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Estimating the Impact of the Congestion Management Model and Congestion Relief Market on the NEM

Prepared for the Energy Security Board of Australia

10 February 2023

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Executive Summary

The Energy Security Board of Australia (ESB) commissioned NERA to perform a power system modelling exercise to assess the impact on the NEM of its proposed options for transmission access reform to facilitate the transition to a predominantly renewables-based electricity system. The scope includes the Congestion Management Model (CMM) and the voluntary Congestion Relief Market (CRM). This report sets out our assumptions, modelling approach and results for the reform options considered and a "status quo" scenario where the current market arrangements remain in place in the future.

We model different reform options for the CMM/CRM by calculating the allocation of access to the RRP

We align our modelling exercise with published modelling assumptions for the NEM. We construct our simulation of the NEM in the PLEXOS energy system modelling software. We choose modelling inputs for the system to reflect the Step Change Scenario from the 2022 Integrated System Plan (ISP) published by the Australian Energy Market Operator (AEMO). AEMO considers this scenario a "most likely" development for the NEM that is consistent with key decarbonisation targets. We configure the transmission representation in the model to follow the "Optimal Development Path" for this option as set out in the 2022 ISP. We describe our modelling assumptions in detail in Chapter 2.

We base our analysis on two main types of modelling runs, representing potential "optimal" dispatch under access reform and the current status quo of the NEM, respectively. Both runs are short-term dispatch runs in PLEXOS and assume the same capacity mix, modelled on the ISP Step Change Scenario. In our "cost-reflective" modelling run all generators, including hydro, pumped hydro energy storage (PHES) and batteries, bid their available capacity in every half-hourly interval at a price equal to their short-run marginal cost. This is the optimal outcome that an access reform aims to achieve through efficient price signals and therefore represents the main modelling run to estimate dispatch and prices under the reform. Our "disorderly bidding" run, on the other hand, reflects the incentives currently present in the NEM to bid at the market floor for plants behind transmission constraints whose bids are settled at the RRP. We use this run to estimate outcomes for a "status quo" scenario where current market arrangements remain in place.

We use the outcomes from these modelling runs to calculate revenues, costs and profits for market participants under the status quo and the proposed reform options. Under the reform, participants are exposed to the LMP at the margin through the following revenue calculation formula that holds for each participant in a given trading interval:

$$\textbf{Revenue} = \textbf{A} \cdot (\textbf{RRP-LMP}) + \textbf{G} \cdot \textbf{LMP}$$

Where

- LMP is a locational marginal price;
- RRP is a regional reference price;
- A is the effective access value which is related to generator's flow-gate entitlement through a "constraint coefficient" which determines the participant's incidence on a particular transmission constraint. In the above formulation, access can be interpreted as

a quantity of a financial transmission right that remunerates the generator for a difference between the RRP and LMP.

Table 1 below presents a brief description of each reform option considered and the sensitivities associated with each option. For each CMM option we consider:

- A "cost-reflective" default option where generators are incentivised to bid cost-reflectively, and all participants receive access based on the above formula following each option's specifications. Storage is not allocated access to the RRP; it therefore pays the LMP to charge and receives the LMP for its generation;
- Another "cost-reflective" sensitivity where out-of-merit (OOM) generators do not receive access to the RRP and earn the LMP if called on to generate;
- A secondary "disorderly" sensitivity where we assume that generators still face the incentive to bid disorderly even with the CMM in place. We review outcomes for this sensitivity in Appendix A and Appendix B to this report.

For the "RRP_{NEM}" CRM we consider two sensitivities:

- "Full participation" where we assume all generators opt into the CRM and are re-dispatched cost-reflectively;
- "Partial participation" where only a subset opts into the CRM. This includes the top 50 per cent of generators with the highest profit differential as a result of participating in the CRM and supplemented by wind and solar generators until we reach 50 per cent of wind and solar generation (based on annual generation output). Remaining generators do not participate and fix their dispatch level and market outcomes to those of the energy market (with disorderly bidding).

See Chapter 3 for more detailed explanations of the access allocation formulas.

Table 1: Overview of Reform Options

Reform Option	Description	Sensitivities
CMM		
Pro-rata Access	Allocates access to each generator in proportion to their available capacity in each interval. We scale availability with a "scaling factor" to ensure feasible dispatch. We then weigh the allocated access based on each generator's "contribution coefficient" for each constraint in which it participates, and the congestion price of these constraints.	Cost-reflective, cost-reflective excl. OOM, Disorderly
Pro-rata Entitlement	This method allocates an entitlement rather than access in proportion to availability, based on a combination of constraint coefficients and offered availability.	Cost-reflective, cost-reflective excl. OOM, Disorderly
Winner-Takes-All	Assigns access to generators in ascending order of constraint coefficients (the generator with the lowest constraint coefficient in the constraint receives entitlements up to its full availability in the constraint, then allocation moves the generator with the next lowest factor etc.). We approximate this allocation using dispatch under disorderly bidding as we assume PLEXOS incorporates constraint coefficients in its dispatch decision with bids at the floor.	Cost-reflective, cost-reflective excl. OOM, Disorderly
Inferred Economic Dispatch	Allocates access on a combination of constraint coefficients and inferred marginal cost. We approximate this allocation method using dispatch under marginal cost bidding, where the most cost-effective generators are prioritised in the dispatch.	Cost-reflective, Disorderly
CRM		
"RRP_{CRM}" CRM	Generators are assigned access to the RRP based on disorderly bidding dispatch. All generators then bid marginal cost to the CRM and are re-dispatched accordingly. The "RRP_{CRM}" option uses RRPs from the CRM (in practice, from the modelling run with cost-reflective bidding) to calculate revenues.	Full participation
"RRP_{NEM}" CRM	This option is analogous to the above in terms of access and dispatch. However, for the calculation of revenues it uses RRPs from the energy market (i.e. based on disorderly bidding).	Full participation, partial participation

Source: ESB/NERA

We run our model for two fiscal years (from July to June of the following year), 2023-24 and 2033-34. We present the modelling results for the two fiscal years in Chapter 4 and Chapter 5, respectively.

We find that system costs decrease when market participants bid cost-reflectively

Table 2 shows variable costs of generator in the cost-reflective (i.e. CMM/CRM) and disorderly case (i.e. the status quo) for 2023-24 and 2033-34.

Table 2: System Costs Modelled, Cost-Reflective v. Disorderly Case ($m, 2023-24 and 2033-34)

Model Run	Generation Cost 2023-24	Generation Cost 2033-34
Cost-Reflective	2,841	1,561
Disorderly	2,881	2,176
Difference (Cost-Ref. - Disorderly)	-40	-615
	(-1.4%)	(-28.3%)

Source: NERA analysis of PLEXOS outputs

In both fiscal years examined, generation costs under cost-reflective bidding are lower than those in disorderly bidding. The lower costs of the cost-reflective case reflect the increased efficiency of dispatch.

The system costs in 2033-34 are lower than in 2023-24 in both scenarios, because of increased deployment of wind and solar capacities in REZ and the decommission of must-run coal plants. Gas is more often at the margin in 2033-34, as most of must-run coal capacity from 2023-24 has retired. As a more expensive form of generation, a difference in dispatch between the two runs translates in a larger difference in system costs between cost-reflective and disorderly case.

Dispatch adjustments often affect inter-regional flows, particularly when congestion is located near the regional boundaries

Table 3 and Table 4 show the decomposition of the profit change compared to the cost-reflective reform options where:

- "DE" is the profit change due to change in dispatch;
- "DA" is the profit change due to change in access;
- "DP" is the profit change due to change in RRP;
- "DX" is the modelling noise.[1] We utilise this component in 2033-34 only.

For the calculation of all revenues in 2023-24, we adjust LMPs in few instances where they do not reconcile with congestion prices on associated lines. In 2033-34, we use "unadjusted" LMPs (i.e. those directly reported by PLEXOS) for all results, except the "DA" component for the two pro-rata options. The "DX" component represents the difference in "DA" components when calculated with unadjusted and adjusted LMPs. We calculate this component for the two pro-rata options (pro-rata access and pro-rata entitlement) as these are the two options in which we allocate access and entitlement based on each plant's contribution to a transmission constraint. For the other CMM options, the reporting discrepancy in our PLEXOS model does not affect our modelling results as the access is inferred from alternative dispatch runs rather than calculated based on congestion prices.

[1] In running scenarios for 2033-34, we found that the PLEXOS model based on the ISP reported LMPs that were inconsistent with congestion prices. That inconsistency may result from the complexity of the problem of solving a complex nodal network with detailed granularity. We refer to "unadjusted" LMPs as LMPs directly reported by PLEXOS and "adjusted" LMPs as LMPs that we constructed using the congestion prices on the lines connecting each node.

Therefore the DX component is zero for all other scenarios. See Section 3.1.4 of the report for a more detailed description of our methodology.

Table 3: Decomposition of the Profit Change in 2023-24 by Cost-Reflective Reform Option ($m)

Scenario	Model Run	DE	DA	Profit Change	DP	Total Profit Change
CMM Scenarios						
Pro-Rata Access	Cost-Reflective	13.4	18.8	32.2	-108.4	-76.2
Pro-Rata Entitlement		13.4	18.5	31.9	-108.4	-76.5
Winner-Takes-All		13.4	-	13.4	-108.4	-95.0
Inferred Economic Dispatch		13.4	-3.2	10.2	-108.4	-98.2
CRM scenarios						
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	13.4	-	13.4	-108.4	-95.0
RRP_{NEM} - 100% opt-in		13.4	-	13.4	-	13.4

Source: NERA analysis of PLEXOS outputs. Notes: Profit Change = DE+DA. Total Profit Change = DE+DA+DP.

Table 4: Decomposition of the Profit Change in 2033-34 by Cost-Reflective Reform Option ($m)

Scenario	Model Run	DE	DA	Profit Change	DP	DX	Total Profit Change
CMM Scenarios							
Pro-Rata Access	Cost-Reflective	538.5	-26.6	511.9	-1,941.9	-250.7	-1,680.7
Pro-Rata Entitlement		538.5	-24.2	514.3	-1,941.9	-252.4	-1,680.0
Winner-Takes-All		538.5	-	538.5	-1,941.9	-	-1,403.4
Inferred Economic Dispatch		538.5	-173.8	364.7	-1,941.9	-	-1,577.2
CRM scenarios							
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	538.5	-	538.5	-1,941.9	-	-1,403.4
RRP_{NEM} - 100% opt-in		538.5	-	538.5	-	-	538.5

Source: NERA analysis of PLEXOS outputs. Notes: Profit Change = DE+DA. Total Profit Change = DE+DP+DA+DX.

The change in dispatch (DE) leads to a higher profit in all cost-reflective reform options, although it changes the areas of congestion between and within the regions. Indeed, coal in Queensland and New South Wales is substituted for renewables and coal in Victoria in 2023-24. In 2033-34 the mechanism substitutes gas in New South Wales, Victoria and South

Australia in favour of renewables and coal in Queensland and renewables in New South Wales, Victoria and South Australia.

Table 3 and Table 4 above show that the pro-rata access and pro-rata entitlement allocation options share a similar profit change due to change in access at the individual plant level (see Figure 4.7 and Figure 4.8 for full 2023-24 results and Figure 5.8 and Figure 5.9 for 2033-34 results). There is no profit change due to access in the CRM scenarios since access is determined by the status quo energy market under this option.

Estimating the real-world impact of access on the profit change in the winner-takes all and inferred economic dispatch reform options is more challenging. In particular, we do not represent real world dynamics such as the clawing back of inter-regional settlement residue deficits from generators. We discuss the results and their implications further in Chapters 4 and 5.

Table 5 and Table 6 below present the most congested lines and their respective congestion prices for the cost-reflective model runs in 2023-24 and 2033-34.[2] This table shows that with efficient dispatch outcomes (i.e. cost-reflective model runs), the congestion often occurs in areas located near regional boundaries.

[2] The comprehensive list of congested lines is in Table 4.1 for 2023-24 and Table 5.2 for 2033-34.

Table 5: Most Congested Lines and Respective Congestion Prices, Cost-Reflective 2023-24

	Region, REZ		Number Periods Congested		Avg. Congestion Price ($/MWh)	
Line (Node 1-Node 2)	**Node 1**	**Node 2**	**Flow**	**Flow Back**	**Flow**	**Flow Back**
Armidale-Tamworth	NSW, N2	NSW, Non-REZ	160	46	8.17	3.50
Bannaby-Sydney West	NSW, Non-REZ	NSW, Non-REZ	21	-	91.56	-
Bayswater-Lake Liddell	NSW, N0	NSW, N0	297	6	3.54	0.00
Collector Windfarm-Marulan	NSW, Non-REZ	NSW, Non-REZ	67	6	9.70	0.00
Darlington Point-Wagga Wagga	NSW, N5	NSW, N6	2,195	114	18.71	0.00
Davenport-Olympic Dam West	SA, S5	SA, S7	37	-	100,000	-
Dederang-Murray	VIC, V1	NSW, N7	5	80	0.00	72.52
Dederang-South Morang	VIC, V1	VIC, Non-REZ	28	-	87.51	-
Woolooga-Palmwoods	QLD, Q7	QLD, Non-REZ	74	2	9.08	0.00
Heywood-South East (Mount Gambier)	VIC, V4	SA, S1	1,166	525	10.85	0.00
Tumut1/2-Murray	NSW, N7	NSW, N7	303	4,761	3.10	21.82
Tailem Bend-Tungkillo	SA, S1	SA, S3	347	438	0.00	8.18

Source: NERA analysis of PLEXOS outputs.

Table 6: Most Congested Lines and Respective Congestion Prices, Cost-Reflective 2023-24

	Region, REZ		Number Periods Congested		Avg. Congestion Price ($/MWh)	
Line (Node 1-Node 2)	**Node 1**	**Node 2**	**Flow**	**Flow Back**	**Flow**	**Flow Back**
Armidale-Tamworth	NSW, N2	NSW, Non-REZ	2,444	-	62.63	-
Bannaby-Sydney West	NSW, Non-REZ	NSW, Non-REZ	2,095	15	187.28	1.34
Canowie-Robertstown	SA, S3	SA, S3	29	622	0.00	27.10
Davenport-Olympic Dam West	SA, S5	SA, S7	103	2	17,491	0.00
Dederang-Murray	VIC, V1	NSW, N7	69	52	4.49	36.00
Dederang-South Morang	VIC, V1	VIC, Non-REZ	7	16	22.47	2.05
Dumaresq-Sapphire Windfarm	NSW, Non-REZ	NSW, N2	12	123	0.00	12.94
Rocklea-Blackwall	QLD, Non-REZ	QLD, Non-REZ	18	25	0.00	8.27
South Pine-Blackwall	QLD, Non-REZ	QLD, Non-REZ	33	18	2.56	0.72
Woolooga-Palmwoods	QLD, Q7	QLD, Non-REZ	2,931	4	77.34	0.00
Heywood-South East (Mount Gambier)	VIC, V4	SA, S1	30	463	0.02	10.12
Keylor-Sydenham	VIC, Non-REZ	VIC, Non-REZ	141	1,349	0.01	39.79
Mount Piper-Wellington	NSW, Non-REZ	NSW, N3	2	51	0.00	97.68
Tumut1/2-Maragle	NSW, N7	NSW, Non-REZ	980	306	74.50	10.43

Source: NERA analysis of PLEXOS outputs.

Dispatch changes due to the reform affect constrained and unconstrained generators on either side of the regional boundary. A proportion of the efficiency gain flows through to generators as an "efficiency dividend" and the remainder is a settlement residue (including both intra-regional and inter-regional settlement residues). There are model limitations to the allocation of the efficiency gain given there is no clamping applied to counter-price flows in PLEXOS which affects the inter-regional settlement residues). Chapter 6 contains further discussion of how the congestion representation affects results.

In our model, results show that disorderly bidding may lead to higher RRPs, resulting in a negative impact on profit

The higher RRPs in disorderly model runs lead to a negative impact on profits (DP) in CMM scenarios in both 2023-24 and 2033-34 (see Table 3 and Table 4). There is no profit change due to RRPs in the CRM scenarios because the RRP is determined by the status quo energy market. However, RRP dynamics are complex to model. In the absence of clamping of counter-price flows by the market operator (see Section 6.1) and strategic bidding calculations by market participants (see Section 6.2), our PLEXOS representation faces model limitations which could affect RRPs outcomes significantly in practice.

Partial participation in the CRM is conducive to more efficient costs compared to the status quo

Table 7 presents variable system costs by level of participation in the CRM for 2023-24 in and 2033-34. We focus on the CRM design in which the RRP is based on the energy market (RRP_{NEM}) where there is disorderly bidding (i.e. RRP_{NEM} = RRP $_{disorderly}$).

