Electricity Fee Structures

August 2020

Consultation Paper

A consultation 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 in accordance with clause 2.11 and clause 8.9 of the National Electricity Rules (Rules).

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

This publication has been prepared by AEMO using information available at [date].

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VERSION CONTROL

Version	Release date	Changes
1.0	18/08/2020	N/a

Executive summary

The current Electricity Market fee structure was determined five years ago. Since then as a result of the outcomes of regulatory changes to accommodate the transforming energy market including the development of the Integrated System Plan (ISP) and new reporting and consultation functions, AEMO has been required to take on additional responsibilities. Further, the market has changed with many new players, and expected new players, that are not representative of the traditional participants currently covered under the fee recovery structure, and there are greater complexities involved with planning and operating systems with the rapid growth of renewable resources and distributed energy resources.

Specifically, obligations and technology investments have increased in the areas of system planning, cyber security protections, connections analysis and commissioning as well as market and operations consultation. Additionally, the recent bush fires and current COVID-19 pandemic have provided harsh reminders of the importance of building resilience and investing in our systems to plan and enhance our rapid response capability. All of these changes are resulting in greater technology and operating expenses for AEMO, and a growing variety of participants that are involved in the costs that AEMO incurs.

AEMO's 2020-21 Final Budget and Fees[1] reported that the bulk of AEMO's expenses are attributed to labour-related expenses and Information Technology (IT), forecasting and operating system maintenance, and investments for planning and operating the grid. AEMO funds its technology-related investments through debt borrowings and participants' fees are set to recover the debt over the life of the asset. Where possible, AEMO also seeks grant funding for some of its capital investments.

AEMO is conducting a consultation on the structure of Participant fees to apply from 1 July 2021 for AEMO's revenue requirements including for:

- The National Electricity Market (NEM).
- Developing Retail Markets and administering Retail Competition.
- The National Transmission Planner (NTP) functions.
- Major Reform Initiatives, including 5MS and Distributed Energy Resources (DER) integration.
- The Energy Consumers Australia (ECA) fees recovered by AEMO from Participant fees.
- Registration.

The current structure of Participant fees expires on 30 June 2021. The objective of the consultation is to provide stakeholders with the opportunity to have input into the development of the structure of Participant fees to apply from 1 July 2021.

The closing date for submissions responding to this paper is Wednesday 23 September 2020.

This consultation only applies to the structure of fees. The actual amount charged for each fee will be determined on an annual basis, via the AEMO budgeting process.

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 set out in the National Electricity Law (NEL) and the National Electricity Rules (NER):

- 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.

[1] Information on the final report available on AEMO's website at: https://aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2020/budget-and-fees---final.pdf?la=en

- 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.

AEMO is acutely aware of the economic challenges confronting both consumers and market participants. Whilst AEMO's fees represent a very small component of overall energy system costs, it is critical that we, along with the rest of the industry, take all prudent actions to deliver our services as efficiently as possible. As outlined in the Corporate Plan, AEMO is undertaking a number of steps to accomplish this objective. We highlight them here awareness as we pursue multiple complementary actions to support our stakeholders:

- AEMO has been engaged in a transformational activity to reduce our operating expenses and improve our service to members, improve our operating practices, increase our use of digital technology and attract and retain the best talent we can to ensure enduring value to members and consumers. Reductions in this years' budget represent some early action we have taken. We are also engaged with Ernst and Young in a comprehensive efficiency and operating review to further support and accelerate our internal efforts. As part of this review we will be looking at comparable organisations to determine how we can best benchmark ourselves and continue to strive for best in class performance in our core activities;
- AEMO's current business model and structure were established at a very different time in our sector. Changes in the industry require that AEMO has the right talent, decision tools and operating systems to manage the increasing complexity of the system and provide value to consumers. The required capital investment can be significant and it is essential that it is both understood and that we work with our members to ensure we can offer the services that they require in a way that is efficient, provides opportunities to reduce participant cost of compliance and supports the sector's ability to take advantage of technology changes to benefit energy consumers. AEMO has commenced a process of reviewing our business structure and financial model to make certain that it is aligned with these outcomes. As part of this process, we are reviewing the system operator scope, legal structure, funding and regulatory models used in other jurisdictions. It is important that our government and industry members engage with us in these considerations and we will be sharing our findings and seeking your input on potential improvements over the course of the year; and
- AEMO is committed to earning and maintaining the trust of all stakeholders and we believe that transparency, information integrity and timely and meaningful consultation and collaboration are key to achieving this trust. To that end, we have just launched a consultation to refresh and uplift our stakeholder framework and engagement approach, seeking your input on how we can best work together to solve challenging emerging system and market issues. As part of this engagement, we will look to provide to our members the opportunity for earlier input into our annual budget processes and to better understand our budgets and fees.

To help stakeholders respond to this paper, AEMO has highlighted a number of areas that stakeholders may wish to comment on. Submissions are not restricted to these areas and comments are welcome on any relevant issue, regardless of whether it is detailed in this document.

Summary of areas for your comment:

- The length of time over which the new structure of Participant fees from 1 July 2021 should apply.
- The current method of recovering costs for the NEM, including:
  - The approach to determining the attribution of costs between categories of participant.
  - The current method of charging Generators and Market Network Service Providers (MNSPs) based on a combination of capacity and energy generated.

- The current method of charging Market Customers based on a rate per megawatt hour (MWh) settled in spot market transactions.
- The current method of recovering costs for the NTP function.
- The current method of recovering costs for the developing retail markets and administering the electricity Full Retail Competition (FRC) function
- Methods of recovering costs for major reform initiatives.
- The current method of recovering costs on behalf of the ECA.
- The current method of charging registration fees based on applicant type.
- The current method of recovering costs for the NEM Participant Compensation Fund (PCF).
- Other issues you wish to raise.

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1. Consultation Overview

The Australian Energy Market Operator Limited (AEMO) invites you to provide a submission on this Consultation Paper - Structure of Participant fees in AEMO's electricity markets.

1.1 Key information

<table>
<tr><th>Purpose</th><th>To provide stakeholders with the opportunity to have input into the development of the structure of Participant fees to apply from 1 July 2021.</th></tr>
<tr><td>Date applicable to new structure</td><td>1 July 2021</td></tr>
<tr><td>Functions covered in this consultation</td><td>National Electricity Market
Developing retail markets and administering Retail Competition
National Transmission Planner function
Energy Consumer Australia fees
Major Reform Initiatives
Registration</td></tr>
<tr><td>Timetable</td><td>The following table contains an outline of the consultation process, including key dates. Please note the key dates are indicative and may change.
<table>
<tr><td>Milestone</td><td>Date</td></tr>
<tr><td>Publication of Consultation paper</td><td>Tuesday 18 August 2020</td></tr>
<tr><td>Submissions on Consultation paper due</td><td>By Wednesday 23 September 2020</td></tr>
<tr><td>Publication of Draft Report (should no stakeholder meetings be requested)</td><td>By Wednesday 21 October 2020</td></tr>
<tr><td>Publication of Draft Report (should stakeholder meetings be requested)</td><td>By Wednesday 25 November 2020</td></tr>
<tr><td>Submissions on Draft report due</td><td>By Monday 18 January 2021</td></tr>
<tr><td>Publication of Final Report</td><td>By Tuesday 2 March 2021</td></tr>
<tr><td>Last date for final decision</td><td>By Wednesday 31 March 2021</td></tr>
<tr><td>New fee structure applicable</td><td>Thursday 1 July 2021</td></tr>
</table></td></tr>
<tr><td>Meetings</td><td>Stakeholders may request a meeting in their submission. Please specify why you would like a meeting. Matters discussed at a meeting may be made available to other stakeholders.</td></tr>
<tr><td>Submissions closing date and information</td><td>AEMO prefers that submissions be forwarded in electronic format (both pdf and Word) as they will be published on the AEMO website</td></tr>
</table>

	Please provide electronic submissions by 5.00pm AEDT Wednesday 23 September to Kevin.Ly@aemo.com.au or to Kevin Ly, Group Manager Regulation Australian Energy Market Operator Limited PO Box A2449 SYDNEY SOUTH NSW 1235 AEMO plans to publish all submissions on its website. Please identify any part of your submission that is confidential and you do not wish to be published. Respondents should also note that if material identified as confidential cannot be shared and validated with other stakeholders then it may be accorded less weight in AEMO's decision making process than published material.
Inquiries	Mr. Kevin Ly Group Manager Regulation, Australia Energy Market Operator Limited Level 2, 20 Bond Street SYDNEY NSW 2001 Email: Kevin.Ly@aemo.com.au

2. Background and Context

The current structure of Participant fees in AEMO's electricity markets commenced on 1 July 2016 for a duration of five years, ending 30 June 2021. The Final Report of the Structure of Participant Fees in AEMO's Electricity Markets was published on AEMO's website[2] on 17 March 2016.

