Electricity Fee Structures

March 2021

Final Report and Determination

A final report and determination on electricity fee structures to apply to Participant fees from 1 July 2021

Important notice

PURPOSE

AEMO consults on its proposed fee structure for participant fees under clause 2.11 of the National Electricity Rules (Rules) and in accordance with the Rules consultation requirements detailed in rule 8.9 of the NER.

This document has effect only for the purposes set out in the Rules; and the Rules and the National Electricity Law (NEL) prevail over this document to the extent of any inconsistency.

This publication has been prepared by AEMO using information available at 22 March 2021.

DISCLAIMER

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies. AEMO has made every effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Executive summary

Background

AEMO has completed the review of the structure of the Participant fees to apply from 1 July 2021 under the National Electricity Rules (NER).

The review considered the structure to be applied to recover AEMO's budgeted revenue requirements, and not the actual amount charged, as the latter occurs through AEMO's annual budget and fee process.

AEMO conducted two stages of consultation with stakeholders and has published all submissions on its website. AEMO has considered the views and comments raised in the submissions, which have informed the determinations made in this Final Report.

Information

Table 1: Information on Final Report

Report Purpose	To present the final Participant fee structure determination to recover AEMO's budgeted revenue requirements for its electricity functions.
Date applicable	1 July 2021
Duration of fee determination	5 years, including a 2-year transition period. (The transition period, 1 July 2021 to 30 June 2023, will apply to certain elements of the fee structure as identified in this report. The final determination for those elements will apply from 1 July 2023 to 30 June 2026.)
Electricity functions covered in consultation	• The National Electricity Market (NEM). • Developing Retail Markets and administering Retail Competition – the current Full Retail Contestability (FRC) fee. • The National Transmission Planner (NTP) functions. • Major Reform Initiatives, including Five Minute Settlement (5MS) and Global Settlement (GS), and Distributed Energy Resources (DER) integration. • The Energy Consumers Australia (ECA) fees recovered by AEMO from Participant fees. • Registrations. • NEM Participant Compensation Fund (PCF). • Incremental service fees.
Consultation process overview	This consultation process undertaken by AEMO for the review of Participant fees in its electricity markets followed the Rules consultation procedure in clause 8.9 of the NER.

Milestone	Publication date	Submissions close	Comments

	Consultation paper	18 August 2020	23 September 2020	15 submissions received[1].
	Draft report	30 November 2020	4 February 2021	13 submissions received[2].
	Final report	26 March 2021	N/A	N/A
Inquiries	Mr Kevin Ly Group Manager Regulation kevin.ly@aemo.com.au			

Guiding principles for electricity fee structure

AEMO consults on its proposed fee structure for Participant fees in accordance with clause 2.11 of the NER. Under the Rules, AEMO only has the power to recover market fees from registered participants.

In determining the structure of Participant fees, AEMO must have regard to the National Electricity Objective (NEO). In addition, the structure of Participant fees must, to the extent practicable, be consistent with the following principles, which are stipulated in the NER, referred to in this document as the Fee Structure Principles and set out in detail in Appendix A:

- The structure of Participant fees should be simple.
- The components of Participant fees charged to each registered participant should be reflective of the extent to which AEMO's budgeted revenue requirements involve that registered participant.
- Participant fees should not unreasonably discriminate against a category or categories of registered participants.
- Fees and charges are to be determined on a non-profit basis that provides for full cost recovery.
- The structure of the Participant fees should provide for the recovery of AEMO's budgeted revenue requirements on a specified basis.

The operation of clause 2.11.1 also needs to be understood in the context of its surrounding provisions which deal with budgets and the payment of Participant fees (which are consulted on separately to this consultation and process):

- Under clause 2.11.3, AEMO is required to prepare and publish its budgeted revenue requirements.
- That budget must take into account and identify revenue requirements for the matters set out in clause 2.11.3(b).
- Some, but not all of these matters are referred to in the components of Participant fees specified in section 2.11.1(c).
- However, AEMO may adopt 'components' of Participant fees which are different to or more than those set out in clause 2.11.1(c).
- Section 2.11.1(b)(2) of the NER provides that Participant fees should recover the budgeted revenue requirements for AEMO determined under clause 2.11.3.
- Under section 2.11.2, AEMO may charge Registered Participants the relevant component of Participants fees in accordance with the structure of Participant fees.

[1] Submissions received in the first stage of consultation is published on the consultation page: https://aemo.com.au/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review

[2] Submissions received in the second stage of consultation is published on the consultation page: https://aemo.com.au/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review

Consequently, the scheme of clauses 2.11.1 to 2.11.3 of the NER is:

- To require AEMO to determine the structure of Participant fees according to certain rules;
- To require AEMO to determine AEMO's budgeted revenue requirements according to certain rules; and
- To empower AEMO to recover the budgeted revenue requirements through charging registered participants in accordance with the structure of Participant fees.

Stakeholder feedback

AEMO received 13 written submissions to its Draft Report and determination published on 30 November 2020[3]. AEMO also held video meetings with stakeholders (individually) who requested them, namely:

- Australian Energy Council (AEC) – 22 January 2021;
- Energy Networks Australia (ENA) – 19 February 2021; and
- AusNet Services – 23 February 2021.

Copies of all written submissions have been published on AEMO's website at: https://aemo.com.au/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review.

A summary of submissions with AEMO's response on the key matters for consultation is outlined in section 2.

Changes to the Draft Report

In developing this Final Report, AEMO has carefully considered the issues raised in its Consultation Paper and Draft Report, stakeholder views raised through submissions, further internal analysis and discussion, the NER Fee Structure Principles, and had regard to the NEO.

As a result, AEMO has determined some changes to some elements of the fee structure since the Draft Report. The detail of these changes is provided in the main section of this Final Report, but in summary:

- Charging network service providers (NSPs) – AEMO's final determination is that Distribution Network Service Providers (DNSPs) will not be charged Participant fees. However, their involvement with AEMO's systems and processes will be monitored throughout the next fee period and should there be a material increase in involvement (e.g. as a consequence of regulatory reform), AEMO will consider a declared NEM fee project consultation process to recover those costs. Note, the proposal in the Draft Report to recover costs from Transmission Network Service Providers (TNSPs) has been adopted.
- Recovery of the Five Minute Settlement (5MS) program – AEMO's final determination is that all costs from the 5MS program, including upgrades to legacy IT systems and costs of complying with the 5MS and Global Settlements rule changes, are to be recovered on a consolidated basis through a new fee category known as "IT upgrade & 5MS/GS compliance". This will be recovered from Generators/MNSP/SGAs/MASPs/DRSPs collectively referred to in this report as "Wholesale Participants", and Market Customers as a separate fee, charged using the same metrics as those determined for the core NEM function fee.
- Recovery of Distributed Energy Resource (DER) integration – AEMO's final determination is that Demand Response Service Providers (DRSPs) will not be charged separately for recovery of <10% of the Wholesale Demand Response (WDR) mechanism establishment costs. The costs of the DER program, including the WDR mechanism, will be allocated to Market Customers (80%) and Wholesale Participants (20%).

The final fee structures in comparison to the existing structure

Table 2 outlines the final determination for the electricity functions that were consulted on to apply from 1 July 2021.

[3] The Consultation Paper is available on AEMO's website at: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-market-participant-fee-structure-review/final-aemo-electricity-fee-structure-consultation-paper_aug-2020.pdf?la=en

Table 2: Comparison of final fee structures for the next fee period with the existing structures

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
National Electricity Market (NEM)	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated costs" and are apportioned on the following basis: (a) 54% Market Customers; and (b) 46% Generators and Market Network Service Providers of which: (i) two-thirds is apportioned to Market Generators in respect of their market generating units, Non-Market Scheduled Generators in respect of their non-market scheduled generating units, Semi-Scheduled Generators in respect of their semi-scheduled generating units and Market Network Service Providers in respect of their market network services; (ii) one-third is apportioned only to Market Generators in respect of their market generating units and Market Network Service Providers in respect of their market network services; and (iii) none is apportioned to Non-Market Non-Scheduled Generators in respect of their non-market non-scheduled generating units. – Generator and Market Network Service Provider charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity in the previous calendar year of generating units and market network services; and (ii) 50% charged as a daily rate based on MWh energy scheduled or metered (in previous calendar year). – Market Customer charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated costs" and are apportioned on the following basis: (a) 54% Market Customers; and (b) 46% Generators (excluding Non-Market Non-Scheduled Generators) and Market Network Service Providers and SGAs and MASPs/DRSPs (collectively referred to in the fee structure as "Wholesale Participants") of which: (i) does not further apportion between Market/Non-Market Scheduled/Semi-Scheduled Generators and MNSPs or to Market Generators and MNSPs. – Wholesale Participant charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity (of energy or FCAS markets) in the previous calendar year of units from Wholesale Participants; and (ii) 50% charged as a daily rate based on MWh energy, or in the case of MASPs/DRSPs the equivalent FCAS enablement, scheduled or metered (in previous calendar year). – Market Customer charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customer charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated costs" and are apportioned on the following basis: (a) 26.6% Market Customers; (b) 55.9% Wholesale Participants of which: (i) does not further apportion between Market/Non-Market Scheduled/Semi-Scheduled Generators and MNSPs or to Market Generators and MNSPs; and (c) 17.5% to Transmission Network Service Providers (excluding Murraylink and Directlink). – Wholesale Participant charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity (of energy or FCAS markets) in the previous calendar year of units from Wholesale Participants; and (ii) 50% charged as a daily rate based on MWh energy, or in the case of MASPs/DRSPs the equivalent FCAS enablement, scheduled or metered (in previous calendar year). – Market Customer charges: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week. – Transmission Network Service Provider charges: charged on the basis of energy consumed for the latest completed financial year. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements

	market transactions in the billing period. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customer charges Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period.	Customers during that financial year. Rate applied to actual spot market transactions in the billing period.	are "unallocated costs" and are allocated 100% to Market Customers. – Market Customer charges: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week.
Electricity Retail Markets	• From 1 July 2016 to 30 June 2019: – Charged to Market Customers with a retail licence and levied for a financial year at a rate per MWh based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers with a retail licence during that financial year against regional reference nodes. Rate applied to actual spot market transactions in the billing period. • From 1 July 2019 to 30 June 2021: – Charged to Market Customers with a retail licence and levied on a per connection point basis per week.	• No change to existing structure.	• No change to existing structure.
National Transmission Planner	• From 1 July 2016 to 30 June 2020: – Charged to Market Customers and levied at a rate per MWh based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • From 1 July 2020 to 30 June 2021: – Charged to Coordinating Network Service Providers in accordance with the mechanism in the transitional rule based on 2019 consumption levels.	• From 1 July 2021 to 30 June 2022: – Charged to Coordinating Network Service Providers in accordance with the mechanism in the transitional rule based on 2019 consumption levels. • From 1 July 2022 to 30 June 2023: – Charged to Coordinating Network Service Providers on the respective jurisdiction's consumption for the latest completed financial year.	• From 1 July 2023 to 30 June 2026: – Charged to Coordinating Network Service Providers on the respective jurisdiction's consumption for the latest completed financial year.
IT upgrade and 5MS/GS compliance	• NA	• For 5MS/GS legacy and specific upgrade costs, both capital and operational expenditure: (a) 87% allocated to Market Customers (same fee structure as	• For 5MS/GS legacy and specific upgrade costs: (a) 82% allocated to Market Customers (same fee structure as core NEM allocated Market Customer fee); and

		core NEM allocated Market Customer fee); and (b) 13% allocated to Wholesale Participants (same fee structure as core NEM allocated Wholesale Participant fee).	(b) 18% allocated to Wholesale Participants (same fee structure as core NEM allocated Wholesale Participant fee).
DER program	• NA	• 80% allocated to Market Customers charged per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • 20% allocated to Wholesale Participants levied on the same basis as above for NEM.	• 80% allocated to Market Customers levied on the basis: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week. • 20% allocated to Wholesale Participants levied on the same basis as above for NEM.
Energy Consumers Australia	• Charged to Market Customers and levied at a rate per small customer (as defined in the National Energy Retail Law) connection point.	• No change to existing structure.	• No change to existing structure.
NEM Participant Compensation Fund	• Charged to Scheduled Generators, Semi Scheduled Generators and Scheduled Network Service Providers in accordance to the NER, levied on 50% maximum capacity and 50% energy generated in the previous calendar year.	• No change to existing structure	• No change to existing structure.
Registration fees	• The fee structure for registration fees for each application type to continue to be charged. • The actual registration fee amounts are to be set as part of the annual budget.	• No change to existing structure.	• No change to existing structure.
Incremental charges	• Where it is practical for AEMO to identify that doing something specific for a participant, and that action causes identifiable and material costs for AEMO, AEMO can seek to levy fees to recover the incremental costs incurred.	• No change to existing structure.	• No change to existing structure.

Contents

1. Final Electricity Markets Fee Structure

1.1 Term of the fee determination

1.1.1 Final determination

The final fee structure is to have a duration of five years, from 1 July 2021 to 30 Jun 2026, with a transition period of two years, from 1 July 2021 to 30 June 2023, to allow for the more fundamental changes in the determination to take effect.

Table 3: Final determination – term of fee determination compared to existing structure

	Existing structure (1 July 2016 to 30 June 2021)	Final structure (1 July 2021 to 30 June 2026)
Term of fee determination	Five-year term.	Five-year term including a two-year transition period.