Table 7: Generation Costs by Level of CRM Opt-In ($m, 2023-24 and 2033-34)

	0% opt in (SQ Disorderly)	Partial opt-in	100% opt-in
2023-24	2,881	2,851 (-1.1%)	2,841 (-1.4%)
2033-34	2,176	1,908 (-12.3%)	1,561 (-28.3%)

Source: NERA analysis of PLEXOS outputs

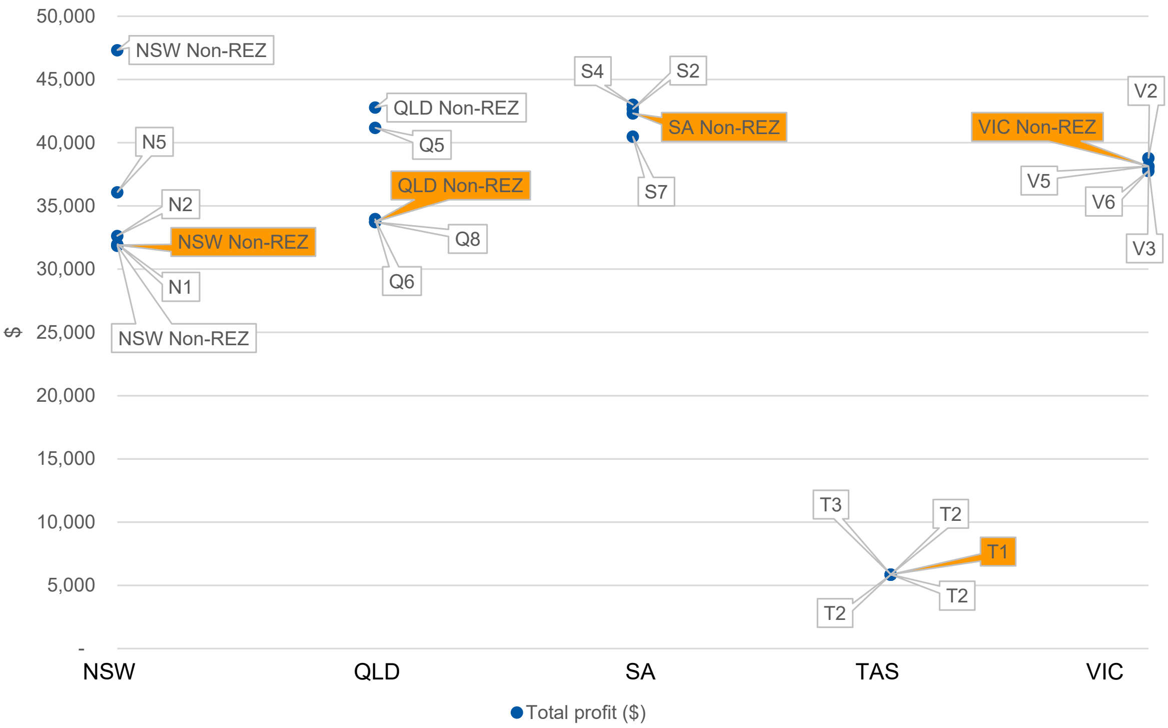
Our results suggest that partial participation in the CRM is already conducive to more efficient cost outcomes compared to the disorderly status quo.

On the other hand, we expect any modelling result of partial participation to be heavily reliant on which set of generators is expected to opt into the mechanism. We adopt a selection method based on relative profits in order to reflect the financial incentive to opt into the CRM, and ensure that at least 50 per cent of renewable generation in each fiscal year opts into the CRM. In 2023-24, our methodology leads to a high level of overall opt-in (around 86 per cent) leading to costs in the partial opt-in scenario being very close to those with full participation – that is, partial participation alone achieves cost savings close to those of full participation. On the other hand, overall opt-in is lower in 2033-34 (around 56 per cent) and partial participation achieves less than half the savings of full participation.

There is scope for a battery located away from the reference node to profit by exploiting the exposure to the LMP

PLEXOS dispatches batteries according to a cost-minimisation logic. In practice, a battery would attempt to optimise its charging and discharging pattern to be able to arbitrage over the spread in prices over a “cycle” of charge and discharge. To illustrate the profit potential of different locations for a battery that arbitrage on the LMP spread, we perform a post-modelling calculation simulating a simple arbitrage-based operation of storage. Figure 1 shows profits for a sample battery based on location in 2023-24. We use each region’s Regional Reference Node plus other distant nodes to illustrate the difference in profits for a battery behind constraints that faces the LMP. We show that batteries are able to exploit the spread between LMP and RRP in areas behind constraints (as is the case in certain areas of NSW and QLD shown below).

Figure 1: LMP Profits for 2-hour, 1 MW Battery by Location ($, 2023-24)



Source: NERA analysis.
Note: Nodes are organised by region; the regional reference node is highlighted in yellow for each region.

Section 4.8 and 5.8 further discuss the operation of a sample battery in 2023-24 and 2033-34, respectively.

We qualitatively review various factors that we cannot represent in the modelling exercise and might impact real-world outcomes of the reform

While we ensure that results are internally consistent and represent the effects of the CMM/CRM accurately, our PLEXOS nodal model constitutes an extremely large and complex optimisation problem. We therefore need to make simplifying assumptions around certain phenomena and behaviours occurring in the real-life operation of the NEM, and make qualitative assessments of their potential impact on results. These elements include:

- Clamping of "counter-price" flows on interconnectors. Counter-price flows occur when power flows from a high-RRP region to a low-RRP region because of discrepancies between local and regional prices. In reality, AEMO would "clamp" these flows, mitigating the price and revenue effects resulting from them;
- Strategic bidding by generation companies. Our modelling simulation does not account for strategic behaviour by generation companies such as exploiting an asset's market power.
- Simplifications around network settings and operation, such as:

  - No stability constraints for generators or network assets, meaning our estimate of congestion might be an under-estimate;
  - No explicit loss modelling on the transmission network. This can impact the size of revenues and profits in both the cost-reflective and disorderly case as in reality participants earn a price adjusted by a marginal loss factor;
  - Hydro does not participate in disorderly bidding due to the risk of disrupting the medium-term storage optimisation constraints calculated before short-term optimisation. In reality, hydro could participate in disorderly bidding if compatible with the shadow value of water, which we do not incorporate in bids.
- Occasional instances of RRP spread across regions that do not reconcile with congestion prices. In a nodal representation as large and complex as ours, it is not feasible to assess whether the reason for this inconsistency lies in the reported congestion prices for lines or in the RRPs. We focus on ensuring consistency between LMPs and the RRP within a region, which is the key driver of CMM/CRM outcomes.

1. Introduction

The energy transition plan in Australia foresees that by 2040 most electricity will be provided by near-zero marginal cost plants such as wind and solar generation (with associated energy storage to firm output) located in Renewable Energy Zones (REZs). The Energy Security Board of Australia (ESB), in conjunction with other energy market bodies, has been looking since 2019 at a package of reforms to substantially update energy market rules in the NEM to accommodate the transition and ensure the new fleet is located and operated efficiently, in accordance with the optimal development paths set out in the market operator's Integrated System Plan (ISP). The ESB published its Post-2025 Market Design review and advice to ministers in 2021 and consulted on potential alternatives with industry participants. [3]

Managing congestion and transmission access is a relevant element in the proposed package of reforms. New renewable generation tends to cluster in certain locations where the renewable resource is abundant, leading to diminishing additional benefits of new capacity as the new plants are often constrained or displace existing capacity. Even after taking into account planned upgrades to the transmission network as set out in the ISP, network congestion is expected to be severe in the future. Moreover, the current market arrangements where generators all receive the Regional Reference Price (RRP) for the energy dispatched, yet receive no compensation if they are constrained off, results in disorderly bidding and inefficient dispatch when congestion arises. This occurs because generators behind constraints have the incentive to bid the market floor price to be dispatched ahead of others and receive the regional price, regardless of their marginal cost.

Against this background, the ESB has proposed a Congestion Management Model (CMM) to complement the ISP transmission projects and the development of REZs for new renewable capacity. Under the proposed mechanism, market participant would incur a charge that reflects the marginal cost of congestion they cause, and are then entitled to a rebate below an "efficient" level of congestion. The ESB is considering different approaches to calculating and allocating the rebate. Several industry participants submitted alternative proposals for managing congestion in the NEM, notably a "Congestion Relief Market" (CRM) based on voluntary participation, where market participants can buy and sell congestion relief to settle outside the energy market when transmission constraints bind.

The ESB has engaged NERA to perform an impact assessment of the proposed CMM and CRM options, to inform a potential rule change in the wholesale electricity market. The assignment is in the form of a power system modelling exercise, in which we construct scenarios to represent and compare the impact of different reform options at different points in the future.

This report sets out our analysis of the impact of the different reform options considered, compared with our modelled "status quo" scenario that assumes the current arrangements continue to exist in the future. The remainder of this document is organised as follows:

- Chapter 2 reviews the set-up and assumptions we employ to represent the NEM generation and transmission system in our modelling software, following published information by the Australian Energy Market Operator (AEMO);

[3] Materials available at: https://esb-post2025-market-design.aemc.gov.au/

- Chapter 3 summarises the modelling methodology used to simulate the market arrangements under the status quo and each reform option;
- Chapter 4 presents modelling results for the fiscal year 2023-24;
- Chapter 5 presents modelling results for 2033-34;
- Chapter 6 discusses potential limitations to the analysis due to modelling constraints and provides a qualitative estimate of their impact on real-world outcomes; and
- Chapter 7 concludes.

We present results for secondary sensitivities and supplementary information on inputs and assumptions in the Appendices at the end of this report.

2. Modelling Set-Up and Assumptions

2.1. The PLEXOS Modelling Software

PLEXOS is a cost-minimising market-modelling and system planning software package, which projects planning decisions and dispatch using a linear programming algorithm. PLEXOS forms the basis of our market modelling of the NEM.

Modelling the market using PLEXOS has a number of key advantages for quantifying the benefits of flexibility:

- PLEXOS is an industry-leading platform for modelling electricity markets for which we and stakeholders already have access to published versions run by AEMO for the NEM, namely the Integrated System Plan (ISP) and the Electricity Statement of Opportunities (ESOO) models;
- As a publicly-recognised modelling platform, stakeholders have much greater clarity and understanding of our results than if we were to use a bespoke, proprietary algorithm; and
- The software is able to optimise the short-term optimal dispatch patterns in the nodal framework. We replicate the capacity expansion modelled in the ISP in our study and given this capacity outlook, we can then observe the dispatch and pricing outcomes in each half hour of the modelling horizon in order to determine outcomes under the different CMM options.

We describe our PLEXOS modelling set-up in further detail in the upcoming sections.

2.2. Defining the Nodal Network

We model the NEM using our PLEXOS-based nodal model, which we originally built in 2019-2020 using inputs from the 2019 ESOO and 2020 ISP models. For this exercise, we have upgraded our existing model with new nodes and new lines to reflect the generation and transmission outlook for the NEM set out in the 2022 ISP.

2.2.1. Overview of Nodes and Transmission Lines

The ESOO and ISP databases do not provide a nodal representation of the NEM. We developed a nodal PLEXOS model on the basis of the existing regional one and locational data provided by AEMO. The resulting nodal infrastructure is a representation of the NEM's "system normal" configuration, that is, the baseline state of the system in which transmission elements are in service and operating in their normal configuration.[4] There are 1,068 nodes in our model in total.

Our PLEXOS nodes are a synthetic representation of real-life substations that connect lines and allow generators to input energy to the grid; in practice, a PLEXOS node can be the equivalent of multiple real-life connection points combined into a substation. For instance, the model may show three power plants belonging to the same complex (e.g. Bayswater plants 1, 2 3, and 4) to be connected to the same node, while in reality each plant has its own connection point.

[4] AEMO (May 2020), Victorian Transfer Limit Advice – System Normal, p.27.

Table 2.1 below summarises the number of nodes in every region and the corresponding Regional Reference Node.

Table 2.1: Summary of Nodes per Region

	Number of Nodes	Reference Node	RRN Voltage (kV)
NSW	334	Sydney West	330
QLD	304	South Pine	275
SA	217	Torrens A Power Station	275
TAS	93	George Town	220
VIC	120	Thomastown	220

Source: AEMC/NERA PLEXOS model

Our PLEXOS representation of the NEM includes a detailed transmission network linking the nodes and contains 1,942 lines. The model also includes contingency constraints, to reflect AEMO's network security practice of monitoring lines and diverting flows to other lines in case of faults.[5]

Our modelled power flows obey Kirchhoff's second law and the lines have physical properties (reactance and resistance) as well as a thermal representation.[6] Using these physical properties ensures that the power flows we model reflect as closely as possible the feasible dispatch in the NEM.

2.2.2. Nodes and Lines Added to Reflect the 2022 ISP

2.2.2.1. Overview

Starting from our existing nodal model, we include additional nodes and lines for two main purposes:

1. To ensure that non-commissioned generators and batteries in the 2022 ISP (i.e. listed as "committed" and "anticipated") can deliver power to the network through a substation; and
2. To reflect the future transmission projects included in the 2022 ISP.

2.2.2.2. Method for new nodes and lines for future generators

In designing the new nodes and lines for generators entering the grid after the start of the modelling horizon, we ensure that the connection from the generator to its assigned substation has sufficient capacity to reach the node i.e. the thermal limit on a transmission line is larger than the generation maximum capacity.

Whenever we cannot identify the connection from a generator to its substation, we choose the closest substation based on the network topology.

5 Specifically, we include an N-1 security envelope in our modelling.

6 Kirchhoff's second law states that the (directed) sum of potential differences across a closed loop in a circuit is zero. Source: Royal Academy of Engineering.

We create a new node and a new line whenever a generator leads to a sufficiently large substation that includes more than one line.

2.2.2.3. Method for new nodes and lines reflecting the 2022 ISP

We follow the transmission outlook set out in the 2022 ISP Step Change Scenario, in particular, Candidate Development Path 12 ("CDP12"). AEMO identifies the Step Change scenario as the most likely outcome according to the stakeholders' panels.[7] AEMO also states that CDP12 is an "optimal development path" for the Step Change scenario.[8]

We have included Priority 1, 2 and 3 projects from AEMO's 2022 ISP as well as the Marinus Link Line from 2036 (as assumed in CDP12). Priority 1 and 2 projects are either listed as "committed", "anticipated" or "actionable" by AEMO, whereas Priority 3 projects are classified as "future ISP projects".[9] Whenever future ISP projects have two options, we picked the first option by default.

Appendix D provides more details on the PLEXOS implementation of the ISP projects.

2.3. Projecting Demand

The ISP contains assumptions on sub-regional demand only.[10] We allocated load to nodes based on "load participation factors", which we derived from data provided by AEMO.

We model demand using the Probability of Exceedance 10 (POE-10, i.e. the demand forecast at the upper decile of the distribution) demand scenario, as provided in the 2022 ISP modelling material. We use Operational Sent-Out ("OPSO") forecasts, which are net of the contribution of rooftop PV to load. As mentioned above, we follow the forecast for the Step Change scenario.

The 2022 ISP adopts a "rolling reference year" approach in demand traces to capture weather diversity in the modelling horizon.[11] A 10-year sequence of reference years (2010/11 to 2019/20, plus an additional "dry year") is rolled forward and repeated over the modelling horizon.

Figure 2.1 shows the evolution of the forecasts over the entire ISP horizon.

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7 AEMO (30 June 2022), 2022 Integrated System Plan, pp. 33-34.

