CS Energy submission: Structure of Participant Fees in AEMO's Electricity markets

Summary

This submission outlines CS Energy's opinion in regard to the structure of Participant Fees that AEMO should adopt from 1 July 2016.

CS Energy considers that AEMO's proposed structure of Participant Fees is not consistent with requirements under the National Electricity Objective (NEO) and has a number of downsides which can be overcome.

The downsides to AEMO's proposed structure are:

- for Market Customers it intends to charge fixed costs in variable fees, distorting incentive to consume electricity from efficient levels; and
- for Generators it intends to charge fixed fees, which cannot be recovered by these participants, distorting incentive to invest in electricity generation from efficient levels.

The downsides can be overcome by fees for Market Customers structured on a $ per connection point basis and fees for generators being minimised.

CS Energy commissioned independent advice from Frontier Economics which considers the reasoning in AEMO's Draft Report, the 2005 Allen Consulting Group report, requirements under the National Electricity Objective and an appropriate fee structure consistent with this objective and economic efficiency. CS Energy's position is supported by the advice from Frontier Economics.

Requirements under the Rules 2.11.1:

In determining Participant fees, AEMO must have regard to the **National Electricity Objective**.

The structure of Participant fees must, to the extent practicable, be consistent with the following principles:

(1) the structure of Participant fees should be ***simple***;

(2) Participant fees should ***recover the budgeted revenue*** requirements for AEMO

(3) 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***;

(4) Participant fees should not ***unreasonably discriminate*** against a category or categories of Registered Participants.

Comments on the Draft Report

CS Energy is of the opinion that AEMO's proposed fee structure does not satisfy the Rules.

The proposed structure of participant Fees relies heavily on 2.11.1.(b).(3) of the Rules, that is, *"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"*.

CS Energy notes AEMO interprets this principle three different ways to justify its proposed structure of fees in the Draft Report.

2.11.1.(b).(3) does not require AEMO structure fees by MWh rather than connection point

CS Energy disagrees with AEMO's consideration that clause 2.11.1(b).(3) is basis to reject a fixed $/connection point fee and endorse a $/MWh fee.

The statement *"AEMO's costs were not found to materially increase according to the number of customers. Therefore this would not be reflective of involvement[1]"*, indicates AEMO considers 2.11.1(b).(3) relates to the concept of marginal costs, yet on the other hand *"AEMO acknowledges it incurs fixed costs regardless of amount of energy dispatched[2]"* indicates AEMO knows it cannot apply the concept of marginal cost.

AEMO's costs do not increase by any identifiable unit. The cost of producing one more unit is known as 'marginal cost'. Total cost divided by the total number of units is 'average cost'. Fees can be set using marginal or average cost, yet neither is applicable to AEMO as it does not produce units. The unit used in setting fees is therefore the approach to distribute fixed costs amongst Registered Participants.

The reflective of involvement clause 2.11.1.(b).(3) is satisfied with either $/MWh or $/connection point fee for Market Customers. This is because the fees adjust per Registered Participant on the basis of MWh (in the case of variable) and customer connection point (in the case of fixed).

It is more efficient to charge fixed costs in fixed prices. As long as the fixed fee is low enough, (which is true with AEMO's fixed costs divided by the number of connection points), the fee will not distort consumption. This is because consumers can make efficient decisions at the margin to consume electricity without including the cost of AEMO.

2.11.1.(b).(3) does not require AEMO to allocate fixed costs to generators

2.11.1.(b).(3) requires AEMO to adjust its *prices* between Registered Participants by each *Registered Participant's* involvement in the budgeted revenue requirements of AEMO.

Remember that AEMO does not have an identifiable unit that Registered Participants consume. This prevents AEMO allocating costs for marginal or average cost fees that each Registered Participant pays.

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[1] 2015 AEMO Draft Report, Structure of Participant Fees, Table 2 p13
[2] 2015 AEMO Draft Report, Structure of Participant Fees, final para, p13

In the Draft Report AEMO apportions 46% of direct allocated costs to generators, citing 2.11.1.(b).(3), 2.11.1(b)(4)[3] and 2.11.1(b)(1)[4] as reason for doing so[5].

It is CS Energy's opinion 2.11.1.(b).(3) does not require AEMO to allocate its costs between Participant class: this is because the price per Registered Participant can vary to satisfy clauses 2.11.1(b) (1),(4) and (3). Freed of these limitations, the cost allocation can instead satisfy the clause 2.11.1(ab), which requires satisfying the NEO.