1.1.2 Rationale

The final determination has been made for the following reasons:

- A five-year fee term will provide participants with greater certainty over costs, as well as providing AEMO with more certainty regarding costs to be recovered from over a longer period.
- The five-year fee term (with a two-year transition period) aligns better with the NER principles, particularly the involvement principle, than the three-year or five-year (with no transition period) option by providing more certainty but allowing for an appropriate transition.
- In AEMO's view, the transition period will allow TNSPs sufficient time to seek to make arrangements necessary to recoup Participant fees which may include seeking a rule change to allow recovery, noting that based on AEMO experience and discussion with the AEMC, a rule change proposal takes approximately nine months to complete. AEMO will fully support and assist TNSPs with the proposal.
- In AEMO's view, the transition period will allow Market Customers to make any necessary changes to their systems and processes to account for proposed changes to the Market Customer fee.

Further, when assessed against the NER principles and NEO, AEMO is of the view a transition period would:

- Be relatively straightforward as the transitional structure remains generally the same as the existing structure, apart from the inclusion of separate 5MS and DER Integration functions;
- On the whole, reflect the level that registered participants are involved in AEMO's core NEM activities as these participant categories continue to remain relevant;
- Not unreasonably discriminate against any participant class, rather it allows consideration of the implementation requirements of the proposed changes;
- Continue to allow AEMO to recover its budgeted revenue requirements in a similar manner to the previous determination; and
- Continue to have regard to the NEO by ensuring implementation of the changes can be progressed effectively and efficiently in the longer-term interests of consumers.

1.2 National Electricity Market (NEM) fee

This section deals with the structure of the fee to recover costs associated with AEMO's core NEM functions in the following 10 broad outputs, which have been detailed further in Appendix B:

- Power system security
- Power system reliability
- Market operation
- Wholesale metering and settlements
- Prudential supervision
- Market development
- Information dissemination including stakeholder engagement and consultation
- Retail markets
- Registration[4]
- DER integration[5].

Appendix B also details the methodology used to determine the level of involvement to inform the allocations to Registered Participants.

1.2.1 Final determination

The determination of the final NEM fee structure is as follows:

- For the transition period, that is 1 July 2021 to 30 June 2023, no change to the existing structure (see Figure 1), except:
  - SGAs and MASPs/DRSPs will be now included in the Generators/MNSP allocation (SGAs, MASPs/DRSPs, Generators (excluding Non-Scheduled Non-Market Generators) and MNSPs collectively referred to in this report as "Wholesale Participants") and charged in a similar manner; and
  - Removal of the division of costs between Non-market generators/MNSPs and Market generators/MNSPs, that is two-thirds of Generators/MNSP costs to all Generators and MNSP (except Non-Market Non-Scheduled Generators) and one-third of Generator/MNSP costs to only Market generators and MNSP.
- From 1 July 2023 to 30 June 2026, the allocation of core NEM fees will be amended (as per Figure 2) in the following manner:
  - Wholesale Participants to be allocated 55.9%, charged on a similar basis to the existing structure;
  - Market Customers to be allocated 26.6%, charged a combination of $/MWh and $/NMI on a 50/50 basis; and
  - TNSPs to be allocated 17.5%, charged on a basis of energy consumed for the latest completed financial year.

[4] This relates to activities that AEMO teams perform to support the registration process that are not captured in the Registration fees section of the fee structure.

[5] This relates to activities that AEMO teams perform related to DER integration that are not captured in the DER Integration capital program, which AEMO proposes to be a separate fee in the fee structure.

Figure 1: Allocation for the core NEM function fee to apply during the transition period

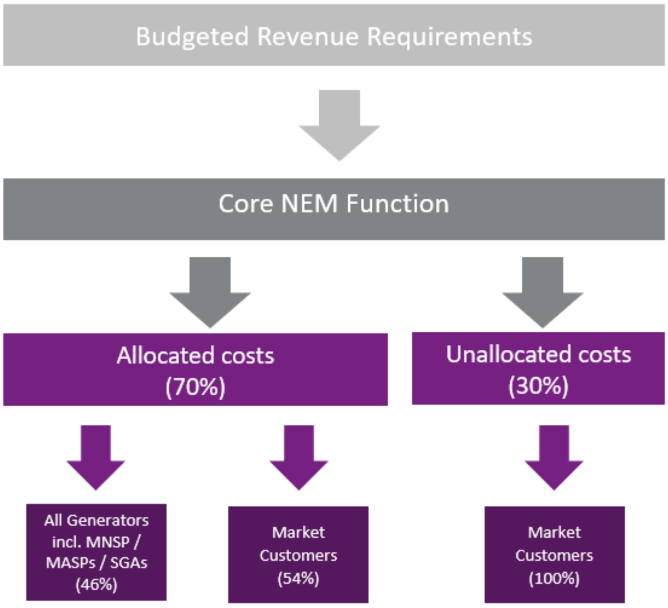


Figure 2: Proposed approximate allocation for the core NEM function Allocated Costs to apply from 1 July 2023 to 30 June 2026[6]

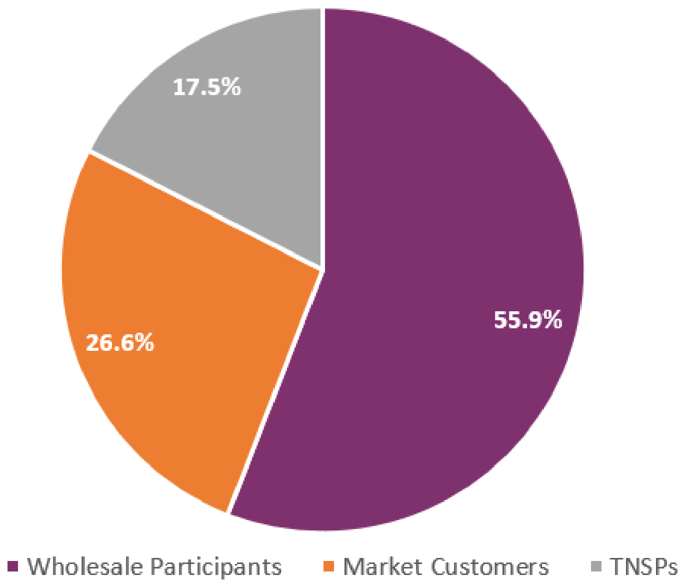


Table 4: Final determination – NEM fee structure compared to existing structure

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
National Electricity Market	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated	• Allocated direct costs: – 70% of AEMO's general budgeted revenue requirements are "allocated

[6] Core NEM fee allocations are shown in the Final Report to the first decimal place.

	costs" and are apportioned on the following basis: (a) 54% Market Customers; and (b) 46% Generators and Market Network Service Providers of which: (i) two-thirds is apportioned to Market Generators in respect of their market generating units, Non-Market Scheduled Generators in respect of their non-market scheduled generating units, Semi-Scheduled Generators in respect of their semi-scheduled generating units and Market Network Service Providers in respect of their market network services; (ii) one-third is apportioned only to Market Generators in respect of their market generating units and Market Network Service Providers in respect of their market network services; and (iii) none is apportioned to Non-Market Non-Scheduled Generators in respect of their non-market non-scheduled generating units. – Generator and Market Network Service Provider charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity in the previous calendar year of generating units and market network services; and (ii) 50% charged as a daily rate based on MWh energy scheduled or metered (in previous calendar year). – Market Customer charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot	costs" and are apportioned on the following basis: (a) 54% Market Customers; and (b) 46% Wholesale Participants of which: (i) does not further apportion between Market/Non-Market Scheduled/Semi-Scheduled Generators and MNSPs and to Market Generators and MNSPs. – Wholesale Participant charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity (of energy or FCAS markets) in the previous calendar year of units from Wholesale Participants; and (ii) 50% charged as a daily rate based on MWh energy, or in the case of MASPs/DRSPs using the data specific to the service these participants provide (in previous calendar year). – Market Customer charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customer charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period.	costs" and are apportioned on the following basis: (a) 26.6% Market Customers; (b) 55.9% Wholesale Participants of which: (i) does not further apportion between Market/Non-Market Scheduled/Semi-Scheduled Generators and MNSPs and to Market Generators and MNSPs; and (c) 17.5% to Transmission Network Service Providers (excluding Murraylink and Directlink). – Wholesale Participant charges: (i) 50% charged as a daily rate based on aggregate of the higher of the greatest registered capacity and greatest notified maximum capacity (of energy or FCAS markets) in the previous calendar year of units from Wholesale Participants; and (ii) 50% charged as a daily rate based on MWh energy, or in the case of MASPs/DRSPs using the data specific to the service these participants provide (in previous calendar year). – Market Customer charges: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week. – Transmission Network Service Provider charges: charged on the basis of energy consumed for the latest completed financial year. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customer charges: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and (ii) 50% charged on a per connection point basis per week.

	market transactions in the billing period. • Unallocated costs: – 30% of AEMO's general budgeted revenue requirements are "unallocated costs" and are allocated 100% to Market Customers. – Market Customer charges: Rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period.		

1.2.2 Rationale

Core NEM fee allocation

Analysis of NEM costs, based on the 2020/21 budget, identified that those costs assessed to be direct, attributable costs to key NEM outputs are approximately 70% and those costs that are assessed to be indirect, non-attributable costs are approximately 30% of NEM costs.

Changes to the attribution of the core NEM allocated fee to participants since the previous determination have been made having regard to the 'reflective of involvement' criteria. The determination has been informed by a survey of AEMO Senior Managers who were tasked with allocating their Division's costs against each of the key outputs identified above on the basis of time of interaction and involvement with specific participant classes.

Results of the cost allocation survey indicated the following key differences to the current NEM allocation:

- AEMO's activities involve other generator participant categories including Small Generator Aggregators (SGAs) and Market Ancillary Service Providers (MASPs)/Demand Response Service Providers (DRSPs).
- An increase in allocation to the Generators reflecting their increased involvement with AEMO's functions.
- There was a material level of allocation to TNSPs reflecting the increase of their involvement with AEMO's operational activities.
- A small allocation to DNSPs reflecting their involvement with AEMO's operational activities.
- The Market Customer allocation was therefore less than the current NEM allocation.

As outlined previously, clause 2.11.1(b)(2) of the NER, all of AEMO's budgeted revenue requirements must be recovered through Participant fees. In addition, AEMO must have regard to the NEO, and the structure of Participant fees must, to the extent practicable, be consistent with the Fee Structure Principles. It should be noted that the Rules do not expressly indicate that one fee structure principle should have greater weight than the others. In application, it will not always be practicable for AEMO to satisfy all of the principles or to an equal degree. Therefore, meeting the Rules requirements typically requires a trade-off between the principles, and AEMO's objective is to strike a balance between the principles wherever possible.

As a result, applying the NER requirements, and in order to reflect AEMO's cost allocation survey, it was determined that the existing attribution of the core NEM allocated fee should be amended as shown in Figure 2.

In relation to the recovery of unallocated costs of the core NEM fee, it has been decided that the current attribution to Market Customers for the duration of the fee period is an appropriate efficient method for recovering unallocated costs from Registered Participants that are closest in the electricity supply chain to end users.

Wholesale Participants charging

Since the last fee structure determination there has been (and will continue to be) a significant increase in variable renewable energy (VRE) or Semi-scheduled and Non-scheduled generators, and AEMO's cost allocation survey identified that there has been an increased level of involvement from the Generator participant category. Going forward, it is expected that the level of involvement from this generator class will account for a higher proportion of AEMO's revenue requirements for core NEM activities (compared with other categories of generators) as greater challenges with modelling, controlling and operating the power system will result from the impact of their penetration levels in the NEM.

As such the final determination in relation to the structure of fees to categories of generators:

- Maintains simplicity of the generator fee and avoids discriminating between generators, while continuing to have regard to the NEO.
- Reflects the results from the core NEM cost allocation survey, to the extent practicable.
- Over time, inherently takes account of the increased level of involvement of VRE in AEMO's revenue requirements related to the NEM compared to other generators.
- Maintains the existing MWh/MW fee metric, as there is no clear reason to change to another metric based on the fee structure principles, having regard to the NEO and stakeholder submissions which supported this fee metric.
- Removes the existing unnecessary complexity to the attribution of generator charges to Non-market scheduled generators as there are no Non-market scheduled or Non-market semi-scheduled generators registered in the NEM.
- Captures participants other than Scheduled and Semi-scheduled generators, e.g. MASPs, SGAs, as well as new participants like DRSPs that will emerge as the WDR mechanism becomes effective from October 2021[7].

Market Customer fee

In making the final determination (that the market customer fee is to be charged 50% on a $/MWh basis and 50% on a $/NMI[8] basis), AEMO firstly considered whether a "variable" $/MWh, a "fixed" $/NMI or an alternative fee is more consistent with the Rules requirements and having regard to the NEO.

While the variable $/MWh fee may encourage consumers to reduce, at the margin, electricity use[9], a Market Customer with a consumer that has a rooftop PV will be charged on a "net" basis; that is, exports from the NMI will be deducted from consumption, reducing the fees paid which effectively means that a customer without rooftop PV is paying more than a customer with rooftop PV. This may result in a Market Customer with a low proportion of customers with solar rooftop PV being treated differently to a Market Customer with a higher proportion of consumers with rooftop PV, which may not be consistent with the non-discriminatory principle.

AEMO also considered the use of gross metered data, and assessment of this option concluded that while the approach may have benefits to simply charging on a net basis, it still suffers from charging fixed costs on a variable basis. Specifically, charging fixed costs on a variable basis encourages consumers to vary their consumption to reduce costs, yet with costs being fixed they do not.