Since the commencement of the current structure, there have been changes which have increased NEM forecasting complexity and regulatory reporting requirements that have affected AEMO's planning and operational activities, in particular:

- Rapid increase in variable renewable and distributed resources;
- Retirement of aging thermal resources;
- Improvements in and use of data; and
- Changes in the behaviour of consumer consumption.

The above changes have required AEMO to increase both personnel and capital investments used to forecast, model and operate the power system. In responding to these developments, AEMO has sought to recognise that efficient expenditure to improve the electricity market can increase the economic surplus of the electricity industry, especially given electricity is ubiquitous to the modern economy.

Additionally, to accommodate the energy transformation occurring and expected to accelerate, the volume of rule changes in the NEM has tripled in the past three years, all of which directly impact AEMO. This has led, and is leading to, implementation expenses related to obligations and technology investments for an increase in:

- System planning, i.e. the introduction of the Integrated System Plan (ISP);
- Cyber security protections;
- Complex system modelling;
- Connections analysis and commissioning;
- Management of demand response programs;
- Market re-design considerations;
- Market and operations consultations; and
- Compliance reporting.

There are new and expected participant categories which may now need to be considered when reviewing the fee allocation so that the structure of fees is consistent with the NER.

Aside from these, AEMO's existing information architecture was no longer capable of keeping up with both data requirements and speed required to effectively meet the needs of the NEM, and we are now in the second year of a five-year program to replace its aging systems. The new digital system will increase the cost-effectiveness of AEMO's operations by:

- Reducing the timing of implementation and transactional costs;
- Taking advantage of cloud computing; and
- Meeting participant and consumer information needs more efficiently.

AEMO's final report for our budget and fees for 2020-21 was published on our website on 30 June 2020.[3] The report focuses on the 2020-21 budget and fees that will support the provision of services across all of AEMO's functions and also provides an estimate of AEMO's capital program over the next two financial years,

[2] Information on the final report, including other consultation documents and submissions, available on AEMO's website at: https://aemo.com.au/consultations/current-and-closed-consultations/electricity-markets-structure-of-participant-fees

[3] Information on the final report, including other consultation documents and submissions, available on AEMO's website at: https://aemo.com.au/consultations/current-and-closed-consultations/2020-21-aemo-draft-budget-and-fees-consultation

for which approximately $500 million has been secured through debt facilities with costs to be recovered from participants once the programs are completed in future years, in accordance with NER clause 2.11.1(b)(2).

For the purpose of providing clarity, this consultation is being conducted in parallel with other consultations including:

- Renewing AEMO's engagement model, which is seeking to deliver a material shift in the level of transparency market participants, consumers, and other stakeholders enjoy regarding AEMO's understanding of current and emerging challenges as well as a more two-way, collaborative experience for stakeholders, in both defining problems and identifying solutions;
- A new operating model, which is reviewing the system operator scope, legal structure, funding and regulatory models used in other jurisdictions as a result of changes in the industry including a major increase in both market obligations and operational complexity. The discussions on a new operating model and any outcomes from those discussions will not form part of matters considered in the consultation on the electricity fee structure; and
- The Gas fee structure consultation.

2.1 Fee Structure Principles

This consultation only applies to the structure of fees considered. The actual amount charged for each fee is determined on an annual basis via the AEMO budgeting process. 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 NEO and the structure of Participant fees must, to the extent practicable, be consistent with number of principles (referred to in this document as the Fee Structure Principles) and these 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 1 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	In determining whether the extent to which the budgeted revenue requirement relating to a particular output

	the extent to which the budgeted revenue requirements for AEMO involve that Registered Participant	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.
Comparability	In developing, reviewing and publishing, the structure of Participant fees, AEMO must consider other fee structures in existence which it thinks appropriate for comparison purposes. Note that this is not strictly a principle but is included for completeness in describing the matters for which AEMO must have regard.	Other relevant fee structures could include: • Other electricity market fee structures such as Western Australia or globally • Gas markets operated by AEMO

The Rules do not expressly indicate that one or another of these Fee Structure Principles should have greater weight than the others. However, where it is not practicable for AEMO to satisfy all of the principles or satisfy them all to an equal degree, AEMO may adopt a structure which is not equally consistent with all the principles. Therefore, meeting the requirements established under the NER typically requires a trade-off between principles. That is, an option to improve the fee structure against one principle may lessen the applicability of another principle.

For example, commonly competing principles are cost-reflectivity and simplicity. While cost-reflectivity in a fee structure could be improved through measures such as disaggregation of fees, markets or services, this would decrease simplicity of the fee structure, and the systems needed to manage the fees would become more complex.

AEMO's objective through this review and consultation process is to strike a balance between competing Fee Structure Principles, through careful consideration of the principles and stakeholder feedback on how any fee structure changes impact various stakeholders.

It is also relevant to note that the participant fees should be sufficient to cover AEMO's budgeted revenue requirements.

2.2 Budget and Fee Structure

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.

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.

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.

3. Key matters for consultation

AEMO seeks feedback from its stakeholders on how existing fee structures could be improved to better balance the Fee Structure Principles to address any emergent market trends, regulatory reforms or stakeholder-identified issues. Your submissions are not restricted to these areas: you may comment on any other relevant issue.

3.1 National Electricity Market fee structure

AEMO's core NEM functions (for the eastern and southern Australian states) for which it can recover fees include:

- Power system security and reliability.
- Market operations and systems.
- Wholesale metering, settlements and prudential supervision.
- Longer-term energy forecasting and planning services.

The current NEM fee structure is presented below, in sections 3.1.2 to 3.1.4.

3.1.1 Period of fee structure

The NER permits AEMO to set a structure of Participant fees for such period of time as AEMO considers appropriate.

The 2006, 2011 and 2015 Final Determinations fixed the term of the structure at five years, where previously they were set for three-year periods.

Having a structure that applies over a longer period provides certainty and predictability of the structure of fees. This needs to be balanced against having the ability to change a Participant fee structure as circumstances change.

Question

1. What is the preferred length of time over which the structure of Participant fees for electricity markets should apply?
2. Are there other factors that should be considered when determining the period of application?

