eastern Australian gas markets to meet energy needs – AEMO reports on demand and supply, and delivery constraints projected for the next 20 years

Retailers across the FRC gas market jurisdictions are currently charged for GSOO costs at a flat rate per customer supply point

Revenue requirement and fees

The 2022-23 fee is $0.00028 per GJ for producers and $0.02352 per customer supply point for retailers.

Table 21 GSOO revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	2.2	1.9	-0.2	-10.0%
Gas Producers Production (PJ)	2,063	2,078	15.0	0.7%
Monthly Average Customer Supply Points (Millions)	4.73	4.81	0.08	1.6%
Fees				
Producer fee ($ per GJ)	0.00031	0.00028	-0.00003	-9.7%
Retailer fee ($ per customer supply point)	0.02669	0.02352	-0.00318	-11.9%

2.12 Supply Hub (GSH)

Purpose of this function

To provide an exchange for the wholesale trading of natural gas to enable improved wholesale trading for an east coast gas market affected by significant liquefied natural gas (LNG) exports in Queensland – through an electronic platform, GSH participants can trade standardised, short-term physical gas products at each of the three foundation pipelines connecting at Wallumbilla

AEMO centrally settles transactions, manages prudential requirements, and provides reports to assist participants in managing their portfolio and gas delivery obligations

Revenue requirement and fees

Fees are determined outside of AEMO's budget and fee setting process and are set within the Gas Supply Hub exchange agreement with changes made in consultation with stakeholders.

The GSH fee schedule is included in this report for information purposes.

Table 22 GSH revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	1.3	1.7	0.4	30.8%
Gas consumption (TJ)	20,360	23,985	3,625	17.8%
Trading Participant Fees				
Fixed Fee - one licence per annum	12,000	12,000	0.00	0.0%
Fixed Fee - additional licence per annum	12,000	12,000	0.00	0.0%
Variable transaction fee – Daily product fee ($/GJ)	0.0300	0.0300	0.00	0.0%
Variable transaction fee – Weekly product fee ($/GJ)	0.0200	0.0200	0.00	0.0%
Variable transaction fee – Monthly product fee ($/GJ)	0.0100	0.0100	0.00	0.0%
Other Participant Fees				
Reallocation participants – Fixed fee per annum	9,000	9,000	0.00	0.0%
Viewing participants – Fixed fee per annum	3,600	3,600	0.00	0.0%

2.13 Gas Capacity Trading Platform (CTP)

Purpose of this function

To facilitate the secondary trading of pipeline capacity.

The following broad services are provided:

- 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.

Revenue requirement and fees

There is no change to current fixed fee for 2022-23.

Effective from 1 July 2021, AEMO has determined to disaggregate compression service fees from other transportation services traded on the CTP and will continue to apply charges on a $/GJ basis.

To encourage participation and increased liquidity in the market, the 2022-23 CTP fees for both compression and other transportation are set at $0.0079, including $0.00294 relating to OTS code panel.

Table 23 CTP revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Fixed Fee - one licence per annum (commodity & capacity) ($)	12,000	12,000	0.00	0.0%
Fixed Fee - one licence per annum (capacity only) ($)	7,000	7,000	0.00	0.0%
Initial Registration Fee - Part 24 Facility Operators ($ per participant) ($)	15,914	16,311	398	2.5%
Variable transaction fee				
Variable transportation fee ($/GJ) Daily/Weekly/Monthly	0.0082	0.0079	-0.0002	-3.0%
Variable compression fee ($/GJ) Daily/ Weekly/ Monthly	0.0082	0.0079	-0.0002	-3.0%

Note: the variable transaction fees for CTP are including a fee of $0.00294 relating to OTS code panel.

2.14 Day Ahead Auction (DAA)

Purpose of this function

To reallocate contracted but unnominated transportation capacity to shippers that value it the most.

The following broad services are provided:

- Auction platform to allocate capacity to shippers
- Settlement and prudential management of auction transactions
- Provide auction results to facility operators to facilitate the delivery of auction transactions
- Update DWGM accreditations in accordance with transactions to a DWGM interface point

Revenue requirement and fees

The DAA revenue requirement is budgeted to remain relatively flat. Gas consumption growth provides scope for fee increases less than the increase in the revenue requirement.