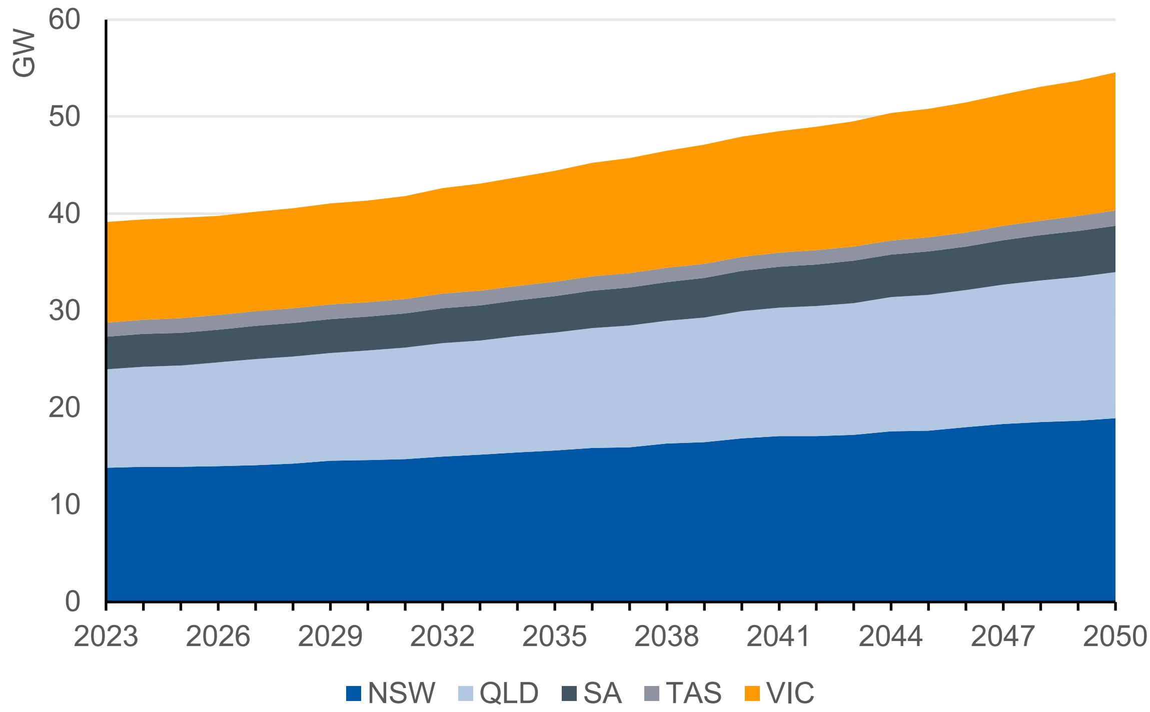
8 AEMO (30 June 2022), 2022 Integrated System Plan, p. 92.

9 AEMO (30 June 2022), 2022 Integrated System Plan, Appendix 5.

10 That is, the ISP 2022 models SA, TAS and VIC as one region, while it splits NSW into four sub-regions and QLD into three.

11 AEMO (30 June 2022), 2022 Integrated System Plan, Model instructions, pp. 4-5.

Figure 2.1: Summer Peak Demand, Step Change Scenario



Source: AEMO Forecasting Portal.

2.4. Representing the ISP 2022 Generation and Storage Capacity Mix

2.4.1. Generation Capacity and its Properties

We aim to set up our model so that it is as close as possible to the representation of the NEM set out in the 2022 ISP and its associated PLEXOS database for the Step Change scenario. We therefore updated the list and characteristics of generators and storage units in our nodal model using new information from the 2022 ISP.

We source most generators and batteries properties from 2022 ISP Step Change Scenario, as represented in the published PLEXOS database and the 2022 Inputs and Assumptions Workbook published with the Final ISP. Properties include, for instance, the maximum capacity of each plant, rating and unit costs.

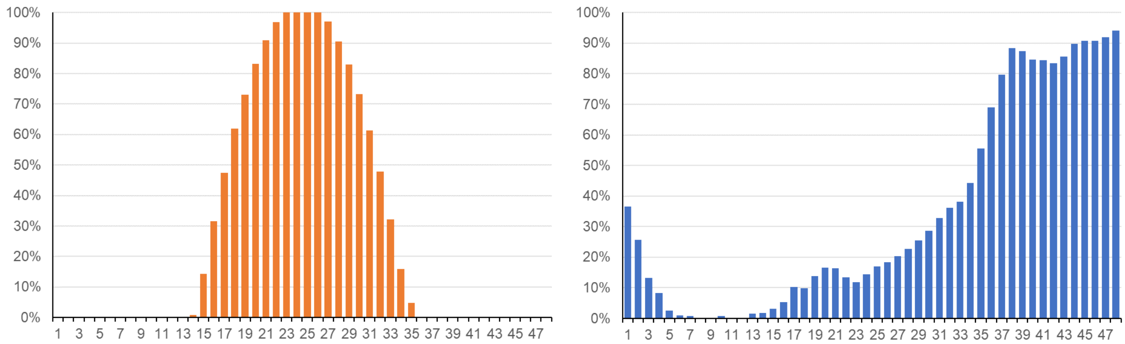
In addition, we add a number of generator properties from the 2021 ESOO model that relate to short-term dispatch dynamics and are therefore absent or simplified in the ISP database. These properties include: minimum up time, must-run units, fixed load, minimum load, maximum ramp up, maximum ramp down, forced outage rate, outage factor and minimum time to repair.

The ISP regional models allocate all generation to a representative node – either the region's reference node or a node for each "sub-region", as described above. We matched generators to nodes by investigating the physical locations of the network connection points and generators. Our nodal database assigns generators to nodes on the basis of their proximity to a substation/set of buses.

We adopt ISP 2022 assumptions on the existing generation fleet. We also programme in scheduled "committed" and "anticipated" projects – largely solar, wind and pumped hydro – expected to be commissioned after 2023, when the 2022 ISP simulation starts. We retire capacity following expected retirement dates in the ISP 2022 assumptions.

We have modelled the availability of renewable plants using rating traces obtained from the ISP 2022 database. As is the case with demand, AEMO uses a "rolling reference year" approach to ratings traces, following the same methodology described for demand. Traces are available half-hourly at plant level, for existing plant, or by REZ for candidate entrants that the model can choose to build in a planning simulation. The traces contain the respective plant's rated generation capacity in every period, normalised to a 1 MW unit, as illustrated in Figure 2.2.

Figure 2.2: Half-hourly Rating Trace on Sample Day for a Solar (Left) and Wind (Right) Generator



Source: AEMO (June 2022), ISP 2022 database. The charts show half-hourly rating (normalised to a 1MW plant) on 31 July 2023 for a solar and a wind plant in the North-West NSW Renewable Energy Zone (REZ). The choice of the day is entirely aleatory for this representation.

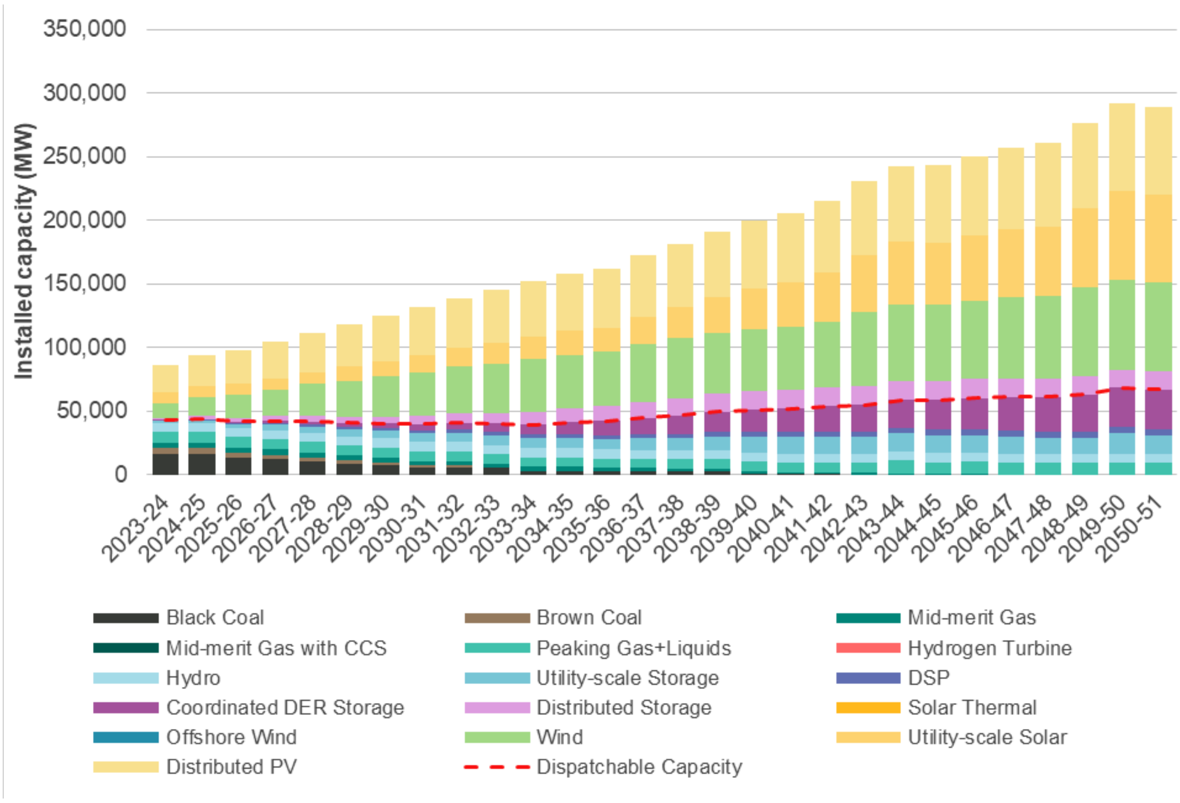
2.4.2. Modelling Generation Expansion

2.4.2.1. "Long-term" assumptions run to align capacity between the nodal model and the 2022 ISP

The assessment of the CMM and CRM implementation options will focus on short-term dispatch and pricing dynamics. However, we ensure consistency with the 2022 ISP by using the generation outlook projected by the 2022 ISP, specifically its Step Change scenario with "CDP12" transmission, and allocating it between the eligible nodes in our nodal model. The allocation ensures that the generation capacity in our model matches the ISP capacity projections by region, by REZ and by type of technology. Within these constraints the total capacity under each subcategory is pro-rated between the applicable nodes of a REZ or outside the REZ areas.

Figure 2.3 represents the capacity mix in the 2022 ISP Step Change (CDP12) scenario.

Figure 2.3: NEM Capacity, 2023-2051



Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12

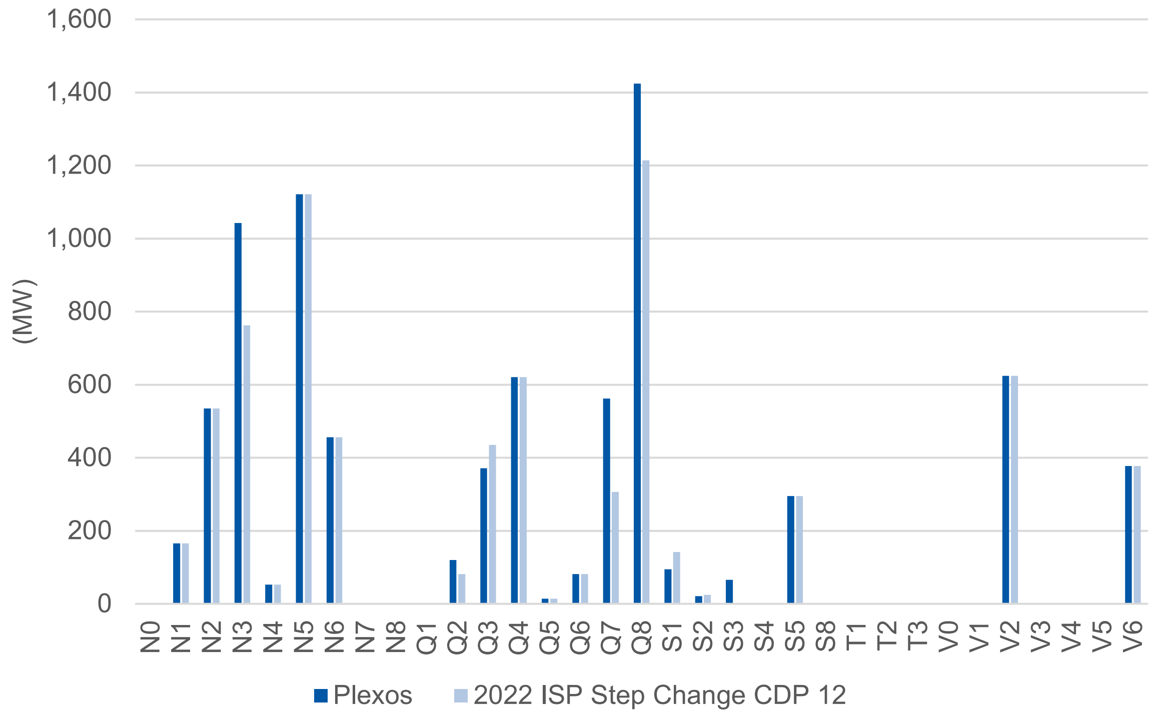
Like the ISP, our PLEXOS model database includes:

- Existing and scheduled (programmed in) generators and storage units, which enter and exit the system on pre-established dates. We align these plants and their capacity to the assumptions contained in the 2022 ISP Step Change PLEXOS database;
- "Candidate" generators and batteries included in the model in addition to the scheduled units, and pro-rated by relevant nodes so that the totals match the ISP's CDP12 scenario.

To replicate the ISP's build pattern of new capacity, we rely on the ISP published capacity outlook by region and REZ.[12] For renewable candidates (wind and solar) we constrain new build in our model to match total capacity by REZ and region as published in the 2022 ISP. For gas and storage candidates we follow a similar procedure at regional level. We therefore recreate the ISP capacity outlook in a nodal dimension. We show the comparison between the ISP capacity and the Plexos capacity in Figure 2.4 and Figure 2.5 for solar capacity and in Figure 2.6 and Figure 2.7 for wind capacity.

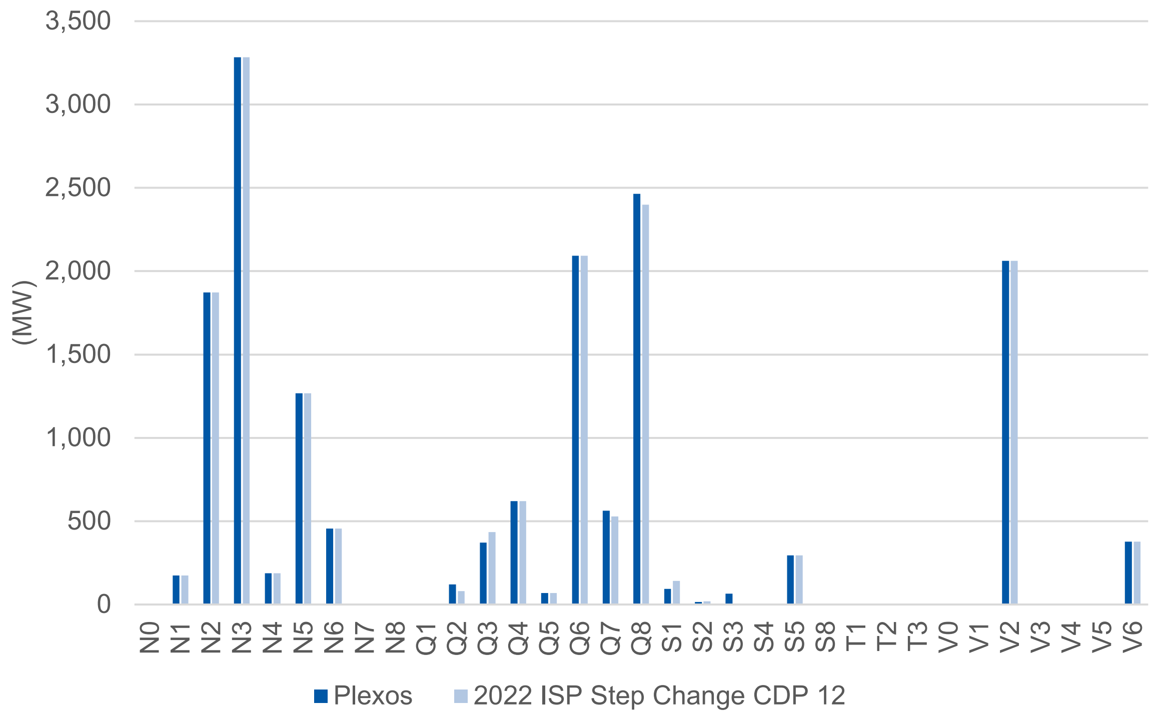
[12] AEMO (30 June 2022), 2022 Integrated System Plan - Supporting material: Generation outlook. URL: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 10 August 2022.