Therefore, the final determination on the market customer fee has been determined for the following reasons:

[7] It is expected MASPs would participate in the WDR under a new registration category called Demand Response Service Providers (DRSP).

[8] The $/NMI portion is to be calculated in the same manner as the $/NMI Electricity Retail Markets fee for all NMIs.

[9] For example, a variable fee may encourage a large smelter to reduce consumption, or a residential customer being encouraged to reduce consumption either directly or through investment in solar PV or demand-side management initiatives.

- Is reflective of the level of involvement from Market Customers regarding revenue requirements for core NEM activities due to the increase in TNSPs involvement with AEMO's revenue requirements as a result of AEMO's activities specifically undertaken for TNSPs.
- Although a fully fixed $/NMI tariff may seem to discriminate in favour of larger consumers, this is reasonable as a consumption fee is not more reflective of involvement in AEMO's revenue requirements.
- Improvements to the variable fee were considered to have little additional benefit as opposed to rebalancing the fee to a fixed fee on a per NMI basis.
- Stakeholder feedback has identified consumers are responsive to energy prices and will moderate consumption accordingly, therefore introducing a $/NMI fee, in part, appears appropriate to allow for consumption changes to occur in response to the fee while also ensuring that Participant fees recover the budgeted revenue requirements for AEMO.
- AEMO recognised that neither NMI nor MWh are perfect metrics upon which to charge participants (and their consumers) therefore, on balance, a combined fixed and a variable fee demonstrates greater consistency with the fee structure principles, has regard to the NEO, and AEMO is more readily able to implement the $/MWh and $/NMI charge as they are fees that AEMO already implements in the fee structure.

Charging NSPs

Although the current fee structure does not charge NSPs, it is a requirement to consider every fee structure determination afresh. Since the last fee determination was made in 2015, an increasing amount of AEMO's activities involve TNSPs and DNSPs in the management of power system security and power system reliability and operations. Correspondingly, the cost allocation survey indicated the level of involvement with both TNSPs (17.5%) and DNSPs (3.0%) has increased since the previous fee determination, though the level of involvement with DNSPs is significantly less than with TNSPs.

While AEMO's Draft Report proposed to charge DNSPs, after considering stakeholder submissions and further consideration of the principles, the final determination has determined not to charge this participant class due to the immateriality of the level of involvement concluded from the cost allocation survey. The structure of Participant fees must be consistent with the principles, including the reflective of involvement and the simplicity principles, to the extent practicable. In AEMO's view this involves consideration of the level of involvement of participants and whether it is practicable to charge fees to all participants that have a minor or immaterial level of involvement with AEMO's revenue requirements. A structure that charges fees to many participants with minor involvement with AEMO's costs such as the level of DNSPs, is less simple, especially in light of the material involvement of other participants such as TNSPs, Wholesale Participants and Market Customers. The fee principles do not prescribe a level of involvement that should be subject to fees and there is no single identifiable point where simple becomes complicated. The level of involvement of 3%, though is considered to be immaterial and is materially different from the level of involvement of TNSPs, Wholesale Participants and Market Customers which are significantly higher. With regard to the NEO, the 3% will be reallocated to Market Customers. This is considered an appropriate means to reallocate the DNSP allocation.

AEMO will review the structure of fees, including the level of involvement, afresh for future fee structure periods by having regard to the fee structure principles and the NEO based on the circumstances at the time. Should the level of DNSP involvement increase materially during the next fee period as a result of a major change, (e.g. in response to regulatory changes), then a declared NEM project consultation process could be undertaken to determine future charging of DNSPs.

AEMO also considered stakeholder feedback on the draft proposal to charge TNSPs. After further assessment, AEMO has determined to adopt the proposal in the Draft Report and determined to charge the core NEM fee to TNSPs (excluding Murraylink and Directlink which have no direct involvement with AEMO's revenue requirements), as charging TNSPs:

- Is consistent with the reflective of involvement principle as initial survey results and verification of those results indicate TNSPs' material involvement with AEMO's revenue requirements for operational activities.

- Since the last fee determination, the reciprocal relationship between AEMO and TNSPs has changed. In the past there was a dependency on the TNSPs in fulfilling AEMO functions, for example through TNSP Operating Agreements, however this is no longer the situation.
- AEMO's interaction with TNSPs has increased through the operational activities AEMO now performs for this participant class. Such activities for TNSPs can include analysis for transmission limits advice and transmission outage scheduling[10] (especially limits relating to system strength), voltage control and contingency violations analysis[11], development, coordination and provision of mainland wide-area PSCAD models for generator connection and system security studies[12], development and coordination of emergency frequency control schemes (such as UFLS, OFGS, CQ-SQ, SIPS), derivation of setting schedules and conducting regular reviews as well as system strength and inertia assessments for TNSPs under various operational conditions.

- Does not unreasonably discriminate as the services included in the cost allocation survey directly involve TNSPs and not any other participant class.
- AEMO clarifies comments in the draft report about administrative arrangements, timing and transitional issues associated with charging TNSPs Participant fees under the Rules. AEMO's comment was intended to explain that implementation and transitional issues are not expressly captured within the NER principles and, in light of some submissions referring to the complexity of recovery, the simplicity principle relates to the simplicity of the fee structure itself, not the simplicity of recovery.
- After considering submissions and the fee structure principles and having regard to the NEO, AEMO has considered the ability of TNSPs to recover participant fees including whether it is reasonably practicable for the NER to be amended to allow TNSPs to recover core NEM fees. In principle the NER allow for the efficient costs of a monopoly network to be passed through to consumers and AEMO therefore expects these fees to add to the cost base of an efficient network and be recoverable. Based on AEMO experience and discussions with the AEMC, a rule change proposal takes approximately nine months to complete and recent experience with the NTP reallocation fee rule change has clarified many issues that AEMO believes would help inform and streamline a rule change proposal to allow TNSPs to recover Participant fees. TNSPs are best placed to lead this work given their expertise in relation to their own pricing methodologies and regulatory determination processes. AEMO would fully support and assist the TNSPs in proposing such a rule change.

As part of AEMO's consideration of the ability of TNSPs to recover Participant fees, to ensure that charging methodologies do not cause significant difficulties in terms of their ability to be recovered by TNSPs, the proposed transition period (i.e. retaining the current core NEM fee allocation to Generators and Market Customers for first 2 years of the fee structure period) is intended to provide sufficient time for TNSPs to seek the necessary transitional arrangements to be put in place for all TNSPs to recover the fees.

Additionally, since the Draft Report, AEMO has further considered the unique planning arrangements in place in Victoria, and as some activities for power system planning and reliability do not 'involve' AusNet Services (Transmission), it will be charged less than other TNSPs for the following reasons:

- Victoria has a set of different structural arrangements – AEMO has a planner role under its Victorian TNSP function while AusNet Services is the declared transmission system operator.
- Costs for functions under AEMO's Victorian TNSP role are fully captured in a separate cost entity.
- AEMO does not perform equivalent Victorian TNSP functions in other jurisdictions.

---

[10] Transmission outage assessment is becoming increasingly complex, with further studies and planning required to support the development of operational advice before these outages are approved to proceed. This work also requires wide stakeholder engagement across industry as multiple market participants can be impacted, including inter-regional impacts.

[11] Voltage control is increasingly becoming an issue across multiple NEM regions and AEMO is working with the TNSPs to develop a joint approach to how this can be managed through NEMOC working groups. This will also involve DNSPs on a region by region basis.

[12] This includes assistance to and training of staff in the use of wide-area PSCAD models.

- Some AEMO functions and services are provided for AEMO's Victorian TNSP function in Victoria, not for AusNet Services and therefore, it is appropriate to allocate AusNet Services less of the TNSP core NEM fee in comparison to other TNSPs.
- AusNet Services will only be charged for functions that relate to NEM Real Time Operations, as sourced from the cost allocation survey results.

The following example illustrates the methodology that will be used to determine AusNet's allocation to the overall TNSP allocation of 17.5%.

TNSPs are charged Participant fees on the basis of energy consumed for the latest completed financial year (consistent with the basis for charging the NTP fee).

Table 5 shows the energy consumption and market share in each of the five (5) NEM regions.

Table 5: Energy consumption in each region

Region	Energy consumption – FY 19/20 (GWh)	Proportion
NSW	65,934	36.8%
QLD	51,076	28.5%
SA	11,741	6.6%
TAS	10,057	5.6%
VIC	40,287	22.5%
Total	179,095	100.0%

AusNet Services will only be charged for functions that relate to NEM Real Time Operations.

The NEM Real Time Operations activities make up 7.5% of the total NEM allocation to TNSPs (which is 17.5%) as sourced from the cost allocation survey results.

Using Table 5, Ausnet is allocated 22.5% of 7.5%, that is 1.7%. The remaining amount to other TNSPs is 1.7% less than 17.5%, that is 15.8%.

The remaining amount of 15.8% is now allocated to the remaining TNSPs proportionally on the basis of energy consumption. As a result, attribution for other TNSPs is shown in Table 6 below.

Table 6: Resulting regional allocation of core NEM allocated fee

Region	Energy consumption – FY 19/20 (GWh)	Proportion	Share of core NEM allocated fee (15.8%*Proportion)
NSW	65,934	47.5%	7.5%
QLD	51,076	36.8%	5.8%
SA	11,741	8.5%	1.3%
TAS	10,057	7.2%	1.1%
Total	138,808	100.0%	15.8%

Therefore, the final attributions for each TNSP for the core NEM allocated fee to apply from 1 July 2023 to 30 June 2026 is shown in Table 7 below.

Table 7: TNSP attributions for core NEM allocated fee

Region	Core NEM allocated fee %

NSW (TransGrid)	7.5%
QLD (Powerlink)	5.8%
SA (ElectraNet)	1.3%
TAS (TasNetworks)	1.1%
VIC (AusNet)	1.7%
Total to TNSPs	17.5%

These attributions of the core NEM allocated fee also apply to TNSPs for the recovery of the Digital Program and Regulatory Compliance program costs.

1.3 Electricity retail markets fee (Electricity Full Retail Contestability (FRC) fee)

Since the inception of the FRC service fee, the activities that are allocated to this category have changed and there needs to be recognition that this fee now encompasses more than just pure FRC (or MSATS) related activities that include:

- Managing data for settlement purposes;
- Support for retail market functions and customer transfers;
- Business to business processes; and
- Market Procedures changes and project implementation.

The fee now also includes a proportion of costs relating to other retail functions as well as the B2B platform, which utilises a 'Shared Market Protocol' that was implemented as part of the Power of Choice (PoC) reforms with the intention of facilitating additional services including those with third parties.

Other changes since the FRC fee was introduced include:

- The introduction of Metering Coordinators as part of the introduction of metering competition;
- Significant changes to MSATS resulting from the 5MS program; and
- Going forward there is likely to be more interaction with the retail market and functions e.g. through the 5MS and DER integration programs.

1.3.1 Final determination

AEMO's final determination on the Electricity Retail Markets fee is to charge market customers on a per connection point ($/NMI) basis.

Table 8: Final determination – Electricity Retail Markets fee structure compared to existing structure

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
Electricity Retail Markets	• From 1 July 2016 to 30 June 2019: – Charged to Market Customers with a retail licence and levied for a financial year at a rate per MWh based on AEMO's estimate of total MWh to be settled in spot market	• No change to existing structure.	• No change to existing structure.

	transactions by Market Customers with a retail licence during that financial year against regional reference nodes. Rate applied to actual spot market transactions in the billing period. • From 1 July 2019 to 30 June 2021: – Charged to Market Customers with a retail licence and levied on a per connection point basis ($/NMI) per week.		

1.3.2 Rationale

The following factors were considered in making the final determination for the Electricity Retail Markets fee structure:

- Extending recovery to Metering Coordinators due to the introduction of this participant category as a result of the PoC reforms which came into effect in December 2017.
- Using transaction data as the charging metric for the fee recovery.

AEMO considered stakeholder feedback on the draft proposal set out in the Draft Report. After further consideration, AEMO has determined to adopt the proposal for the following reasons:

- While the number of Metering Coordinators in the NEM has increased since the previous fee structure determination, their level of involvement with the revenue requirements for AEMO retail activities is not material enough to consider in this fee determination.
- Cost recovery on a per transaction basis using MSATs and B2B data would in fact make the fees more complex, provides no improvement in economic efficiency, and doesn't necessarily indicate a significantly higher involvement of one retailer than another because customers' demands on retailers and meter data providers (who work for retailers) is largely the same.
- The retailer "market share" basis of recovery better reflects this function's purpose to the industry and consumers, as opposed to the MWh consumption basis of recovery because AEMO's electricity retail markets capability is built to handle a total number of individual meters and the actual energies flowing through them is incidental.
- Recovery on a per connection point basis has largely the same distributive effect to the end consumer as the per transactions approach.

1.4 National Transmission Planner (NTP) function

Prior to 1 July 2020, the costs incurred by AEMO in providing NTP services (referred to in the Rules as 'NTP function fees') were recovered from Market Customers under AEMO's existing Participant fee determination.

From 1 July 2020, the Integrated System Planning Rule (ISP Rules)[13] required the ISP to replace the initial stages of the RIT-T process, that is the Project Specification Consultation Report (PSCR), for projects made actionable by the ISP, providing a ready-made modelling suite with assumptions, transparent justifications for actionable projects and greater certainty of success once a project has been determined actionable. The ISP Rules also required AEMO to allocate NTP function fees to TNSPs, rather than Market Customers.