This recommendation is sensible because if AEMO allocate costs to generators (as it proposes to do in the Draft Report), given the costs are fixed, this allocation will only reduce economic efficiency:

- if the fee is variable ($/MWh) then the fee is allocatively inefficient (by distorting consumption of electricity as prices do not reflect marginal costs); or
- dynamically inefficient if the fee is fixed (distorting investment as generator registered participants cannot recover the fixed fees, at least in the medium term).

As stated above, because fixed costs can be allocated to Market Customers in fixed $/connection point fees with little to no inefficiency, we see no reason for AEMO to allocate a significant proportion of costs to generators.

2.11.1.(b).(3) does not require AEMO to consider if generators can pass on costs

In the Draft Report, we note AEMO interprets[6] of 2.11.1.(b).(3) in a way that requires the costs allocated to generators must not be passed onto consumers (as may occur with a variable fee). It is CS Energy's opinion that this interpretation of 2.11.1.(b).(3) is unfounded. Whether a Registered Participant manages to pass on the fee to customers is of no concern to the Rules, bar satisfying the NEO.

The NEO is specified in 2.11.1(ab) and would be improved by AEMO refraining from allocating costs to generators in the first instance.

Frontier Economics report

CS Energy engaged Frontier Economics to provide an independent review of AEMO's Draft Report on the Structure of Participant Fees in AEMO's Electricity Markets and have provided this report for your consideration.

CS Energy is of the opinion that AEMO should adopt the recommendations of Frontier Economics.

[3] Participant fees should not unreasonably discriminate against a category or categories of Registered Participants
[4] The structure of Participant fees should be simple
[5] 2015 AEMO Draft Report, Structure of Participant Fees, 4.1.4, p10
[6] 2015 AEMO Draft Report, Structure of Participant Fees, paragraph 2, p12

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AEMO Participant Fees

A REPORT PREPARED FOR CS ENERGY

January 2016

AEMO Participant Fees

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Tables and figures

Executive summary

Frontier Economics has prepared this report for CS Energy in response to AEMO's Draft Report on the Structure of Participant Fees in AEMO's Electricity Markets. Our report considers the reasoning in AEMO's Draft Report, as well as the 2005 report prepared by the Allen Consulting Group (ACG) for NEMMCO.

The relevant NER requirements for AEMO's participant fee structure are set out in clause 2.11.1 of the National Electricity Rules (NER). These include:

- The fee structure should be simple
- The components of participant fees charged to each participant should be reflective of the extent to which AEMO's budgeted revenue requirement involve that participant
- Participant fees should not unreasonably discriminate against a category or categories of participant.

Many of the above requirements are ambiguous. For example:

- Simplicity is a matter of degree and it could refer to either or both of understandability and implementation difficulty. We interpret understandability to require – as a guide – that the fee structure ought to be of a form that would likely be comprehensible to a small retail customer. We consider that simplicity of implementation requires that the fee structure should be able to be adopted without the need for AEMO to acquire additional information beyond what it has available through its systems.
- 'Involve' has no established economic meaning, but it appears to be wider than a direct causative relationship between the participant's decisions and AEMO's costs. We interpret this principle in a manner similar to how transmission and distribution network service providers need to set prices for negotiated services – between the avoidable and standalone cost of providing the service to the customer.
- No unreasonable discrimination implies that reasonable discrimination is permissible. We interpret this to permit any form of price discrimination reasonably justifiable by reference to economic efficiency – a key component of the national electricity objective.

In applying these principles to the recovery of AEMO's costs, we note that AEMO is essential to the operation of the NEM and the majority of its core services costs are fixed and do not vary with the decisions of individual participants.

We have not attempted to comment on every aspect of the ACG report. In many respects, we agree with ACG's observations. However, we take issue with:

- ACG's discussion of options for pricing approaches. In particular, we disagree with ACG's conclusions regarding the merits of multi-part pricing compared to Ramsey pricing.
- ACG's discussion of the recommended fee structure. In particular, we disagree with ACG's reasoning in favour of its proposed 'fixed' fees based on generators' historical energy output. We also disagree with ACG's reasoning in favour of a variable fee on market customers, where ACG suggests that a per-connection fee would not obviously be any better from an economic efficiency perspective.
- ACG's recommended allocation of AEMO's budgeted costs as between various participant classes. This allocation appears to be based on an activity-based costing approach. Given the drivers of AEMO's core services costs, there is no basis to presume that such an allocation would promote efficiency.

From an economic efficiency perspective, it would be preferable to recover as large a share of AEMO's core services costs as possible from market customers. This would avoid distorting generator operating and investment decisions through charges that do not reflect the drivers of AEMO's budgeted costs.

