Purpose of paper

The congestion management technical working group (**TWG**) requested that the Energy Security Board (**ESB**) provide a more detailed description of the congestion management model (**CMM**) to inform a discussion of the design choices.

This paper will be shared with:

- NERA to develop its approach to model outcomes of rebate allocation methods for different market participants
- TWG (operational subgroup) to understand and assess the intent and implications of the rebate allocation methods and to identify preferences, where possible.

The ESB has issued a companion paper for the congestion relief market (**CRM**) to provide a reference understanding of its design and operation and to enable NERA to develop its approach to model outcomes.

Context

The CMM is designed to retain the existing NEMDE optimisation algorithm but applies changes to settlement to address congestion management by affecting bidding incentives at the margin. The approach requires an allocation method for the settlement residue.[1]

The settlement residue arises from the difference between the local price, due to the CMM congestion charge and the regional reference price (**RRP**) across all dispatched generators. The allocation method distributes the residue amongst the eligible parties.

There are a number of candidate allocation methods, and it is important for the ESB to explore the implications of these with stakeholders to decide which is the most appropriate method. This paper covers the following:

1. Reference scenario
2. Status quo arrangements
3. How will the CMM lead to efficient dispatch?
4. How do the rebate allocation methods work?
5. How should out-of-merit generators be treated?
6. Incentives and operation of the CMM with storage
7. Conclusions

Further work is in progress to assess winners and losers associated with different options, both under the CMM and other models.

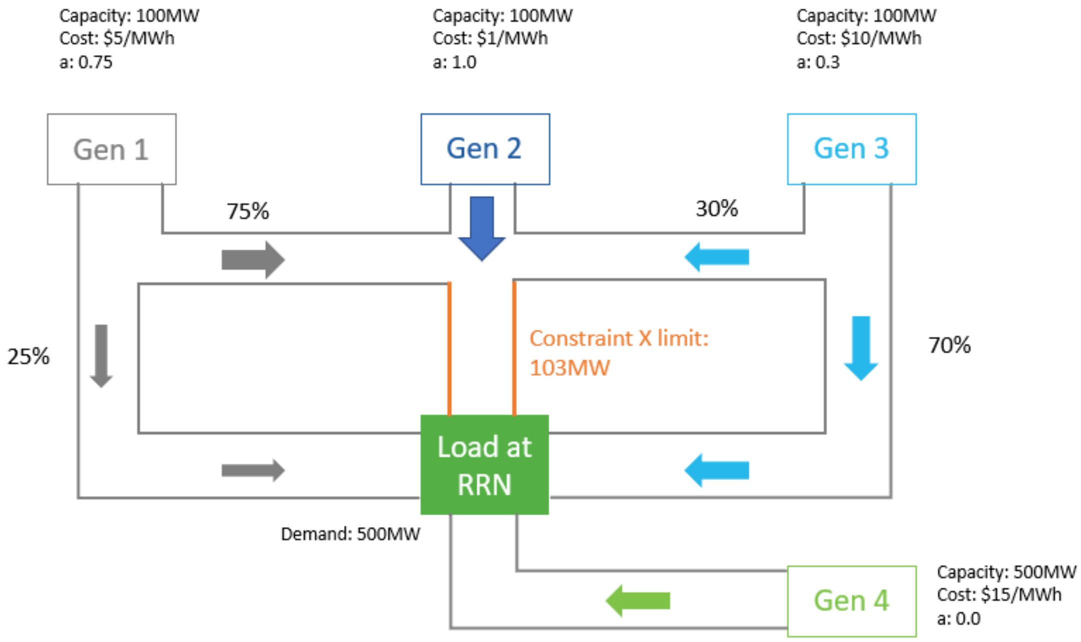
[1] ESB, https://esb-post2025-market-design.aemc.gov.au/transmission-and-access consultation paper, May 2022

1. Reference scenario

Figure 1 provides an illustrative example of a looped network with a flowgate constraint of 103MW. This paper continues to apply this reference scenario to create worked examples of physical and financial outcomes under the status quo and the CMM.

To understand the theory, we have simplified the worked examples and ignored marginal loss factors from the calculations.

Figure 1 Flowgate capacity of 103MW (constraint RHS)



Note: a = contribution factor of a generator in the constraint

A flowgate is a transmission element by which electricity power flows. The constraint limit (or flowgate capacity) reflects the capacity of the associated transmission element or the transmission network more generally.

Figure 1 illustrates the impact of the contribution factors on dispatch outcomes. For example:

- Gen 1 has a coefficient of 0.75. For every 1MW flowing through the constraint, 1.33MW is dispatched around the constraint.
- Gen 2 has the highest coefficient of 1.0. For every 1MW flowing through the constraint, 0MW is dispatched around the constraint.
- Gen 3 has the lowest coefficient of 0.3. For every 1MW flowing through the constraint, 2.33MW is dispatched around the constraint.

Maximising dispatch based on a combination of bid price and contribution factor leads to a lower cost outcome.