[13] See Energy Security Board (ESB), Converting the Integrated System Plan into Action: Recommendation for the National Electricity Amendment (Integrated System Planning) Rule 2020, Decision Paper, March 2020 and final rule as approved at http://www.coagenergycouncil.gov.au/publications/actionable-isp-final-rule-recommendation.

Subsequently, the Reallocation of National Transmission Planner Costs Rule 2020[14] provided transitional and administrative mechanisms within the Rules to allow AEMO to recover NTP function fees from Co-ordinating Network Service Providers (CNSPs) and CNSPs to include these fees in their transmission pricing.

1.4.1 Final determination

Following consideration of stakeholder feedback, AEMO has determined to allocate NTP function fees to CNSPs from the commencement of the new fee structure, 1 July 2021 to 30 June 2022 based on 2019 consumption levels and thereafter (until 30 June 2026) based on their respective jurisdiction's consumption for the latest completed financial year.

Table 9: Final determination – NTP final fee compared with the existing structures

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
National Transmission Planner	• From 1 July 2016 to 30 June 2020: – Charged to Market Customers and levied at a rate per MWh based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period. • From 1 July 2020 to 30 June 2021: – Charged to Coordinating Network Service Providers in accordance with the mechanism in the transitional rule based on 2019 consumption levels.	• From 1 July 2021 to 30 June 2022: – Charged to Coordinating Network Service Providers in accordance with the mechanism in the transitional rule based on 2019 consumption levels. • From 1 July 2022 to 30 June 2023: – Charged to Coordinating Network Service Providers on the respective jurisdiction's consumption for the latest completed financial year.	• From 1 July 2023 to 30 June 2026: – Charged to Coordinating Network Service Providers on the respective jurisdiction's consumption for the latest completed financial year.

1.4.2 Rationale

AEMO's final determination is consistent with the AEMC's final rule and determination published on 29 October 2020 that takes into account AEMO's close collaboration with the ENA in developing the charging mechanism, which included an assessment of alternative options.

1.5 Cost recovery for the Five-Minute Settlement program

The Five-Minute Settlement program (5MS program), which coordinates the implementation of changes as a result of the Five-Minute Settlement rule change and the Global Settlement (GS) rule change and makes significant upgrades to affected IT systems, is not reflected in the current fee structure.

5MS and GS requires major changes to wholesale systems and processes (settlement, prudentials, and bidding/dispatch) and retail systems and processes (metering data management and MSATS). These changes may be categorised as follows:

- Changes that may be considered as 'legacy upgrades', i.e. the IT systems require a technology uplift due to their age and technology, which can be expected as part of any systems life cycle; and

[14] AEMC, National Electricity Amendment (Reallocation of National Transmission Planner Costs) Rule 2020: Rule Determination, 29 October 2020.

- Changes that may be considered as '5MS/GS specific upgrades', i.e. the IT systems must be changed to give effect to the 5MS and GS rule changes specifically.

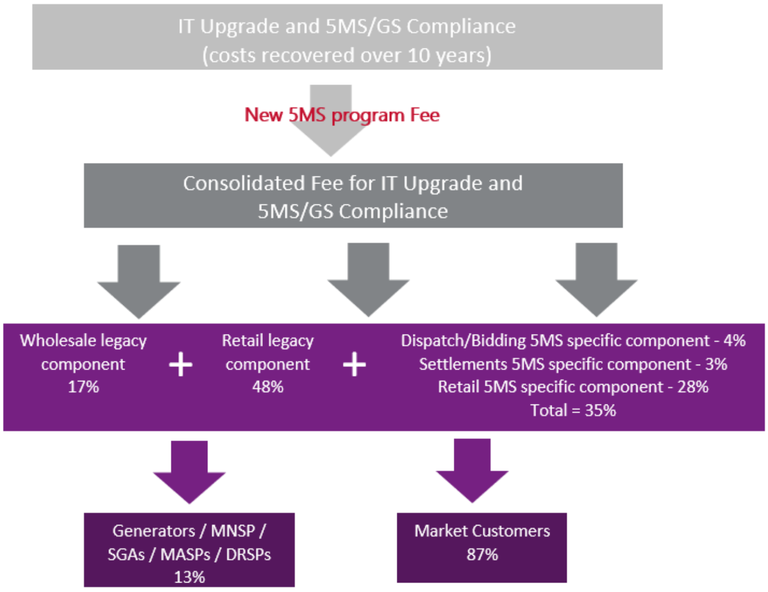
1.5.1 Final determination

AEMO's final determination is to recover costs of the IT upgrade and 5MS/GS compliance as a separate fee in a consolidated manner, that is to recover both legacy upgrades and 5MS/GS specific upgrades together, as follows[15]:

- Legacy upgrades apportioned to wholesale systems (17% allocation) and retail systems (48% allocation); and
- 5MS/GS specific upgrades required to dispatch/bidding, settlements and retail systems (35% allocation in total).

This new fee category will be titled "IT upgrade and 5MS/GS compliance". It will include the capex incurred under the 5MS Program and the opex associated with the affected IT systems (Dispatch, Settlements and Retail/Metering Data Management). The separate IT upgrade and 5MS/GS compliance fee is to be charged to Wholesale Participants (13% allocation) and Market Customers (87% allocation) in the first 2 years (transition period) via the same metrics as the core NEM allocated fee metrics (see figure 3 below). In years 3 to 5, the Wholesale Participant allocation is 18% and the Market Customer allocation is 82%.

Figure 3: IT upgrade and 5MS/GS compliance cost recovery allocation (for first 2 years)



[15] Note, budget percentage ratios are approximate and to be confirmed in the Annual Budget and Revenue process.

Table 10: Final determination – IT upgrade & 5MS/GS compliance cost recovery

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
IT Upgrade & 5MS/GS compliance	• NA	• For 5MS/GS legacy and specific upgrade costs: (a) 87% allocated to Market Customers (same fee structure as core NEM allocated Market Customer fee); and (b) 13% allocated to Generators/MNSPs/SGAs/MASPs/DRSPs (collectively referred to in the fee structure as "Wholesale Participants"). Same fee structure as core NEM allocated Wholesale Participant fee.	• For 5MS/GS legacy and specific upgrade costs: (a) 82% allocated to Market Customers (same fee structure as core NEM allocated Market Customer fee); and (b) 18% allocated to Wholesale Participants (same fee structure as core NEM allocated Wholesale Participant fee).

1.5.2 Rationale

The final determination provides transparency of costs for 5MS upgrades and associated with BAU legacy upgrades. AEMO did not consider it necessary to have a separate fee for each, because this unnecessarily complicates the fee structure. Merging these costs into a single fee simplifies the fee structure and reduces the number of fees used to charge Market Customers. It should be noted that the end result, in terms of which participant pays, is the same as in the Draft Determination.

The tables below outline the basis for allocation to each participant which is consistent with the reflective of involvement principle.

Table 11: Allocation to participants for 1July 2021 to 30 June 2023 – IT upgrade & 5MS/GS compliance cost recovery

Item	Updated (February 2021) Allocations			Basis for Allocation
	Budget % Ratio	Market Customers	Wholesale Participants	
Legacy Upgrade:				
• **Wholesale**	17%	9%	8%	Allocated as per core NEM fee allocation
• **Retail**	48%	48%	0%	Entirely allocated to Market Customers
5MS Specific:				
• **Dispatch**	4%	0%	4%	Entirely allocated to Wholesale Participants
• **Settlements**	3%	2%	1%	Allocated as per core NEM fee allocation
• **Retail**	28%	28%	0%	Entirely allocated to Market Customers
Total	100%	87%	13%	

Table 11b: Allocation to participants for 1July 2023 to 30 June 2026 – IT upgrade & 5MS/GS compliance cost recovery

Item	Updated (February 2021) Allocations			Basis for Allocation
	Budget % Ratio	Market Customers	Wholesale Participants	

Legacy Upgrade:				
• **Wholesale**	17%	5%	12%	Allocated 32.2% to Market Customers and 67.8% to Wholesale Participants[16]
• **Retail**	48%	48%	0%	Entirely allocated to Market Customers
5MS Specific:				
• **Dispatch**	4%	0%	4%	Entirely allocated to Wholesale Participants
• **Settlements**	3%	1%	2%	Allocated 32.2% to Market Customers and 67.8% to Wholesale Participants
• **Retail**	28%	28%	0%	Entirely allocated to Market Customers
Total	100%	82%	18%	

Additionally:

- It should be noted there was approximately a 30% reduction in total costs by undertaking the legacy upgrade concurrently with 5MS implementation.
- Budget percentage ratios between wholesale and retail have changed since the draft determination because there have been budget increases in the Retail workstream associated with the delays in that workstream, resulting in a greater proportion of project costs for Retail (both legacy upgrade and 5MS specific) and proportionately lower to Wholesale. Budget ratios are estimated based on the current budget and may be revised for changes to budget over time through the annual budgeted revenue requirements process.
- The basis for allocating between Market Customers and Wholesale Participants is unchanged from the draft determination.

1.6 Cost recovery of the DER integration program and Energy Consumer Data Right (CDR) project

The DER integration program is not included in the current fee structure but is an integral program to evolve the national electricity system for the future, particularly given the rate of uptake of DER that is occurring and projected. The program involves initiatives that AEMO is working on in partnership with the Energy Security Board (ESB), market bodies, and stakeholders to design and implement the technical integration of DER.

The DER integration program comprises:

- Consumer data – to empower industry innovation and value to consumers through delivering accessible energy data, including the DER register, Customer Switching and the Energy Consumer Data Right
- Markets – to bring DER and demand response into the wholesale market (e.g. WDR mechanism, Virtual Power Plants)
- Operations – to identify emerging and future operational challenges related to DER, and develop and implement suitable mitigation measures
- Standards – supporting development of minimum technical requirements to ensure system security and interoperability
- Demonstrations – trials to inform regulatory changes to effectively integrate DER into the grid and markets. This includes, among others, the VPP demonstration program and the Victorian DER Marketplace trial.

[16] These percentages were calculated by excluding the TNSP percentage and normalising the relevant core NEM fee allocation to Market Customers and Wholesale Participant percentages i.e. Market Customers (26.6% / (1-(1-17.5%)) = 32.2% and Wholesale Participants (55.9% / (1-17.5%)) = 67.8%. 17.5% is the core NEM fee allocation to TNSPs.

1.6.1 Final determination

Costs associated with the DER integration are to be recovered as a separate fee as follows:

- Recovery from Market Customers (80% allocation) for developing markets and products to enable improved participation and competition for consumers, charged using the general Market Customer fee as follows:
  - A $/MWh basis through the transition period (1 July 2021 to 30 June 2023), then
  - 50% charged on a $/MWh basis and 50% charged on a $/NMI basis (as per the core NEM fee from 1 July 2023).
- Recovery from Wholesale Participants (20% allocation) due to DER integration providing improved system security and visibility, charged using the general Wholesale Participants NEM fee.
- NSPs excluded because the current estimated involvement is immaterial. However, AEMO notes that it would reconsider an allocation to NSPs, in particular DNSPs, as major reforms such as the two-sided market reforms progress, either through a declared NEM project under the Rules within the next fee period, or subsequent fee structure review.

The final determination for the Energy CDR program is to defer a determination, as there remain uncertainties associated with funding arrangements and implementation timing, although there is potential for the program to meet the criteria of a declared NEM project.

Figure 4: DER integration cost recovery allocation

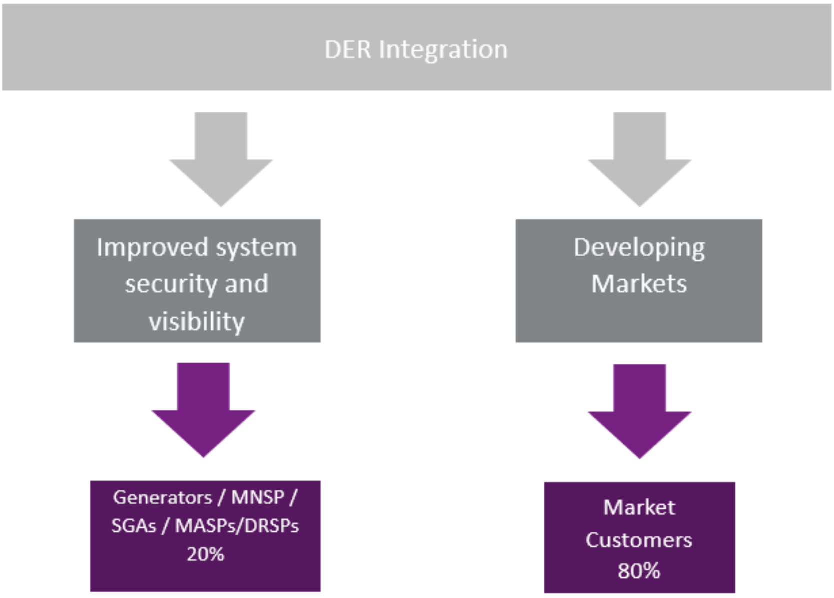


Table 12: Final determination – DER integration cost recovery

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
DER program	• NA	• 80% allocated to Market Customers levied on: (i) charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market transactions in the billing period; and	• 80% allocated to Market Customers levied on: (i) 50% charged as a rate per MWh for a financial year based on AEMO's estimate of total MWh to be settled in spot market transactions by Market Customers during that financial year. Rate applied to actual spot market

		• 20% allocated to Wholesale Participants levied on the same basis as above for the core NEM allocated fee.	transactions in the billing period; and (ii) 50% charged on a per connection point basis per week. • 20% allocated to Wholesale Participants levied on the same basis as above for the core NEM allocated fee.