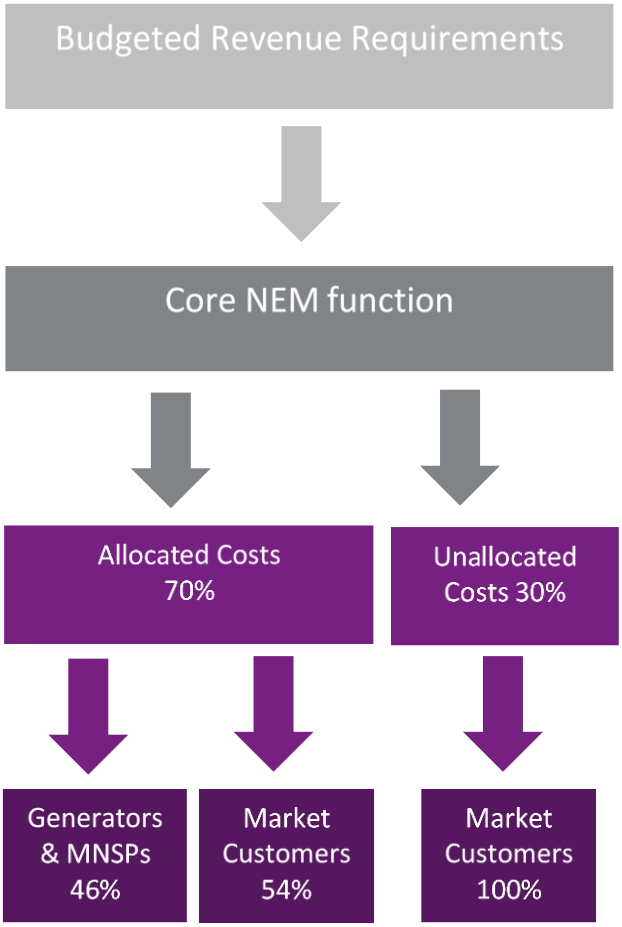
3.1.2 Attribution of costs between categories of Participants

As outlined in Section 2.2, clause 2.11.1(b)(2) of the NER states that all of AEMO's budgeted revenue requirements must be recovered through Participant fees. Figures 1 and 2 below show the fees for the core NEM functions recover two types of costs, allocated (direct) costs and unallocated (indirect costs). The current apportionment of the budgeted revenue requirements is 70% to allocated costs and 30% to unallocated costs, as shown below in Figure 1.

Allocated costs are costs which can be readily allocated to either a particular function (e.g. system security and reliability functions), or to a participant category or class (e.g. FRC fees). Currently, 46% of the allocated costs are currently attributed to either Generators and Market Network Service Providers (MNSPs) and 54% to Market Customers.

Unallocated (indirect) costs are costs which cannot be readily allocated to a particular participant category or function (e.g. corporate overheads) and based on principles of economic efficiency having regard to the NEO, are fully recovered from Market Customers.

Figure 1 – Current attribution of NEM fees to participants



The attribution of the allocated costs to Generators/MNSPs or Market Customers is based on AEMO's activities and outputs and the cost drivers associated with them and the extent of the involvement of the participants for each of the outputs and revenue requirements. In determining the extent to which the outputs and 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 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 are given rise to, or caused by, that class of Registered Participant's presence in the NEM.

The outcome of the consideration of these matters is important as it reflects changes in the NEM occurring or expected to occur and its impact on AEMO's roles and responsibilities so that the extent of involvement of Registered Participants with the budgeted revenue requirements can be considered in determining the fee structure. With changes such as the retirement of ageing thermal plant, increasing levels of large-scale

renewable generation as well as distributed resources and declining energy consumption due to COVID-19, consideration of these matters may show that a broader participant base is involved in AEMO revenue requirements, Figure 2 shows an example of a new allocation approach.

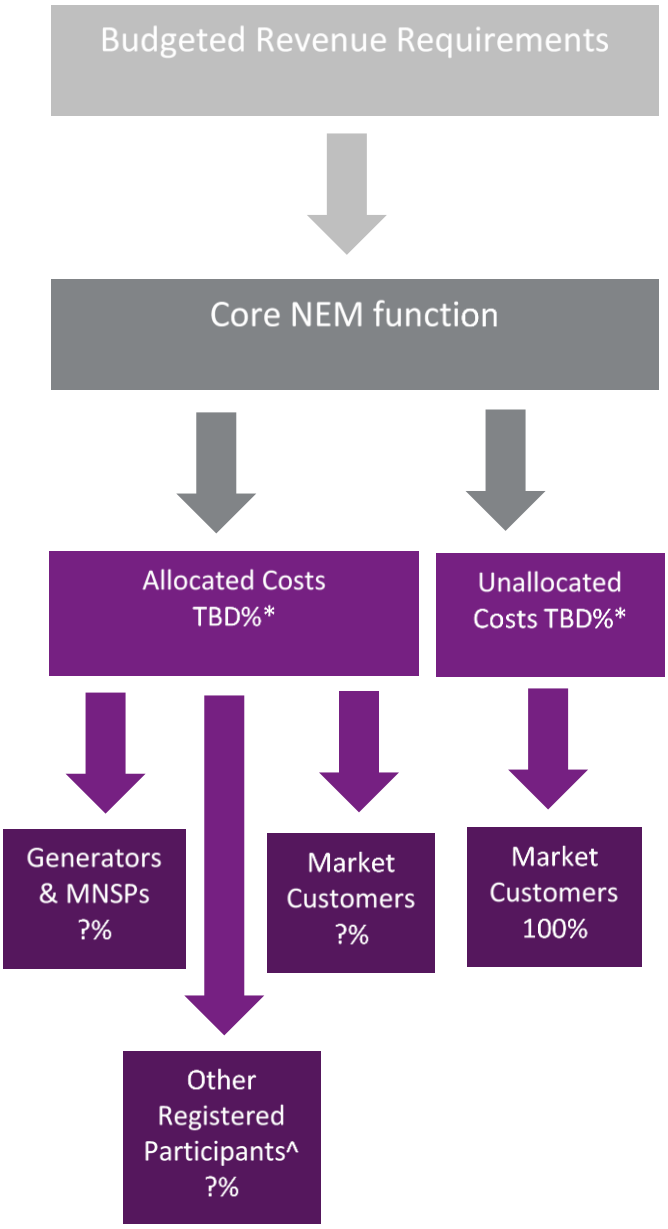
Categories of Registered Participants that could also now be charged include:

- TNSPs – development of the ISP has resulted in the Rules requirement that the NTP function is now to be recovered from these participants. Improvements to AEMO's digital, cyber and security systems can benefit TNSPs and their interactions with and reliance on such systems, therefore it could be argued that this participant class should also be allocated some of these costs.
- DNSPs – the DER integration program creates a potential market for DNSPs to participate. Additionally, DNSPs are using AEMO's market systems more to track customer types and recover distribution tariffs through the retailer billing systems. Therefore this increased involvement of DNSPs in AEMO revenue requirements should be considered where there is justification that it is efficient to do so.
- Metering Coordinators[4] – there is a growing number of new entrants who have benefited from Power of Choice reforms which expanded competition in metering and the market-led deployment of advanced meters. These participants also utilise MSATS frequently which leads to the broader discussion in section 3.3 on the redefinition of the current Electricity Full Retail Contestability (FRC) fee to one that covers all NEM retail functions/services.
- Market Ancillary Service Providers (MASPs) – currently MASPs have no ongoing cost levied against them however the volume of ancillary services provided from this participant class is starting to increase now and particularly once the Wholesale Demand Response (WDR) mechanism is in place from 1 October 2021[5], thereby increasing their interaction with AEMO dispatch systems. Therefore, this increased involvement of MASPs in AEMO's revenue requirements should be considered.

[4] Caution will need to be taken to make sure Metering Coordinators are not being charged twice since they operate in accordance with Chapter 7 of the NER.

[5] From this point MASPs will be known as Demand Response Service Providers (DRSPs).

Figure 2 – New attribution of NEM fees to participants



*To be determined through AEMO's cost allocation survey
^Such as TNSPs, DNSPs, MASPs, MSGAs, Metering Coordinators etc

New categories of Registered Participants that enter during the fee period

Whilst participants that are not yet Registered Participant categories under the NER cannot be considered for this fee structure, it is worth noting that there are some new categories expected to enter the market over the next fee period, i.e. once they are legislated in the NER/NEL, and the extent of their involvement with AEMO's revenue requirements may need to be considered at that time. For example, Market Stand-Alone Power System Resource Providers (MSRPs) are expected to be effective from December 2021 and will utilise MSATS. Additionally, there will be a growth in Embedded Network Service Providers once new rules and legislation proposed by the AEMC through their review on Updating Regulatory Frameworks for Embedded Networks become effective[6].