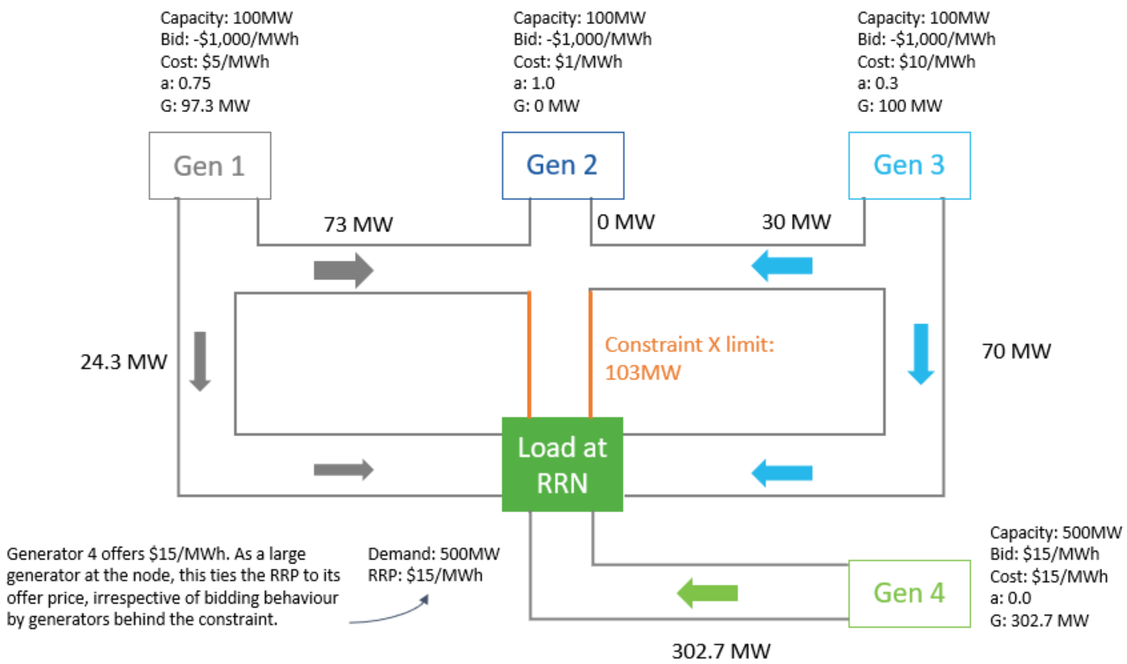
2. Status quo arrangements

Under the status quo, generators receive the RRP for every megawatt (MW) that is dispatched in each five-minute dispatch interval. Generators are incentivised to maximise their physical dispatch quantity (*G*) for every five-minute period when the RRP is greater than its short-run marginal costs (**SRMC**).[2]

There are a number of factors that play into bidding dynamics but, for the purpose of this example, we assume that all generators are merchant and profit-maximising, all constrained generators bid to the market price floor at -$1,000/MWh and the unconstrained generator (Gen 4) bids at cost being $15/MWh.

Figure 2 shows the dispatch outcomes for this bidding behaviour and Table 1 shows the financial outcomes.

Figure 2 Status quo dispatch outcomes bidding to the floor



a = contribution factor of a generator in the constraint, G = dispatch MW

Figure 2 shows that when the constrained generators bid equally to the market price floor, they are dispatched in favour of their contribution factor i.e. Gen 3 with a coefficient of 0.3 is dispatched to its maximum of 100MW before Gen 1 is dispatched with a coefficient of 0.75. Gen 2 is not dispatched in this scenario given its coefficient of 1.0 and the constraint X limit of 103MW, despite having the lowest cost of production at $1/MWh.

Gen 4 does not participate in the constraint and has the highest cost of $15/MWh. Gen 4 will always be dispatched only once the other generators are constrained from further dispatch and it will provide the residual load not supplied by Gen 1-3.

[2] WattClarity wrote a good article on this topic: https://wattclarity.com.au/articles/2022/05/who-gets-to-run-when-everyone-bids-the-same-a-crash-course-in-disorderly-bidding-and-tie-breaking/

Table 1 Status quo financial outcomes (constrained generators bidding at the floor price)

Unit	a coefficient	G MW	RRP $/MWh	Cost $/MWh	Revenue $ G x RRP	Cost $ G x Cost	Profit $ Revenue – Cost
Gen 1	0.75	97.3	15	5	1,460	487	973
Gen 2	1.0	0	15	1	0	0	0
Gen 3	0.3	100	15	10	1,500	1,000	500
Gen 4	0.0	302.7	15	15	4,540	4,540	0
Total		**500**			**7,500**	**6,027**	**1,473**

Table 1 summarises the financial outcomes for each generator and provides a point of comparison for cost and profit outcomes under the CMM.

3. How will the CMM lead to efficient dispatch?

When constraints are binding, the CMM introduces a dual mechanism of a congestion charge and a congestion rebate.

CMM$ = G x RRP - congestion charge + congestion rebate

Where:

CMM$ = energy settlement under CMM

G = dispatch MW (generation)

RRP = regional reference price

Congestion charge

The CMM encourages more efficient dispatch by exposing generators to a congestion charge during operational timeframes. A generator is effectively settled at its locational marginal price (**LMP**) for energy dispatched. The LMP is linked to the bids of generators located "behind" the constraint.[3] Generally, in the event of congestion, a generator's LMP will be lower than the RRP.

The congestion charge in the CMM encourages a generator to bid at its SRMC, thereby aligning the incentives of generators with an overall least-cost dispatch. With cost-reflective bidding and LMP settlement, generators are only dispatched if their LMP is no lower than their cost.

The locational marginal price is:

$$LMP = RRP - a \times CP$$

Where:

LMP = locational marginal price

RRP = regional reference price

a = contribution factor of a generator in the constraint

CP = congestion price being the negative of the marginal value of the constraint, i.e. the reduction in the total cost of dispatch if the constraint is relaxed by 1MW.

[3] Behind refers to generators that have a positive contribution factor in the constraint, meaning that output from that particular generator exacerbates the constraint in question.

Disorderly bidding

The congestion price in the worked example of status quo arrangements (Figure 2) is $1,353/MWh. Relaxing the constraint by 1MW would allow an additional 1.33MW of generation from Gen 1 at a price of -$1000/MWh and cost of $1/MWh to flow through the line (1MW through the constraint and 0.33MW around the constraint) with a corresponding 1.33MW reduction from Gen 4 at a cost saving of $14/MWh.