The best option would be to set fees to market customers as a fixed annual amount per NMI or TNI. This would amount to less than $6 per NMI per year. It is highly unlikely that a fixed fee of such a magnitude would lead to any harm to efficiency or equity. This fee structure would also be very simple. It could be modified to reflect the involvement principle by ensuring that each participant in these classes pays at least AEMO's avoidable cost of providing core services to them, which would be a nominal amount.

We do not consider that the levying of a nominal fee on generator participants would violate the 'unreasonably discriminate' requirement. This is because, as noted above, we consider it would be reasonable to discriminate between participant classes where this would be expected to promote economic efficiency. Alternatively, a nominal allocation of fees on generators would also be appropriate if one interprets the unreasonable discrimination principle to refer to the *final incidence* of fees rather than the *initial imposition* of fees. In our view, it would be unreasonably discriminatory to levy fees on retailers that they could pass on to end-use customers and hence not bear themselves, while levying fees on generators that they would bear, at least in the short run.

1 Introduction

Frontier Economics has prepared this report for CS Energy in response to the Australian Energy Market Operator's (AEMO's) Draft Report on the Structure of Participant Fees in AEMO's Electricity Markets (Draft Report).

This report evaluates AEMO's proposed fee structures and recommends an alternative approach that in our view better meets the requirements of clause 2.11.1 of the National Electricity Rules (NER), including the national electricity objective.

Our report focuses on the appropriate fee structure for recovering AEMO's costs of providing core services, which include:

- Power system security, market operations and systems
- Power system reliability and planning
- Wholesale metering and settlements and
- Prudential supervision.

Our report considers the reasoning in AEMO's Draft Report, as well as the 2005 report prepared by the Allen Consulting Group (ACG) for NEMMCO (ACG report).[1] This is because the AEMO Draft Report refers to the ACG report in several instances.

This report is structured as follows:

- Section 2 reiterates and comments on the relevant NER requirements for AEMO's participant fees structure.
- Section 3 critiques particular aspects of the ACG report, including ACG's review of the various options for pricing approaches and ACG's recommended fee structures for generators and market customers.
- Section 4 reviews AEMO's Draft Report proposed fee structure and sets out our recommended changes to it.

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1 The Allen Consulting Group, *Report to NEMMCO on economic issues relating to Participant Fee structure*, 22 December 2005.

2 NER requirements

This section briefly recounts and provides our interpretation of the requirements of clause 2.11.1 of the NER.

The relevant NER requirements for AEMO's participant fee structure include:

- AEMO must have regard to the national electricity objective (as set out in section 7 of the National Electricity Law (NEL))
- The fee structure should be simple
- Participant fees should recover AEMO's budgeted revenue requirement
- The components of participant fees charged to each participant should be reflective of the extent to which AEMO's budgeted revenue requirement involve that participant
- Participant fees should not unreasonably discriminate against a category or categories of participant.
- The components of participant fees may include but are not limited to, *inter alia*:
  - Registration fees
  - Ancillary services fees (for non-market ancillary services)
  - Power system operations fees
  - Metering fees
  - Billing and settlements fees
  - NTP function fees
  - Additional advisory function fees
  - Administration fees, to recover the remainder of AEMO's budgeted revenue requirement.

We note that many of the above requirements are ambiguous, such as:

- The requirement for the fee structure to be 'simple'. Simplicity is a matter of degree and it could refer to either or both of understandability and implementation difficulty. With respect to understandability, we note that the new pricing principles for distribution network direct control services do not refer explicitly to simplicity. However, clause 6.18.5(i) of the NER states that:

  > The structure of each tariff must be reasonably capable of being understood by *retail customers* that are assigned to that tariff, having regard to:
  >
  > (1) the type and nature of those *retail customers*; and

(2) the information provided to, and the consultation undertaken with, those *retail customers*.

We consider that network tariffs that are reasonably capable of being understood by retail customers would need to be relatively simple. Therefore, we interpret the understandability dimension of the need for AEMO's fee structure to be simple to require – as a guide – that the fee structure ought to be of a form that would likely be comprehensible to a small retail customer. Regarding the implementation dimension of simplicity, we consider that this requires the fee structure should be able to be adopted without the need for AEMO to acquire additional information about participants beyond what it has available through its systems.