Figure 2.4: Comparison of ISP capacity and PLEXOS capacity in 2023-24 (MW)



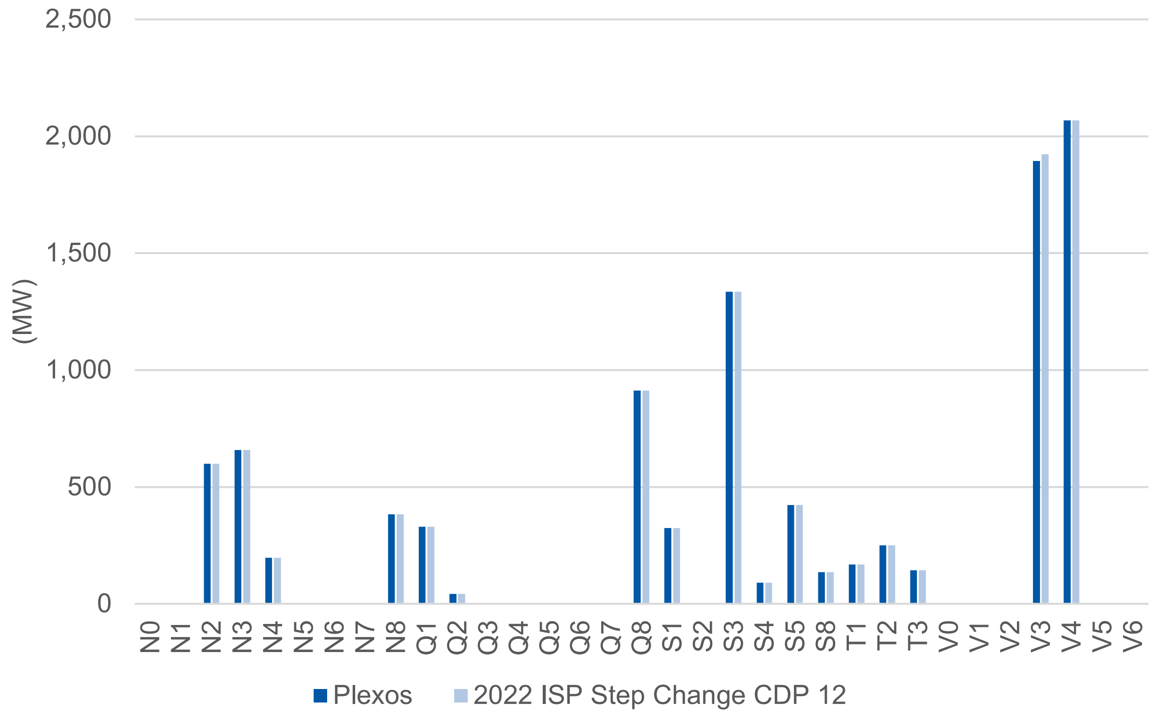
Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12. PLEXOS results.

Figure 2.5: Comparison of ISP solar capacity and PLEXOS capacity in 2033-34



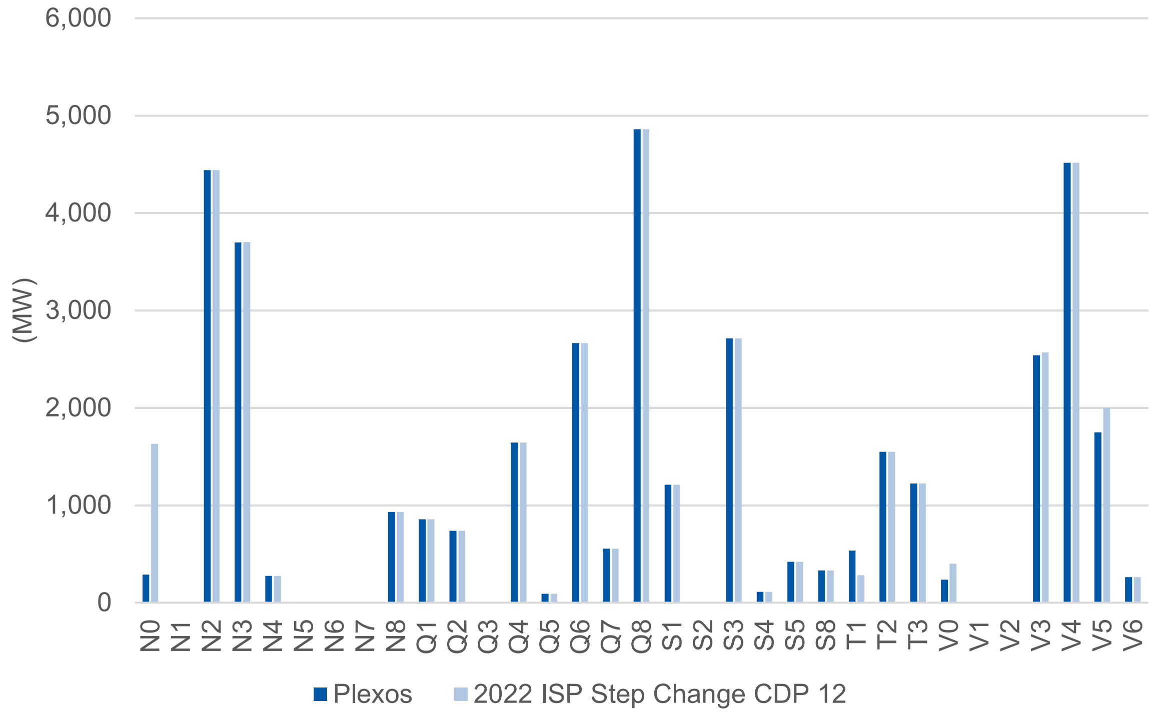
Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12. Plexos results.

Figure 2.6: Comparison of ISP wind capacity and PLEXOS capacity in 2023-24



Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12. Plexos results.

Figure 2.7: Comparison of ISP wind capacity and PLEXOS capacity in 2033-34



Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12. Plexos results.

2.4.2.2. Specifications of "candidate" plants for new capacity build

The Step Change "CDP12" scenario does not build any additional coal, biomass, hydrogen, solar thermal and offshore wind capacity. Therefore, we only include in our model new gas, wind and solar plants. The ISP storage capacity expansion covers large scale batteries and pumped hydroelectric energy storage (PHES). Based on the ISP we include 1-hour, 2-hour, 4-hour and 8-hour large-scale batteries in the model.[13] We model new entrant PHES as 8-hour, 24-hour and 48-hour batteries, with the cost profiles of PHES based on the ISP assumptions.

In the case of new renewable capacity, we do not have an individual generation trace for most nodes, as is the case for existing wind and solar capacity. We have used traces by REZ for the missing nodes, published as part of the 2022 ISP PLEXOS model.

We constrain the number of nodes at which construction of gas and renewable plant can take place. We also constrain building of wind and solar new capacity to REZ and non-REZ areas where the ISP models new build. For thermal generators, we constrain new construction to nodes with existing generation outside of metropolitan areas. For large-scale batteries, we build both within and outside REZs (including the nodes already selected for thermal build and nodes with existing renewable generators). Construction of PHES is constrained to areas with existing hydro generation, as a proxy for areas with terrain and hydro-geological conditions suitable for this technology.

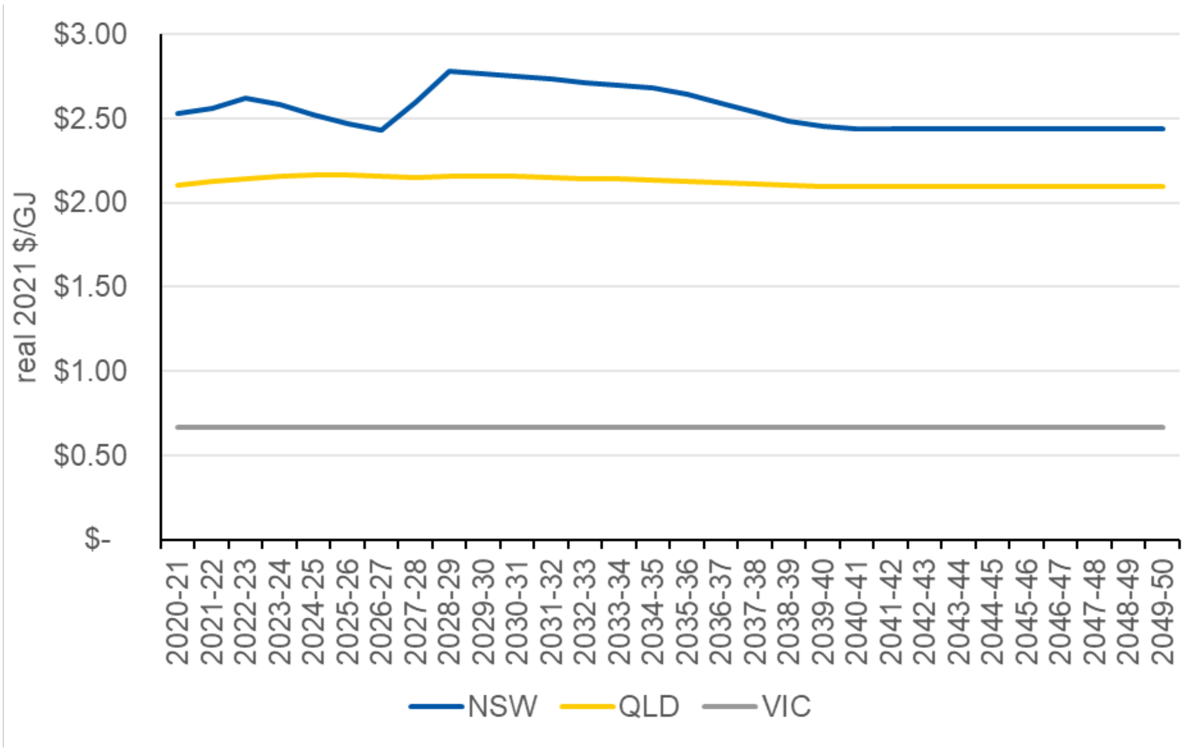
2.5. Fuel Prices

We use ISP 2022 assumptions on fuel prices in real 2021 $/GJ, as shown in Figure 2.8, Figure 2.9, and Figure 2.10 below. As can be seen from the Figures, AEMO forecasts that gas prices will rise in real terms until the mid-2030s before plateauing until the end of the modelling horizon. Coal prices remain broadly flat in Queensland and Victoria but decrease from 2030 to their level in 2020 in New South Wales.

Our first set of results covers the fiscal year 2023/24. It is likely that actual fuel prices in this year will be impacted by the global energy crisis and therefore be higher than the ISP 2022 estimate. We maintain the ISP assumptions in order to better align to the published models.

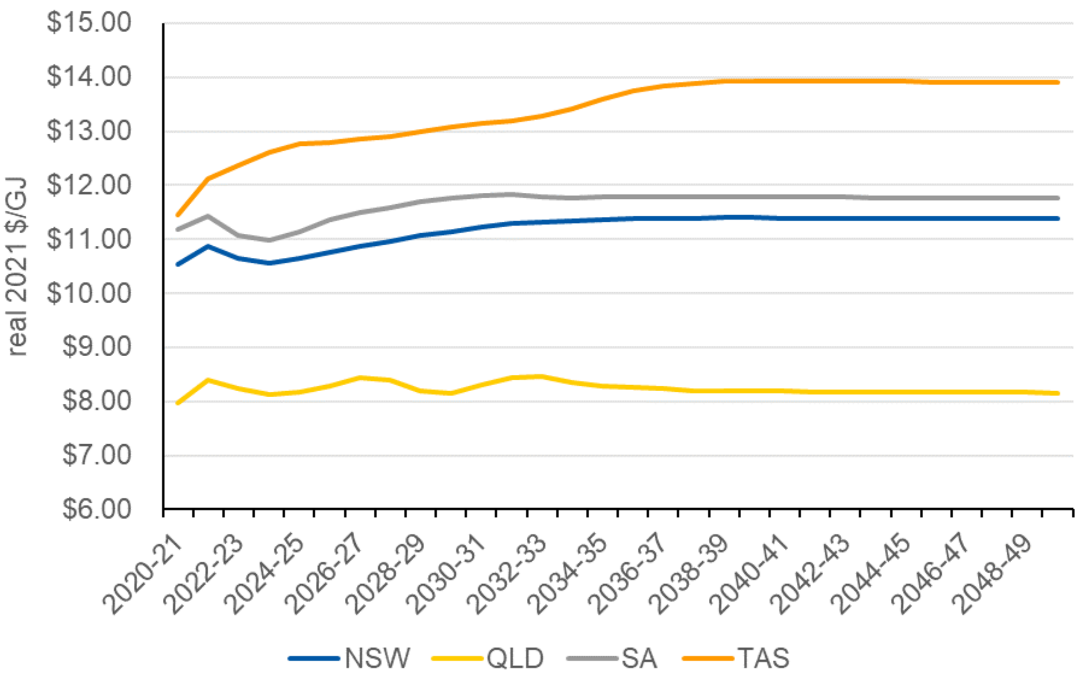
[13] A 4-hour battery is a battery that that takes 4 hours to discharge at full capacity (for instance, a 1 MW battery can generate 4 MWh with a full charge)

Figure 2.8: Average Coal Prices, Step Change Scenario



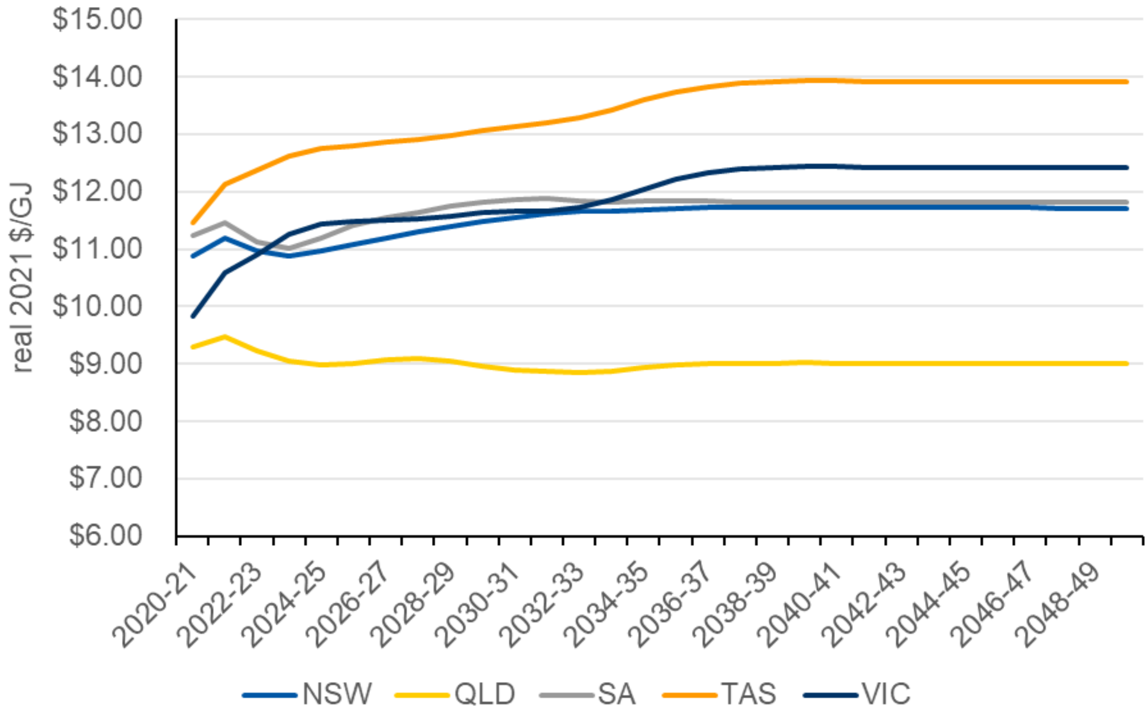
Source: AEMO (June 2022), 2022 ISP Inputs and Assumptions Workbook.

Figure 2.9: Average Gas Prices (CCGT), Step Change Scenario



Source: AEMO (June 2022), 2022 ISP Inputs and Assumptions Workbook.

Figure 2.10: Average Gas Prices (OCGT & Steam), Step Change Scenario



Source: AEMO (June 2022), 2022 ISP Inputs and Assumptions Workbook.

2.6. Main Modelling Runs and their Use in CMM/CRM Assessment

We use our PLEXOS nodal model, with the generation and transmission assumptions outlined in the previous chapters, to run short-term simulations of dispatch and pricing outcomes in the NEM. These runs serve as baseline for "status quo" outcomes in the absence of access reform and "optimal" dispatch outcomes under reform. We also use outputs from these runs to inform our calculations of the key elements of the CMM options and CRM such as differentials between regional reference prices and LMPs at each node, generator access and entitlements to redistribute congestion rent. Below we describe our two main model runs and how we used them to assess CMM/CRM options and sensitivities.

2.6.1. Our Two Main Modelling Runs: "Cost-Reflective" and "Disorderly" Bidding

We base our analysis on two main types of modelling runs, representing potential "optimal" dispatch under access reform and the current status quo of the NEM, respectively. Both runs are short-term dispatch runs in PLEXOS and assume the same capacity mix, modelled on the ISP Step Change Scenario as described in Section 2.4.2.1.