Table 2 LMP calculation for the three generators

Unit	Cost $/MWh	RRP $/MWh	a coefficient	CP* $/MWh	LMP $/MWh RRP – a x CP
Gen 1*	5	15	0.75	1,353	-1,000
Gen 2	1	15	1.0	1,353	-1,338
Gen 3	10	15	0.3	1,353	-391

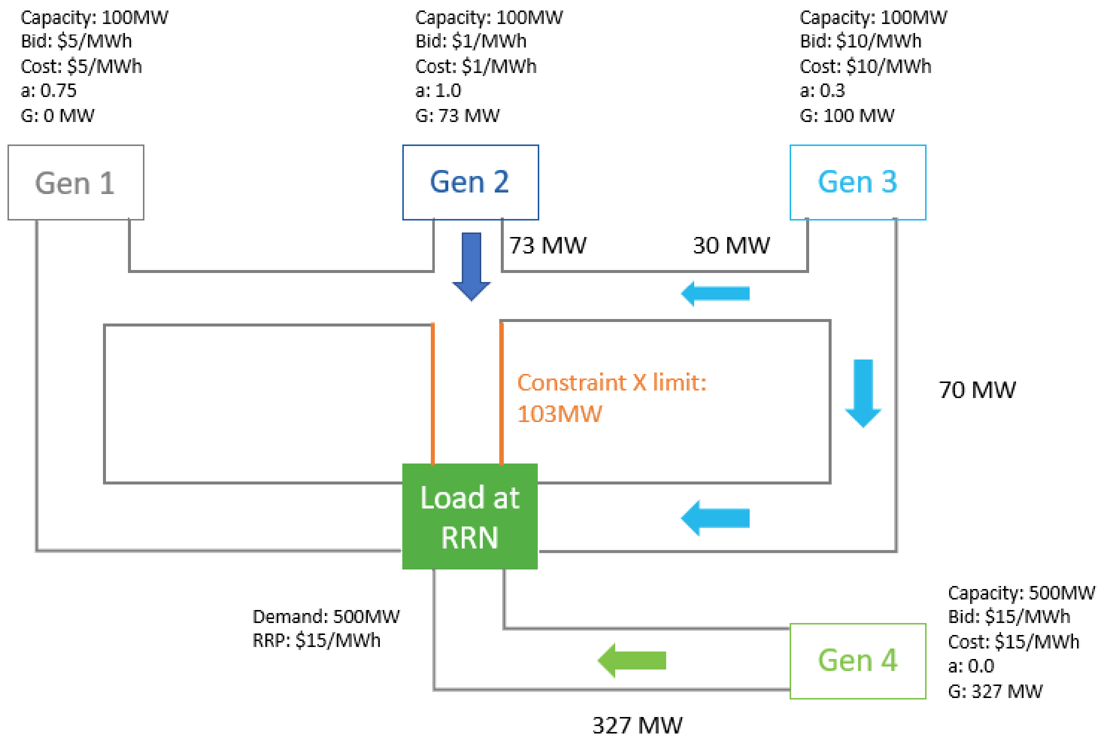
Note: * In this scenario, Gen 1 is the marginal generator. CP = (RRP – LMP) / a = (15 – (-1000)) / 0.75 = 1,353.
Gen 4 does not participate in the constraint and does not face a congestion charge, nor is it eligible for a congestion rebate.

If the generators were exposed to these prices on the margin, they would make a loss for any electricity generated during this interval and hence it would encourage cost-reflective bidding.

Cost reflective bidding

If the generators bid at their SRMC, Figure 3 shows the updated physical outcomes and Table 3 the financial outcomes.

Figure 3 Dispatch outcomes with cost-reflective bidding



The MW dispatch of Gen 4 has increased by 24MW from 302.7MW (disorderly) to 327MW (cost reflective) despite having the highest marginal cost of $15/MWh. The increased costs of Gen 4 dispatch are more than offset by the cost differential between Gen 1 ($5/MWh) and Gen 2 ($1/MWh).

Table 3 Financial outcomes bidding at cost

Unit	G MW	RRP $/MWh	Cost $/MWh	**Revenue** $ G x RRP	**Cost** $ G x Cost	**Profit** $ Revenue – Cost
Gen 1	0	15	5	0	0	0
Gen 2	73	15	1	1,095	73	1,022
Gen 3	100	15	10	1,500	1,000	500
Gen 4	327	15	15	4,905	4,905	0
Total	**500**			**7,500**	**5,978**	**1,522**

Table 4 Summary of cost and profit comparison between disorderly and cost reflective bidding

Unit	Cost			Profit		
	Disorderly $	**Cost reflective** $	**Variance** $	**Disorderly** $	**Cost reflective** $	**Variance** $
Gen 1	487	0	-487	973	0	-973
Gen 2	0	73	73	0	1,022	1,022
Gen 3	1,000	1,000	0	500	500	0
Gen 4	4,540	4,905	365	0	0	0
Total	**6,027**	**5,978**	**-49**	**1,473**	**1,522**	**49**

Table 4 shows that with all generators bidding reflective of their marginal cost, the overall cost of dispatch has decreased from $6,027 to $5,978. This outcome achieves the transmission access reform objective for efficient dispatch.

Individual financial outcomes have changed but there is higher overall profitability, assuming that there is no change in the RRP which is true in this scenario with a large marginal generator at the RRN being Gen 4.

The congestion price in the worked example with cost reflective bidding is $14/MWh. Relaxing the constraint by 1MW would allow another 1 MW of generation from Gen 2 (cost $1/MWh) to flow through the line with a corresponding 1 MW reduction from Gen 4 (cost $15/MWh) at a cost saving of $14/MWh.

Table 5 LMP calculation for the three generators

Unit	Cost $/MWh	RRP $/MWh	a coefficient	CP $/MWh	**LMP** $/MWh RRP – a x CP
Gen 1	5	15	0.75	14	4.50
Gen 2 *	1	15	1.0	14	1.00
Gen 3	10	15	0.3	14	10.80

Note: *In this scenario, Gen 2 is the marginal generator. CP = (RRP – LMP) / a = (15 –1) / 1.0 = 14

Congestion rebate

A key element of the CMM is the congestion rebate. It is intended to make market participants, in aggregate, indifferent to the introduction of the congestion charge. There are different ways in which the settlement residue can be allocated as the rebate.