- The need for fee components charged to each participant to be reflective of the extent to which AEMO's budgeted costs 'involve' that participant. 'Involve' has no established economic meaning, but it appears to be wider than a direct causative relationship between the participant's decisions and AEMO's costs. Therefore, we believe this principle permits the setting of fees in excess of the avoidable cost of AEMO's services to a participant in the relevant participant class. At the same time, a fee that exceeds the standalone cost of serving a participant in a given class would appear to go beyond the extent to which AEMO's costs 'involve' the participant. Accordingly, we consider that it would be appropriate to interpret the 'involve' principle in a manner similar to the principles around how transmission and distribution network service providers need to set prices for negotiated services – prices to a customer for such services must be between avoidable cost and standalone cost of providing the service to the customer (see clauses 6A.9.1(2) and 6.7.1(2), respectively). This band would is commonly referred to as the range of 'subsidy-free' prices. It would be wider in some cases (eg AEMO's core services costs) and narrower in others (eg registration and FRC fees).
- The need for the fee structure to not 'unreasonably discriminate' against a category of participant. This implies that reasonable discrimination is permissible. We interpret reasonable discrimination as permitting any form of price discrimination justifiable by reference to economic efficiency – a key component of the national electricity objective. Further, there does not appear to be any prohibition against setting a participant fee structure that involves efficiency-enhancing price discrimination *within* a participant category.

Interpreting some of these principles in the context of recovering AEMO's core services costs is not straightforward. This is because AEMO performs a singular role in the NEM – as market and system operator, it is essential to the market as presently designed. As a result, the majority of AEMO's core services costs are fixed and do not vary with the decisions of individual participants. This is consistent with the view adopted in the ACG report.[2] The result is that the marginal or incremental cost of AEMO's core services with respect to the decisions of a given participant is effectively zero. Therefore, an attempt to implement first-best marginal cost-based prices is unlikely to yield material prices or fee revenue. The problem of how to efficiently recover the AEMO's core services costs can be likened in many ways to the question of how to tax participants to recover a fixed quantum of revenue most efficiently. In this context, a Ramsey pricing approach is likely to promote the most efficient outcomes, at least in the short run. As noted in the ACG report, Ramsey pricing involves setting prices to members of different groups in inverse relation to the price sensitivity of those groups, with the aim of minimising distortions to demand in the final (retail) market.[3] We consider that a Ramsey pricing approach could be modified in the present case to take into account potential long run distortions to investment decisions as well.

Having regard to all of these NER requirements, we consider that it would be appropriate for AEMO to adopt a participant fee structure incorporating the following elements:

- To the extent that the decisions of participants within a class require AEMO to incur higher or lower costs (ultimately leading to a higher or lower budgeted revenue requirement), AEMO fees to customers in that class should reflect a reasonable estimate of those costs. The pricing of such 'incremental services' raises no significant difficulties and are not discussed further in this report.
- The remainder of AEMO's budgeted revenue requirement (which we assume comprises principally of the cost of core services) should be recovered via fees that:
  - Are relatively simple, as in likely to be comprehensible to someone with the understanding of a small retail customer;
  - Fall within the bounds of the avoidable and standalone cost of AEMO providing its services to participants in the relevant class;
  - Vary as between participant classes to an extent reasonably expected to promote economic efficiency; and
  - Vary within a participant class to an extent reasonably expected to promote economic efficiency.

  We consider that promoting economic efficiency in the recovery of AEMO's remaining revenue requires that the fee structure minimises the extent to which participants' operating and investment decisions vary from the decisions they

2 ACG report, p.12.

3 ACG report, p.13.

would make in the absence of fees to recover the remainder of AEMO's budgeted revenue. This reflects the thinking behind Ramsey pricing, but extends it to take account of participants' investment as well as operating decisions.

The next section assesses AEMO's propose fee structure in its Draft Report according to the above framework.

3 Review of ACG report

We have not attempted to comment on every aspect of the ACG report. In many respects, we agree with ACG's observations, as indicated in the previous section. However, we consider it worth highlighting three areas where we take issue with the analysis in the ACG report. These are:

- The discussion of options for pricing approaches in section 3.4
- The discussion of the recommended fee structure in section 4.3 and
- The discussion of the recommended allocation of AEMO's budgeted costs as between various participant classes in section 4.4.

3.1 Options for pricing approaches

Sections 3.3 and 3.4 of the ACG report purport to examine various pricing options for how well they meet the relevant criteria in the NER and the NEL. We note that the criteria considered by ACG in 2005 are slightly different to those applicable now, but we do not consider the differences to be significant.

The options considered by ACG were:

- Marginal cost pricing
- Average cost pricing
- Fully distributed cost pricing
- Ramsey pricing
- Multi-part pricing

In a way, we consider this to be an odd comparison, because while some of these options refer to reasonably specific methodologies (eg marginal cost pricing, Ramsey pricing), other options refer to general forms that do not offer definitive guidance for how prices are to be derived. For example, a multi-part price can take a wide range of forms, most of which will offer advantages and disadvantages compared to other structures.