Cost recovery metrics for new Registered Participant categories that enter the market during a fee period are sometimes determined via transitionary arrangements specified in the Rules which gives effect to the new participant category. AEMO may make submissions on cost recovery for new Registered Participants as part of rule changes processes, however if cost recovery is not explicitly determined through the rule change process, then AEMO would either recover costs through the NEM fee (allocated if possible, or unallocated) or a declared NEM project consultation may be undertaken.

This fee structure review is seeking stakeholder feedback on the appropriateness of broadening the fee recovery base to other existing Registered Participants as well as feedback on the appropriate metric for fee recovery for each participant class.

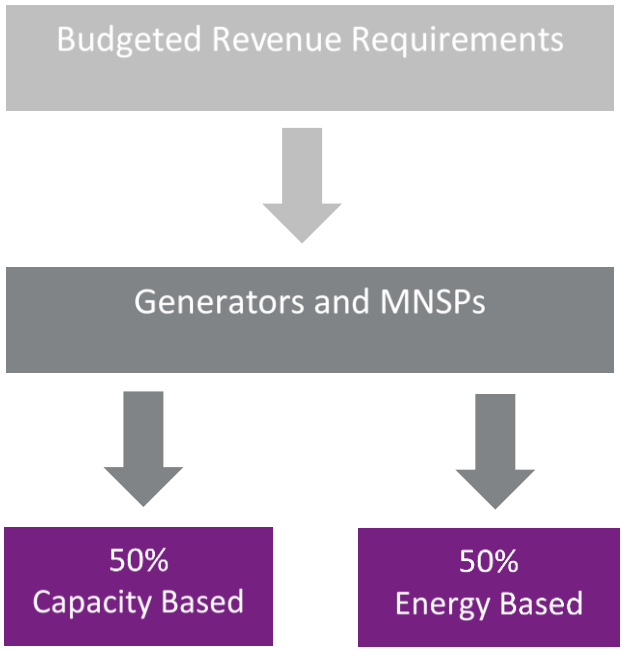
Question

1. What do the Fee Structure Principles outlined in Table 1 mean to stakeholders?
2. What are your general comments on the current NEM fee structure?
3. Which other Registered Participants should NEM fees be recovered from?
4. For each Registered Participant, what is the appropriate metric to recover allocated costs?

3.1.3 Generators

Generators and MNSPs are currently charged with an equal allocation to capacity and energy, that is 50% capacity-based and 50% energy-based, see Figure 3.

Figure 3 – Current allocation charge to Generators and MNSPs



[6] Information on the final report and submissions received to the review on Updating Regulatory Frameworks for Embedded Networks is available on the AEMC's website at: https://www.aemc.gov.au/market-reviews-advice/updating-regulatory-frameworks-embedded-networks

There current division of Generator/MNSP costs are as follows:

- Two-thirds apportioned to Market generators (Scheduled, Semi-scheduled and Non-scheduled), Non-market scheduled generators and MNSPs; and
- One-third apportioned to Market generators (Scheduled, Semi-scheduled and Non-scheduled) and MNSPs.

This means that Non-market scheduled generators currently pay less than Market generators, and Non-market non-scheduled generators do not pay anything. This was designed to recognise that Non-market generators have less involvement with AEMO's functions, for example they are not required to settle with AEMO. As there are currently no non-market scheduled or semi-scheduled generators registered, the current division of costs could be considered an unnecessary complexity.

Furthermore, there is currently no division between market generators that are Scheduled, Semi-scheduled and Non-scheduled, meaning they pay fees on an identical basis. Since the last fee determination there has been (and will be going forward) a significant increase in the number of Semi-scheduled and Non-scheduled generators, and AEMO is expected to experience greater challenges with modelling, controlling and operating the power system, potentially resulting in greater AEMO involvement in the market. Therefore, consideration could be given to division of costs between Market generator categories that is more reflective of involvement in AEMO's revenue requirements.

After the allocation of costs to types of generators, there remains the question of how the costs should be charged, e.g. per MW or MWh.

Changing the equal allocation to capacity versus energy could be considered to reflect the increase in capacity of generation expected in the future at a rate greater than expected energy (see Figures 4 and 5) as more renewables connect and capacity factors decrease. That is, allocation could be biased towards the capacity contribution to better reflect the extent of involvement, see Figure 6 that depicts this option.