We define our first modelling run as **"cost-reflective"**, as all generators, including hydro, PHES and batteries, bid their available capacity in every half-hourly interval at a price equal to their short-run marginal cost. This is the optimal outcome that an access reform aims to achieve through efficient price signals. In the PLEXOS model this outcome is achieved by minimising the total variable cost of meeting the system demand subject to all the transmission and storage constraints.

Our **"disorderly bidding"** run, on the other hand, reflects the incentives currently present in the NEM to bid at the market floor for plants behind transmission constraints whose bids are settled at the RRP. Generators that have a marginal cost below the RRP but in an export-constrained node are overcompensated for their generation by the difference between the LMP and the RRP. In such circumstances, they have incentives to bid to the market floor price of *minus* $1,000/MWh in order to be dispatched by AEMO in preference to lower-cost plant (known as "race to the floor bidding"). Distorting bids therefore has the potential to increase system costs because AEMO selects the lowest-cost combination of plant to meet load given the bids submitted.

We identify the incentive to bid at the floor in PLEXOS through the following method:

1. **Identify Pattern of Competitive Dispatch ("Cost-Reflective" Run):** Run the "cost-reflective" run described above. In this run, generators bid their short-run marginal cost as an offer price and PLEXOS selects the cost-minimising dispatch.
2. **Identify Generators with an Incentive to Race to the Floor (Off-Model Manipulation):** From the cost-reflective run in step 1, in every half-hour of the modelling horizon we identify generators that:

   A. Had a short-run marginal cost lower than the price they would have received under regional settlement for half-hour, by more than $1/MWh;

   B. Had an LMP lower than the RRP by more than $1/MWh.

   These generators have an incentive to bid to the market floor price in order to secure priority dispatch and earn the regional reference price. This methodology by construction excludes all generators located at regional reference nodes from this set, as they would not realistically face a constraint. We also exclude all hydro, storage and PHES units from this dynamic. The reason for treating these categories of generators differently is the underlying PLEXOS dispatch logic. The dispatch of these plants in PLEXOS is determined on the basis of total system cost minimization, also considering global hydro resource availability over the annual horizon. As a result, the dispatch of these types of units in PLEXOS is not always responsive to bid prices. We are still able to observe differences in operation of these units between the cost-reflective and disorderly runs.

   The assumptions that hydro and PHES units bid their short-run marginal cost in both the cost-reflective and disorderly run also excludes the shadow value of water resources from these plants' price bid; the value of water enters the PLEXOS optimization indirectly through the formulation of water resources constraints over the medium term. In reality, hydro plants consider the shadow value of water when formulating their bid; we examine the impact of this simplification on results for hydro plants in Section 4.7.
3. **Distort Bidding and Re-run Dispatch ("Disorderly" Run):** Re-run PLEXOS such that generators identified in step 2 are constrained to bid *minus* $1,000/MWh in all half-hours where they have an incentive to race to the floor. All generators bid their SRMC in the remaining settlement periods.

We run these two types of runs for a sample year (2023-24 and 2033-34), to observe the impact of disorderly bidding over the ISP modelling horizon.

Our method does not perfectly reflect incentives to race to the floor. It assumes that generators race to the floor based on *perfect foresight* of prices in the *cost reflective run*. In practice, generators' incentives to race to the floor will be determined by *imperfect foresight* of prices that occur under the *disorderly run*. Modelling imperfect foresight is necessarily challenging and strong assumptions are necessary about what imperfections persist. Modelling the disorderly prices and multiple second-order equilibria that could exist is also not possible in a PLEXOS cost-minimising framework. As a result, we believe the above method is a reasonable approximation of likely incentives to distort dispatch.

2.6.2. Use of the "Cost-Reflective" and "Disorderly" Runs in the CMM/CRM Options

The "cost-reflective" and "disorderly" runs provide data for us to derive the key outcomes of the different CMM and CRM options considered. The table below summarises the modelling tools proposed for calculating generation, LMPs, RRPs and access parameters for each market design option: this information allows us to calculate generators' revenues and therefore distributional effects of each option.

Table 2.2: Usage of PLEXOS Runs Under Different CMM/CRM Options

Design Option	Source for Generation, LMP	Source for RRP	Source for Access Calculation
CMM – Pro-rata Access	Cost reflective bidding	Cost reflective bidding	Pro-rata Access Allocation Formula
CMM – Pro-rata Entitlement	Cost reflective bidding	Cost reflective bidding	Pro-rata Entitlement Allocation Formula
CMM – Winner-takes-all	Cost reflective bidding	Cost reflective bidding	Generation based on disorderly bidding
CMM – Inferred economic dispatch	Cost reflective bidding	Cost reflective bidding	Generation based on cost reflective bidding
RRP_{CRM} CRM	Cost reflective bidding in the CRM	Cost reflective bidding	Generation based on disorderly bidding
RRP_{NEM} CRM	Cost reflective bidding in the CRM	Disorderly bidding in the energy market	Generation based on disorderly bidding

The main group of runs described in Table 2.2 uses PLEXOS cost-reflective bidding as we assume that the CMM/CRM will incentivise plants to bid their true cost, as they are settled for congestion relief or increase under the mechanisms under consideration. We have also introduced several sensitivities for each option to explore specific circumstances, such as:

- Using disorderly bidding instead of cost-reflective as a source for dispatch outcomes, to see whether such behaviour would become unprofitable for generators under the CMM/CRM;[14]

[14] In these sensitivities we assume that all generators bid disorderly. We have not tested if an individual generator could improve profitability by bidding disorderly where other generators continue to bid cost-reflective.

- For CMM options, allocating access/entitlement excluding out-of-merit generators, to study the difference in financial outcomes for these generators with and without the mechanism;
- Accounting for an imperfect uptake of the CRM, where a subset of generators participate in the CRM.

We provide more details on the methodologies for each option and sensitivity in the following sections of this report.

3. Summary of Methodology

3.1. Overview of CMM Options

3.1.1. The CMM Logic Allocates the Congestion Rebate to Generators Based on a Calculation of Access

The CMM (Congestion Management Model) aims to address congestion in the NEM and facilitate efficient dispatch in the system. The mechanism maintains the existing pattern of dispatch set out in the NEMDE algorithm. However, it also collects an additional "congestion charge" and re-allocates a "congestion rebate" based on generators' contribution to a transmission constraint.

The congestion charge effectively ensures that a generator is settled at its LMP by creating a spread between the local value of energy and the RRP. This incentivises efficient dispatch by exposing generators to LMP at the margin. Introducing LMP would make some generators worse off than under the existing arrangements and may make generators as a whole worse off to the extent that consumers would benefit from congestion rents currently paid to generators.

ESB considers several different rebate allocation methods which we also describe in greater detail in the sections below.[15] A general CMM approach can be expressed with the following formula for the generator revenues in a trading interval:

$$\textbf{Revenue} = \textbf{A} \cdot (\textbf{RRP-LMP}) + \textbf{G} \cdot \textbf{LMP}$$

Where

- LMP is a locational marginal price;
- RRP is a regional reference price;
- A is the effective access value which is related to generator's flowgate entitlement by the constraint coefficient.[16] In the above formulation, access can be interpreted as a quantity of a financial transmission right that remunerates the generator for a difference between the RRP and LMP;[17]

  Access or entitlement are decision-variables under the design of each CMM regime. Although access may vary under the different proposed designs, each shares a common feature that they are exogenous to the level of generation and do not depend on the bids of market participants but are exogenous properties of the generators and/or network.

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15 Congestion management technical working group, Working paper for the congestion management model, 21 July 2022. https://www.datocms-assets.com/32572/1659656736-20220721_twg-working-paper-cmm-allocation-methods_final.pdf

16 The congestion rebate is shared between the generators via flowgate entitlement, which is related to access via the "constraint coefficient". Entitlement=Access * Constraint coefficient. The entitlements are allocated in such a way as to maintain the feasibility of dispatch i.e, total allocated entitlements should not exceed the flow-gate capacity. Constraint coefficients are explained in Section 3.1.2 of this report.

17 CMM in general does not guarantee access to the RRP. The effective access is the equivalent financial access that the CMM rebate delivers.

- G is the actual generation of a generator;

The ESB intends the *congestion rebate* to ensure market participants, in aggregate, are financially indifferent between existing market arrangements and the introduction of the charge and rebate mechanism, while maintaining the incentives for efficient dispatch at the margin.

3.1.2. We Calculate Rebates and Generator Revenues Under Different Methods

In this section, we consider the following alternative CMM options and describe our approach to modelling them:

- Pro-rata access;
- Pro-rata entitlement;
- Winner-takes-all; and
- Inferred economic dispatch.

For each of the CMM methods, we derive the key inputs for the CMM calculations from our half-hourly outputs of PLEXOS dispatch simulations, as explained in Table 2.2 of this report. We present the modelling results in Chapter 4.

3.1.2.1. Pro-rata access

The pro-rata access method allocates access to each generator in proportion to their available capacity in each interval. We first introduce the individual components of the access calculation:

- **Constraint coefficients** (also known as a contribution factor, participation factor or constraint factor) for a generator's node *i* and a line *j* **(α_{ij}):** these coefficients determine the generator's incidence on a particular transmission constraint. Positive coefficients (relative to the direction of flow) indicate that a generator's output increases congestion, while negative coefficients mean the generator's output is relieving congestion.

  We derive constraint coefficients from the power transfer distribution factor (PTDF) matrix extracted from our modelling runs. PTDF matrix shows the additional flow on a given line resulting from an injection of 1 MW at a node matched by a withdrawal at a single reference point (the "slack bus" for the network). For the purposes of CMM calculations, we need to rebase the PTDF matrix so that for each node, the corresponding withdrawal values refer to the corresponding regional reference node, rather than a single slack bus for the entire NEM.

  We apply the following transformation to the PTDF matrix to normalise it with respect to regional reference nodes and to calculate the constraint coefficients α:

  $$\alpha_{ij} = a_{ij} - a(R)_{ij},$$

  where a_{ij} are the elements of the PTDF matrix corresponding to node i and line j, and $a(R)_{ij}$ are the elements of the PTDF matrix corresponding to line j and the regional reference node for the region where node i is located.

Further manipulation of the data needs to be performed before the constraint coefficients can be used in CMM calculations. The coefficients need to be appropriately "oriented" to correspond to the direction of the congestion. Each line in the model has a reference direction, so if the direction of the congestion does not match the direction of the line, we "orient" the corresponding constraint coefficients by inverting their sign.[18]

- **Entitlement for constrained-on generators:** these are the generators that are called on by the dispatch engine to relieve congestion on a constraint, and therefore have a negative constraint coefficient (relative to the direction of congestion). Calculating entitlement for these generators is a policy choice. One option of the CMM implementation assigns zero entitlement to constrained-on generators. An alternative option, which we implemented in our model, is calculating the entitlement for these generators as their generation output multiplied by the constraint coefficient. $Eon_{ij}=Generation_i \cdot \alpha_{ij}$, which will be a negative number for constrained-on generators that have a positive generation. Therefore the first option pays the constrained on generator the (higher) LMP, the second option the (lower) RRP.
- **Entitlement for constrained-off generators**: these generators increase congestion on a constraint and therefore have a positive constraint coefficient. They are allocated entitlement based on their available capacity multiplied by their constraint coefficient for a given constraint and scaled by the scaling factor k, as described below.

  $Eoff_{ij} = k \cdot Availability_i \cdot \alpha_{ij}$, for the constrained off generators, the entitlement value is either a positive number or a zero.
- **Scaling factor (k):** to ensure feasibility of dispatch, some CMM methods require application of a scaling factor to the "Target entitlements" ($Availability_i \cdot \alpha_{ij}$) of constrained-off generators so that the total of actual entitlements of all generators do not exceed the capacity of a flow-gate. The scaling factor k is set so that it satisfies the following equation:

  $$\sum_i \alpha_{ij} \cdot k_j \cdot \text{Availability}_i = \text{FGX}_j$$

  Where FGX is a flow gate capacity of the constrained line, which is calculated for each period based on the physical capacity of the line and usage by unscheduled load.
- **Generators' access on a constraint (A_{ij}):** The entitlement is set equal to either the con-off or constrained-on entitlement, depending upon which is relevant. Therefore, the corresponding access is defined as either $A_{ij} = Eof_{ij}/\alpha_{ij}$ or $A_{ij} = Eon_{ij}/\alpha_{ij}$, whichever is applicable, where the numerator is the entitlement as defined above, whereas the denominator is a non-zero constraint coefficient. A generator gets zero access to a line where its corresponding constraint coefficient is zero.
- **Congestion price of each constraint (CP_j)**: we extract this value directly from PLEXOS solution related to each line. In each period, we perform the access calculation only on lines with a congestion price, i.e. when congestion arises.

18 The shadow prices of the line constraints reported by PLEXOS do not change the sign with the direction of the congestion. We infer the direction of the congestion from the difference of the LMPs reported by PLEXOS at both ends of the corresponding line.

There is a following identity that holds between the LMP_i, RRP, CP_j and $\alpha_{ij,}$ for any node and line, which explains the difference between RRP and LMP at each node with a sum of products of the constraint prices and constraint coefficients:

$$RRP\text{-}LMP_i = \Sigma_j (\alpha_{ij} \cdot CP_j).$$

Using all the components above, the effective access of a generator over all constraint is the sum of access on all individual constraints, weighted by the constraint coefficient and congestion price of each constraint:

$$\text{Effective Access}_i = (\Sigma_j \alpha_{ij} \cdot A_{ij} \cdot CP_j)/ (\Sigma_j \alpha_{ij} \cdot CP_j).$$

We calculate generator's revenue in a trading interval according to the rearranged revenue formula described above:

$$\text{Revenue} = RRP \cdot \text{Effective Access}_i + LMP \cdot (G - \text{Effective Access}_i)$$

3.1.2.2. Pro-rata entitlement

The pro-rata entitlement allocation method is based on a combination of constraint coefficients and offered availability. It allocates entitlements (Access·α) (rather than access) in proportion to availability. In practice, this method uses the same formula for access as the pro-rata access option described above in Section 3.1.2.1, with individual components defined in the same way. The key change compared to pro-rata access is that for constrained-off generators the entitlement is expressed as:

$$Eoff_{ij} = \min(\alpha_{ij}, k_j) \text{ x } \text{Availability}_i$$

Where k is again a scaling factor to ensure feasible dispatch. That is k is chosen such that

$$\sum_i \min(\alpha_{ij}, k_j) \text{ x Availability}_i = FGX_j$$

Due to non-linearities in the above equation k cannot be derived with a single formula; we therefore employ a search algorithm to derive the optimal value of k.

After calculating the constrained-on and constrained-off entitlements, where applicable, we obtain access for a particular constraint by dividing the respective entitlement by the generator's constraint coefficient to the constraint. We then calculate a generator's total allocated access and revenues as described for the pro-rata access method.

3.1.2.3. Winner-takes-all

The winner-takes-all allocation method assigns access to generators in ascending order of constraint coefficients. The generator with the lowest constraint coefficient in the constraint receives entitlements up to its full availability in the constraint; the generator with the next lowest factor then receives access, continuing until the constraint limit is met.

Where there are multiple points of congestion, the winner-takes-all CMM method operates similarly to the other CMM variants by calculating the access allocated on each binding constraint and then combining these into the "effective access" measure.

Instead of replicating this method from constraint coefficients, we approximate the calculation of access by assuming for each generator that access is equal to its dispatch outcome (i.e. generation output) under disorderly bidding. In the presence of equal bids, such as in the "race to the floor" case, PLEXOS prioritises generators with the lowest constraint coefficients. We therefore assume that the "winner-takes-all" logic of access allocation is already reflected in the generation levels in the disorderly dispatch scenario.[19]

Given that the general formula for generator revenues under CMM is

$$\text{Revenue} = \text{RRP} \cdot \text{Effective Access} + \text{LMP} \cdot (\text{G} - \text{Effective Access});$$

In our approximation of the winner-takes-all CMM approach, we replace effective access with the generation from the disorderly bidding scenario. The revised formula for generator revenues becomes:

$$\text{Revenue} = \text{RRP}_{\text{marginal\_cost}} \cdot \text{G}_{\text{disorderly}} + \text{LMP}_{\text{marginal\_cost}} \, (\text{G}_{\text{marginal\_cost}} - \text{G}_{\text{disorderly}}),$$

In the above calculation, RRP, LMP and generation dispatch are extracted from the cost-reflective run. Whereas access is based on the dispatch from the disorderly run.