From FY2021-22 two variable fees apply:

- Other transport fees of 0.03324 ($/GJ) which have decreased 7.8% compared with the current variable fee
- Compression fee of 0.02818 ($/GJ) which is remaining unchanged from 2021-22

Table 24 DAA revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	1.4	1.38	0.0	-1.2%
Gas Consumption (DAA) (TJ) – Transportation	35,570	39,556	3,986	11.2%
Gas Consumption (DAA) (TJ) – Compression	6,559	7,810	1,251	19.1%
Fees				
Other transportation fee ($/GJ)	0.03605	0.03324	-0.0028	-7.8%
Compression fee ($/GJ)	0.02818	0.02818	0.0	0.0%
Initial Registration Fee - Auction participants ($ per participant)	15,914	16,311	398	2.5%

Note: the variable fee for DAA is including a fee of $0.00294 relating to OTS code panel.

2.15 Operational Transportation Service (OTS) Code Panel

Purpose of this function

To assess and consult on proposals to amend the Operational Transportation Service Code and develop proposals to amend the Code, prepare impact and implementation reports on proposals, make recommendations in relation to proposals, report to the AER on proposals, develop proposals at the request of the AER and other related functions

Revenue requirement and fees

OTS Code Panel revenue requirement is budgeted to increase 10.5% due mainly to increased forecast volumes. The fee of $0.00294 per GJ is levied on all CTP and DAA trades.

Table 25 OTS Code Panel revenue requirement and fee

	Budget 2021-22	Budget 2022-23	Variance	Variance
OTS Code Panel Revenue Requirement ($m)	0.13	0.14	0.01	10.5%
OTS Code Panel ($/GJ)	0.00318	0.00294	-0.00025	-7.8%

Other notes

AEMO is permitted to recover costs incurred in relation to the OTS Code Panel including establishing and operating the OTS Code Panel, the participation of the AEMO member on the OTS Code Panel and providing services to facilitate the functioning of the OTS Code Panel.

2.16 Gas Bulletin Board (GBB)

Purpose of this function

To provide information relating to gas production, transmission, storage, and usage for facilities that are connected to the east coast gas market

GBB provides market participants timely data to assist in decision making. This includes capacity outlooks, nominations and forecasts, actual flows, line pack adequacy and additional information for maintenance planning

Revenue requirement and fees

The revenue requirement has increased in 2022-23 due to under recovery in 2021-22 and escalation of labour costs.

Fees have been increased 27.8% to $0.0006267/GJ for Producers and $0.003209/GJ for Participants in Wholesale Gas Markets.

Table 26 GBB revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Revenue Requirement ($m)	1.96	2.52	0.6	28.7%
Gas Producers Production (PJ)	2,063	2,078	15	0.7%
Fees				
Producer ($/GJ)	0.0004904	0.0006267	0.000136	27.8%
Participants in Wholesale Gas Market ($/GJ)	0.002493	0.003209	0.000716	28.7%

2.17 Western Australian Gas Services Information (GSI)

Purpose of this function

To ensure:

- Security, reliability, and availability of the supply of natural gas
- Efficient operation and use of natural gas services
- Efficient investment in natural gas services
- Facilitation of competition in the use of natural gas services

The GSI function includes the WA GBB and WA GSOO:

- Similar to the GBB on the East Coast, the WA GBB is an information website hub to provide flow information on gas, transmission, storage, emergency management with supply disruptions, and demand in WA
- The WA GSOO is an annual planning document providing medium to long-term outlook of WA gas supply and demand and transmission and storage capacity.

Revenue requirement and fees

The GSI recovery is to decrease to $1.56m in 2022-23 from $1.75m in 2021-22, this includes returning of surplus from prior year, partially offset by increases in underlying costs.

Table 27 GSI revenue requirement and fees

	Budget 2021-22	Budget 2022--23	Variance	Variance
GSI revenue requirement ($m)	1.75	1.56	-0.19	-11.0%

Other notes

The current three-year ERA determination on AEMO's allowable revenue and capital expenditure covers the period from 1 July 2022 to 30 June 2025.