Figure 4 – Future capacity by technology

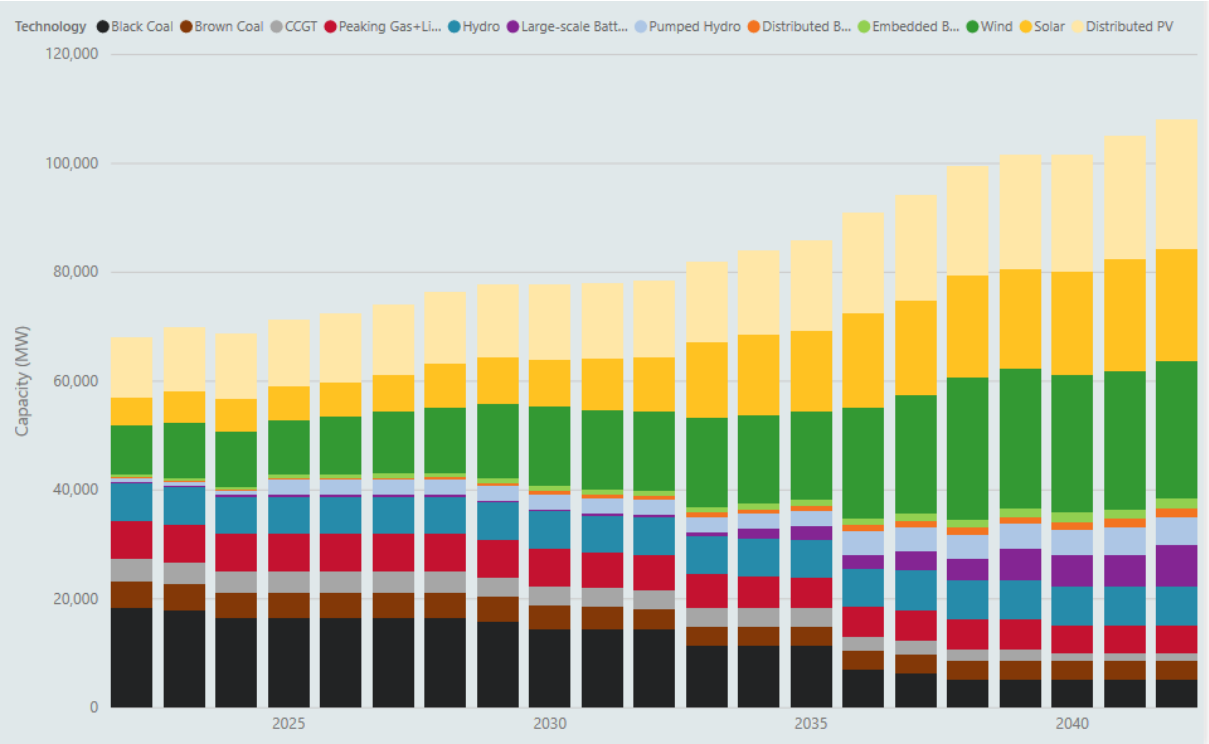


Figure 5 – Future energy by technology

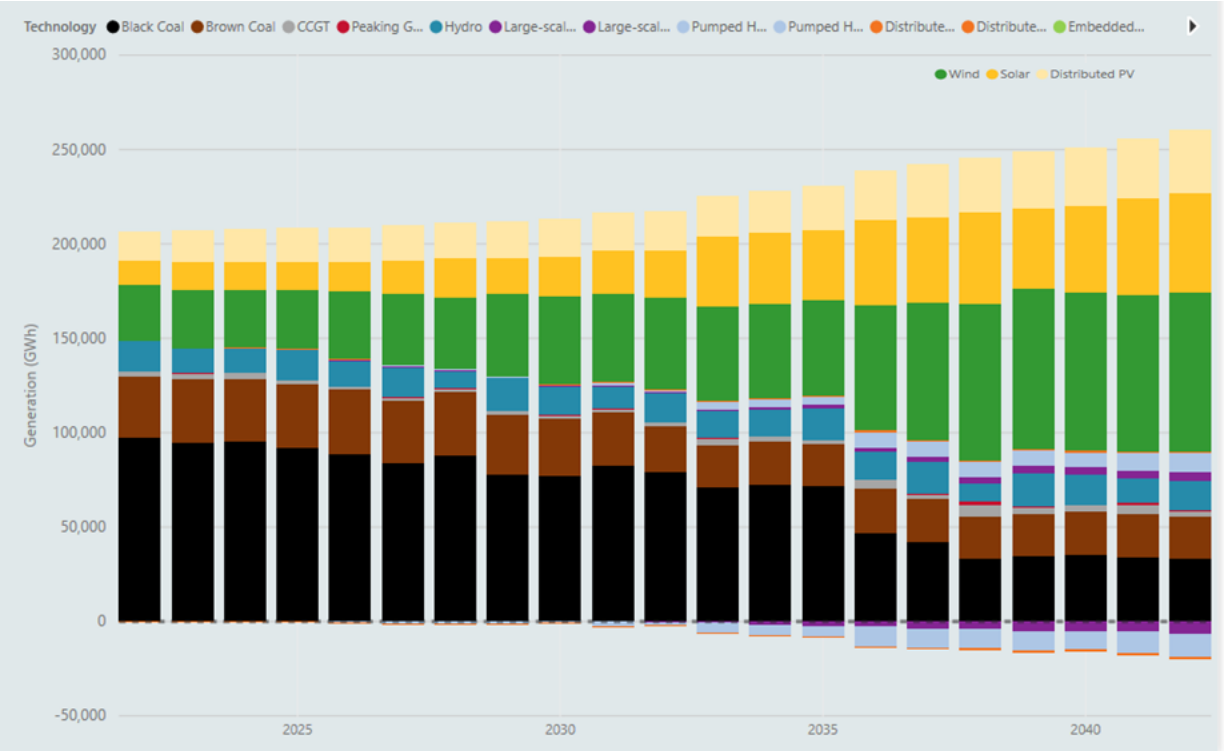
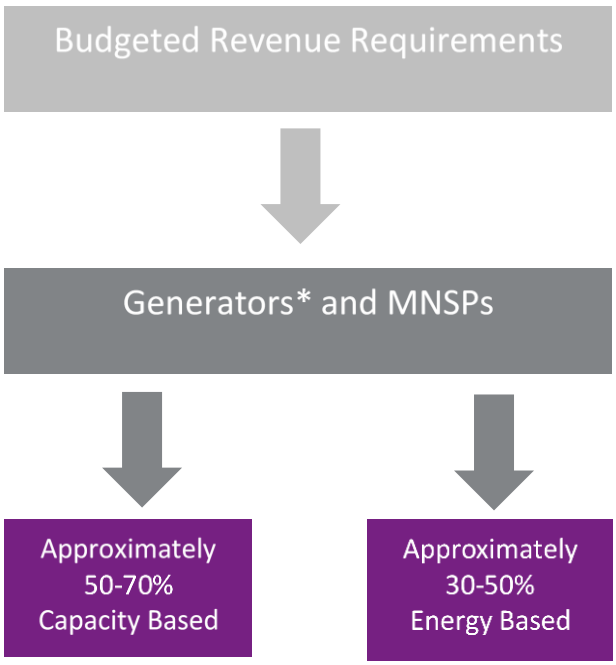


Figure 6 – Potential allocation charge to Generators and MNSPs



*May exclude Semi-scheduled generation. If so, Semi-scheduled generation will have its own fee charge.

A noticeable trend in the electricity market is the segmentation of services from providers. The NEM has historically been "heavy baseload" from investments in coal fired power stations. These stations have typically

provided a number of services, energy, FCAS and sometimes SRAS and have also provided a number of synchronous services, such as inertia, fault contribution and dynamic, voltage control as a by-product of producing energy. This is unlikely to continue and new, non-energy revenue streams and non-energy players may develop.

For example, the Ancillary Service Unbundling Rule allowed Market Ancillary Service Providers (MASPs) to enter the FCAS market. These participants are not charged under the current structure. New synchronous condensers are operating in South Australia (owned by TNSPs) to improve system strength – these are not charged generator fees under a MW or MWh. Is it worth considering whether providers of non-energy synchronous services may attract a fee? If the value of these services develops and more revenues and participants are attracted to non-energy markets, it may be sensible to spread costs across these participants by charging them. This could be done by charging on revenue, or some other characteristic.

For example, Table 2 shows how the FCAS market has developed with new specialist entrants whose FCAS revenue far in exceeds their energy revenues (in the case of batteries) or bears no relation to energy revenues (in the case of MASPs). The data ignores FCAS costs and energy consumption.

Table 2 Revenue from FCAS participants

	FCAS $m – 2019-20	FCAS market share	% of energy revenue for the FCAS participants
Other	$289	70%	3%
Battery	$98	24%	1207%
MASP	$16	4%	N/A
FCAS Load	$5	1%	N/A
WF	$2	1%	6%
VPP	$2	0%	N/A
Total	$413	100%	N/A

The question therefore is whether "generation" be it in MW or MWh are the determinants to fees paid, or are there other more efficient metrics that would satisfy clause 2.11.1?

Other approaches that could be considered to allocate direct costs to generators include:

- Using their inherent characteristics contributing to maintain the security and reliability of the power system such as inertia, system strength, FCAS, reactive or active power contributions.
- Applying a percentage of a generator's total revenue in settlements, including FCAS revenues, or a revenue per MW metric as a scalar to the capacity-based charge.
- Changing the capacity value used for cost allocation from the larger of the registered and maximum capacity values, noting that there are clear differences between a thermal and renewable plant's registered capacity versus its maximum capacity.
- Recovering the costs from utility scale batteries and MASPs where appropriate, particularly as their volumes in the market begin to increase.

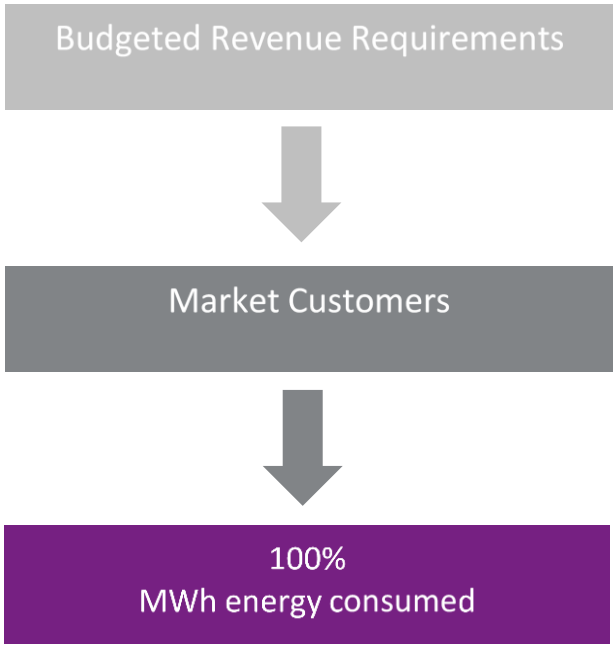
Question

1. Should there be a separate fee category for semi-scheduled and non-scheduled generation?
2. Is the current method of charging Generators and MNSPs appropriate? Is there an alternative approach that would be more economically efficient and consistent with the Fee Structure principles?