ACG found in favour of multi-part pricing, in preference to Ramsey pricing. This was partly because Ramsey pricing is difficult to apply in practice and unlikely to satisfy the requirement for simplicity. Further, the ACG report claimed that:[4]

> It has been shown that it is always possible to design multi part fees that are more efficient than fees based on Ramsey pricing.

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4 ACG report, p.17.

While we accept that the strict application of Ramsey pricing is informationally demanding and may not be feasible, the basic prescription of Ramsey pricing – allocating costs to those likely to change their decisions to the least extent – is more practicable and is an approach frequently applied by policy-makers and regulators. Further, ACG similarly noted that the information required for the implementation of optimal multi-part pricing is very difficult to acquire and hence it may not be possible to implement optimal multi-part fees (p14).

In addition, we take issue with ACG's contention that it is always possible to design multi-part fees that are superior to Ramsey pricing. The ACG report cited a paper by Robert Willig.[5] However, the Willig paper does not support the point alleged by ACG. Rather, the Willig paper favourably compared nonlinear[6] pricing to a *uniform (per unit) price that exceeds marginal cost* under circumstances where the firm in question incurs positive marginal costs. This is inapplicable to a critique of Ramsey pricing applied to AEMO's fee structure for two reasons:

- First, an AEMO fee structure based on Ramsey pricing would not be a uniform per unit price charged to all participants – a Ramsey pricing-based structure would comprise lump sum charges that varied according to some characteristic(s) of the participant and/or participant class.
- Second, in the present case, AEMO incurs virtually no additional costs in providing its core services as:
  - the number of market participants
  - participants' capacity or size
  - participants' number of customers;
  - participants' peak injections or offtakes or
  - participants' energy production or consumption

  increase(s).

  Therefore, AEMO's core services marginal cost with respect to any of these variables is effectively zero.[7]

What the Willig paper does show is that one can always construct an appropriately designed pricing schedule which incorporates two-part (multi-part) tariffs that result in a Pareto-superior fee structure to the uniform price. However, the resulting Pareto-dominant fee schedule *must* consist of providing consumers with

5 Willig, R.D., "Pareto-Superior Nonlinear Outlay Schedules", *The Bell Journal of Economics*, Vol.9 No.1 (Spring), pp.56-69.

6 A nonlinear price is a price that varies according to the amount purchased.

7 As noted above, any of AEMO's services costs do vary with the decisions of participants are incremental services and should be charged at marginal cost. Marginal cost pricing in these cases would be first-best and could not be bettered by multi-part tariffs.

the *option* of choosing between the uniform tariff and the two-part tariff, not simply mandating the two-part tariff.[8]

Indeed, Wilson (1993)[9] states that:

> [A] Pareto-improving tariff can be constructed by allowing customers the option of purchasing each unit from the old price schedule or the new one. The new tariff can be of various kinds, such as a two-part tariff or the old tariff amended by the inclusion of additional quantity discounts.

> And

> "It is important to realize that electing the two-part tariff must be optional, not required"

Instead of adopting broad and questionable generalisations about different pricing options, we consider it more useful to apply the framework developed in the previous section – that is, where AEMO core services costs need to be recovered, the fee structure should be:

- Relatively simple
- Fall within the bounds of the avoidable and standalone cost – to reflect 'involvement'
- Vary as between participant classes to an extent reasonably expected to promote economic efficiency – to avoid 'unreasonable discrimination'
- Vary within a participant class to an extent reasonably expected to promote economic efficiency

We apply this framework in our review of AEMO's proposed fee structure in section 4 below.

3.2 Recommended fee structures

As noted above, the ACG report found in favour of multi-part pricing on the grounds that it would be most likely to satisfy the relevant criteria in the NER and the NEL. According to ACG, the multi-part fee structure should comprise:

8 Without the choice, a two-part tariff increases aggregate consumer welfare but creates a skewed and undesirable income distributional effect. Those with large demands benefit from the mandated two-part tariff while those with small demands are hurt by the two-part tariff; this is therefore not a Pareto-improvement compared with a uniform tariff structure. Allowing for the choice between tariffs, those with small demands choose to remain on the uniform tariff, and those with large demands choose the two-part tariff, and so no party is worse off. Further, Willig shows that such a schedule does not reduce (in fact, it is shown to increase) revenue recovered compared with a uniform tariff. See Willig, R.D., "Pareto-Superior Nonlinear Outlay Schedules", *The Bell Journal of Economics*, Vol.9 No.1 (Spring), pp.60-65.

9 Wilson, R (1993) *Nonlinear Pricing*, Oxford University Press, Published in association with the Electric Power Research Institute, pp.108, 121 (of Chapter 5.2 and 5.4)

- A fixed component, which cannot be varied by changes in a participant's activity in the NEM, or involvement with AEMO, in the year in which the fees are levied and
- A variable component likely to satisfy the NER and NEL criteria.