2.18 Other budgeted revenue requirements

Purpose of this function

AEMO also collects revenue to recover the costs of the following functions.

- The SA planning function expenditure is budgeted to remain stable in 2022-23
- Expenses associated with administration of the Settlement Residue Auction (SRA) 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.

Table 28 Other revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
SA Planning ($m)	1.00	1.00	0.00	0.0%
Settlement Residue Auctions ($'000)	0.68	0.75	0.07	10.3%

2.19 Energy Consumers Australia (ECA)

Purpose of this function

To promote the long-term interests of energy customers, residential and small business customers

Revenue requirement and fees

AEMO is required to recover the funding for the ECA from market participants (i.e., pass through recovery). The budgeted ECA revenue requirement to be recovered in 2022-23 is $6.02m (2021-22: $6.43m).

The electricity ECA fee is $0.01104 per connection point per week in 2022-23.

The gas ECA fee is $0.03925 per customer supply point per month in 2022-23 (1.7% increase). The fee increase is largely due to recovery of the 2021-22 deficit.

Table 29 ECA revenue requirement and fees

	Budget 2021-22	Budget 2022-23	Variance	Variance
Electricity				
Revenue Requirement ($m)	6.43	6.02	-0.41	-6.3%
Electricity FRC - Connection Points (Millions)	10.49	10.59	0.11	1.0%
Electricity Fee ($/connection point for small customers per week)	0.01185	0.01104	-0.00081	-6.8%
Gas				
Revenue Requirement ($m)	2.19	2.26	0.08	3.6%
MIRN's Basic Meters - Total (Millions)	4.73	4.81	0.08	1.6%
Gas Fee ($/customer supply point per month)	0.03861	0.03925	0.00064	1.7%

Appendix A.

A1.1 Consolidated Profit and Loss

Table 30 AEMO Enterprise Consolidated Profit and Loss

	AEMO (excl. Vic TNSP)			Victorian TNSP			AEMO		
	Budget 2021-22 $'m	Budget 2022-23 $'m	Variance $'m	Budget 2021-22 $'m	Budget 2022-23 $'m	Variance $'m	Budget 2021-22 $'m	Budget 2022-23 $'m	Variance $'m
REVENUE									
Fees and Tariffs	255.0	378.5	123.5	-	-	-	255.0	378.5	123.5
TUoS Income	-	-	-	603.0	623.9	20.9	603.0	623.9	20.9
PCF Fees	1.0	0.1	(0.9)	-	-	-	1.0	0.1	(0.9)
Settlement Residue	(0.1)	(0.0)	0.1	43.5	20.0	(23.5)	43.4	20.0	(23.4)
Other Revenue	19.5	30.8	11.3	58.4	66.0	7.6	77.9	96.8	18.9
TOTAL REVENUE	**275.5**	**409.3**	**133.8**	**275.5**	**709.9**	**434.4**	**275.5**	**1,119.2**	**843.7**
NETWORK CHARGES	0.1	-	(0.1)	(678.7)	(663.3)	15.4	(678.7)	(663.3)	15.3
NET REVENUE	**275.5**	**409.3**	**133.9**	**26.2**	**46.6**	**20.4**	**301.7**	**455.9**	**154.3**
OPERATING EXPENDITURE	-		-	-			-		-
Total Labour	155.6	191.4	35.9	155.6	17.8	(137.8)	155.6	209.2	53.6
Consulting	10.9	21.1	10.2	10.2	10.7	0.5	21.1	31.8	10.7
Fees-Agency, Licence and Audit	2.0	2.6	0.6	2.0	-	(2.0)	2.0	2.6	0.6
Information Technology & Telecommunication	47.3	71.5	24.1	47.3	0.0	(47.3)	47.3	71.5	24.1
Occupancy	7.7	10.0	2.3	-	-	-	7.7	10.0	2.3
Training & Recruitment	3.5	5.0	1.5	3.5	0.1	(3.4)	3.5	5.1	1.6
Travel & Accommodation	1.9	2.3	0.4	1.9	0.1	(1.8)	1.9	2.3	0.5
Other Expenses from Ordinary Activities	10.2	13.1	2.9	10.2	0.0	(10.2)	10.2	13.1	2.9
Depreciation and Amortisation	43.9	69.0	25.1	0.1	0.1	0.0	43.9	69.0	25.1
Financing Costs	2.1	9.4	7.4	-	-	-	2.1	9.4	7.4
OPERATING EXPENDITURE (excluding external recoverable costs)	**285.0**	**395.4**	**110.4**	**285.0**	**28.7**	**(256.3)**	**285.0**	**424.2**	**139.1**
External Recoverable Consultancy	3.6	6.2	2.6	3.6	3.2	(0.4)	3.6	9.3	5.7
Corporate Recovery (TNSP)	(10.7)	(18.0)	(7.3)	10.7	18.0	7.3	0.0	(0.0)	(0.0)
TOTAL OPERATING EXPENDITURE	**278.0**	**383.6**	**105.7**	**35.7**	**49.9**	**14.2**	**313.6**	**433.5**	**119.9**
ANNUAL SURPLUS / (DEFICIT)	**(2.5)**	**25.7**	**28.2**	**(9.5)**	**(3.3)**	**6.2**	**(11.9)**	**22.4**	**34.4**
Transfers to Reserves	(1.0)	(0.3)	0.7	(1.0)	-	1.0	(1.0)	(0.3)	0.7
Brought Forward Surplus	(53.6)	(72.8)	(19.3)	(53.6)	6.8	60.4	(53.6)	(66.0)	(12.4)
ACCUMULATED SURPLUS / (DEFICIT)	**(57.0)**	**(47.4)**	**9.6**	**3.5**	**3.6**	**0.1**	**(53.5)**	**(43.9)**	**9.6**