3.1.4 Market Customers

Market Customers are currently charged based on a rate ($/MWh) derived by a yearly energy forecast value, multiplied by the actual megawatt (MWh) settled in spot market transactions for that Market Customer in respect of each billing period, see Figure 7.

Figure 7 – Current allocation charge to Market Customers



The current approach can create under or over recovery if actual energy consumption is different to the forecast value used. This is because AEMO's costs do not vary with electricity consumption. In previous fee determinations AEMO has considered the revenue amount charged on a per MWh basis is unlikely to change consumers' behaviour in the consumption of electricity. There is a risk that some consumers with more elastic demand, such as high electricity consumption smelters, may be encouraged to reduce consumption, invest in substitutes, or close, to avoid the AEMO fee. This would be an economically inefficient outcome, given AEMO's costs may not be reduced by such behaviour. A similar example is distributed PV where consumers are encouraged, more than they would be otherwise, to invest in PV to avoid variable per MWh costs, which under the current fee structure includes AEMO fees.

An approach to address this risk is by normalising the $/MWh rate throughout the year to account for actual consumption. This may pass the variability to retailers with fixed tariffs. Another approach would be to charge on a per connection basis, which may be a more stable denominator than MWh, similarly to the current approach for Energy Consumers Australia and Full Retail Contestability.

Alternatively, a rate that incorporates a fixed component could be introduced along with the variable component based on consumption. Introduction of a fixed component would provide additional certainty of

some cost recovery at times of over-forecasting energy consumption and therefore an increase in participant fees would not be as large in the following year. This approach aligns with the principle of providing for recovery of AEMO's budgeted revenue requirements whilst still being relatively simple and reflective of involvement.

Further, fees that are currently charged on an energy (MWh) basis are assessed on their net energy volume for each wholesale connection point (TNI), and then an absolute value applied. This means that a retailer with unregistered embedded generation (e.g. small-scale solar PV) as well as load has a reduced fee allocation as a result of offsetting the import and export flows. If it is determined through this consultation process that MWh fees should continue to be charged on this basis, a modification to the 'net flow' arrangement that could be considered is to use the gross flow for each customer (NMI) and sum up the energy irrespective of flow[7] which means that unregistered embedded generation are no longer offsetting load. This charging approach aligns with the simple and reflective of involvement principles and could be used for all MWh fees for market customers.

Question

1. What are your comments on the current method of charging Market Customers fees based on actual energy consumed? Is there a more appropriate method to charge?

3.2 National Transmission Planner

Participant fees for AEMO's role as the NTP are presently charged separately from other Participant fees and AEMO currently recovers its NTP costs from Market Customers on the basis of energy consumed.

On 1 July 2020, the ISP replaced the initial stages of the RIT-T process, that is the Project Specification Consultation Report (PSCR), 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 plan also included Renewable Energy Zones.

Amendments were made to the NER to incorporate ISP development and NER clauses 2.11.1(c)(5A) and 6A.23.3 now stipulate costs for AEMO's NTP function are to be recovered from TNSPs. With regards to the charging methodology, AEMO and the ENA have drafted arrangements for NTP fees to be invoiced from 1 January 2021. TNSPs are to be levied based on their respective jurisdiction's consumption (per GWh basis) for the latest completed financial year. This allocation methodology is in place until 30 June 2022 assuming the draft Rules are adopted.

The draft Rules also state that AEMO is to advise each TNSP of their revenue requirement for the upcoming financial year by 15 February. Since the determination for the next fee period commencing 1 July 2021 is not expected to be completed before 15 February 2021, one option to consider is for any change to the transitional methodology of recovery from TNSPs for the NTP function that results from this consultation becomes effective from 1 July 2022.

[7] There are implications of this alternative arrangement on metering and settlement systems, however this is partially mitigated by changes introduced as part of 5MS.

Question

1. Since the allocation methodology is expected to be in place until 30 June 2022, is there another method that could be applied thereafter?

3.3 Electricity Retail Markets (currently Electricity Full Retail Competition)

Participant fees recovered under the electricity Full Retail Competition (FRC) fee are charged separately from other Participant fees. Currently, electricity FRC fees are charged to Market Customers on a per NMI basis which has been in effect since 1 July 2019 as a result of the 2015 fee determination. FRC fees were originally intended to separately recover the costs of full retail contestability, that is to largely reflect the cost of implementing and operating MSATS, and transition arrangements were in place for jurisdictions as they progressively adopted FRC.

The 2017 FRC consultation[8] confirmed the same charging arrangements should remain, and also that third party B2B participants would not pay fees in the short term but is an area that would be reviewed.

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. 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 Power of Choice 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 to as part of the introduction of metering competition;
- Significant changes to MSATS resulting from the 5MS program (discussed further below); and
- Going forward there is likely to be more interaction with the retail market and functions e.g. 5MS program and DER integration.

With the above in mind, AEMO is asking participants whether the current FRC fee service should be amended to an electricity retail market fee that reflects a service-based approach. This would more accurately allocate retail market functions within AEMO for recovery by the appropriate Registered Participants to align with the reflective of involvement principle. This would allow:

- The separation of MSATS services relating to the retail function (e.g. charged on per NMI basis, or other option) and the broader NEM function (an allocated charge on per MWh basis).
- Ability to allocate costs of 5MS where a portion relates to (i) MSATS upgrade at the retail level for 5MS (ii) MSATS upgrade at the wholesale level for 5MS and (iii) MSATS upgrades for future capability.
- Recovering costs from metering coordinators and even B2B third parties[9], should there be a material enough uptake of these third parties.

As such, consideration should be given on the metric if it is decided to redefine the FRC fee as a service fee, that is, whether the current charge on a per NMI basis remains appropriate for retail function. Options include:

[8] Information on the final report and determination, including other consultation papers and submissions, available on AEMO's website at: https://www.aemo.com.au/consultations/current-and-closed-consultations/structure-of-participant-fees-in-aemos-electricity-full-retail-competition-market

[9] Clause 2.11.1A Application for the purposes of rule 2.11 only, Third Party B2B Participants (other than Third Party B2B Participants who are also Embedded Network Managers) and book build participants who are not otherwise Registered Participants are deemed to be Registered Participants.

- Remain on a per NMI basis;
- Change to a per MWh basis;
- Change to a per MSATS-service basis, or per transactions basis, e.g. transferring a customer account between retail participants, or any other participants that use the system which may allow for the cost of MSATS to be charged to those retailers and implicitly the consumers that use the system.[10]

AEMO welcomes comments on the options above for allocating fees currently recovered through the electricity FRC service.

Question

1. Should AEMO continue to separately recover costs for the retail function from AEMO's other NEM functions? Who should the fee be recovered from?
2. What are stakeholders' comments on the scope of the retail function? Are there others that should be included?
3. How should the electricity retail markets fee be charged?

3.4 Major reform initiatives

Under AEMO's current business structure, AEMO cannot retain operating capital but instead relies on debt borrowings to pre-fund known capital expenses and any unrecovered operating expenses. AEMO's current capital requirements cover ongoing maintenance of its operating systems and license fees, upgrades to forecasting and decision tools to address increasing complexities in system planning and operations, required investments in cyber security, and market reforms such as the implementation of 5 minute and global settlement and the reforms of the Wholesale Electricity Market (WEM).

Additionally, AEMO's existing IT platforms and architecture were no longer able to cope with the speed, scope of change and data requirements being experienced due to the transformation occurring and expected to occur in the energy industry. AEMO is currently in the second year of a multi-year digital uplift that will require the available debt funding envelope of up to $500 million to support the ability to meet projected capital requirements.

This section outlines the capital programs expected to be incurred over the next three to five years for recovery from participants.

3.4.1 5MS program

On 28 November 2017, the AEMC made a final determination and rule to alter the settlement period for the wholesale electricity spot market from 30 minutes to five minutes, to align with the dispatch period. The AEMC determined that Five-Minute Settlement would provide a better price signal for investment in fast response technologies, such as batteries, new gas peaking generation, and demand response. The AEMC also determined that the alignment of the operational dispatch and financial settlement periods are expected to lead to more efficient bidding and operational decisions.