1.6.2 Rationale

Following consideration of stakeholder feedback, AEMO has determined that the specific charge to DRSPs based on a percentage of the WDR mechanism establishment costs should be removed. This determination is different to the proposal in the draft determination. AEMO's decision has been based on further investigation by AEMO and taking account of stakeholder submissions and discussions, and consideration of the principles and regard to the NEO which concluded:

- There is too much uncertainty at this stage on the level of participation by DRSPs in the WDR mechanism, and any charge to this new entrant may unfairly benefit or penalise them depending on their timing of market entry.
- There are complexities associated with implementation of a specific allocation and user charge to DRSPs, as AEMO would be required to determine either a fixed price (or tariff) for a floating revenue amount, or a fixed revenue amount, with a floating price (or tariff), as a result of the uncertainty surrounding participation rate, which creates a risk of over or under-recovery.
- DRSPs would still be subject to DER integration costs through the broader 20% allocation to Wholesale Participants. That is, DRSPs will be charged as part of the Wholesale Participant allocation for improvement to security and visibility from the DER integration program.

While recovery of the DER integration program could also be allocated more broadly using the core NEM fee across all participants, this approach would not be as reflective of involvement as the final determination outlined in section 1.6.1.

Additionally, NSPs have been excluded from the fee as there is still some uncertainty around future levels of participation and involvement of NSPs in the programs at this relatively early stage of the DER integration program, including the amount of data readily available that could be used to develop an appropriate metric for charging. AEMO considers that the costs and complexities of implementing this at an early stage are likely to outweigh the benefits. AEMO would reconsider an allocation to NSPs, in particular DNSPs, should the distribution market operator (DMO) / two-sided market reforms progress, either through a declared NEM project under the Rules within the next fee period, or subsequent fee structure review.

This therefore makes the final position more aligned with the NER principles as it is simple to implement and apply while also ensuring those who are involved with, or ultimately benefit from, the program are charged directly.

As per the Draft Report, deferment of the Energy CDR cost recovery determination is due to:

- The CDR rules and standards, as they apply to the energy sector, have not yet been finalised and thus the exact scope of the roles AEMO will play are yet to be detailed;
- The ACCC are presently considering a phasing approach to the roll out of the CDR, therefore it is not yet clear which retail market participants may be subject to obligations under the CDR, and thereby are involved or benefit from the program; and
- Amendments to the NEL and NER, to enable AEMO to play its roles in the CDR program and recover associated costs, have not yet been finalised.

As these issues begin to be addressed through 2021, AEMO will be able to more meaningfully engage with members on the expected costs of delivering and operating our CDR services[17] and therefore in a better position to determine an appropriate means of cost recovery of the program.

1.7 Cost recovery of the Digital and Regulatory compliance programs

AEMO's digital program is expected to incur significant capital expenditure over the next few years as a result of AEMO's systems nearing end-of-life. Additionally, the significant increase in data volumes necessitates an increase in computational capability, analytics, design, and digitalisation to support the real-time operation of AEMO's energy systems and markets.

Regulatory compliance programs are changes required to market systems, processes or regulatory instruments for AEMO to comply with NEM regulatory changes and are directly related to the NEM core functions.

1.7.1 Final determination

AEMO's final determination is to allocate directly to the core NEM fees participant categories (including TNSPs) in the following manner:

- For the digital program, the costs are to be recovered from both the NEM allocated and unallocated categories on the same basis as the core NEM fee.
- For the regulatory compliance program, the costs are to be recovered from the NEM allocated category.
- For significant regulatory reforms, AEMO proposes to apply the declared NEM project framework, where required.

1.7.2 Rationale

In making its final determination, AEMO also considered allocating costs associated with the digital program and regulatory compliance program more broadly across the fee structure where applicable, e.g. to the Electricity Retail Markets fee, NTP fee as well as the core NEM fee. However, the reasons for making the final determination were:

- It is likely that all projects related to digital and regulatory compliance requirements will provide benefit broadly across all NEM participants.
- It is less complex than recovering across the broader fee structure as projects will not need to be assessed on a case-by-case basis.
- Assessment of projects on a case-by-case basis may lead to unreasonable discrimination of some participants.

1.8 Energy Consumers Australia (ECA)

The Council of Australian Governments (COAG) Energy Council approved the establishment of Energy Consumers Australia (ECA) by 1 January 2015, providing a focus on national energy market matters of strategic importance for energy consumers, in particular residential and small business consumers.

The ECA replaced the existing Consumer Advocacy Panel (CAP) for which AEMO currently collects funds through participant fees in the National Electricity Market (NEM) and gas markets. AEMO is also required to collect funding for the ECA.

[17] Any engagement with our members on CDR costs and cost recovery was outside the scope of this fee structure review.

1.8.1 Final determination

AEMO has determined that ECA fees for electricity will be levied on Market Customers based on a fee per connection point for small customers. This maintains the existing structure.

Table 13: Final determination – ECA electricity fee final fee structure compared with the existing structure

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
Energy Consumers Australia	• Charged to Market Customers and levied at a rate per small customer (as defined in the National Energy Retail Law) connection point.	• No change to existing structure.	• No change to existing structure.

1.8.2 Rationale

AEMO notes that establishment of the ECA, its constitution, and mandate of activities is to provide a focus on national energy market matters of strategic importance in particular to benefit residential and small business consumers. It is therefore considered the $/NMI charge is simple and aligns with the NEO for the charging of small customers.

1.9 NEM Participant Compensation Fund (PCF)

In accordance with the NER, AEMO is required to maintain a Participant Compensation Fund (PCF) for the NEM to pay compensation to Scheduled Generators, Semi Scheduled Generators and Scheduled Network Service Providers for scheduling errors as determined by the Dispute Resolution Panel.

1.9.1 Final determination

AEMO has decided to maintain the existing structure. That is, a 50/50 capacity/energy split for Scheduled and Semi-Scheduled Generators and NSPs.

Table 14: Final determination – NEM PCF final fee structure compared with the existing structure

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
NEM Participant Compensation Fund	• Charged to Scheduled Generators, Semi Scheduled Generators and Scheduled Network Service Providers in accordance to the NER, levied on 50% maximum capacity and 50% energy generated in the previous calendar year.	• No change to existing structure	• No change to existing structure.

1.9.2 Rationale

The NER requires that funding requirements of the NEM PCF are to be recovered only from Scheduled Generators, Semi Scheduled Generators and Scheduled Network Services Providers.

It is considered the 50/50 capacity/energy split for scheduled and semi-scheduled generators and NSPs remains appropriate and meets all NER principles, particularly the simple and non-discriminatory principles as well as the NEO.

1.10 Registration

Registration fees reflect the costs to AEMO in the registration of all registered participants in the NEM. This review did not consider the quantum, only the structure of these fees.

1.10.1 Final determination

AEMO's final determination is to maintain the existing structure.

Table 15: Final determination – Registration final fee structure compared with the existing structure

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
Registration fees	• The fee structure for registration fees for each application type to continue to be charged. • The actual registration fee amounts are to be set as part of the annual budget.	• No change to existing structure.	• No change to existing structure.

1.10.2 Rationale

AEMO's final determination reflects that no changes should be made until the upcoming review on the quantum of registration fees is completed.

1.11 Incremental charges

Where it is practical for AEMO to identify that doing something specific for a participant, and that action causes identifiable and material costs for AEMO, AEMO seeks to levy fees to recover the incremental costs incurred.

1.11.1 Final determination

AEMO's final determination is to maintain the existing structure.

Table 16: Final determination – Incremental charges final fee structure compared with the existing structure

Fee	Existing structure (1 July 2016 to 30 June 2021)	Transition period structure (1 July 2021 to 30 June 2023)	Final structure (1 July 2023 to 30 June 2026)
Incremental charges	• Where it is practical for AEMO to identify that doing something specific for a participant, and that action causes identifiable and material costs for AEMO, AEMO can seek to levy fees to recover the incremental costs incurred.	• No change to existing structure.	• No change to existing structure.

1.11.2 Rationale

AEMO's final determination has been made on the basis that the existing structure remains simple and reflective of involvement.

2. Submissions received on the Consultations

AEMO received 15 submissions in the first stage of consultation from:

- AEC;
- AGL;
- Ausgrid;
- ENA;
- Enel X;
- EnergyAustralia;
- Energy Queensland;
- ERM Power;
- Essential Energy;
- EUAA;
- Mondo;
- Origin Energy;
- PIAC;
- PLUS ES; and
- Red Energy and Lumo Energy.

In the second stage of consultation, that is the Draft Report, AEMO received 13 submissions from:

- AEC;
- AGL;
- Ausgrid;
- AusNet Services;
- ENA;
- Endeavour Energy;
- Enel X;
- Energy Queensland;
- ERM Power;
- Origin Energy;
- PIAC;
- SAPN; and
- Stanwell.

These submissions are published on AEMO's website at https://aemo.com.au/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review.

All submissions were considered in detail when preparing the Final Report.

AEMO responded to matters raised in the first stage of consultation in the Draft Report.

Sections 2.2 to 2.9 below outline in detail AEMO's responses to the second stage/Draft Report submissions which have led to the final determinations outlined in Section 1.

2.1 Summary of stakeholder feedback

The table below provides an overview of the main issues raised by stakeholder groups in response to AEMO's Draft Report proposals that were made to address the main issues under consultation.

Table 17: Summary of stakeholder feedback on the draft report

Electricity stakeholders	Summary of stakeholder feedback
NSPs (Endeavour Energy, Ausgrid, EQL, ENA, SAPN, AusNet Services)	• Do not support allocation to NSPs – notes majority of NSP stakeholders didn't support charging NSPs • Draft structure requires a rule change to enable NSPs to recover costs of NEM fees from customers (transitional period does not resolve cost recovery concerns) • Charging NSPs is not consistent with revenue and pricing principles in the NEL • Administrative burden/costs will increase • Greater transparency of cost allocation and survey process is required • AusNet suggests AEMO should be charged (not them) due to VIC planning role
Wholesale and retail industry association (AEC)	• Supportive of broadening fee recovery base to all other registered participants, including the allocation to NSPs • Given the materiality of reallocations, further survey detail would be prudent • Supportive of market customer allocation but further explanation could be provided on more complex options to address anomalies created by variable/behind the meter resources • Supports the proposed duration and the use of a transition period
Generators (Stanwell, AGL, Origin)	• Supportive of AEMO's draft proposals (AGL suggests existing allocation to market customers is appropriate but no concerns over AEMO's draft proposal and recommends AEMO explore ways to make sure NSP charges are not inflated) • AGL suggested the WDR specific allocation to DRSPs should be 50%, and suggest further consideration of capex/opex split for 5MS • Origin suggest more clarity in the Final Determination on 5MS costs for each category, including rationale for excluding NSPs and MDPs
DER/Demand response/battery (Enel X)	• Does not support allocation of WDR establishment costs to DRSPs only as consumers ultimately benefit (Note: draft determination did not suggest 100% allocation of WDR costs to DRSPs) • Too much uncertainty in DER cost recovery proposal to determine materiality • Registration fees need to reflect economies of scale e.g. currently does not enable smaller DER to register
Energy consumer group (PIAC)	• Cost recovery should be on a beneficiary-pays basis • Concerns with charging DRSPs WDR establishment costs as WDR benefits consumers
Retailers (ERM Power)	• Largely supportive of the draft report. • Requested further explanation on the Market Customer charge and 5MS allocation.

2.2 Term of fee determination

In the Draft Report, AEMO proposed a five-year fee determination with a two-year transition period. There were six respondents to this proposal.

Table 18: Summary of stakeholder comments on the draft proposal for term of fee determination

Stakeholder	Main comments from stakeholders' submissions	AEMO response
Stanwell, AGL, AEC	• Supportive of AEMO's draft proposal	• Noted. AEMO has determined to adopt the proposal in the Draft Report.
Ausgrid, Endeavour Energy	• Transition period does not resolve cost-recovery concerns	• AEMO considers that the transitional period provides adequate time for a rule change proposal for TNSPs to be submitted and considered - refer to section 1.1.2 of the Final Report for further detail. • A longer transition period would leave less time for the NSP charge to become effective during the term of the fee structure. • Should TNSPs decide to recover Participant Fees via a rule change process, for example that akin to the NTP Reallocation rule change, a two-year transition period is sufficient time for such a process to be finalised (the standard two stage Rule Determination process typically takes approximately nine months to complete once a rule change is developed).
ERM Power	• Preference for a shorter transition period	• AEMO's view is a transition period less than two years would not provide adequate timing for all participants to account for the changes to the fee structures.