Appendix B. Fee schedules

B1.1 Fee schedule of electricity functions

Table 31 Budgeted total revenue requirement by function

Function	Budget 2022-23 $'000	Rate	Paying Participants
NEM			
General Fees (unallocated)	58,729	$0.33365/MWh of customer load	Market Customers
Allocated Fees			
Market Customers	73,998	$0.42039/MWh of customer load	Market Customers
Wholesale Participants	63,036	Daily rate calculated on 2021 capacity/energy basis	Wholesale Participants
NEM Revenue Requirement	195,762		
Participant Compensation Fund	51	Daily rate calculated on capacity/ energy basis	Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers
Registration fees	2,876		Participants that intend to register
Other	23,698		Dependent on service provided
Project developer		$6,524 per facility	Project developers
NEMDE queue		$15,836 per application	Registered participants
TOTAL NEM	**222,388**		
FRC ELECTRICITY			
FRC operations	13,916	$0.02519 per connection point per week	Market Customers with a Retail Licence
Other		$897 per book build application	Voluntary Book Build Participant Accreditation Fee
TOTAL FRC ELECTRICITY	**13,916**		
National Transmission Planner	19,633		Transmission Network Service Providers
Energy Consumers Australia	6,024	$0.01104/connection point for small customers/week	Market Customers
Additional Participant ID		$5,807 per additional participant ID	Existing Participants
IT UPGRADE AND 5MS/GS COMPLIANCE			
Market Customers	37,540	$0.21327/MWh of customer load	Market Customers
Wholesale Participants	5,609	Daily rate calculated on 2021 capacity/energy basis	Wholesale Participants

Function	Budget 2022-23 $'000	Rate	Paying Participants
Total IT upgrade and 5MS/GS compliance	43,149		
DER			
Market Customers	4,192	$0.02382MWh of customer load	Market Customers
Wholesale Participants	1,048	Daily rate calculated on 2021 capacity/energy basis	Wholesale Participants
Total DER	5,241		
WA WHOLESALE ELECTRICITY MARKET			
WEM Market Operator fee	14,232	$0.4913/MWh	WA Market Customers and Generators
WEM System Management fee	27,667	$0.6646/MWh	WA Market Customers and Generators
WA WEM Revenue Requirement	41,899		
WA Economic Regulatory Authority fee	6,201	$0.1727/MWh	WA Market Customers and Generators
Energy Policy WA Coordinator Fee	2,579	$0.0718/MWh	WA Market Customers and Generators