ACG went on to recommend separate fee structures for generators and market customers. These recommended structures are discussed below.

3.2.1 Generators

The ACG report recommended that NEM generators pay:

- A fixed fee based on the generator's 'historical' capacity
- A so-called 'fixed' fee based on the generator's historical scheduled energy.[10]

The ACG report claimed that a fixed fee based solely on a generator's capacity would unduly favour baseload generators, whereas a fee based solely on a generator's historical output would unduly favour peaking generators. The recommended fee structure appears to have been a mix of both to avoid favouring either type of plant. ACG rejected the imposition of variable fees on generators, such as one based on energy scheduled in the year the fee is to be paid. This was because such fees would be very likely passed on in higher bid prices, "thus defeating the purpose of levying fees on Generators in the first place".[11]

We agree with ACG that adopting exclusively fixed fees on generators should be avoided. Not only would it disproportionately harm peaking generators, but it would distort plant investment and retirement decisions against peakers in the long run. We also agree with ACG that $/MWh fees imposed on the basis of generators' current output would likely be passed on to market customers via higher offer prices and hence higher wholesale prices. In this sense, we agree with them that imposing such fees would be pointless from a final incidence perspective. Further, by distorting generator offers, it could result in economically inefficient dispatch. However, it is difficult to see why ACG did not apply the same reasoning to its proposed so-called 'fixed' fees based on generators' historical scheduled energy output. In fact, it is difficult to understand why ACG referred to this structure as a fixed fee rather than a variable fee. Assuming such historical output was in respect of the immediately preceding year or a recent previous year, generators would have incentives to raise their current offer prices in anticipation of the variable fees they would reasonably expect to incur on their current output in the near future.

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10 It is unclear how old – or how 'historical' – was the capacity or scheduled energy upon which these charges were to be based. Hence, the parentheses.

11 ACG report, p.21.

3.2.2 Market Customers

The ACG report recommended that market customers pay variable fees based on load in the current year.

The ACG report claimed that fixed fees on market customers would create economies of scale for retailers, harming competition and efficiency. According to the report, a so-called 'fixed' fee based on historical load would not create economies of scale. However, the report pointed out that if load in one year were highly correlated to load in the following year, and if retailers were forward-looking:[12]

> Fixed fees of this type may affect a Market Customer's pricing decisions… and so many of the efficiency benefits of a fee of this type may be lost.

In light of this statement, it is unclear why ACG did not acknowledge the same drawback of so-called fixed fees based on generators' historical scheduled energy output.

The ACG report commented that fees on market customers based on current load would satisfy all NER criteria and be reasonably efficient, even though it might be expected to be passed on to end users:[13]

> Because the quantum of fees to be levied on Market Customers would be likely to be small relative to their total costs the effect on energy prices and thus energy demand would be expected to be small, so the efficiency cost of this variable fee would also be expected to be small.

We agree that the allocative efficiency losses caused by AEMO recovering its core services costs from market customers via variable fees would be relatively small – given the likely low level of such fees. On the assumption that small $/MWh fees imposed on market customers would be passed through to end-use customers as a higher volumetric retail tariff, such fees are unlikely to cause end-use customers to reduce their consumption by a significant degree. However, the degree of allocative inefficiency would not be zero. Certainly, we would expect such efficiency losses to be greater than those arising from a fee structure based on a more Ramsey pricing-like approach.

The ACG report went on to consider the possibility of a variable fee based on the number of customer connections. However, ACG stated that:[14]

> This fee would be passed on to consumers in terms of higher service to property charges, and it is not obvious that this would be any better, from any efficiency viewpoint, than a fee based on load which was passed thon as higher energy charges.

12 ACG report, p.21.

13 ACG report, p.21.

14 ACG report, p.22.

We consider this to be an extraordinary statement. Recovering fixed costs via unit-based fees is widely understood to compromise allocative efficiency. In the present case, it would inefficiently discourage electricity consumption (and hence production) because AEMO's core services costs do not vary with consumption. Drawing a parallel again with network pricing, a report by consultants, NERA, for the AEMC commented:[15]

> To improve the efficient use of existing infrastructure, whilst simultaneously allowing network businesses to recover the total cost of network services requires pricing strategies that encourage the greatest possible use of the available network capacity. In other words, **prices should not discourage the use of infrastructure where the cost incurred from such usage is low or effectively zero**. This means that mark-ups on usage charges should be minimised, particularly when customers are likely to be sensitive to changes in price. [Emphasis added]

In the context of recovering residual network costs, the AEMC noted that "the general principle should be that tariffs should encourage optimal use of existing infrastructure by consumers."[16] The AEMC then said:[17]

> The underlying principle that minimises distortions to efficient usage decisions is to assign residual costs to tariff components in inverse proportion to consumers' responsiveness to that tariff component.