On 6 December 2018, the AEMC made a final determination and rule that requires a move to a Global Settlement (GS) framework for the demand side of the wholesale electricity market. The key reasons why the AEMC made this decision was to improve transparency of unaccounted for energy (UFE) and to allow retail competition on equal terms.

[10] However it should be noted that AEMO's costs do not relate to the number of customer switches, otherwise this would be charged separately under a direct fee. Given the number of customer switches varies and the costs of running MSATS largely fixed, this may require AEMO to consider utilising the sub provisions to 2.11.1(b)(2)(i) which allow for rollover of excess and recovery of shortfall.

In November 2019, AEMO published its final decision[11] that determined the 5MS Program met the criteria in the NER to be a declared NEM project pursuant to clause 2.11.1(ba)(1) and clause 2.11.1(ba)(3) of the NER. Should it be necessary, this allows AEMO to structure a fee separately for 5MS.

AEMO established the 5MS Program in order to coordinate the implementation of changes as a result of the Five-Minute Settlement rule change[12] and the Global Settlement rule change[13].

On 6 July 2020, the AEMC made a final determination and rule that delays the commencement of 5MS and GS by three months, with a new effective date of 1 October 2021.

5MS requires major changes to existing metering, settlement, prudentials, and bidding processes (referred to in this section as changes to incremental components), as well as AEMO's electricity retail and wholesale market systems which are also in need of an uplift due to age and capability to keep up with the transforming energy sector (referred to in this section as changes to general or legacy components).

Implementation of the program will have impacts on Market Customers (electricity retailers), Distribution Businesses as well as generation and demand side technologies. The breadth of impact of this program to many classes of Registered Participants reiterates the issue described in section 3.1.2 regarding the extent of involvement in AEMO's revenue requirements of other registered participant categories.

It is estimated that total costs of the project, to be amortised over 10 years, are approximately $121 million with capital expenditure for the program approximately $80 million of the total cost.

Consistent with the earlier determination that 5MS meets the criteria of a declared NEM project, AEMO is of the view that where appropriate the cost recovery of the 5MS Program should be kept separate from general NEM fees. However, AEMO has identified a proportion of the 5MS Program costs are related to a general uplift in metering and settlement systems, and not directly related to the 5MS and GS reforms.

With respect to the component of 5MS Program costs directly attributable to the 5MS and GS reforms, AEMO is considering the appropriate metric to apportion across registered participants. The options for this may include the existing per-MWh or per-NMI allocation used for Market Customers, or some other metric that better reflects the recovery principles.

If a separate 5MS recovery is determined, AEMO must also give consideration to when this should commence. At present 5MS and GS reforms are scheduled to commence on 1 October 2021.

Question

1. What are your comments on options for cost recovery of the 5MS program including the charging methodology? Who should the costs be recovered from?
2. When should the recovery of 5MS Program costs commence?
3. Over what time should the 5MS Program costs be recovered?

3.4.2 DER integration

DER integration 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. This is considered an integral program to evolve the system for the future, particularly when the rate of uptake of DER is projected.

[11] Information regarding this final determination, including other consultation papers and submissions, is published on the AEMO website at: https://aemo.com.au/consultations/current-and-closed-consultations/declared-nem-project-5ms-program

[12] Information regarding the rule change, including the final determination and rule, is published on the AEMC website at: https://www.aemc.gov.au/rule-changes/five-minute-settlement

[13] Information regarding the rule change, including the final determination and rule, is published on the AEMC website at: https://www.aemc.gov.au/rule-changes/global-settlement-and-market-reconciliation

The program has five workstreams which aim to better integrate DER into the power system:

- Consumer Data – empower industry innovation and value to consumers through delivering accessible energy data. This roadmap is comprised of four key initiatives:
  - Consumer Data Right (CDR), discussed further in section 3.4.5;
  - Establishment of a DER Register;
  - Improvement of the Customer Switching process; and
  - Improving consumer access to energy data for comparison purposes through CDP and Energy Made Easy
- Markets – this initiative aims to identify and enable improved market structures, based on evidence gathered through demonstrations, to maximise future state value for consumers in an evolving industry, and is comprised of:
  - Wholesale Demand Response – providing mechanisms for wholesale players to engage in demand response;
  - DER Markets & Mechanisms - Examination of mechanisms that better integrate DER into wholesale and ancillary services markets such as use of capacity markets, network dynamic operating envelopes and local distribution markets using evidence gathered through trials and industry consultation.
- Operations – identify emerging and future operational challenges related to DER, developing and implementing suitable mitigation and management measures. The three key initiatives for this roadmap are:
  - DER behaviour during disturbances (Understanding behaviour; DER and load model; Solar Analytics collaboration);
  - Emergency frequency control schemes (South Australia; Other regions; Long-term options); and
  - System restart.
- Standards – drive state-of-the-art DER Standards that adequately support system security and provide consumers with the capabilities required to unlock the full value of their system and is comprised of two key initiatives:
  - DER Standards and connections (AS/NZS4777.2 and AS/NZS4755.2 uplift, new standards for DER data, communications, interoperability and cyber-security; and
  - DER operational requirements; Identifying system limits and methods to align DER behaviour with power system security.
- Demonstrations – inform evidence-based policy, regulatory and operational process changes through innovative trials, including, among others:
  - VPP demonstration program;
  - Queensland Integrated Power Plant; and
  - Victorian DER Marketplace.

As outlined above, the Markets roadmap includes the implementation of the wholesale demand response (WDR) mechanism[14] which commences on 1 October 2021. Under this mechanism, a new category of registered participant, a demand response service provider (DRSP), will be able to bid demand response directly into the wholesale market as a substitute for generation. A DRSP can also engage directly with a customer without the involvement of that customer's retailer. Benefits of the program include greater demand side transparency and additional capability to manage peak system demand as well as increasing the level of consumer choice in relation to wholesale demand response.

[14] Information regarding this final rule and final determination, including other consultation papers and submissions, is published on the AEMC website at: https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism

Another aspect of DER is that it can behave like a generator by providing capacity reserves into the market. The VPP Demonstration Project has confirmed these resources can respond to energy market signals and can also provide contingency FCAS services. The market impact of enabling FCAS from DER will, at scale, reduce contingency FCAS cost providing benefits to Generators, who benefit for a fall in contingency raise cost, and Market Customers, who benefit from a fall in contingency lower costs.

Although AEMO is seeking government funding to minimise the impact on participant fees for the above programs, there will still be some costs to be recovered from participants. The programs will provide new sources of revenue generation and increase competition in the market and therefore consideration of any cost recovery from other registered participants, for example DNSPs and DRSPs, who will also be able to participate in VPP, should be considered.

With the above benefits that would result from various workstreams of the DER program, options for fee structure include:

- Recovering any legacy system upgrades required to accommodate DER integration (i.e. for future capability) through allocated NEM fees; and
- Recovering any incremental costs from DNSPs or DRSPs through the electricity retail markets service on a per MWh basis; or
- Recovering incremental costs from DNSPs or DRSPs through the electricity retail markets service on a per NMI basis.

AEMO welcomes feedback on the recovery of the DER program and the metric to be applied.

Question

1. How should costs from the DER program be recovered?
2. Who should cost recovery be allocated to? How should the program be charged?

3.4.3 Digital platform, system and cyber refresh

Currently, a high proportion of AEMO's systems are bespoke and are nearing end of life. 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.

AEMO is planning a significant refresh of its systems over the coming years that will include the development of a modern digital platform that will provide more reliable and transparent data. This major refresh of our IT systems to a modern digital platform will significantly increase our data processing capability and reduce both our members' and our own operating expenses through simpler architecture and cloud-based systems.