2.3 Core NEM fee

In the Draft Report, AEMO proposed the following four elements of the core NEM fee:

- Charging Wholesale Participants:
  - Maintain the existing percentage attribution (46%) of core NEM allocated fees to Wholesale Participants for the first two years of the next fee structure period, that is the transition period; then
  - Increase the percentage attribution of core NEM allocated costs to Wholesale Participants from 1 July 2023 to 56%, reflecting an increased level of involvement with the revenue requirements for AEMO's core NEM activities; and
  - Maintain the existing charging approach for Wholesale Participants based on an average share of output (MWh) and capacity (MW).
- Market customer fee:
  - Maintain the existing percentage attribution (54%) of the core NEM allocated costs to Market Customers for the two-year transition period, that is from 1 July 2021 to 30 June 2023. For the transition period, the current method of a rate per MWh for a financial year would be used;
  - From 1 July 2023, the percentage attribution of the core NEM allocated costs to Market Customers will reduce to 23%;
  - From 1 July 2023, amend the Market Customer fee to a combination of $/MWh and $/NMI on a 50/50 allocation so that there is some consideration of demand elasticity to a volume fee, reflection of the differences between small and large customers, and to reflect the fact the bulk of AEMO's costs are fixed; and
  - From 1 July 2021 for the duration of the fee structure period, to maintain the existing attribution of the unallocated costs to Market Customers.
- Charging Network Service Providers (NSPs):
  - Maintain the existing allocation of core NEM fees to Wholesale Participants and Market Customers for the first two years of the next fee period, that is the transition period; then

– Introduce a separate allocation of the core NEM function costs to TNSPs (18%) and to DNSPs (3%) from 1 July 2023, to reflect the extent of their involvement with AEMO' core NEM activities, on the basis of energy consumed.

2.3.1 Wholesale Participants charging

There were five stakeholders who responded to the draft proposal for Wholesale Participant charging.

Table 19: Summary of stakeholder comments on the draft proposal for the charging of Wholesale participants

Stakeholder	Main comments from stakeholders' submissions	AEMO response
Stanwell, AGL, AEC, PIAC, Origin	• Supportive of AEMO's draft proposal • Stanwell and AGL welcomed the realignment of fees to more accurately reflect the level of involvement of participants. • AEC noted that it supports allocating DRSPs, MASPs and SGAs the same charges as conventional generators (both capacity and energy). • PIAC is supportive of AEMO not having a separate cost allocation for VRE and recommend reconsidering how fees are allocated to VRE when the market design has been updated.	• Noted. • While AEMO has determined to broadly adopt the proposal set out in its Draft Report, it has clarified that the chosen approach is not to charge the services, like energy, FCAS and/or any new services, which may result in charging generators and MNSPs per service, but instead charge the new wholesale participant in a similar way to generators, using the data specific to the service these participants provide.

2.3.2 Market Customer fee

Six stakeholders responded to the draft proposal on the Market Customer fee.

Table 20: Summary of stakeholder comments on the draft proposal for the Market Customer fee

Stakeholder	Main comments from stakeholders' submissions	AEMO response

Stanwell, AEC, AGL, ERM Power, Origin	• Supportive of AEMO's draft proposal.
	• AEC commented:
	  – It was disappointed there was no analysis or explanations of complexities of other options, in particular anomalies associated with variable/BTM resources
	  – Agrees the draft approach is simple but it is not reflective of involvement
	• AGL noted that even though the existing method is appropriate and less complex, the draft proposal may lead to a more balanced allocation between retailers with a large number of small customers and those with a small number of large customers.
	• ERM Power noted it disagrees with the 100% allocation to market customers for unallocated costs, however recognises
		• Noted. AEMO has determined to adopt the proposal set out in its Draft Report.
		• AEMO considered the use of gross metered data, and assessment of this option concluded that the approach may have benefits to simply charging on a net basis, it still suffers from charging fixed costs on a variable basis.
		• Improvements to the variable fee were considered to have little additional benefit as opposed to rebalancing the fee to a fixed fee on a per NMI basis. In addition, AEMO is more readily able to implement the $/NMI and $/MWh charge (being fees that AEMO already implements in the fee structure).
		• AEMO's final determination of a combination fee allows, in part, consideration of consumers who are responsive to energy prices and will seek to reduce consumption accordingly, therefore reflective of involvement.

	that this will be offset by a steep drop in the allocated cost proportion.	• AEMO considers that allocating all unallocated costs to participants closest in the electricity supply chain to customers remains appropriate.
Energy Queensland	• Supportive of the current tariff of $/MWh to protect the interests of small customers and retailers serving these customers. • The combination tariff disadvantages retailers who serve predominantly small customers.	• While there are disadvantages of all fee structure approaches, a consumption fee is not more reflective of involvement in AEMO's revenue requirements. • The combination fee allows, in part, consideration of consumers who are responsive to energy prices and will seek to reduce consumption accordingly, therefore reflective of involvement.

2.3.3 Charging NSPs

Ten stakeholders responded to the draft proposal on charging NSPs.

Table 21: Summary of stakeholder comments on the draft proposal for charging NSPs

Stakeholder	Main comments from stakeholders' submissions	AEMO response
Stanwell, AEC, AGL, PIAC	• Supportive of AEMO's draft proposal • AEC commented: – The allocation of costs to DNSPs demonstrates forward thinking and it is beneficial that AEMO's draft determination explicitly recognises an involvement with DNSPs already exists and lays a path for recovery of these costs to grow as the involvement grows. – The allocation to TNSPs of allocated direct costs is welcome and long overdue. This mostly arises from AEMO's power system security function, which is intricately involved with overseeing and managing the transmission grid. • AGL noted the new allocation of core NEM fees to TNSPs and DNSPs may have the benefit that these participants will be incentivised to utilise AEMO resources more efficiently. • PIAC questions whether the proposed two-year transition period for their introduction is necessary – PIAC suggests NSPs should be able to apply for a cost pass-through and be granted it sooner than the transition period.	• Noted. • AEMO has determined not to charge DNSPs for following reasons: – Level of involvement of DNSPs is considered to be immaterial. – In terms of the overall fee structure, the proposed NSP charge is simple, based on the outcomes of the cost allocation survey. – AEMO will monitor the level of involvement over the fee period and undertake a declared NEM project consultation should there be a major change as reforms (such as two-sided markets progress) and the level increases materially. • AEMO's determinations were made in accordance with the principles outlined in the NER and having regard to the NEO, with each option being assessed against every principle.
Endeavour Energy, ENA, Ausgrid, SAPN, EQL, AusNet Services	• Do not support charging NSPs, with main issues including: – New structure is not simple – Will increase administrative and regulatory burden	• As highlighted above, AEMO has determined not to charge DNSPs. • In terms of the overall fee structure, the proposed TNSP charge is simple, based on the outcomes of the cost allocation survey and proposes a fee metric that is simple to understand and already applied through the NTP function fee.

	– More efficient to recover costs from retailers • Endeavour Energy commented: – Draft proposal is inconsistent with revenue and pricing principles in the NEL which AEMO should have greater regard to – AEMO should submit a rule change proposal on behalf of NSPs to progress in parallel with the Fee determination • ENA noted: – AEMO's cost recovery principles should be properly designed and applied to promote the NEO – No reasons have been provided for down-grading the importance of the NEO • SAPN highlighted that consideration should be given with the AER's revenue control periods. • AusNet Services commented: – Operational and planning costs should be allocated to AEMO as the Victorian planner rather than AusNet. – Any rule change for the NSPs to recover costs must allow for annual direct cost pass through with no materiality threshold to ensure NSPs can recover costs on an annual basis.	• The structure of Participant fees must, be consistent with the fee structure principles, to the extent practicable, while the NEO remains a relevant consideration that AEMO must have, and has had, regard to in making the determination. • The Rules do not expressly indicate that one principle should have greater weight than the others. While AEMO must apply the principles to the extent practical, it is not practical to adopt a fee structure that satisfies all the principles equally, and therefore meeting the requirements may require a trade-off between principles. AEMO acknowledged in its Consultation Paper that simplicity and cost-reflectivity are often competing principles. • In relation to how NSPs are able to recover their Participant fees, AEMO's notes that: – While AEMO has acknowledged that there will be implementation implications for TNSPs to recover these costs, this is not an express NER requirement for AEMO in determining the fee, nor are the revenue and pricing principles in the NEL however, after considering submissions and the principles and having regard to the NEO, AEMO has considered the ability of TNSP to recover fees including whether it is practicable for the NER to be amended to allow TNSP recovery. – TNSPs will need to consider the scope and proposed solution for recovery of the NEM Fee costs, including whether this should be an annual direct cost pass through. – AEMO is willing to work the ENA and its TNSP members to provide advice/support for the development of a cost recovery mechanism that is fit-for-purpose. The TNSPs have the expertise about their pricing methodologies, and regulatory reset processes. • AEMO has taken into account AusNet's feedback on the unique planning arrangements in Victoria and has decided to reduce the allocation of the TNSP charge to AusNet for the reasons outlined in section 1.2.2.

2.4 Electricity retail markets fee

AGL was the only stakeholder to respond to the draft proposal, supporting AEMO's proposal.

2.5 NTP function fee

There were two stakeholders (AEC and AGL) who responded to the draft proposal, both supporting AEMO's proposal.

2.6 Cost recovery of IT upgrade and 5MS/GS compliance

Seven respondents commented on the draft proposal for the cost recovery of the 5MS program.

Table 22: Summary of stakeholder comments on the draft proposal for the cost recovery of IT upgrade and 5MS/GS compliance

Stakeholder	Main comments from stakeholders' submissions	AEMO response
Stanwell, ERM Power, AEC, AGL, Origin, AusNet Services	• Supportive of AEMO's draft proposal • Stanwell supports AEMO recovering costs across a 10-year period and supports the separate 5MS fee structure, acknowledging this goes some way to improving the level of transparency into the program costs attributable to market participants • ERM Power commented that while it does not fully agree with the split of specific and legacy costs, it understands AEMO's logic. • AGL suggested consideration of: – Allocating capital expenditure and operating expenditure separately. – Disclosing the fees to 5MS and that to GS. – The cost recovery period balancing both the impact on participant cashflow and the cost of capital which will be lower if a shorter timeframe applies. • Origin Energy noted further clarification is required on the differentiation between legacy and 5MS/GS costs and quantum as well as rationale for excluding NSPs and MDPs.	• Noted. • As outlined in section 1.5.1 of the final report, AEMO's final determination has changed slightly to that proposed in the draft report in that IT legacy upgrade costs and 5MS specific upgrade costs will be consolidated and allocated to the Wholesale participants and to Market Customers on the basis of the core NEM allocated fee metrics. • AEMO understands and accepts participant calls for transparency of the relevant costs associated with the 5MS program, and has provided a breakdown of the allocations between legacy upgrade and 5MS/GS compliance to provide that transparency. The consolidated fee provides a more simple approach than what was proposed in the draft report, but transparency has not been compromised in this simplification through the additional information provided by AEMO. • In terms of the appropriate cost recovery period, AEMO has aligned the 10-year recovery period with the expected life of the systems that are being implemented/upgraded to provide a cost reflective allocation of AEMO's costs. • Upgrades to meet GS compliance requirements have been fully integrated with upgrades to meet 5MS compliance requirements. Separation of the costs would be artificial and would lack the reliability to provide meaningful information for participants. • Capex and opex have been integrated into a single fee recovery category to follow finance practices, where the costs associated with the IT assets (such as depreciation, resource opex and non-resource opex) are maintained in a single category rather than fragmented across multiple categories. • In response to Origin Energy's request for further clarification: – AEMO has provided the relevant percentage allocation of legacy and 5MS specific upgrades in Figure 3. – NSPs are not included in the cost recovery of 5MS program consistent with the basis for the Electricity Retail Markets fee. – Under the Rules, AEMO can only charge fees to Registered participants and the principles only allow consideration of the extent to which the budgeted revenue requirements for AEMO involve a Registered Participant. MDPs are not registered participants, they are engaged by Metering Coordinators, and

		therefore, AEMO cannot charge participant fees to MDPs or consider the extent of MDP involvement.
EQL	• Believes the 5MS program costs should be subjected to a more rigorous cost-benefit analysis with a hard cap applied to AEMO's future operating and capital expenditure costs to ensure cost impacts for consumers are minimised.	• This consultation is in relation to the structure of participant fees, rather than the quantum of the fees. A consultation on AEMO's budget is being conducted in the near future where there will be opportunities for stakeholders to provide input on that process.

2.7 Cost recovery of the DER integration program and Energy CDR program

Eight stakeholders provided feedback on the draft determination for DER integration cost recovery, and proposed approach for the Energy CDR program. All stakeholders who responded to the draft determination to defer consideration of the Energy CDR fee structure supported this approach.

Table 23: Summary of stakeholder comments on the draft proposal for the cost recovery of the DER integration program

Stakeholder	Main comments from stakeholders' submissions	AEMO response
Stanwell, AEC, Origin, AusNet, AGL	• Supportive of AEMO's draft proposal. • The AEC broadly supports AEMO's draft proposals but considers AEMO should attempt to ensure DRSPs, through their registration and on-going fees, pay at least the WDR establishment cost over the first 10 years and thereby avoid cross-subsidising this project from uninvolved participants. • Origin suggest it may be necessary to apportion costs to DRSPs over a forward period to avoid creating a barrier to entry. • AGL suggests that DRSPs should be charged more than 10% of WDR establishment costs e.g. 50%. • AusNet agrees that NSPs should be excluded from the DER integration charge.	• Noted. • As outlined in section 1.6.1 of this report, since the draft report, AEMO has reconsidered its approach to recovering a portion of the WDR mechanism establishment costs from DRSPs for the following reasons: – There is too much uncertainty at this stage on the level of participation by DRSPs in the WDR mechanism, and any charge to this new entrant may unfairly benefit or penalise them depending on their timing of market entry. – There are a number complexities associated with implementation of a specific allocation and user charge to DRSPs, including risks of under or over-recovery. • DRSPs will still be charged as part of the Wholesale participant allocation for improvements to security and visibility from the DER integration program.
Enel X, PIAC	• Both stakeholders do not support WDR establishment costs being allocated to DRSPs – the reflective of involvement principle should consider consumers who ultimately benefit from the mechanism. • Enel X commented further that: – There is too much uncertainty with the DER proposal to understand materiality. – Phasing the fee over time may unfairly benefit or penalise DRSPs depending on when they enter the market.	• As per the response above, AEMO has reconsidered its approach to charging DRSPs a separate charge. • AEMO is also of the view that recovery of the costs of the DER integration program as a separate fee from those who are more involved directly with, or benefit from the program, is more consistent with the Fee Structure Principles than recovering costs through the core NEM fee.