ACG also claimed that per connection charges could be problematic for equity reasons and may fail the extent of involvement test. This was because:[18]

> A market customer with a small number of large end users would pay lower fees than a market customer with a large number of small end users. Yet, if they both purchase about the same amount of electricity in the NEM, then arguably, they have the same involvement with NEMMCO and should pay about the same fees.

However, the relevant question is not the participant's 'involvement' with AEMO, but *the extent to which AEMO's budgeted costs involve that participant*. If – as ACG acknowledged – AEMO's costs are not driven by NEM electricity consumption, we see no reason why a participant's electricity consumption should define the extent to which AEMO's costs involve that participant.

Regarding ACG's concern about equity, we note that equity is not an element of the applicable NER requirements for the structure of AEMO's fees. In any case, we understand that even if all of AEMO's core services costs were recovered via a fixed fee per end-user connection point, it would only amount to less than $6 per

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15 NERA, *Economic Concepts for Pricing Electricity Network Services, A Report for the Australian Energy Market Commission*, 21 July 2014, p.4.

16 AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p.158.

17 AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p.159.

18 ACG report, p.22.

NMI per year. It is difficult to see how such a modest charge could raise material equity issues.

3.3 Recommended AEMO cost allocation

The ACG report briefly considered how NEMMCO's general costs should be allocated, primarily as between generators and market customers. The report did not attempt to answer this question from first principles, but simply referred to a document entitled "NEMMCO Activity Survey and Cost Analysis", which allegedly found that:[19]

> …most of NEMMCO's general costs could be allocated to either Market Customers or Generators, with the relative split being 55 per cent to Market Customers and 45 per cent to Generators.

The methodology used in this document is not stated, but based on its title, it appears to have utilised an activity-based costing approach. Accordingly, an allocation of AEMO costs based on this report would appear to reflect a fully distributed cost pricing approach.[20] The ACG report noted that such a pricing approach would not generally be considered efficient. Yet despite this, the ACG report uncritically employed the 55/45 allocation for its recommended fee allocation in section 4.4.

The result was that ACG recommended that:

- 45% of NEMMCO's general costs should be recovered from generators, with:
  - Half to be recovered via fees based on the generator's capacity in the previous year and
  - Half to be recovered via fees based on the generator's energy generated in the previous year.
- 55% of NEMMCO's general costs should be recovered from market customers via fees based on load in the current year.

Although ACG commented that economic theory does not provide a unique mapping of possible fee structures to cost allocation, the report nevertheless claimed that the proposed allocation and fee structure would be consistent with the relevant requirements in the NER and NEL and "the NEM objective of economic efficiency".

However, we would contend that any activity-based costing methodology is only relevant to the extent that it identifies costs attributable to incremental services, because such costs are incurred as a result of participants' individual decisions.

19 ACG report, p.22.

20 ACG report, p.13.

AEMO's approach has been to identify those activities and therefore costs that it considers generators and market customers *in aggregate* use. Given the rejection of a fully distributed cost pricing approach by AGC and the more appropriate application of this to incremental services, we consider this cost allocation approach is of little relevance to the structure of fees for core services.

4 Review of AEMO proposed fee structure

AEMO's proposed fee structure for core services as set out in its Draft Report is approximately as follows:[21]

- Allocated direct costs (comprising 70% of AEMO's general budgeted revenue requirement) to be recovered:
  - 54% from market customers via a $/MWh charge on wholesale market purchases in the relevant billing period
  - 46% from generators and MNSPs, with:
    - Half to be recovered via a daily rate fee based on the higher of the generator's registered capacity and notified maximum capacity in the previous calendar year and
    - Half to be recovered via a daily $/MWh rate on energy scheduled or metered in the previous calendar year.
- Unallocated costs (comprising 30% of AEMO's general budgeted revenue requirement) to be recovered 100% from market customers via a $/MWh charge on wholesale market purchases in the relevant billing period.

Based on the framework outlined in section 2, we consider that AEMO's proposed fee structure could be significantly improved.

From an economic efficiency perspective, it would be preferable to recover as large a share of AEMO's core services costs as possible from market customers. This would avoid distorting generator operating and investment decisions through charges that do not reflect the drivers of AEMO's budgeted costs (which are independent of the decisions of individual generators). While recovering all AEMO core services costs from market customers would theoretically increase the risk of distorting the decisions of end-use customers, this could be minimised by structuring fees appropriately.