The systems refresh focus areas over the next 12 months will include:

- Providing more granular, timely and actionable data to stakeholders.
- Refreshing forecasting systems to absorb new data sets, fine tune algorithm accuracy and improve scalability and timeliness.
- Uplifting the security posture by enabling new capability across cyber and data control to detect and prevent attack and control data leakage.
- Improving industry preparedness to detect and coordinate response to cyber-attack.

Question

1. What are your comments on the Digital platform, security and cyber refresh program?

3.4.4 Regulatory compliance programs

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

- Operational programs – including implementation of mandatory primary frequency response, RERT staged improvements, MTPASA improvements.
- Reliability and forecasting – including meeting regulatory commitments for the Reliability Retailer Obligation (RRO).

As these types of projects are required to meet a NEM regulatory change and are related to the core NEM functions, AEMO is considering recovery of these amounts as part of the general allocated cost.

It may be appropriate to use the criteria[15] similar to that used for determining declared NEM project status to determine whether a regulatory obligation results in material implementation costs so that cost recovery is through a specific fee category. The relevant criteria are:

- A major reform or development (including an anticipated reform or development) of the market; or
- A major change (including an anticipated change) to a function, responsibility, obligation or power of AEMO under the Rules; or
- A major change (including an anticipated change) to any of the computer software or systems that AEMO uses in the performance of any of its functions, responsibilities, obligations or powers under the Rules.

Alternatively, when considering whether a regulatory obligation is a major reform or a major change, it may be relevant to consider a threshold for the implementation costs.

Question

1. What are your comments on what constitutes Regulatory compliance programs?
2. Do you agree with the cost recovery approach through the general allocated costs?
3. Is there an implementation cost threshold that could be considered for major reform or major change as a result of a regulatory obligation?

3.4.5 Energy Consumer data rights (CDR) program

The Consumer Data Right is an important reform that will empower consumers to have greater control over their data. The CDR has already commenced in the banking sector, and the Federal Treasurer has now designated that the CDR be rolled out in the energy sector. The Australian Competition and Consumer Commission (ACCC) is currently consulting on the Rules framework for the energy sector, with the CDR Rules expected to be finalised in the first half of 2021.

[15] NER clause 2.11.1(ba)

The Energy CDR program seeks to offer energy consumers with easy access and greater control over their energy consumption data so that they can make more informed decisions about their energy supply and investments in distributed energy resources (DER) and energy-efficient appliances. Access to consumer's data will be provided through a single gateway, with the ACCC proposing that AEMO assumes the gateway role. AEMO will also be a data holder under the CDR program, responsible for providing access to metering, NMI Standing and DER register data, with the consent of the customer. These obligations are expected to be incorporated as a new statutory function for AEMO in the NEL and NER in time.

The program is expected to be implemented in the second half of 2022. Currently, capital funding for the program is expected to be provided by the Australian Government (with any potential recovery mechanism yet to be determined). Operating expenditure for ongoing delivery of the CDR functions in the energy sector is expected to be recovered from registered participants through AEMO's fee structure.

As a new regulatory obligation will be imposed on AEMO relating to the core NEM functions (i.e. the supply and consumption of energy), costs would most likely be allocated and recovered from market customers. Consideration could also be given to recovering the costs of the function from "users", such as retailers through the electricity retail markets function.

Question

1. What are your comments on a cost recovery approach for CDR? Which Registered Participants could costs be recovered from?
2. Are there any innovative pricing / product structure that AEMO could use to pay for the CDR?

3.4.6 Transformational market initiatives

Transformational initiatives are major reform work currently in progress and under consultation through AEMC or ESB processes and result in costs that will need to be recovered. Such programs include Ahead Markets, Two-sided markets and Essential System Services programs, which may be implemented over the next fee period.

It is expected the allocation of charges to Registered participants resulting from implementation of these NEM reform programs would be determined explicitly by the AEMC or ESB once their consultation has completed, with amendments made to the NEL and/or NER to reflect new or amended regulatory obligations. That is, in a similar manner to the NTP function following implementation of the ISP Rules. However, if allocation of charges is not explicitly determined through the AEMC or ESB processes, then AEMO would either recover costs through the NEM fee (allocated if possible, or unallocated) or a declared NEM project consultation may be undertaken.

While AEMO is not consulting on the structure of cost recovery for these initiatives at this time, it is important to highlight that once these projects are implemented they will need to be incorporated into AEMO's cost recovery in some manner.

3.5 Energy Consumers Australia (ECA) fees

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 Consumer Advocacy Panel (CAP), the fees for which AEMO previously recovered through Participant fees in the National Electricity Market (NEM) and gas markets.

In October 2014 AEMO conducted a consultation process[16], prior to the commencement of the ECA, and it was determined that the electricity component of ECA fees would be recovered from NEM customers on the basis of a charge per connection point for small customers.[17]

Question

1. What are your comments on the current approach of recovering ECA costs on the basis of a fee per connection point for small customers?
2. Is there a more appropriate method for apportioning the recovery of ECA costs?

3.6 Registrations

Registrations fees are a charge reflecting the costs to AEMO in the registration of all registered participants in the NEM.

In the 2011 determination, AEMO set the fee structure for registration fees along with the actual registration amount based on application types. The complexity of the registration process can vary significantly depending on the application type and this was reflected in the different fees charged for the different application types.

For the 2016 determination, as AEMO was in the process of reviewing the end to end registration process for each application type, it was decided that it was appropriate to retain the existing fees for each application type until that end to end process review was complete. It was then proposed to review the amount of the fees for each applicant type to ensure they are cost reflective, and any changes to the amount of the fees to be set via AEMO's annual budgeting and fee setting process. The review resulted in the existing fees being retained.

AEMO is considering a review of registration fees since the last one was completed in 2018. This may be appropriate since the macro environment has substantially changed since the last review.

Question

1. What are your comments on the current registration fee structure and the option to determine and set the actual amount of the registration fees for each application type via the annual AEMO budget and fee setting process?

3.7 NEM Participant Compensation Fund

Under the NER, AEMO is required to maintain the Participant Compensation Fund (PCF) for the NEM. The purpose of this fund is to pay compensation to Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers for scheduling errors as determined by the Dispute Resolution Panel.

The NER prescribes:

- The funding requirements for each financial year.

[16] The final report on the ECA fee collection methodology, including the consultation and submissions received, is available on AEMO's website available at: https://www.aemo.com.au/consultations/current-and-closed-consultations/energy-consumers-australian-fee-collection-methodology

[17] Small customers are defined in the National Energy Retail Law.

http://www.aemo.com.au/Consultations/National-Electricity-Market/Energy-Consumers-Australian-Fee-Collection-Methodology

- That the funding requirements can only be recovered from Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers.

AEMO currently charges NEM PCF fees to Scheduled Generators, Semi-scheduled Generators and Scheduled Network Service Providers on a 50% capacity and 50% energy basis.

Question

1. What are your comments on how to charge NEM PCF fees to Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers?

3.8 Incremental service fees

Where it is practical for AEMO to identify that doing something specific for a participant or another party, and that action causes identifiable and material costs for AEMO, AEMO will continue to seek to levy fees to recover the incremental costs incurred. This may include:

- Subscription fees for services or reports requested to be produced for non-AEMO members.
- Charging for ad-hoc reports and services developed by AEMO and delivered from the retail systems, for example, the Snap Shot report from MSATS which is used by participants to reconcile their systems against what is held in MSATS.
- Applying a user-pays service charge for AEMO support hub enquiries from participants who call the support hub for assistance on specific procedural requirements.

Question

1. What are your comments on charging for incremental services fees where a specific service is performed?
2. Do participants consider there are any costs of AEMO that could be allocated in this way?

3.9 Other comment and issues

Question

1. We welcome your comments on any other issues relating to the structure of Participant fees in AEMO's electricity markets.

4. Appendix A: 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 3 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 Aggregated Generator	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)	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