Under current arrangements, the congestion rebate is proportioned on the basis of the volume of actual generation dispatched (G). This leads participants to bid to maximise dispatch rather than disclose their costs. Allocating rebates on other metrics will change those incentives.

The CMM provides incentives for more efficient bidding and dispatch by removing the link between the allocation of settlement residue and physical dispatch.

4. How do the rebate allocation methods work?

To encourage cost-reflective bidding and hence efficient dispatch, generators need to be exposed on the margin to their LMP i.e. each extra MW is paid LMP.

This could be achieved by paying generators *LMP x dispatch quantity (G)* in settlement. However, because LMP is often less than RRP, this leaves generators receiving less, in aggregate, than they do today. It also leaves a residue in settlement because non-scheduled load continues to pay the RRP in settlement.

To address both issues, the residue could be paid out to generators. However, to ensure that generators continue to be paid LMP at the margin, the residue shares must be independent of dispatch output. This is the conceptual basis (and challenge) for the CMM to define residue shares which are independent of generator output, otherwise bidding behaviours may be distorted as in status quo arrangements.

The original CMM proposal in the ESB post-2025 options paper published in March 2021 proposed a pro-rata access allocation metric whereby a generator would receive a proportion of the settlement residue equal to their proportion of total availability participating in the constraint. This paper outlines the pro rata and alternative rebate allocation methods below.

$$
\begin{aligned}
\text{CMM\$} &= \text{G x RRP} - \text{congestion charge} + \text{congestion rebate} \\
&= \text{G x RRP} - \text{G x (RRP-LMP)} + \text{E x CP} \\
&= \text{G x LMP} + [\text{ A x a }] \text{ x } [\text{ (RRP – LMP) / a }] \\
&= \text{G x LMP} + \text{A x (RRP – LMP)} \\
&= \text{A x RRP} + \text{(G – A) x LMP}
\end{aligned}
$$

where:

A access MW

a contribution factor

CMM$ energy settlement under CMM

CP congestion price = (RRP – LMP) / a

E entitlement MW = A x a

G generator output (dispatch MW)

LMP locational marginal price

RRP: regional reference price

The rebate is allocated by allocating entitlements (*E*) to qualifying generators on a flowgate and then rebating an amount *E x CP*. The total residue under LMP settlement is the product of the congestion price and the constraint limit. So long as the sum of the entitlements equals the flowgate constraint limit, the settlement residue is exactly sufficient to fund the rebates.

Given *E = A x a*, *E* represents the amount of flow through the constraint from a generator dispatched at a level *A*. Any feasible allocation of entitlements (*E*) represents a corresponding feasible dispatch of access (*A*). We can consider the allocation problem in either of two ways;

a. Identify a set of entitlements (Es) that add up to the constraint limit
b. Identify a set of access (As) that represent a feasible dispatch.

Table 6 describes the alternate mathematical expressions. Note that the three expressions are mathematically equivalent.

Table 6 Description of alternate mathematical expressions

Mathematical expression	Description
CMM$ = G x RRP - congestion charge + rebate	This is the "plain English" description proposed in the ESB consultation paper.[4]
CMM$ = G x LMP + A x (RRP - LMP)	In this formulation, generators are settled at LMP, but are awarded a quantity "A" of financial transmission rights (FTRs), which provide them with the rebate.
CMM$ = A x RRP + (G-A) x LMP	In this formulation, generators are allocated access and paid RRP on this level. They are then paid LMP on any unders and overs between access and physical dispatch. This is similar to the CRM, where "A" is the "energy dispatch" and *(G-A)* is the "CRM dispatch".

Fundamentals

- The settlement residue is shared between available, participating generators.
- It is shared via flowgate entitlements, which are related to access through the contribution factors.
- Allocated access must represent a feasible dispatch which binds the relevant constraint.

Allocation methods

The allocation methods vary the net financial outcomes by affecting the congestion rebate.

Four potential allocation methods include:

- Pro-rata access based on offered availability[5]
- Pro-rata entitlements based on a combination of contribution factors and offered availability
- Winner-takes-all based on contribution factors
- Inferred economic dispatch based on a combination of contribution factors and inferred costs.

[4] ESB, https://esb-post2025-market-design.aemc.gov.au/transmission-and-access consultation paper, May 2022
[5] Refer to ESB post 2025 consultation paper, https://esb-post2025-market-design.aemc.gov.au/32572/1619564172-part-b-p2025-march-paper-appendices-esb-final-for-publication-30-april-2021.pdf, March 2021

The ESB has engaged NERA economic consulting to conduct a quantitative analysis of the impact of the allocation metrics on the market over time. The results of this study will provide a better indication into the relative impacts of each metric in a range of scenarios.

For this working paper, we have provided simplified theoretical examples using Figure 3 as the basis for physical dispatch outcomes. For simplicity, Gen 4 is excluded from the rebate calculation tables given that it does not participate in the constraint and does not pay congestion charges or receive rebates.

Table 7 provides a summary of access and entitlement calculations for each of the four allocation methods. The values are based on the worked examples.

Table 7 Comparison of MW access and entitlements by allocation method

			Access by allocation method (MW)				**Entitlements by allocation method (MW)**			
Unit	**AV** MW	**G** MW	**Pro-rata access** MW	**Pro-rata entitlement** MW	**Winner takes all** MW	**Inferred economic dispatch*** MW	**Pro-rata access** MW	**Pro-rata entitlement** MW	**Winner takes all** MW	**Inferred economic dispatch*** MW
Gen1	100	0	50	49	97	0	38	37	73	0
Gen2	100	73	50	37	0	73	50	37	0	73
Gen3	100	100	50	100	100	100	15	30	30	30
Total	**300**	**173**	**150**	**185**	**197**	**173**	**103**	**103**	**103**	**103**

Note * outcomes refer to worked examples where RRP is $15/MWh.