Table 32 Fee schedule of new NEM registrations

Application type	2022-23 $
Registration as Scheduled Market Generator [A]	25,011
Registration as Semi-Scheduled Market Generator	33,710
Registration as Non-Scheduled Market Generator	21,748
Registration as Scheduled Non-Market Generator	18,486
Registration as Semi-Scheduled Non-Market Generator	28,273
Registration as Non-Scheduled Non-Market Generator	15,224
Transfer of Registration	11,962
Registration as Market Ancillary Service Provider	17,399
Registration as Market Customer	11,962
Registration as Market Small Generation Aggregator	11,962
Registration as Network Service Provider	10,874
Registration as Metering Co-ordinator (MC) [B]	11,962
Registration as Trader	15,224
Registration as Reallocator	14,136

Application type	2022-23 $
Registration as an Intending Participant	6,525
Classification of a Dedicated Connection Asset	5,437
Exemption from registration	6,525
Frequency Control Ancillary Services	
Classification of generating units as frequency control ancillary services (FCAS) generating units [B]	10,874
Classification of load as frequency control ancillary services load – new ancillary services or classify load in a new region [C]	10,874
Amendment of the relevant plant associated with its existing load classification, and/or aggregating further load to its existing load classification for frequency control ancillary services purposes	2,175
Wholesale Demand Response	
Registration as Demand Response Service Provider	17,399
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]	10,874
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	2,175
Aggregation of existing load already classified as wholesale demand response unit	2,175
Disbursement charges	
Disbursement Charge – Additional Energy Conversion Model – Semi Scheduled Market Generator	5,437
Disbursement Charge – Additional Energy Conversion Model – Non-Scheduled Market Generator	2,719

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 Market Ancillary Service Provider or Demand Response Service Provider.
D. This fee is additional to the fee required to register as a Demand Response Service Provider.

Table 33 Fee schedule of new WA WEM registrations

Application type	2022-23 $
Rule Participant Registration Application Fee	2,450
Facility Registration Application Fee	4,550
Facility Transfer Application Fee	2,450
Conditional Certification of Reserved Capacity	1,230
Resubmission - Application for Early Certified Reserved Capacity	11,250
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)	550

Note: Rule Participant De-registration and Facility De-registration will remain at zero.

Table 34 Fee schedule of new Power of Choice accreditations

Application type	2022-23 $
Initial Deposit – Embedded Network Manager	2,000
Initial Deposit – Metering Data Providers	5,000
Initial Deposit – Metering Providers	5,000
Incremental charge rate per hour	Per Table 38

B1.2 Fee schedule of gas functions

Table 35 Gas fee by function

Function	Rate 2022-23	Basis
Vic Declared Wholesale Gas Market		
Energy Tariff	0.11071	$/GJ withdrawn
Distribution Meter	1.3287	$/day per meter
PCF	Nil	$/GJ withdrawn
VIC Gas FRC	0.05650	$ per customer supply point/ mth
QLD Gas FRC	0.28627	$ per customer supply point/ mth
SA Gas FRC	0.21905	$ per customer supply point/ mth
NSW/ ACT Gas FRC	0.13949	$ per customer supply point/ mth
WA Gas FRC	0.12286	$ per customer supply point/ mth
Annual fee – members	22,434	per annum
Annual fee – associate members*	4,375	per annum
STTM		
Activity Fee	0.03382	$/GJ withdrawn
PCF Fee – Syd	Nil	$/GJ withdrawn per hub per ABN
PCF Fee – Adel	Nil	$/GJ withdrawn per hub per ABN
PCF Fee – Bris	Nil	$/GJ withdrawn per hub per ABN
Energy Consumers Australia	0.03925	$ per customer supply point/ mth
Gas Statement of Opportunities		
Producer fee	0.00027985	$/GJ produced
Retailer fee	0.02352	$ per customer supply point/ mth
Gas Supply Hub		
Fixed Fee – Trading Participants	12,000	$ per licence per annum
Fixed Fee – Trading Participants	12,000	$ per additional licence per annum