As mentioned above, we also present a CMM sensitivity where we assume that the market participants continue to bid disorderly under the CMM mechanism. To simulate the outcome of this scenario, under the winner takes it all method, we use the RRPs, LMPs and dispatch from the disorderly bidding scenario and apply the following formula:

$$\text{Revenue} = \text{RRP}_{\text{disorderly}} \cdot \text{G}_{\text{disorderly}} + \text{LMP}_{\text{disorderly}} \, (\text{G}_{\text{disorderly}} - \text{G}_{\text{disorderly}}),$$

Which reduces the revenues calculation to Revenue = $\text{RRP}_{\text{disorderly}} \cdot \text{G}_{\text{disorderly}}$

3.1.2.4. Inferred economic dispatch

This CMM method allocates access on a combination of constraint coefficients and inferred marginal costs. Where there are multiple points of congestion, the inferred economic despatch CMM method first calculates the access allocated on each binding constraint and then combines these into the "effective access" measure.

The bottom-up application of this method would require calculation of the entitlement and access parameters using rankings based on constraint coefficients and marginal costs. We approximated this method of CMM by directly modelling marginal cost dispatch in PLEXOS and using the corresponding optimal generation results as estimates of access.[20] The revenue formula under this method becomes:

$$\text{Revenue} = \text{RRP}_{\text{marginal\_cost}} \cdot \text{G}_{\text{marginal\_cost}} + \text{LMP}_{\text{marginal\_cost}} \, (\text{G}_{\text{marginal\_cost}} - \text{G}_{\text{marginal\_cost}}),$$

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19 This is likely to be a good approximation to the WTA CMM method when there is a single binding constraint in a region, but may be less accurate when there are multiple binding constraints. Note also that in a "tie-break" case with equal bids, the NEMDE shares dispatch between the generators pro-rated to availability. PLEXOS, on the other hand, randomises the allocation of access rather than pro-rating; therefore in our simulation two equal bids might see one of the two generators dispatched at its full availability, and the other dispatched residually.

20 This is likely to be a good approximation to the inferred economic dispatch CMM method when there is a single binding constraint in a region, but may be less accurate when there are multiple binding constraints.

The revenue calculation therefore simplifies to

$$\text{Revenue}=\text{RRP}_{\text{marginal cost}} * \text{G}_{\text{marginal\_cost}}.$$

In the sensitivity where we assume that the market participants continue to bid disorderly under the inferred economic dispatch mechanism, we use the RRPs, LMPs and dispatch from the disorderly bidding scenario and apply the following formula:

$$\text{Revenue} = \text{RRP}_{\text{disorderly}} \cdot \text{G}_{\text{marginal\_cost}} + \text{LMP}_{\text{disorderly}} \, (\text{G}_{\text{disorderly}} - \text{G}_{\text{marginal\_cost}})$$

3.1.3. We Include a Sensitivity which Excludes Out-of-Merit Generators from the CMM Allocation

One of the policy questions for the development of the CMM is the treatment of out-of-merit (OOM) generators under each option for the mechanism. OOM generators are those whose marginal cost exceeds the RRP at a given time. The “standard” CMM methodology allocates revenue based on access, and OOM generators can be allocated access if they bid as available for dispatch.[21]

We are interested in observing the impact of CMM policies when we exclude OOM generators for the allocation of access. Following the revenue formula presented above, with access set to zero these generators would receive the LMP for their dispatched outputs (if any output is dispatched, often due to disorderly bidding).

To do so, we first calculate access for all generators based on their availabilities and constraint coefficients, following the methodology for each option as detailed in Section 3.1.2. In a following step, before calculating the payment to generators, we set access of the OOM generators to zero. As a result, these generators are settled at their respective LMPs, so they are still getting paid if they are generating.

The modelling approach quantifies the 'windfall' profits if OOM generators are included in the CMM access allocation. However, to limit modelling complexity, it does not redistribute the access allocation from OOM to in-merit generators.

If the CMM design is implemented in practice, it would be essential to ensure that in-merit generators do not lose access due to the presence of out-of-merit generators, so the CMM design envisages redistribution of access of OOM generators to in-merit generators.

3.1.4. We Account for Inconsistencies in PLEXOS Results in Remote Areas of the Network

As discussed above, our calculations of access and revenues under the various policy options relies on the reconciliation of RRP and LMP for any node *i* through the congestion prices on related constraints, following the formula:

$$\text{RRP-LMP}_i = \Sigma_j \, (\alpha_{ij} \cdot \text{CP}_j).$$

21 ESB (21 July 2022), Congestion management technical working group: Working paper for the congestion management model, p.13. Available at: https://www.datocms-assets.com/32572/1659656736-20220721_twg-working-paper-cmm-allocation-methods_final.pdf

In our analysis of the PLEXOS outcomes for 2023-24 we identify few nodes located in remote areas of the network (for instance, the Far North Queensland and Northern Queensland REZs) that experience continued instances of extremely high LMPs, at or near the system value of lost load. At the same time, we observe that the PLEXOS outputs do not assign appropriate congestion prices to the lines involving these nodes, therefore violating the equation above. If these PLEXOS outputs are used directly, access would not be allocated to the constrained-on generators in the affected nodes, as the CMM only allocates access on congested lines, and they will be settled at LMP getting extremely high revenues.[22]

We assess that this is not a genuine outcome of the CMM logic. Therefore, to avoid including this source of bias into our estimates of the impact of the proposed reforms, we identify all instances where the equation above does not hold and in those instances we replace the value of the LMP with the value inferred by the equation in the calculation of access (i.e. $LMP_i = RRP\text{-}\Sigma_j\ (\alpha_{ij} \cdot CP_j)$. This ensures the CMM does not pay generators an LMP that is higher than the RRP.[23]

In 2033-34 it becomes more complex to perform this correction as we notice that the corrected LMPs are not consistent with the pattern of dispatch. We therefore opt to maintain unadjusted LMPs to rely on dispatch outcomes for most results. In the case of the two CMM options where reconciliation of congestion prices and LMP is crucial for the calculation of revenues (pro-rata access and pro-rata entitlement) we opt to use adjusted LMPs to illustrate the impact of access on profits. We also present the impact of discrepancy between the LMPs and congestion prices as a separate "modelling discrepancy" component. We present these results in Sections 5.3 and 5.4.

3.1.5. We Do Not Include Storage in the CMM Allocation

The CMM working paper considers the policy option of not allocating a rebate to storage (pump hydro and batteries), effectively having the storage units face the LMP at their location. This might incentivise storage to charge during periods of congestion (i.e. with low LMPs at their location) and vice versa to discharge during higher price periods where there is no congestion.[24]

Note, however, that estimating incremental impact of facing LMP on the bidding behaviour of storages is not possible within our PLEXOS framework which already dispatches batteries based on a cost-minimisation logic, therefore implicitly assuming that they are bidding against LMP.[25]

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22 Given the algebra of the equation, this effect is observed in the event of negative constraint coefficients.

23 Note that we perform the modification in the context of the calculation of access – therefore this impacts generators' revenues in the CMM/CRM options, but not, for instance, the prices used in the disorderly bidding logic or the LMPs paid by storage units to charge.

24 ESB (21 July 2022), Congestion management technical working group: Working paper for the congestion management model, p.15. Available at: https://www.datocms-assets.com/32572/1659656736-20220721_twg-working-paper-cmm-allocation-methods_final.pdf

25 By "storage" here we describe items modelled as a battery in PLEXOS. As described in Chapter 2, this includes large-scale batteries and endogenously built candidate PHES. Existing and anticipated PHES is modelled as a generator with hydro properties and is therefore included in CMM rebate allocations.

Our modelling results report the RRP revenues and costs for batteries reflecting the current status quo arrangements and LMP based revenues and costs in the CMM scenarios.

In addition, we perform an off-model illustration of potential strategic operation of batteries facing the LMP at different locations in the network. We discuss in further detail and present the results of this analysis in Section 4.8.

3.1.6. Treatment of Interconnectors

As described in Chapter 2, the transmission network configuration in our nodal model follows the "Optimal Development Path" for the 2022 ISP's Step Change model.

We understand that, in practice, an interconnector enters a region's merit order with importing flows, and therefore could be considered in the allocation of access under the CMM (or CRM, described below). In this exercise, we do not include interconnectors in the access calculation due to the complexity of the modelling logic of treating an entity separate from generators in PLEXOS. We also do not treat HVDC lines (such as Basslink) as a generator/load pair and exclude it from the analysis due to the unavailability of constraint coefficients in PLEXOS reporting.

The treatment of interconnectors is relevant to the analysis of the impact of reform on the settlement residue, i.e. the difference between the amounts paid by loads (customers and storage) and the revenues earned by generation. We present the results of our analysis in Section 4.5. The allocation of access to interconnectors in the CMM leads to the remaining settlement residue (after generators have been paid the CMM congestion rebate) being allocated between interconnectors through the Inter-Regional Settlement Residue ("IRSR"). In the absence of this allocation, the aggregate level of settlement residue does not change, but it is not possible to attribute its distribution between interconnectors.

In Section 6.1, we discuss how interconnector flows in PLEXOS can occur in "counter-price" fashion, i.e. from a high-price region to a low-price region, where it is cost-efficient for the modelling engine under nodal dispatch, and how this affects modelling results compared to real dispatch in the NEM.

3.2. Overview of CRM Options

3.2.1. 100% CRM participation

As detailed by the ESB in its CRM working paper, the CRM (Congestion Relief Market) is a voluntary mechanism in which market participants can buy and sell access to revise their position after first being dispatched under the "status quo" arrangements. Prospective sellers are likely generators that participate in a constraint and are dispatched under the status quo (or loads that are not consuming), while prospective buyers are generators initially constrained off.[26]

This mechanism can be summarised as a combination of the energy market dispatch (under current arrangement) and CRM adjustments (where generators participating in the CRM receive LMP for their CRM adjustments).

[26] ESB (21 July 2022), Working paper for the congestion relief market, p.5.

Our 100% CRM participation scenario assumes that generators are assigned access to the RRP based on the initial disorderly bidding dispatch. All generators then bid marginal costs to the CRM and are re-dispatched accordingly. Within this framework, there are two possible sets of RRPs that can be used in settling the CRM design:

a) RRP_{NEM} where the RRP is taken from the energy market which is based on disorderly bidding.

b) RRP_{CRM} where the RRP is taken from the CRM which is based on cost reflective bidding

Under RRP_{NEM} settlement, the generators receive the following revenues where RRP is based on disorderly bidding in the energy market:

$$\text{Revenue} = RRP_{disorderly} \cdot G_{disorderly} + LMP_{marginal\_cost}\,(G_{marginal\_cost} - G_{disorderly}),$$

Under RRP_{CRM} settlement, the generators revenues are determined using the following formula where the RRP is based on the CRM.

$$\text{Revenue} = RRP_{marginal\ cost} \cdot G_{disorderly} + LMP_{marginal\_cost}\,(G_{marginal\_cost} - G_{disorderly}),$$

We can see that this formulation is functionally analogous to the winner-takes-all case described above.

We understand that RRP_{NEM} is the RRP calculation originally proposed by the Clean Energy Council as the first dispatch resembles the current operation of the NEM more closely. We have applied RRP_{NEM} as the default RRP calculation for the CRM scenarios, and applied RRP_{CRM} as a sensitivity.

3.2.2. We Estimate a Sensitivity with Partial Participation in the CRM

Participation in the CRM is voluntary, we are therefore interested in assessing the impact of different levels of participation on reform outcomes.

We need to apply some assumptions as to which participants are less likely to participate in the CRM. After interaction with the ESB and stakeholders, we understand that renewable generators could be more likely to not participate in the CRM if their contract arrangements are based on metered output. Based on existing commercial models, wind and solar PV generators might prefer to be settled exclusively at the RRP rather than amend their bidding strategy. Fossil fuel generators are often at the margin and would be more likely to revise their bidding strategy and opt in to the CRM.

We design a partial participation scenario based on the ranking of incremental profits that generators are likely to receive if they all participated in the CRM, compared to not participating. We compare the derived profits of the CRM (RRP_{NEM}) with full participation and the disorderly status quo (i.e. a scenario with no participation in the CRM) for all generators that engage in disorderly bidding in the disorderly status quo. We expect generators with high profits under the CRM to continue to opt-in, while those with lower profit differences relative to the status quo might not participate in the CRM and continue to earn the status quo profits.

The selection of non-participants only considers plants that engage in disorderly bidding at least once in the disorderly status quo. Hydro plants are excluded from our disorderly bidding logic, and are automatically assumed to opt into the CRM.

We then rank the generators engaging in disorderly bidding by their profit differential. The highest positive difference between the CRM and the status quo being highest in ranking, indicates the plant most likely to participate in the CRM. We select highest ranking generators for participation until we reach 50 per cent of total wind and solar generation (based on annual generation output).[27] The remaining generation does not participate. The comparison of profits does not assume that opting into the CRM would be loss-making for generators ranked "low" in our ranking. The comparison assumes that all generators collectively participate or do not participate; in practice, the decision is individual for each participant and the equilibrium results in reality would differ.

Our methodology allows non-renewable plants to participate in the CRM as we rank all generators by their profit differential. We follow the ranking until the selection contains enough participating renewables to meet the 50 per cent threshold. If thermal plants are ranked higher than the selected renewables, they also participate in the CRM. In 2023-24, while by construction 50 per cent of renewable generation participate, more than 99 per cent of fossil fuel generators also participate, as shown in the table below.

Table 3.1: Summary of Opt-In by Technology – RRP_{NEM} CRM (2023-24)

Technology Type	Opt-in Share (% of technology generation)[28]	Opt-in Share (% of total generation – gen. + storage)[29]
Renewables (Wind, Solar)	49.9%	13.5%
Hydro	100.0%	9.4%
Fossil Fuels (Coal, Gas, Liquids)	99.8%	62.3%
Storage (Pump Hydro, Large scale battery)	100.0%	1.2%
Total Opt-In	**-**	**86.4%**

Source: NERA analysis.

The opt-in pattern for thermal changes in 2033-34. In this fiscal year, more thermal generators are not participating in the voluntary CRM based on their ranking. The overall opt-in share of total generation therefore declines, as shown in Table 3.2. However, 50 per cent of renewable generation opting in now amounts to 35.4 per cent of total generation, as more renewable capacity enters the system by 2033-34.

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27 The total generation figure includes renewable plants that never engage in disorderly bidding, which as assumed to opt in as stated above.

28 Renewables 49.9 per cent opt-in share indicates that 49.9 per cent of renewable generation opts in and the remaining 50.1 per cent of renewable generation opts out. Fossil fuels 99.8 per cent opt-in indicates that 99.8 per cent of fossil fuel generation opts in and the remaining 0.2 per cent of fossil fuel generation opts out.

29 Renewables 13.5 per cent opt-in share indicates that 13.5 per cent of generation comes from opt-in renewable generators. Hydro 9.4 per cent opt-in share indicates that 9.4 per cent of generation comes from opt-in hydro generators (not pump units). The total 86.4 opt-in indicates that 86.4 per cent of generation comes from opt-in generators and the remaining 13.6 per cent is generation coming from NEM participants that retained their energy market dispatch (did not participate in the CRM).

Table 3.2: Summary of Opt-in by Technology – RRP_{NEM} CRM (2033-34)

Technology Type	Opt-in Share (% of technology generation)	Opt-in Share (% of total generation – gen. + storage)
Renewables (Wind, Solar)	50.0%	35.4%
Hydro	100.0%	5.1%
Thermal (Coal, Gas, Liquids)	37.8%	5.9%
Storage	100.0%	9.8%
Total Opt-In	**-**	**56.1%**

Source: NERA analysis.

Once the participants and non-participants are selected, we need to "fix" the status quo disorderly dispatch outcome for non-participating generators (as per the energy market dispatch) and redispatch the rest based on the marginal cost bidding (in the CRM). We fix the half-hourly quantity bid of non-participants in PLEXOS at their dispatch level achieved under the disorderly status quo. Their price bid is the same as in the disorderly status quo bidding, i.e. either equal to their marginal cost or to the floor in the same periods as the floor bids in the status quo. The opt-in plants are free to bid cost-reflectively based on their full availability in any interval.

Our procedure ensures that the dispatch outcomes for non-participants are as close as possible to their outcomes under the disorderly status quo.[30] However, fixing the output and price offered by generators at half-hourly level places a heavy constraint on the PLEXOS simulation. This can lead to counter-intuitive outcomes such as higher system cost under 50 per cent CRM participation than under the disorderly status quo (i.e. 0 per cent participation and the lowest amount of cost-reflective bids) as PLEXOS has limited degrees of freedom for minimising costs across the system.