	– It is likely some MASPs/DRSPs will only participate in FCAS markets and not the WDR mechanism, and therefore shouldn't pay establishment costs. – Should be recovered through the core NEM fee. • PIAC also commented that charging DRSPs may: – Discourage provision of WDR by imposing cost on early entrants. – Recommends smearing the capital cost of the WDR mechanism as its main beneficiaries are consumers and the market. This cost should be recovered per participant per year over a long period and erring on under-recovery rather than over-recovery.	
EQL	• Believes the DER integration program costs should be subjected to a more rigorous cost-benefit analysis with a hard cap applied to AEMO's future operating and capital expenditure costs to ensure cost impacts for consumers are minimised.	• This consultation is in relation to the structure of participant fees, rather than the quantum of the fees. A consultation on AEMO's budget will commence shortly where there will be opportunities for stakeholders to provide input into that process.

2.8 Cost recovery of the Digital and Regulatory Compliance programs

Three stakeholders responded to the draft proposal for cost recovery of the digital and regulatory compliance programs.

Table 24: Summary of stakeholder comments on the draft proposal for the cost recovery of Digital and Regulatory compliance programs

Stakeholder	Main comments from stakeholders' submissions	AEMO response
AGL	• Supportive of AEMO's draft proposal.	• Noted.
EQL	• Believes the Regulatory reform program costs should be subjected to a more rigorous cost-benefit analysis with a hard cap applied to AEMO's future operating and capital expenditure costs to ensure cost impacts for consumers are minimised.	• This consultation is in relation to the structure of participant fees, rather than the quantum of the fees. A consultation on AEMO's budget is being conducted in the near future where there will be opportunities for stakeholders to provide input in that process.
AusNet Services	• Does not support recovery from NSPs as these programs are primarily to the benefit of customers and the wholesale market by improving efficiency or reducing costs in that market. • Should be recovery through the core NEM cost allocation.	• As highlighted in section 1.7.2 of this report, assessment concluded that it is likely that all projects related to digital and regulatory compliance requirements will provide benefit broadly across all NEM participants, including TNSPs who will be charged under the new fee structure for the core NEM allocated fee for the reasons identified in section 1.2.2 of this report.

2.9 Other comments

Other main themes of feedback in stakeholder submissions are provided below.

Table 25: Other comments from stakeholder submissions

Stakeholder	Main comments from stakeholders' submissions	AEMO response
Endeavour Energy, ENA, Ausgrid, AEC, AGL	• Regarding AEMO's cost allocation survey: – Limited transparency was provided on AEMO's cost allocation survey design and process. – AEMO may need to provide underlying detail behind the cost allocation survey. – The fee structure must be based on a transparent and replicable cost allocation methodology (Ausgrid makes note of the DNSPs cost allocation methodology approved by the AER under clause 6.15 of the Rules).	• As outlined in section 3.2 of the draft report, the survey process was a detailed internal process undertaken through extensive and iterative engagement across every department, involving 23 Senior Managers. • Care was taken to ensure the surveys were completed in a consistent manner in accordance with the reflective of involvement principle; and the results were interrogated through follow-up engagement to ensure they were accurately interpreted and understood. • Further details of the survey results, and the key functions, outputs and activities that formed the basis of the survey, were published on AEMO's web site[18].
AEC, Endeavour Energy	• Regarding AEMO's governance and operating model review: – The AEC suggested further clarity is required on publicly available material on AEMO's governance review. – Endeavour Energy noted that it is more prudent to maintain status quo until completion of AEMO's governance and operating model review.	• The details of this review have not been finalised yet.
Endeavour Energy, Ausgrid	• Regarding stakeholder feedback as part of the consultation process: – Demonstration on how stakeholder feedback has been taken on board is inadequate. – Majority of stakeholders did not support charging NSPs.	• A table of stakeholder feedback and AEMO's response was included as Appendix D of the Draft Report and included in each relevant section of the Draft Report. • This feedback informed AEMO's assessment of the issues, and its draft determinations and has been taken into account and further informed AEMO's final determination. • AEMO has included additional detail about how it has taken account of stakeholder feedback on the draft determination in relation to charging NSPs – refer to section 1.2.2 of the Final Report.

[18] Survey results were made available on 17 December 2020 at: https://aemo.com.au/consultations/current-and-closed-consultations/electricity-market-participant-fee-structure-review

3. Appendix A: Fee structure principles

In determining the structure of Participant fees, AEMO must have regard to the NEO and the structure of Participant fees must, to the extent practicable, be consistent with number of principles.

The fee structure principles are set out in the table below with an explanation and some examples of how these requirements may be applied to reviewing the electricity fee structure.

Table 26: Principles applicable to fee structures

Fee Structure Principle	Requirement	Application and examples
National Electricity Objective (NEO)	In determining Participant fees, AEMO must have regard to the national electricity objective. The objective of the NEL is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to— (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system	The Second Reading Speech to the National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005 makes it clear that the NEO is an economic concept and should be interpreted as such. The Speech gives an example that investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources, including infrastructure, are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities. The Speech goes on to state that the long-term interests of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the NEM is efficient in an economic sense, the long-term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised. Applying an objective of economic efficiency recognises that, in a general sense, the NEM should be competitive, that any person wishing to enter the market should not be treated more, or less, favourably than persons already participating, and that particular energy sources or technologies should not be treated more, or less, favourably than others. Since 2006, the NEO has been considered in a number of Australian Competition Tribunal determinations, which have followed a similar interpretation. See, for example, Application by ElectraNet Pty Ltd (No 3) [2008] ACompT [15]: "The national electricity objective provides the overarching economic objective for regulation under the Law: the promotion of efficient investment in the long term interests of consumers. Consumers will benefit in the long

		run if resources are used efficiently, i.e. resources are allocated to the delivery of goods and services in accordance with consumer preferences at least cost.” The NEO is clearly a relevant consideration where AEMO has to exercise judgment or discretion in reaching its determination, for example, if there is a number of Participant fee structures each of which can satisfy the Fee Structure principles, or where the relevant provisions of the Rules are ambiguous.
Simplicity	The structure of Participant fees should be simple	As “simple” is not defined in the Rules, it must be given its ordinary meaning as understood in the context of clause 2.11 of the Rules. The New Shorter Oxford English Dictionary’s definition of “simple” (in this context) is: “not complicated or elaborate” and “plain, unadorned”. Whether a fee structure fits these definitions is largely a matter of judgement. There is a wide range of possible fee structures. There is no single identifiable point where “simple” becomes “complicated”. It is clear from this provision that a certain degree of complexity was envisaged in that the structure of Participant fees may involve several components and budgeted revenue consists of several elements. The structure of Participant fees need not demonstrate absolute simplicity. The simplest fee structures are unlikely to be consistent with the other criteria. However, it is possible to find fee structures that, while consistent with the other criteria, are relatively simple, in comparison to alternative structures. Further, AEMO considers that the use of the word “simple” in this context also involves a degree of transparency. AEMO considers that the simplicity principle means that the basis of the fee structure and its application to various Registered participants should be: • straight-forward • easily understood by participants • readily applied by Registered participants and AEMO • foreseeable and forecastable in terms of impacts and costs.
Reflective of Involvement	The components of Participant fees charged to each Registered Participant should be reflective of the extent to which the budgeted revenue requirements for AEMO involve that Registered Participant	In determining whether the extent to which the budgeted revenue requirement relating to a particular output involves a class of Registered Participant, AEMO relies on the experience and expertise of its general managers and staff, and

		considers factors such as the degree to which the class of Registered Participant: (a) interacts with AEMO in relation to the output; (b) uses the output; (c) receives the output; and (d) benefits from the output. AEMO also considers how the revenue requirements are given rise to, or caused by, that class of Registered Participant’s presence in the NEM. AEMO must determine the structure of Participant fees “afresh”. That is, it must freshly consider the application of the criteria in clause 2.11.1 of the Rules and the NEL to the facts and analysis available to it at this time. In doing so, however, AEMO will have regard to its previous determinations under clause 2.11.1 of the Rules, where appropriate. The principle of “reflective of extent of involvement” does not have a specialised meaning in economics. It is consistent with the economic notion of ‘user pays’ but as a matter of ordinary language, it indicates a degree of correspondence (between AEMO and its costs and participants) without connoting identity. However, this principle does not involve a precise degree of correspondence. Where fixed and common costs are involved, multiple registered participants may be involved with AEMO costs in relevantly similar ways. AEMO’s analysis and experience shows that there are categories or classes of Registered Participants that share certain characteristics that mean that the way in which they interact with AEMO is likely to have the same or similar cost implications for AEMO. Where it is practical for AEMO to identify costs that are fixed or common in nature that can reasonably be allocated to a class or classes of Participants that share characteristics such that their involvement with AEMO’s outputs is likely to have the same or similar cost implications, AEMO will seek to do so.
Non-discriminatory	Participant fees should not unreasonably discriminate against a category or categories of Registered Participants	In past Participant Fee determinations, AEMO (and its predecessor, NEMMCO) adopted the following definition of discriminate: “Discriminate means to treat people or categories of people differently or unequally. Discriminate also means to treat people, who are different in a material manner, in the same or identical fashion. Further, “discriminate against” has a legal meaning which is to accord “different treatment

		… to persons or things by reference to considerations which are irrelevant to the object to be attained”. This principle allows AEMO to discriminate against a category or categories of Registered participants where to do so would be reasonable. Where a degree of discrimination between categories of Registered Participants is necessary or appropriate to achieve consistency with the other principles in clause 2.11.1(b) of the Rules, or the NEL, the discrimination will not be “unreasonable”. In considering a past fee determination, the Dispute Resolution Panel accepted that this principle is to be applied to the extent practicable and it is only unreasonable discrimination that offends.

4. Appendix B: Survey cost allocation methodology and AEMO's key outputs and their activities

Core NEM function cost allocation

In order to have a basis on which to allocate AEMO's budgeted revenue requirements in relation to the NEM, it is necessary to understand AEMO's activities and outputs and the costs attributed to them. That is, the services and functions provided by AEMO to participants.

AEMO has used its 2020/2021 budget for its core NEM function as the basis for this cost attribution analysis. This budget provides the most up-to-date information AEMO has available for the purposes of this Final Determination. Although AEMO's annual costs will vary over the duration of the new structure, the 2020/21 budget provides a robust basis for notionally dividing AEMO's annual budgeted revenue requirements in relation to the NEM between AEMO's outputs during the period covered by the new structure.

The first step in the analysis of NEM costs was to identify those costs assessed to be direct, attributable costs to key NEM outputs and those costs that are assessed to be indirect costs that are allocated to the NEM function. Based on the 2020/21 budget, approximately 70% of NEM costs are assessed to be direct, attributable costs and approximately 30% of NEM costs are assessed to be indirect, non-attributable costs.

The second step in the analysis of NEM costs was to identify the key broad outputs of AEMO's activities in relation to AEMO's function. AEMO has identified a number of activities that it undertakes to support this function, which can be categorised into 10 broad outputs as follows:

- Power system security
- Power system reliability
- Market operation
- Wholesale metering and settlements
- Prudential supervision
- Market development
- Information dissemination including stakeholder engagement and consultation
- Retail markets
- Registration
- DER integration.

The next step in analysing the NEM costs was to allocate the NEM direct costs to each of the separate outputs identified above by using a survey. AEMO Senior Managers, 23 in total, were surveyed and requested to allocate their Division's costs against each of the key outputs identified above on the basis of time of interaction and involvement with specific participant classes.

Surveyed Senior Managers were instructed that in determining the extent to which the outputs involves a class of Registered Participant, the following factors should be considered:

- the class of Registered Participant that interacts with AEMO in relation to the output;
- the class of Registered Participant that uses the output;
- the class of Registered Participant that receives the output;

- the class of Registered Participant that benefits from the output; and
- those revenue requirements that are given rise to, or caused by, that class of Registered Participant's presence in the NEM.

Senior Managers were provided with a detailed list of activities that were developed to represent each of the key outputs. The results of the survey were used to form the basis of the allocation of the NEM direct, attributable costs to the key outputs.

Example of the Survey Process Conducted

This section highlights an example of the process conducted with Senior Managers. This example was for Senior Managers in the Strategy and Markets division. The process illustrated was replicated with all other Senior Managers in other Departments. This ensured uniformity and consistency in approach to derive reliable survey results.

- Step 1 – Senior Managers in the Strategy and Markets department were notified that AEMO is running a NEM Participant Fee consultation. They were advised an important part of this process is determining who pays for AEMO's costs the NEM cost entity and this was to be done through the AEMO internal cost allocation survey. As part of this notification a presentation was provided to explain context and background to the survey. A survey spreadsheet was provided with key outputs and the activities associated with each output.
- Step 2 – A teleconference was conducted to go through background on the NEM Participant consultation and the internal AEMO survey on cost allocation. This teleconference allowed the survey respondents to ask any clarifying questions to ensure a consistency approach to answering the survey.
- Step 3 – Filling out the survey – the Strategy and Markets survey had the following key outputs (functions) and key activities associated with each key output as shown in the table below.