Allocation methods have been designed so that MW allocation of access does not exceed the generator’s available capacity. Total MW allocation of entitlements must sum to 103, which is the constraint limit in the reference scenario.

Pro-rata access – worked example

Pro-rata access provides access to each qualifying generator in proportion to their availability i.e. governed by the equation $A_i = k \times AV_i$ where AV_i is the availability of generator *i* and *k* is a global scaling factor which is set to ensure the dispatch is feasible.

Table 8 Calculating access and entitlements under the pro-rata access model

Unit	**AV** MW	**k** scaling factor	**A** (MW) AV x k	**a** coefficient	**E** (MW) A x a
Gen 1	100	0.50	50	0.75	38
Gen 2	100	0.50	50	1.0	50
Gen 3	100	0.50	50	0.3	15
Total	**300**		**150**		**103**

Table 9 Calculating net financial outcomes under the pro-rata access model

Unit	**a** coefficient	**A** MW	**G** MW	**RRP** $/MWh	**LMP** $/MWh	**Cost** $/MWh	**A x RRP** $	**(G-A) x LMP** $	**Cost x G** $	**Profit**** $
Gen 1	0.75	50	0	15	4.50	5	754	-226	0	528
Gen 2	1.0	50	73	15	1.00	1	754	23	73	703
Gen 3	0.3	50	100	15	10.80	10	754	537	1,000	291
Total		**150**	**173**				**2,261**	**334**	**1,073***	**1,522**

Note: Cells marked in grey are consistent with Figure 3 and Table 5. Access '*A*' is the key field affected by the allocation method.

*Total costs exclude Gen4 in order to focus the worked example on the constrained generators and their rebate allocation.

** Profit $ = A x RRP + (G-A) x LMP – cost x G.

Pro rata entitlement – worked example

Pro rata entitlement provides *entitlements* (rather than *access*) in proportion to a generator's availability. Given $A = E/a$, a generator with a low contribution factor will receive a higher level of access (relative to generators with higher contribution factors) compared to the pro-rata access method. However, where this would lead to an implied access level greater than its availability, the entitlement is reduced accordingly. Thus $E_i = \min(k, \alpha_i) \times AV_i$ where, again, *k* is a global scaling factor set to ensure dispatch feasibility.

Table 10 Calculating access and entitlements under the pro-rata entitlement model

Unit	**AV** MW	**k** scaling factor	**a** coefficient	**E** (MW) min(k,a) x AV	**A** (MW) E / a
Gen 1	100	0.37	0.75	37	49
Gen 2	100	0.37	1.00	37	37
Gen 3	100	0.37	0.30	30	100
Total	**300**			**103**	**185**

Note The k factor is 0.37. Gen 3's entitlement is capped by its contribution factor = 0.3 so that its access level does not exceed its available capacity of 100 MW.

Table 11 Calculating net financial outcomes under the pro-rata entitlement model

Unit	**a** coefficient	**A** MW	**G** MW	**RRP** $/MWh	**LMP** $/MWh	**Cost** $/MWh	**A x RRP** $	**(G-A) x LMP** $	**Cost x G** $	**Profit** $
Gen1	0.75	49	0	15	4.50	5	730	-219	0	511
Gen2	1.0	37	73	15	1.00	1	548	37	73	511
Gen3	0.3	100	100	15	10.80	10	1,500	0	1,000	500
Total		**185**	**173**				**2,778**	**-183**	**1,073**	**1,522**

Note: Cells marked in grey are consistent with Figure 3 and Table 5. Access '*A*' is the key field that is affected by the allocation method.

Compared to the financial outcomes in the pro-rata access method, Table 12 shows that profits are redistributed from the higher contribution generators (Gen 1 and Gen 2) to the lowest contribution generator (Gen 3) in the pro-rata entitlement method.

Table 12 Comparison of net financial outcomes between the pro-rata access and pro-rata entitlement methods

Unit	**a** coefficient	**Pro-rata access**			**Pro-rata entitlement**		
		A MW	**E** MW	**Profit** $	**A** MW	**E** MW	**Profit** $
Gen1	0.75	50	38	528	49	37	511
Gen2	1.0	50	50	703	37	37	511
Gen3	0.3	50	15	291	100	30	500
Total		**150**	**103**	**1,522**	**185**	**103**	**1,522**

Winner-takes-all (WTA) – worked example

The WTA allocation method assumes that access is allocated on the basis of contribution factors. The generator with the lowest contribution factor in the constraint is allocated entitlements up to its full availability in the constraint, moving upwards until all entitlements have been allocated up to the constraint limit. This is similar to the status quo, where physical dispatch is decided on the basis of contribution factors in the presence of disorderly bidding.

In Table 13 below, generators are listed in order of lowest to highest contribution factor.

Table 13 Calculating access and entitlements under the WTA model

Unit	**AV** MW	**A** MW	**a** coefficient	**E** (MW) A x a
Gen3	100	100	0.3	30
Gen1	100	97	0.75	73
Gen2	100	0	1.0	0
Total	**300**	**197**		**103**

Note: Gen 3 has the lowest coefficient of 0.3 and is allocated access of 100 MW (entitlement 30 MW). Gen 1 has the next lowest coefficient of 0.75 but is capped at 73 MW entitlements (97 MW access) given 103 MW availability in the constraint.

Table 14 Calculating net financial outcomes under the winner takes all model

Unit	a coefficient	A MW	G MW	RRP $/MWh	LMP $/MWh	Cost $/MWh	A x RRP $	(G-A) x LMP $	Cost x G $	Profit $
Gen1	0.75	97	0	15	4.50	5	1,460	-438	0	1,022
Gen2	1.0	0	73	15	1.00	1	0	73	73	0
Gen3	0.3	100	100	15	10.80	10	1,500	0	1,000	500
Total		**197**	**173**				**2,960**	**-365**	**1,073**	**1,522**

Inferred economic dispatch – worked example

Inferred economic dispatch uses inferred generator costs to calculate the economic dispatch if generators offered these inferred costs. The access allocation is set to be identical to this inferred economic dispatch.