In cases where there is no feasible way to redispatch in a way that achieves a lower cost outcome, the CRM would leave the original dispatch unchanged as it would be the least cost outcome. To estimate the costs of partial participation CRM, we use the following method:

- We compare the daily total system costs of the status quo disorderly dispatch and the 50 per cent participation dispatch.[31] We perform the comparison on a daily basis because PLEXOS optimises short-term operation in daily steps; using daily results ensures consistency of outcomes within the simulation step;
- Among the two simulation options, for each day we choose the one with the lowest costs.

We present and discuss key results under this method in Section 4.6.

30 On average, the difference between generation output in the status quo disorderly run and the CRM run with partial participation for those plant choosing to not participate in the CRM is within -2%. The negative difference is due to the capped offer quantities; plants can in theory be dispatched less than in the status quo, but not more as their offer in every interval is capped at the level of status quo dispatch.

31 We use daily cost comparisons to remain consistent with the PLEXOS dispatch optimisation horizon. PLEXOS optimises dispatch in daily steps which also involve intertemporal optimisation of storages. Choosing lower cost half-hours within a day from two different model runs would result in inconsistent usage of storage resources.

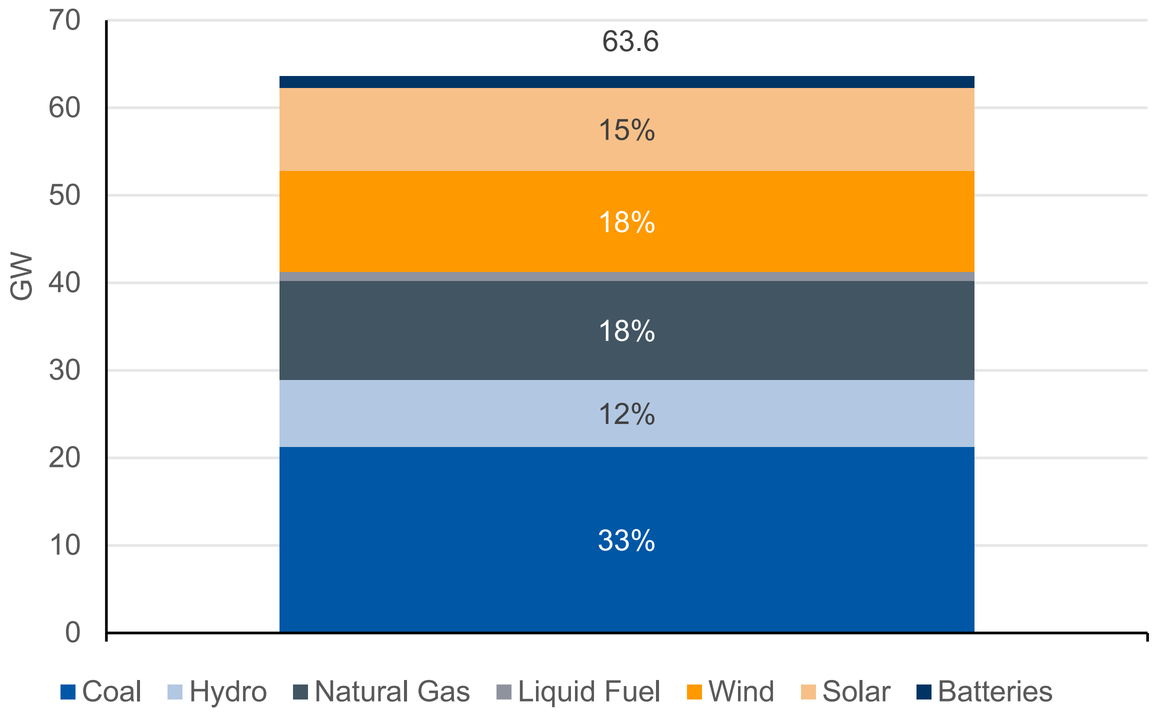
4. Main Results for the 2023-24 Fiscal Year

4.1. In 2023-24, Coal is the Main Contributor to the Generation Mix

The PLEXOS 2023-24 run uses the generation capacity in Figure 4.1. The generation output is presented in Figure 4.2.

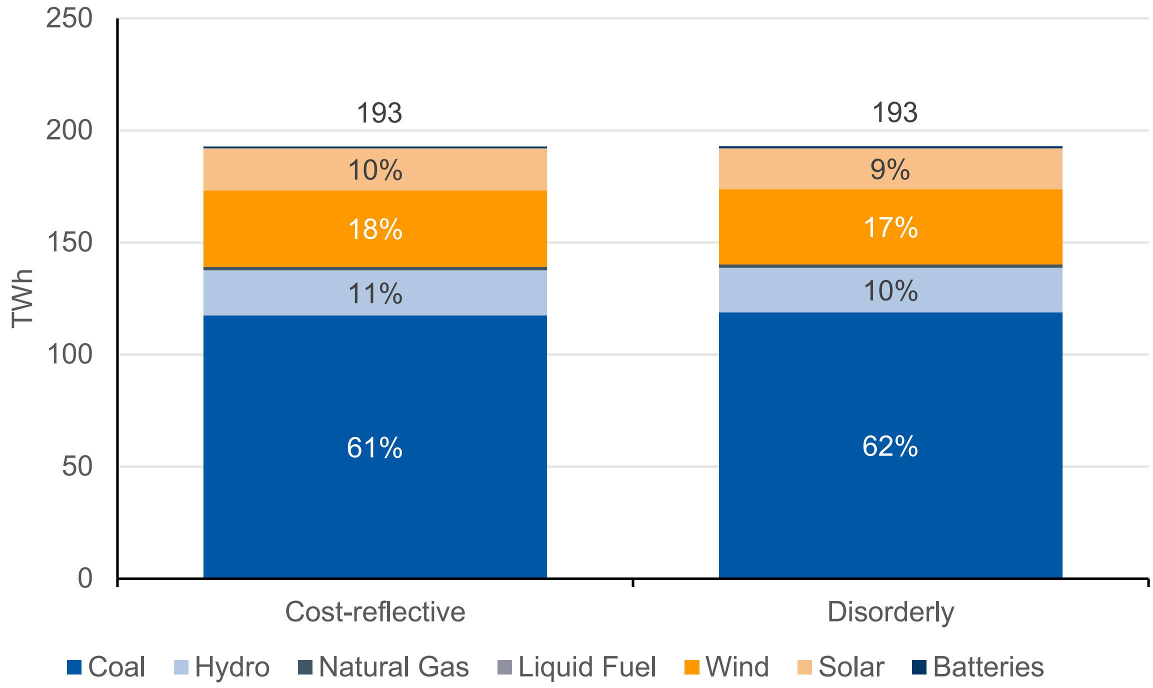
We can see that in this fiscal year coal still plays a key role in the system, as it constitutes a third of capacity installed and over 60 per cent of energy generated in both the cost-reflective and disorderly run. Zero marginal cost renewables (wind and solar) account for another third of capacity but only for approximately 30 per cent of generation in both the cost-reflective and disorderly modelling run. However, most of the coal capacity is set to retire in the years following 2023-24; we discuss how the capacity mix changes in future years in Chapter 5.

Figure 4.1: Generation Capacity in 2023-24, Cost-Reflective and Disorderly Case (GW)



Source: NERA analysis of PLEXOS inputs.

Figure 4.2: Generation Mix in the 2023-24 run, Cost-Reflective v. Disorderly Case (TWh)



Source: NERA analysis of PLEXOS outputs.

Table 4.1 presents an overview of congested lines in the cost-reflective and disorderly run. We can observe that, out of almost 2,000 lines represented in our model, only 20 experience any congestion across the cost-reflective and disorderly scenario in 2023-24. Congestion is particularly pronounced near regional boundaries, and especially at the border between NSW and QLD (e.g. near the "N2" New England REZ) and between NSW and VIC. We discuss the impact of this congestion on prices and outcomes for market participants in the coming sections. We include a visual map of the REZs in Appendix C, to reconcile REZ codes and their location within the NEM.

Table 4.1: Overview of Congested Lines and Congestion Prices, Cost Reflective v. Disorderly Run

			Cost-Reflective				Disorderly			
	Region, REZ		Number Periods Congested		Avg. Congestion Price ($/MWh)		Number Periods Congested		Avg. Congestion Price ($/MWh)	
Line (Node 1-Node 2)	**Node 1**	**Node 2**	**Flow**	**Flow Back**	**Flow**	**Flow Back**	**Flow**	**Flow Back**	**Flow**	**Flow Back**
Tumut1/2-Murray	NSW, N7	VIC, N7	303	4,761	3.10	21.82	476	3,899	7.32	19.61
Darlington Point-Wagga Wagga	NSW, N5	NSW, N6	2,195	114	18.71	0.00	2,194	98	708.88	0.00
Heywood-South East (Mount Gambier)	VIC, V4	SA, S1	1,166	525	10.85	0.00	1,020	444	9.03	0.00
Tailem Bend-Tungkillo	SA, S1	SA, S3	347	438	0.00	8.18	366	405	0.04	10.53
Woolooga-Palmwoods	QLD, Q7	QLD, Non-REZ	74	2	9.08	0.00	524	3	2,303	0.00
Dederang-Wodonga	VIC, V1	VIC, Non-REZ	7	4	1.27	20.43	21	336	23.36	123.87
Bayswater-Lake Liddell	NSW, N0	NSW, N0	297	6	3.54	0.00	166	8	4.38	0.00
Armidale-Tamworth	NSW, N2	NSW, Non-REZ	160	46	8.17	3.50	79	9	12.83	1.35
Dederang-Murray	VIC, V1	VIC, N7	5	80	0.00	72.52	6	80	1.97	54.96
Dederang-South Morang	VIC, V1	VIC, Non-REZ	28	-	87.51	-	25	55	78.11	11.58
Collector Windfarm-Marulan	NSW, Non-REZ	NSW, Non-REZ	67	6	9.70	0.00	57	2	6.20	0.00
Davenport-Olympic Dam West	SA, S5	SA, S7	37	-	100,000	-	37	-	100,000	-
Tumut3-Yass	NSW, N7	NSW, Non-REZ	19	1	9.24	0.00	16	3	6.26	0.03
Bannaby-Sydney West	NSW, Non-REZ	NSW, Non-REZ	21	-	91.56	-	4	-	46.25	-
Canowie-Robertstown	SA, S3	SA, S3	1	1	0.00	0.00	-	3	-	0.51
Para Reservoir (Gould Creek)-Templers West	SA, S3	SA, S3	-	1	-	0.00	-	3	-	806.37
Marulan-Yass	NSW, Non-REZ	NSW, Non-REZ	-	4	-	3.61	-	2	-	3.86
Tumut3-Murray	NSW, N7	VIC, N7	-	-	-	-	-	1	-	1.01
Canberra-Yass	NSW, Non-REZ	NSW, Non-REZ	-	1	-	0.00	-	-	-	-
Yallah-Kangaroo Valley	NSW, Non-REZ	NSW, Non-REZ	-	5	-	5.95	-	-	-	-

Source: NERA analysis of PLEXOS outputs

4.2. Cost-Reflective Bidding Achieves Lower System Costs than Disorderly Bidding

The table below displays system cost outcomes for the two “status quo” PLEXOS runs, one where generators bid their marginal costs and one where some generators distort their bids to the market floor ($ -1,000/MWh) when their LMP and marginal cost are below the RRP. The calculation includes total system costs of generators and storages (mainly fuel costs and variable O&M costs). We discuss the costs incurred by batteries and storages to charge later in Section 4.5.

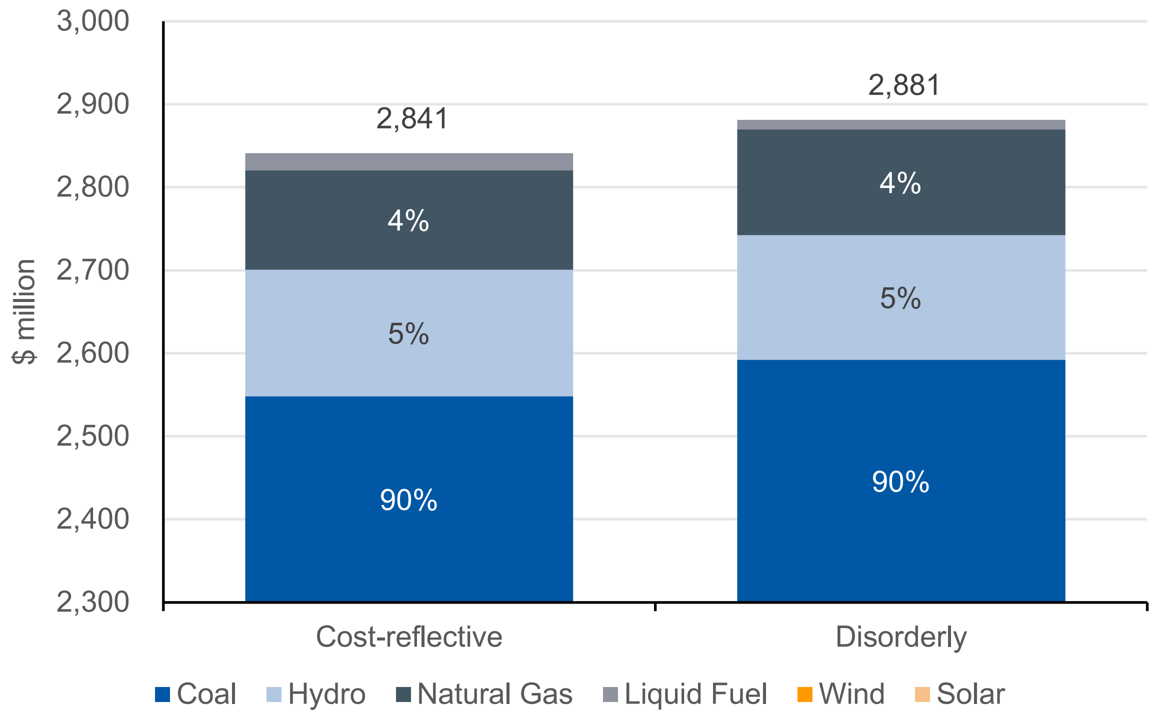
Table 4.2: System Costs Modelled, Cost-Reflective v. Disorderly case ($m)

Model Run	Generation Cost
Cost-Reflective	2,841
Disorderly	2,881
Difference (Cost-Reflective - Disorderly)	-40
	(-1.4%)

Source: NERA analysis of PLEXOS outputs

Figure 4.3 shows the cost breakdown in Table 4.2 by technology.

Figure 4.3: System Costs Modelled by Technology, Cost-Reflective v. Disorderly case (£m)



Source: NERA analysis of PLEXOS outputs. Note: the left axis starts at $2,300 million.

In aggregate, we see that cost-reflective bidding achieves a more cost-efficient outcome compared to the disorderly status quo scenario. System costs decline by around $40 million (-1.4 per cent). The reduced costs illustrate the increased efficiency of dispatch in the cost-reflective case, where bids allow the system operator to identify the least-cost available plants.

Our modelling results also depend on assumptions we draw to represent the operation of the system, for instance on the distribution of nodal demand and the frequency of binding constraints in the network. We also assume that generators bid the market floor whenever our logic detailed in Chapter 3 indicates they have the incentive to do so. Under the status quo arrangements in the NEM, AEMO clamps interconnectors when counter-price flows become excessively large. The criteria used by AEMO are not transparently and easily modelled in PLEXOS. As a result, our modelling does not clamp the interconnectors in the case of counter-price flows. Moreover, for simplicity, we do not model certain real-world bidding behaviours such as strategic bidding choices. We elaborate further on the potential impact of such assumptions in Chapter 6.

4.3. Under the CMM, Revenues Decline Compared to the Status Quo

We calculate total revenues, costs and profits for all our modelled scenarios. As explained in Table 2.2, we use PLEXOS outputs from the disorderly bidding run to derive revenues, costs and profits for the status quo scenario and for the CRM energy market related parameters, whereas for all other scenarios reported in this section, we use the marginal cost bidding run. We discuss further sensitivities in Appendix A.

In a mesh network, nodal prices reflect the relative costs of backing off generation at export constrained locations on the grid in favour of less constrained locations. When generators bid disorderly, the perceived costs of constraints on the system increase and our modelling suggests that RRPs are higher on average in the larger regions where most generation occurs, as seen below in Table 4.3.