Function	Rate 2022-23	Basis
Fixed Fee – Reallocation participants	9,000	$ per licence per annum
Fixed Fee – Viewing participants	3,600	$ per licence per annum
Variable Fee – Daily product fee	0.03	$/GJ
Variable Fee – Weekly product fee	0.02	$/GJ
Variable Fee – Monthly product fee	0.01	$/GJ
Gas Trading Platform*		
Fixed Fee – commodity and capacity	12,000	$ per licence per annum
Fixed Fee – capacity only	7,000	$ per licence per annum
Variable transportation fee	0.008	$/GJ Daily/Weekly/Monthly
Variable compression fee	0.008	$/GJ Daily/Weekly/Monthly
Day Ahead Auction*		
Other transportation fee	0.033	$/GJ
Compression fee	0.028	$/GJ
Gas Bulletin Board		
Producers	0.00063	$/GJ withdrawn
Wholesale market participants	0.00321	$/GJ withdrawn
WA Gas Services Information	1,559	$'000
WA Economic Regulatory Authority revenue requirement	154	$'000
WA Energy Policy WA Coordinator revenue requirement	160	$'000
Additional Participant ID	5,807	$ per additional participant ID

Note: the variable fee for CTP and DAA is including a fee of $0.00294 relating to OTS code panel.
* Associate members are self-contracting users that are party to the WA Gas Retail Market Agreement.

Table 36 Fee schedule of new gas registrations

Market	Budget 2022-23	Basis
Victoria Retail Gas		
Market Participant - Retailer	20,661	$ per registration
Market Participant - Other	20,661	$ per registration
QLD Retail Gas		
Retailer	18,486	$ per registration
Self-Contracting User	18,486	$ per registration
SA Retail Gas		
Retailer	17,399	$ per registration
Self-Contracting User	17,399	$ per registration
NSW Retail Gas		
Retailer	20,661	$ per registration
Self-Contracting User	20,866	$ per registration
WA Retail Gas		
WA Retail Gas - Member	13,904	$ per member
WA Retail Gas - associate member	2,780	$ per associate member
Victoria Wholesale Gas		
Market Participant - Retailer	21,084	$ per registration
Market Participant - Trader	21,084	$ per registration
Market Participant - Distribution Centre	20,469	$ per registration
Short Tern Trading Market		
STTM User (BRI, ADL, SYD hubs)	21,392	$ per registration
STTM Shipper (BRI, ADL, SYD hubs)	21,392	$ per registration
STTM Allocation Agent	17,394	$ per registration
STTM Pipeline Operator	37,382	$ per registration
STTM Distributor	37,074	$ per registration
STTM Storage Facility Operator	37,382	$ per registration
STTM Production Facility Operator	37,382	$ per registration
Pipeline Capacity		
Part 24 Facility Operator	16,311	$ per registration
Day ahead auction – Auction Participant	16,311	$ per registration
Gas Bulletin Board		
BB allocation agents	16,311	$ per registration

Market	Budget 2022-23	Basis
BB transportation facility user	11,962	$ per registration
BB capacity transaction reporting agents	11,962	$ per registration

B1.3 Quoted Registration fees for registerable capacity

Table 37 Quoted registration fees for registerable capacity

Market
DWGM
Market Participant - producer
Market Participant - Transmission customer
Market Participant - Storage Provider
Participant - Declared transmission system service provider
Participant - Interconnected transmission pipeline service provider
Participant - Distributor
Participant - Producer
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

B1.4 AEMO charge-out rates

Table 38 AEMO charge-out rates*

Market	2022-23	Basis
Senior Leadership	510	$ per hour
Manager/ Specialist	430	$ per hour
Principal	340	$ per hour
Senior	300	$ per hour
Analyst/ Engineer	280	$ per hour
Officer/ Intern	240	$ per hour

Note, a $30/hour uplift will be applied to the rates in this table to reflect cost recovery for dedicated work undertaken for the Connections Reform Initiative

List of Tables

Symbols and abbreviations

Term	Definition
5MS	5 Minutes Settlement
BCG	Boston Consulting Group
CTP	Capacity Trading Platform
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DWGM	Declared Wholesale Gas Market
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
FCC	Finance Consultation Committee
FRC	Full Retail Contestability
GBB	Gas Bulletin Board
GJ	Gigajoule
GSOO	Gas Statement of Opportunities
GWh	Gigawatt hour
MWh	Megawatt hour
NEM	National Electricity Market
PJ	Petajoule
TJ	Terajoule
TNSP	Transmission Network Services Provider