For instance, the operating costs of different generation types could be assumed to be consistent with the cost forecasts adopted by AEMO in its initial Inputs, Assumptions and Scenarios report. This document, which underpins AEMO's ISP and ESOO, draws on expert advice (including advice on generator costs from CSIRO) and is subject to a rigorous consultation process.

The order in which generators are allocated access is now a combination of contribution factors and inferred cost e.g. a generator with a lower cost but higher contribution might be dispatched in preference to a generator with higher cost but lower contribution. The methodology for inferring generation costs would need to be developed and would be expected to be based on historical generation bidding and dispatch, rather than a bottom-up cost-analysis of each generator.

Table 15 Calculating access (and entitlements) under the inferred economic dispatch model (RRP = $15/MWh)

Unit	AV MW	RRP $/MWh	Cost $/MWh	A MW	a coefficient	**E** (MW) A x a
Gen1	100	15	5	0	0.75	0
Gen2	100	15	1	73	1.00	73
Gen3	100	15	10	100	0.30	30
Total	**300**			**173**		**103**

Note: In this case, the access allocation is identical to the efficient dispatch outcome calculated in Table 3.

Table 16 Calculating net financial outcomes under the inferred economic dispatch model (RRP = $15/MWh)

Unit	a coefficient	A MW	G MW	RRP $/MWh	LMP $/MWh	Cost $/MWh	A x RRP $	(G-A) x LMP $	Cost x G $	Profit $
Gen1	0.75	0	0	15	4.50	5	0	0	0	0
Gen2	1.0	73	73	15	1.00	1	1,095	0	73	1,022
Gen3	0.3	100	100	15	10.80	10	1,500	0	1,000	500
Total		**173**	**173**				**2,595**	**0**	**1,073**	**1,522**

If the RRP was higher, the outcomes would change. Assume Generator 4 has an outage, and a new Generator 5 sets the RRP with its bid at $100/MWh, the efficient outcome is to dispatch Gen 1 and Gen 3. With a high RRP, the cost differences between generators become less relevant because they all have similar cost differences to RRP. Contribution factors become more relevant than costs in determining the lowest cost dispatch. This is similar to a WTA outcome when generators bid the same price and are dispatched in order of contribution factor.

Table 17 Calculating LMP for the three generators (RRP = $100/MWh)

Unit	**RRP** $/MWh	**Cost** $/MWh	**a** coefficient	**CP** $/MWh	**LMP** RRP – a x CP
Gen 3	100	10	0.3	127	62
Gen 1 *	100	5	0.75	127	5
Gen 2	100	1	1.0	127	-27

Note: *In this scenario, Gen 1 is the marginal generator. CP = (RRP – LMP) / a = (100 –5) / 0.75 = 126.67

Table 18 Calculating access (and entitlements) under the inferred economic dispatch model (RRP = $100/MWh)

Unit	**AV** MW	**RRP** $/MWh	**Cost** $/MWh	**A** MW	**a** coefficient	**E** (MW) A x a
Gen3	100	100	10	100	0.30	30
Gen1	100	100	5	97	0.75	73
Gen2	100	100	1	0	1.00	0
Total	**300**			**197**		**103**

Note: In this case, the access allocation is identical to the WTA outcome calculated in Table 13. This will typically be the case for high RRP scenarios.

Table 19 Calculating net financial outcomes under the inferred economic dispatch model (RRP = $100/MWh)

Unit	**a** coefficient	**A** MW	**G** MW	**RRP** $/MWh	**LMP** $/MWh	**Cost** $/MWh	**A x RRP** $	**(G-A) x LMP** $	**Cost x G** $	**Profit** $
Gen1	0.75	97	97	100	5	5	9,733	0	487	9,247
Gen2	1.0	0	0	100	-27	1	0	0	0	0
Gen3	0.3	100	100	100	62	10	10,000	0	1,000	9,000
Total		**197**	**197**				**19,733**	**0**	**1,487**	**18,247**

Note: Cells marked in grey remain consistent with Figure 3 and Table 5.

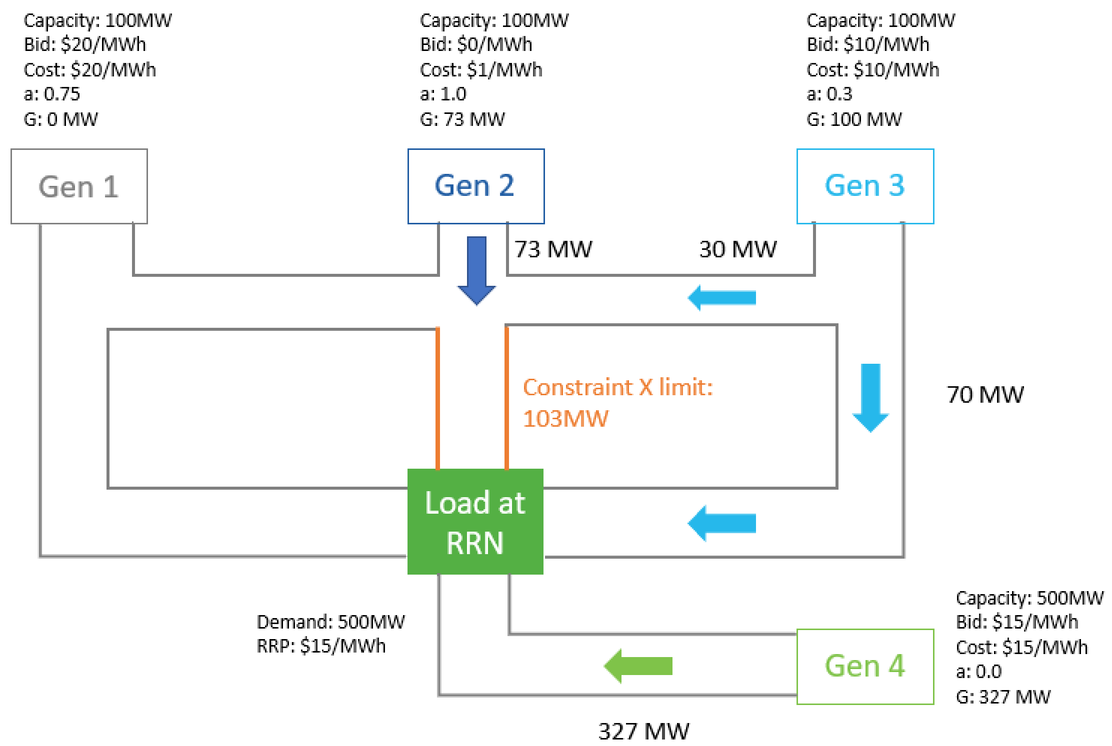
The access allocation reflects the efficient dispatch solution. Assuming that costs are inferred accurately and generators bid at cost, the inferred and actual dispatches will be the same. Disorderly bidding by a generator will not lead to increased access because the access level is determined by inferred costs, not bids and hence would not be an economic bidding strategy under this allocation method.