Table 27: AEMO's key outputs and their activities for the Strategy and Markets department survey

Key output	Activity
Market operation **This output involves determining the efficient dispatch of scheduled and semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services for the NEM. This involves balancing supply and demand of electricity, while maintaining power system security to achieve an efficient price. Also includes monitoring of wholesale markets to ensure their outcomes deliver on effective market design.**	• Providing information systems for the receipt and processing of dispatch bids, dispatch offers, and market ancillary services offers. • Managing central dispatch processes, which includes the publication of pre-dispatch schedules and spot price forecasts. • Determining and publishing spot prices and ancillary service prices. • Collecting and disseminating information necessary to enable the market to operate efficiently (i.e. pricing and power system incident reports). • Investigating market events and errors and reporting on findings. • NEMDE Queue service. • Quarterly reporting on market dynamics, trends and outcomes.
Wholesale metering and settlements **This output involves determining amounts owing and owned in the NEM, and the facilitation of cash transactions (at a wholesale level).**	• Acquisition of metering data. • NMI standing data management. • Metering for FRC, e.g. profiling, aggregation, maintenance/upgrades to MDM. • Preparation of settlements statements. • Billing and Austraclear processing. • 5MS program activities.
Prudential supervision **This output aims to deliver a high degree of confidence that payments will be made to creditors in the NEM (i.e. Market Generators).**	• Calculating maximum credit limits. • Monitoring Market Participant outstanding. • Maintaining required credit support.

	• Prudential crisis management.
Market development **This output includes programs that AEMO is working in partnership with, including the Energy Security Board (ESB), market bodies, and stakeholders on market design and development**	• All ESB related work including post-2025. • AEMC rules consultations and interactions. • AER interactions.
Information dissemination[19] **This output involves the provision of information to parties operating in the wholesale exchange. All Market Participants are involved in this output in that they benefit from a transparent market and forums within which participant concerns can be raised**	• Output of data from AEMO's processes including general information provision and participant support, i.e. QED reports, Generator Information Page. • Stakeholder forums, e.g. IT forums/working groups, forecasting reference group, electricity retail consultative forum.
Retail markets **This output involves calculating the financial liabilities of, and credits to, market participants daily, publishing retail electricity market procedures and facilitating retail customer transfers**	• Customer transfers, i.e. MSATS procedures, maintenance/upgrades to CATS. • NMI standing data managements. • B2B (including B2B procedures, maintenance/upgrades to eHub). • Metering for FRC, e.g. profiling, aggregation, maintenance/upgrades to MDM. • 5MS program activities
Registration **This output involves the activities associated with AEMO's registration process including updating and maintaining information on Registered Participants.**	• Administering the registration process including due diligence on applications received. • Maintaining registration information including changes to capacity or de-registration. • Project-related work, e.g. VPP/WDR.
DER integration **This output includes programs that AEMO is working in partnership with, including the Energy Security Board (ESB), market bodies, and stakeholders to design and implement technical integration of DER**	• Consumer data, e.g. DER register, CDR, improvement of customer switching process and access to energy data. • Markets, e.g. WDR and other DER markets/mechanisms. • Operations, e.g. DER behaviour during disturbances, emergency frequency control schemes, system restart.

The survey spreadsheet has columns of NEM Registered Participants which allowed survey respondents to enter a percentage across relevant registered participants to reflect involvement. The registered participants included:

- Generators and MNSPs
- Market Small Aggregated Generator
- Market Customers
- Market Ancillary Service Provider
- Metering Coordinator
- TNSP
- DNSP
- Trader
- Reallocator
- B2B third parties

The survey respondents were instructed to update the spreadsheet for their team where they see fit i.e. to incorporate a key activity that has not been listed and to provide comments where necessary. It was emphasised that the allocation was to be only for the NEM cost entity.

[19] Including stakeholder engagement and consultation.

Verbal and written survey instructions were provided. The written survey instructions were:

- These are the key outputs (functions) that your department/team is likely to be involved in.
- Put a percentage (%) against the class of Registered Participant that interacts with, uses, receives, benefits from the key output/function, or causes the need for the output/function.

In effect, the outputs and activities listed with each output together with the instruction to allocate involvement with relevant Registered Participant classes was the survey question posed to survey respondents.

- Step 4 – Weightings were applied to the survey results to reflect the proportion of the relevant departments NEM allocated cost to the total NEM allocated cost. The survey results for Senior Managers in the Strategy and Markets division together with similar surveys from other Departments, were used to determine total cost allocations attributable to Registered Participants.

Results were also verified with the relevant Senior Manager to explain differences noted from the previous determination.

Table 28 below includes all outputs (functions) and activities associated with each function that AEMO's Senior Managers across all AEMO Departments. The table shows the key output and function applicable to each AEMO department. The survey methodology outlined from the Strategy and Markets department was replicated across other AEMO departments to derive the overall allocated participant involvement against for the 10 broad outputs listed in section 1.2 as part of the cost allocation survey.

Note, AEMO's Technology department have direct NEM costs, however as they are providing services to internal teams to support NEM systems, their survey process was undertaken via a two-step process:

1. Technology teams allocate their direct NEM costs to the internal teams.
2. The survey allocation to those internal teams were then used to determine the Technology allocation to participant types for each of the 10 outputs.

Table 28: AEMO's key outputs and their activities

Key output	Activity	AEMO department surveyed
Power system security **This output delivers a secure power system. All those who are connected to the power system are involved in this output. A secure power system ensures that equipment belonging to TNSPs, DNSPs and end use customers is not damaged.**	• Control room operations. • System simulations. • Outage co-ordination. • Dispatch of ancillary services. • Power system analysis and performance monitoring. • Network connections work (assessing simulation models, commissioning and post-commissioning activities). • Generator performance standard non-compliance studies/investigations. • Demand reduction calculation work as part of the restart and restoration process after a system black.	• Operations • System Design and Engineering
Power system reliability **This output ensures supply is delivered to end customers with a specified level of probability of supply, facilitating stable prices while supply is being met, provision of information through PASA processes, provision of information**	• Reserve monitoring in a range of timeframes (e.g. pre-dispatch, short-term, medium-term). • Provision of PASA information. • Interconnection reviews. • processes associated with Statement of Opportunities and the Energy Adequacy Assessment Project. • RERT activities including forecasting and administering contracts. • Forecasting accuracy reporting.	• Operations • System Design and Engineering

through SOOs to facilitate new investments.	• Regarding AEMO's governance and operating model review: • The AEC suggested further clarity is required on publicly available material on AEMO's governance review. • Endeavour Energy noted that it is more prudent to maintain status quo until completion of AEMO's governance and operating model review.	
Market operation **This output involves determining the efficient dispatch of: scheduled and semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services for the NEM. This involves balancing supply and demand of electricity, while maintaining power system security to achieve an efficient price. Also includes monitoring of wholesale markets to ensure their outcomes deliver on effective market design.**	• Providing information systems for the receipt and processing of dispatch bids, dispatch offers, and market ancillary services offers. • Managing central dispatch processes, which includes the publication of pre-dispatch schedules and spot price forecasts. • Determining and publishing spot prices and ancillary service prices. • Collecting and disseminating information necessary to enable the market to operate efficiently (i.e. pricing and power system incident reports). • Investigating market events and errors and reporting on findings. • NEMDE Queue service. • Quarterly reporting on market dynamics, trends and outcomes.	• Operations • Strategy and Markets
Wholesale metering and settlements **This output involves determining amounts owing and owned in the NEM, and the facilitation of cash transactions (at a wholesale level).**	• Acquisition of metering data. • NMI standing data management. • Metering for FRC, e.g. profiling, aggregation, maintenance/upgrades to MDM. • Preparation of settlements statements. • Billing and Austraclear processing. • 5MS program activities.	• Strategy and Markets • Technology – Infrastructure and Operations
Prudential supervision **This output aims to deliver a high degree of confidence that payments will be made to creditors in the NEM (i.e. Market Generators).**	• Calculating maximum credit limits. • Monitoring Market Participant outstanding. • Maintaining required credit support. • Prudential crisis management.	• Strategy and Markets
Market development **This output includes programs that AEMO is working in partnership with, including the Energy Security Board (ESB), market bodies, and stakeholders on market design and development**	• All ESB related work including post-2025. • AEMC rules consultations and interactions. • AER interactions.	• Strategy and Markets
Information dissemination[20] **This output involves the provision of information to parties operating in the wholesale exchange. All Market Participants are involved in this output in**	• Output of data from AEMO's processes including general information provision and participant support, i.e. QED reports, Generator Information Page. • Stakeholder forums, e.g. IT forums/working groups, forecasting reference group, electricity retail consultative forum.	• Operations • System Design and Engineering • Strategy and Markets

[20] Including stakeholder engagement and consultation.

that they benefit from a transparent market and forums within which participant concerns can be raised		
Retail markets **This output involves calculating the financial liabilities of, and credits to, market participants daily, publishing retail electricity market procedures and facilitating retail customer transfers**	• Customer transfers, i.e. MSATS procedures, maintenance/upgrades to CATS. • NMI standing data managements. • B2B (including B2B procedures, maintenance/upgrades to eHub). • Metering for FRC, e.g. profiling, aggregation, maintenance/upgrades to MDM. • 5MS program activities	• Strategy and Markets
Registration **This output involves the activities associated with AEMO's registration process including updating and maintaining information on Registered Participants.**	• Administering the registration process including due diligence on applications received. • Maintaining registration information including changes to capacity or de-registration. • Project-related work, e.g. VPP/WDR.	• Strategy and Markets
DER integration **This output includes programs that AEMO is working in partnership with, including the Energy Security Board (ESB), market bodies, and stakeholders to design and implement technical integration of DER**	• Consumer data, e.g. DER register, CDR, improvement of customer switching process and access to energy data. • Markets, e.g. WDR and other DER markets/mechanisms. • Operations, e.g. DER behaviour during disturbances, emergency frequency control schemes, system restart.	• Operations • System Design and Engineering • Strategy and Markets

A similar survey process was applied for each relevant department and the final attributions to Participants for the core NEM allocated fee were derived (shown in Table 29)[21].

Table 29: Final determination for each Registered Participant – attribution to the core NEM allocated fee

Key output	NEM Registered Participants							
	Wholesale Participants	Market Customers	Metering Coordinator	TNSP	DNSP	Trader (i.e. SRA)	Reallocator	B2B third parties	Total
Power system security	19.2%	6.3%	0.0%	10.7%	0.0%	0.0%	0.0%	0.0%	36.2%
Power system reliability	8.6%	3.7%	0.0%	2.3%	0.0%	0.0%	0.0%	0.0%	14.7%
Market operation	7.3%	2.2%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	11.4%
Wholesale metering and settlements	4.0%	2.6%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	6.9%
Prudential supervision	1.4%	1.9%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	3.5%
Market Development	2.2%	1.7%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	4.2%

[21] Since the Draft Determination, the attribution to DNSPs has been allocated to Market Customers.

Information dissemination including stakeholder engagement and consultation	7.3%	4.0%	0.0%	1.5%	0.0%	0.0%	0.0%	0.0%	12.8%
Retail Markets	0.0%	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%
Registration	5.4%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.1%
DER integration	0.5%	1.5%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	2.3%
Total	55.9%	26.6%	0.0%	17.5%	0.0%	0.0%	0.0%	0.0%	100%

5. Appendix C: Registered participants

A range of Registered Participants are part of the electricity market and benefit from the services that AEMO provides.

Below is a summary of registered participants.

Table 30: Registered participants

Participant category	Description	Registered participant class
Generators	Any person who owns, controls or operates a generating system connected to a transmission or distribution network	• Market Scheduled • Market Non-scheduled • Market Semi-scheduled • Non-market Scheduled • Non-market Non-scheduled • Non-market Semi-scheduled
Small Generation Aggregator	An SGA can supply electricity aggregated from one or more small generating units, which are connected to a distribution or transmission network. A small generating unit is owned, controlled and/or operated by a person who AEMO has exempted from the requirement to register as a generator.	• Market Small aggregated generator
Customers	A customer is a registered participant that purchases electricity supplied through a transmission or distribution system to a connection point	• Market customer • First-tier customer • Second-tier customer
Network Service Providers	A person who owns, operates or controls a transmission or distribution system	• Transmission network service provider • Distribution network service provider • Market network service provider
Special Participant	A delegate appointed by AEMO to carry out, on AEMO's behalf, some or all of AEMO's rights, functions and obligations under Chapter 4 of the Rules. A Distribution System Operator who is responsible, under the Rules or otherwise, for controlling or operating any portion of a distribution system (including being responsible for directing its operations during power system emergencies).	• System operator • Distribution system operator
Reallocator	Anyone that wishes to participate in a reallocation transaction undertaken with the consent of two market participants and AEMO	• Reallocator
Trader	Anyone who wants to take part in a Settlements Residue Auction (SRA), and is not already registered as a customer or generator	• Trader

Metering Coordinator	Has the overall responsibility for coordination and provision of metering services at a connection point in the NEM	• Metering coordinator
Market Ancillary Service Provider (MASP) / Demand Response Service Provider (DRSP)[22]	Delivers market ancillary services in accordance with AEMO's market ancillary services specifications, by offering a customer's load, or an aggregation of loads into FCAS markets.	• Market ancillary service provider • Demand response service provider

[22] The DRSP category will enter the market once the WDR mechanism commences in October 2021 and we expect those currently registered as MASPs in the VPP program will register as a DRSP.