Perhaps the best option would be to set fees to market customers as a fixed annual amount per NMI or TNI. We note that if all AEMO costs were recovered entirely from market customers in this way, they would amount to less than $6 per NMI per year. It is highly unlikely that a fixed fee of such a magnitude would lead to any changes to end-use customers' decisions regarding:

- Their consumption of electricity or
- Their connection to the NEM power system.

[21] AEM Draft Report, p.2.

Consequently, such fixed fees would also not distort generators' operating or investment and retirement decisions. This implies that levying AEMO fees in this manner would ensure no loss of economic efficiency whatsoever. If desired, the level of the fixed annual fee could be made dependent on a variable that was likely to reflect the willingness of the market customer's end use customers to pay for access to the centralised power system. For example, the fixed fee could vary by connection voltage or whether the end use customer was a 'small retail customer' (as recorded in AEMO's systems) or a non-small customer or a customer directly connected to the transmission system.

Such a fee structure would be very simple, both from a customer/participant understanding perspective and from an implementation perspective.

To ensure that the proposed fee structure reflects the involvement principle, it could be modified to allocate a share of AEMO's core services fee budget on generators and MNSPs. As noted in section 2, we consider that the involvement principle could be met by ensuring that each participant in these classes pay at least AEMO's avoidable cost of providing core services to them.

As such avoidable costs are likely to be extremely low, we consider that a *de minimis*/nominal fee on generators and MNSPs would be sufficient to satisfy this principle.

Accordingly, we propose that to satisfy the 'involvement' principle in clause 2.11.1(b) of the NER, AEMO could levy a fee on generators of:

- $0.01/MWh variable fee imposed on the actual output of generators and actual power transfer of MNSPs in the relevant billing period.
- A $/MW fixed fee calculated annually to provide a generator in the NEM with a NEM-average capacity factor a fixed fee equal to its expected variable fee imposed on the current rated capacity of generators and MNSPs.

As these fee would be small, they would impose a minimal distortion on plant operating and investment (and retirement) decisions. For example:

- A 1000 MW baseload generator with a 60% capacity factor would pay a total fee of $93,280 per annum, comprised of:
  - A variable fee of $52,560 per annum and
  - A fixed fee of $40,720 per annum
- A 200 MW peaking generator with a 30% capacity factor would pay a total fee of $13,400 per annum, comprised of:
  - A variable fee of $5,255 per annum and
  - A fixed fee of $8,145 per annum

In this context, we do not accept the contention in the ACG report that levying variable fees on generators based on energy scheduled in the year the fee is to be paid would be problematic. This is because whether variable fees are levied on generators' current year output or their previous year's output would have little impact on their bidding or investment decisions. In either case, generators would have incentives to raise their current offer prices. This highlights the importance of ensuring that total fees on generators are kept to a minimum nominal amount.

As explained in section 2 above, we do not consider that the levying of a nominal amount of fees on generator participants would violate the 'unreasonably discriminate' requirement in clause 2.11.1(b)(4) of the NER. This is because by implication, 'reasonable discrimination' would be permitted. We consider it would be reasonable to discriminate between participant classes in devising an AEMO fee structure where this would be expected to promote economic efficiency, a key component of the national electricity objective (itself a relevant consideration for the setting of a participant fee structure in clause 2.11.1(ab) of the NER). In the present case, the levying of any fees on generators is likely to distort generator operating and investment decisions to some extent, whereas levying our proposed fixed per-connection fees on market customers is extremely unlikely to impose any efficiency cost. In our view, this strongly suggests that allocating a nominal share of AEMO core services fees on generators would be reasonable.

Alternatively, a nominal allocation of fees on generators would also be appropriate if one interprets the 'unreasonable discrimination' principle to refer to the *final incidence* of fees rather than the *initial imposition* of fees. Economists use the term 'incidence' to refer to the party who ultimately bears the burden of a charge (or tax). This is often a different party to the one upon whom the charge is levied initially, because the initial party is able to pass on the fee to others through (say) higher prices. It is uncontroversial that any variable per unit fee or fixed per connection fees on retailers would be passed-on to end-use customers. Therefore, most market customers are unlikely to bear the final incidence of AEMO fees levied upon them. Conversely, any fixed fee imposed on a generator would be borne by them, at least in the short run. In the long run, such fees would be likely to delay new plant entry and/or hasten plant retirement, leading to higher wholesale prices. This would mean that some of the incidence of the fee would fall on end-use customers. We consider that it would be unreasonably discriminatory to levy fees on retailers that they would not bear, while levying fees on generators that they would bear, at least in the short run.

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