5. How should out-of-merit generators be treated?

Out-of-merit (OOM) generators are those where *operating costs > RRP*. The allocation methods described in Section 4 allocate an access level to generators that bid in as available to the dispatch. Apart from the inferred economic dispatch method, this can lead to a scenario where OOM generators are included in the allocation of entitlements and access.

As an illustration, Figure 4 updates the operating costs of Gen 1 to be $20/MWh (previously $5/MWh in Figure 3). Gen 1's operating costs now exceed the RRP of $15/MWh.

Figure 4 Dispatch outcomes bidding at cost including out-of-merit generator



There are design choices to be made for the treatment of OOM generators. In this section, the pro-rata access method is modified to demonstrate how this design choice might apply. A similar approach can be adopted for the pro rata entitlements or WTA method.

Table 20 and Table 21 show the access level outcomes depending on whether Gen 1 is included or excluded from the allocation of entitlements.

Table 20 Calculating access (and entitlements) under the pro rata access method including OOM generators

Unit	**AV** MW	**k** scaling factor	**A** (MW) AV x k	**a** coefficient	**E** (MW) A x a
Gen1	100	0.50	50	0.75	38
Gen2	100	0.50	50	1.00	50
Gen3	100	0.50	50	0.30	15
Total	**300**		**150**		**103**

Table 21 Calculating access (and entitlements) under the pro rata access method excluding OOM generators

Unit	**AV** MW	**k** scaling factor	**A** (MW) AV x k	**a** coefficient	**E** (MW) A x a
Gen1	0	0.79	0	0.75	0
Gen2	100	0.79	79	1.0	79
Gen3	100	0.79	79	0.3	24
Total	**200**		**158**		**103**

Note: In this case, Gen1 is excluded from the entitlements and receives 0 access level.

Table 22 Calculating net financial outcomes under the pro-rata access model including OOM generators

Unit	a coefficient	A MW	G MW	RRP $/MWh	LMP $/MWh	Cost $/MWh	A x RRP $	(G-A) x LMP $	Cost x G $	Profit $
Gen 1	0.75	50	0	15	4.50	20	754	-226	0	528
Gen 2	1.0	50	73	15	1.00	1	754	23	73	703
Gen 3	0.3	50	100	15	10.80	10	754	537	1,000	291
Total		**150**	**173**				**2,261**	**334**	**1,073**	**1,522**

Table 23 Calculating net financial outcomes under the pro-rata access method excluding OOM generators

Unit	a coefficient	A MW	G MW	RRP $/MWh	LMP $/MWh	Cost $/MWh	A x RRP $	(G-A) x LMP $	Cost x G $	Profit $
Gen 1	0.75	0	0	15	4.50	20	0	0	0	0
Gen 2	1.0	79	73	15	1.00	1	1,188	-6	73	1,109
Gen 3	0.3	79	100	15	10.80	10	1,188	224	1,000	413
Total		**158**	**173**				**2,377**	**218**	**1,073**	**1,522**

Note: Cells marked in grey remain consistent with the pro rata access method (including out-of-merit generators) in Table 9. Gen 1 costs have been updated to $20/MWh and the access '*A*' is the key field affected by the allocation method.

The tables above show the net financial outcomes depending on whether Gen 1 (OOM) is allocated access or not. The access revenue earned by Gen 1 (OOM) in Table 22 is redistributed to Gen 2 and Gen 3 (in-merit) in Table 23.

The OOM generator is easily identified if it bids at cost. However, an OOM generator may bid strategically (i.e. *LMP < bid < RRP*, despite *bid < operating costs*) to earn revenues from its allocated access. The access allocation method may need to consider inferred economic costs to appropriately identify and exclude OOM generators, similar to the inferred economic dispatch method.

6. Incentives and operation of the CRM with storage

The CMM provides storage providers with access to higher profits relative to the status quo.

If storage chooses (or is mandated) to not receive a rebate and is exposed to the congestion charge, it will be incentivised to charge during periods of congestion (when *LMP < RRP*) and to discharge when the network is not constrained (when *LMP = RRP*). This could lead to overall higher profits from energy arbitrage compared to the status quo.

Figure 5 CMM with a storage provider, BESS 1

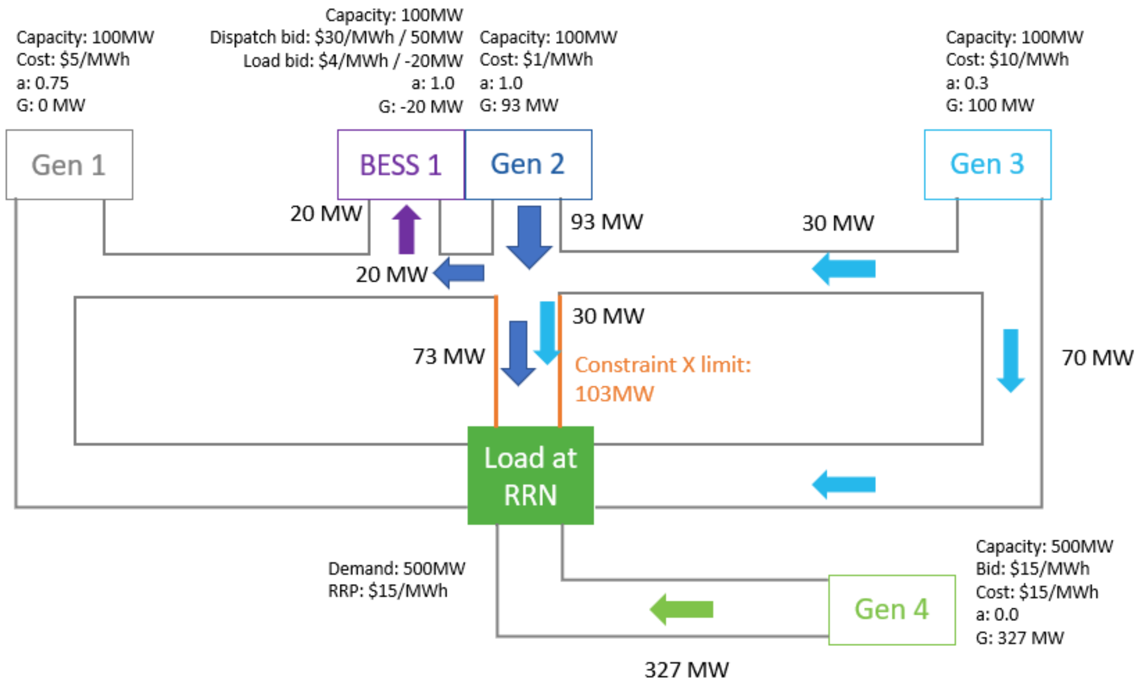


Figure 5 provides a simplified example where BESS1 is part of the loop flow. It has a dispatch bid of $30/MWh (50MW) and load bid of $4/MWh (-20MW). Gen2 has remained the marginal generator with the addition of BESS1.

Status quo: BESS1 charging would relieve constraint X by 1.0 MW for every MW dispatched. But BESS 1 does not charge or discharge given the RRP is higher than its load bid of $4/MWh and lower than its dispatch bid of $30/MWh.

CMM: BESS1 pays the LMP of $1/MWh to charge (as per Table 24) rather than the RRP of $15/MWh.

Table 24 LMP calculation for the three generators and storage provider

Unit	**Cost** $/MWh	**RRP** $/MWh	**a** coefficient	**CP** $/MWh	**LMP** $/MWh RRP – a x CP
Gen 1	5	15	0.75	14	4.50
Gen 2*	1	15	1.0	14	1.00
Gen 3	10	15	0.3	14	10.80
BESS1 – charge	4	15	1.0	14	1.00

Note: *Gen 2 is the marginal generator in this scenario. CP = (RRP – LMP) / a = (15 –1) / 1.0 = 14.

Table 25 Calculating access and entitlements under the pro-rata access model

Unit	AV MW	k scaling factor	**A** (MW) AV x k	a coefficient	**E** (MW) A x a
Gen1	100	0.50	50	0.75	38
Gen2	100	0.50	50	1.0	50
Gen3	100	0.50	50	0.3	15
Total	**300**		**150**		**103**

Access and entitlement MW in Table 25 are consistent with the pro rata access model in Table 8. The scenario assumes BESS1 chooses (or is mandated) to not receive a rebate and is not allocated access.

Table 26 Calculating net financial outcomes with a storage provider assuring pro rata access method

Unit	a coefficient	A MW	G MW	RRP $/MWh	LMP $/MWh	Cost $/MWh	A x RRP $	(G-A) x LMP $	Cost x G $	Profit $
Gen1	0.75	50	0	15	4.50	5	754	-226	0	528
Gen2	1.0	50	93	15	1.00	1	754	43	93	703
Gen3	0.3	50	100	15	10.80	10	754	537	1,000	291
BESS1	1.0	0	-20	15	1.00	4	0	-20	-80	60
Total		**150**	**173**				**2,261**	**334**	**1,013**	**1,582**

Table 26 shows that BESS1 accessed a lower LMP to charge compared to the RRP and was able to relieve the constraint by 20MW.

Table 27 summarises the consequent economic gain (producer surplus) for BESS1.

Table 27 Calculating economic gain for BESS1 under CMM

Scenario	Price reference	Price to charge $/MWh	G MW	Value $
Status quo	Cost to dispatch	4.00	20	80
CMM	LMP	1.00	20	20
Economic gain				**60**

During periods of no congestion, the RRP will apply and enable BESS 1 to maximise its opportunities for price arbitrage (assuming *RRP ≥ BESS1 discharge bid price*).

The worked example for storage is simplified. An additional working paper will be developed and shared with the TWG to explore the locational signals and impacts for storage as a result of the proposed congestion models in operational timeframes.

7. Conclusion

There is no “right” answer for the choice of rebate allocation method. The methods can be tailored to meet different objectives e.g. simplicity and transparency, sharing financial impacts of congestion risk between affected participants, similarity to actual dispatch to reduce basis risk, excluding out of merit generators.

This paper gives a base level of common understanding for the ESB and TWG to explore key outstanding questions for the detailed design of the CMM. The ESB will share outcomes of detailed modelling so that market participants can better identify the impact of the proposed methods.