Table 4.3: Overview of RRPs per region ($/MWh)

	Time-Weighted RRPs		Load-Weighted RRPs		Gen.-Weighted RRPs	
Region	**Cost-Ref.**	**Disorderly**	**Cost-Ref.**	**Disorderly**	**Cost-Ref.**	**Disorderly**
NSW	26.05	27.28	27.85	29.13	27.07	28.50
QLD	24.95	25.29	26,67	27.94	26.68	27.90
SA	25.95	24.27	31.11	31.24	25.56	25.91
TAS	20.45	19.55	20.53	19,86	19.72	19.23
VIC	24.22	22.42	26.48	25.44	25.68	25.16
NEM avg.	24.91	24.99	27.08	27.74	26.03	26.71

Source: NERA analysis of PLEXOS outputs.

Load-weighted RRPs determine the amount paid by customers for energy. We review outcomes for the status quo and the reform options in Section 4.5. Generation-weighted RRPs, on the other hand, determine generators' and storages' revenues under status quo arrangements. Load-weighted RRPs and generation-weighted RRPs are different because a region can be a net exporter of electricity during a given half-hourly period, i.e. the regional demand is fulfilled by generators located in other region(s) that send their electricity via interconnectors. However, this interpretation of load and generation-weighted average RRPs is limited to counter-price flows between the regions (see Section 6.1).

Under the status quo and RRP_{NEM} CRM, generators are paid disorderly RRPs for their generation; under the CMM, they earn the cost-reflective RRPs on their access.

Under the CMM, all generators earn the RRP on their access and LMP on their incremental generation above (or pay LMP for generation below) their access. In principle, revenues may be lower or higher following the introduction of the CMM because generation-weighted RRPs may increase (as shown for Victoria and Tasmania in Table 4.3 above) or decrease (as shown for New South Wales, Queensland and South Australia) under cost reflective bidding. Moreover, total generator revenues will also tend to be higher under the CMM wherever generators systematically generate more than their access at high priced nodes and less than their access at low priced nodes.

As an empirical matter, profits tend to be lower under the CMM under most of the mechanism designs studied. Table 4.4 presents revenues, costs and profits for all the cost-reflective scenarios. We also show a comparison with the disorderly status quo, as this scenario represents our approximation of the operation of the NEM under current arrangements.

Table 4.4: Overview of Revenues, Costs and Profits by Cost-Reflective Scenarios ($m)

Scenario	Model Run	Total Revenues	Total Costs	Profits (Rev. - Costs)	Profit diff. with Status quo disorderly	
Status Quo	Disorderly	4,924	2,900	2,025	-	-
CMM Scenarios						
Pro-Rata Access	Cost-Reflective	4,815	2,866	1,949	-76.2	-3.8%
Pro-Rata Entitlement		4,815	2,866	1,948	-76.5	-3.8%
Winner-Takes-All		4,796	2,866	1,930	-95.0	-4.7%
Inferred Economic Dispatch		4,793	2,866	1,927	-98.2	-4.9%
CRM scenarios						
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	4,796	2,866	1,930	-95.0	-4.7%
RRP_{NEM} - 100% opt-in		4,904	2,866	2,038	13.4	0.7%

Source: NERA analysis of PLEXOS outputs

As shown in the table above, most scenarios are less profitable for generators and batteries by around 4-5 per cent. Only the CRM scenario with RRP from the energy market (RRP_{NEM}) is narrowly more profitable than the status quo.

In our current methodology for access allocation, detailed in Section 3.1.2, constrained-on generators (i.e. those whose LMP is higher than the RRP) effectively receive access equal to their generation and therefore earn the RRP, rather than being exposed to the LMP. If an alternative policy design opted to allow these generators to earn the LMP, they would receive additional revenues amounting in total to \$3.6 million, calculated as the sum of all generation in constrained-on periods, multiplied by the difference between LMP and RRP in the period.

On the other hand, in Table 4.5 we present the same results for the cost-reflective CMM sensitivity where OOM generators do not get access (see below in Table 4.5). In these scenarios, costs remain unchanged compared to the scenarios where OOM generators get access (Table 4.4).

Table 4.5: Overview of Revenues, Costs and Profits by Cost-Reflective Scenarios with OOM Generators Excluded from RRP Access Allocation (\$m)

Scenario	Model Run	Total Revenues	Total Costs	Profits (Rev. - Costs) + diff. w/default case	Profit diff. with Status quo disorderly	
Status Quo	Disorderly	4,924	2,900	2,025	-	-
CMM Scenarios						
Pro-Rata Access	Cost-Reflective excl. OOM	4,807	2,866	1,941 (-8)	-84.3	-4.2%
Pro-Rata Entitlement		4,806	2,866	1,940 (-8)	-84.8	-4.2%
Winner-Takes-All		4,796	2,866	1,930 (0)	-95.0	-4.7%
Inferred Economic Dispatch		4,793	2,866	1,927 (0)	-98.2	-4.9%

Source: NERA analysis of PLEXOS outputs. The difference with the default case refers to the results in Table 4.3 above.

In the pro-rata access and pro-rata entitlement scenarios revenues are lower than the cases giving access to OOM generators, both by \$8 million. This result represents the “windfall” from not allocating access to generators in constrained-off areas. In the default pro-rata options presented in Table 4.4, OOM generators earn the difference between the RRP and their LMP on the access allocated, despite not being dispatched.

The revenues in the winner-takes-all and inferred economic dispatch options remain broadly unchanged under this sensitivity. In the case of inferred economic dispatch, OOM generators are not dispatched in the “default” case and therefore do not receive access– their cost is above the RRP, and therefore the dispatch is not economic. In the case of winner-takes-all, our modelling approximates access with disorderly dispatch. OOM generators do not bid the floor in the status quo as per our modelled disorderly bidding logic (which requires the generator’s marginal cost to be below RRP by more than \$1/MWh for disorderly bidding to occur). They therefore usually do not get dispatched and do not receive access under the winner-takes-all “default” option.[32]

[32] An exception to this general rule is when OOM generators have must-run assumptions or are constrained on under disorderly dispatch (that is, their LMP is above their marginal cost, which in turn is higher than the RRP). In our system, only coal and few gas plants have must-run constraints. In 2023-24 the instances of OOM generators being dispatched under disorderly bidding are rare enough that the difference in profitability between the default option and

4.4. The Change in Access Explains the Difference in Profit Change Across the CMM and CRM scenarios

To further understand the drivers of the change in profitability between the various reform options and the status quo, we break down the profit difference with the status quo disorderly scenario into three components:

- The profit change due to change in dispatch ("DE"). The effect of change in dispatch can be interpreted as the "efficiency dividend" from improved generation patterns. It is calculated as a product of the difference in generation between CMM/CRM scenarios and the status quo disorderly scenario, and the difference between LMP and the marginal cost. If a more cost-efficient plant is dispatched at a node under cost-reflective bidding, it can increase its revenue relative to the status quo due to increased generation and the differential between its marginal cost and the LMP.[33]

$$DE = (LMP_{CMM,CRM} - \text{Marginal Cost}\ \ ) \times (Gen_{CMM,CRM} - Gen_{SQ\ disorderly})$$

- The profit change due to change in RRP ("DP"). The effect of change in RRP on profit change is calculated as a product of the difference in RRP between CMM/CRM scenarios and the status quo disorderly and the generation of the status quo disorderly scenario. This values the impact of the change in RRP on revenues while keeping generation constant. The CRM scenario with RRP_{NEM} uses disorderly RRPs in the calculation of revenue and therefore has a DP of zero.

$$DP = (RRP_{CMM,CRM} - RRP_{SQ\ disorderly})\ \times Generation_{SQ\ disorderly}$$

- The profit change due to change in access ("DA"). The effect of a change in access on the profit change is calculated as a product of a) the difference between access in the CMM/CRM scenarios and generation in the status quo "disorderly" scenario (i.e. access to the RRP in the status quo) and b) the difference between RRP in CMM/CRM scenarios and the LMP in the CMM/CRM scenario. This component will be zero for the winner-takes-all and CRM options, as access under these options is equivalent to status quo dispatch.

$$DA = (RRP_{CMM,CRM} - LMP_{CMM,CRM}) \times (Access_{CMM,CRM} - Generation_{SQ\ disorderly})$$

The three components combined give the total profit differential between the policy options considered and the status quo.

Table 4.6 presents the break-down for cost-reflective scenarios (treating OOM in the same way as other generators).

the option where OOM generators are excluded from access is below $1 million. In 2033-34, where gas plays a larger role, the difference is more noticeable (see Chapter 5).

[33] Conversely, when a more expensive generator is dispatched under disorderly bidding where it would not be under cost-reflective bidding, its LMP is below its marginal cost; therefore its costs decrease more than its revenues and its profits increase, resulting in a positive DE component.

Table 4.6: Decomposition of the Profit Change by Cost-Reflective Reform Option ($m)

Scenario	Model Run	DE	DA	Profit Change	DP	Total Profit Change
CMM Scenarios						
Pro-Rata Access	Cost-Reflective	13.4	18.8	32.2	-108.4	-76.2
Pro-Rata Entitlement		13.4	18.5	31.9	-108.4	-76.5
Winner-Takes-All		13.4	-	13.4	-108.4	-95.0
Inferred Economic Dispatch		13.4	-3.2	10.2	-108.4	-98.2
CRM scenarios						
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	13.4	-	13.4	-108.4	-95.0
RRP_{NEM} - 100% opt-in		13.4	-	13.4	-	13.4

Source: NERA analysis of PLEXOS outputs.

The effect of change in dispatch on profit change is identical across all cost-reflective CMM and CRM scenarios, as they rely on the same cost-reflective dispatch pattern. The profits increase by $13.4 million compared to Status Quo disorderly scenario, which is equal to the total difference in profits between the RRP_{NEM} CRM scenario and the status quo (given that the only difference between these two scenarios is dispatch). This shows the presence of a small "efficiency dividend" due to more efficient dispatch. The increase in profits is smaller than the decrease in costs shown in Table 4.2 – the remaining reduction in cost savings is passed on to customers.

The effect of change in RRP on profit change is identical across all cost-reflective CMM and CRM scenarios (i.e. all except the RRP_{NEM} CRM scenario), as they all use the same RRPs from the cost-reflective run. The profits decrease by $108.4 million compared to the status quo disorderly scenario. This is due to RRPs being overall lower in the areas of the NEM with the most generation – we discuss the distribution of this result across areas and technologies more in detail in Section 4.7.

The effect of change in access on profit change is similar in the pro-rata access and pro-rata entitlement scenarios, respectively an increase in $18.8 million and $18.5 million. The inferred economic dispatch scenario sees a decrease in profit from the change in access compared to the status quo disorderly scenario.

4.5. The Settlement Residue at the NEM Level Increases Under Reform

In this section we provide the summary of the settlement residue calculation for the NEM under the status quo and reform scenarios.

Our calculation of the settlement residue consists of the following components:

a. payments by unscheduled customer load; plus

b. charging costs of storages; minus

c. payments to generators and storages;

We already discussed the changes in revenues relative to the status quo in the section above. We calculate the customer payments as the sum of customer load valued at the RRP in each region. We value the charging load for batteries and pumped storages, as discussed in Section 3.1.4, at RRP in the status quo case, and at LMP in CMM and CRM reform options.

As is the case with costs, customer payments depend on load weighted RRPs and not on the CMM allocation method; therefore customer payment outcomes are constant across scenarios that use the same dispatch run.

Table 4.7 presents the settlement residue calculation by scenario for the NEM.

Table 4.7: NEM-Wide Settlement Residue by Reform Option ($m)

Scenario	Cust. Payment	Storage Cost to charge	Gen. Revenue	Batt. Revenue	NEM SR
	[1]	[2]	[3]	[4]	[5]=[1]+[2]-[3]-[4]
Status Quo Disorderly	4,995	18.2	4,899	25.4	89
Status Quo Cost-Reflective	4,897	25.2	4,766	27.1	129
CMM scenarios					
Pro-rata Access	4,897	25.1	4,788	27.1	107
Pro-rata Entitlement	4,897	25.1	4,787	27.1	107
Winner-Takes-All	4,897	25.1	4,769	27.1	126
Inferred Economic Dispatch	4,897	25.1	4,766	27.1	129
CRM scenarios					
RRP_{CRM} - 100% opt-in	4,897	25.1	4,769	27.1	126
RRP_{NEM} - 100% opt-in	4,995	25.1	4,877	27.1	116

Source: NERA analysis of PLEXOS outputs.

If participants bid cost reflectively into the energy market ($RRP_{cost\ reflective}$), then customers pay $98 million less compared to the status quo.

In the case of the CRM, the RRP_{CRM} scenario uses both customer load and RRPs from the cost-reflective run, therefore the customer costs are in line with those of the CMM options. The RRP_{NEM} scenario, on the other hand, uses customer load from the cost-reflective run and RRPs from the disorderly run, in accordance with the allocation mechanism in this scenario. Therefore the customer cost is in line with the status quo disorderly scenario.[34]

Overall, the reduced revenues for generators under the reform compared to the status quo outweigh the reduction of the customer payments in the CMM options, in the RRP_{CRM} and

[34] This occurs because customer load is the same in disorderly and cost-reflective results, as customer demand in the system is unchanged in the two cases – unlike battery or pump storage operation. Therefore the CRM (RRP_{NEM}) option using load from the cost-reflective run has the same level of customer payments as the disorderly status quo.

RRP_{NEM} scenarios, resulting in an increase in the settlement residue compared to the status quo.

Table 4.8: NEM-Wide Settlement Residue by Scenario with OOM Generators settled at LMP ($m)

Scenario	Cust. Payment	Storage Cost to charge	Gen. Revenue	Batt. Revenue	NEM SR
Status Quo Disorderly	4,995	18.2	4,899	25.4	89
CMM scenarios					
Pro-rata Access	4,897	25.1	4,780	27.1	115 (+8)
Pro-rata Entitlement	4,897	25.1	4,779	27.1	116 (+8.3)
Winner-Takes-All	4,897	25.1	4,769	27.1	126 (0)
Inferred Economic Dispatch	4,897	25.1	4,766	27.1	129 (0)

Source: NERA analysis of PLEXOS outputs.

In CMM scenarios where OOM generators do not get access (Table 4.8), the customers payments remain unchanged compared to the scenarios where they get access, shown above in Table 4.7, because dipatch remains unchanged. However, the change in revenue allocation as seen in Table 4.5 results in an increase of the net settlement revenue in pro-rata access and pro-rata entitlement scenarios, i.e. $115 and $116 million respectively (Table 4.8) when excluding OOM generators and $107 million when OOM generators are given access.[35] The settlement for winner-takes-all and inferred economic dispatch is unchanged, as OOM generators do not receive access by default, as discussed above.

4.6. Partial CRM Participation Reduces Dispatch Costs

As described in Chapter 3, the CRM as proposed is a mechanism with voluntary participation. Therefore, in addition to the main results, we estimate the impact of the CRM on market participants assuming partial participation. We have detailed our methodology for selecting opt-in plants in Chapter 3.

For this sensitivity, we assume that the RRP is based on the energy market (RRP_{NEM}) where there is disorderly bidding (i.e. RRP_{NEM} = RRP $_{disorderly}$). We have also described the approximation we adopt to estimate the system costs of the partial participation scenario.

Table 4.9 presents the cost outcomes for the whole NEM.

35 This is due to our method of modelling the OOM sensitivity, where we allocate access to all generators then set the access for OOM generators to zero. This leads to the “lost” revenues for OOM generators under the sensitivity excluding them from access feeds into the settlement residue. Another method would be to redistribute the access from OOM generators to other generators/interconnectors, which would not impact the settlement residue.

Table 4.9: Generation Costs by Level of CRM Opt-In ($m)

	0% opt in (SQ Disorderly)	Partial opt-in	100% opt-in
Generation Costs	2,881	2,851	2,841
Diff. w/ SQ Disorderly	-	-31	-40
	-	(-1.1%)	(-1.4%)

Source: NERA analysis of PLEXOS outputs

Our results suggest that partial participation in the CRM is already conducive to more efficient cost outcomes compared to the disorderly status quo.

On the other hand, we expect any modelling result of partial participation to be heavily reliant on which set of generators is expected to opt into the mechanism. We adopt a selection method based on relative profits in order to reflect the financial incentive for generators; under our current methodology, renewable generators almost exclusively represent the non-participants. As we assume almost all other technologies (including large thermal plants) to bid cost reflectively, our partial participation scenario is by design closer to full participation than to full disorderly bidding. A scenario with more expensive technology not participating in the CRM and therefore also receiving the same outcomes as the disorderly status quo might show increased costs and/or revenues for the partial participation case.

4.7. The Reform Options Considered Create "Winners" and "Losers" Among Different Technologies and Locations

4.7.1. We Review Profit Differentials by Plant Across REZs

The series of figures below reviews the distribution of profits by node and technology, organised by location and compared to the disorderly status quo. As discussed above, we analyse the profit differential of each reform option compared to the status quo by looking at its three components:

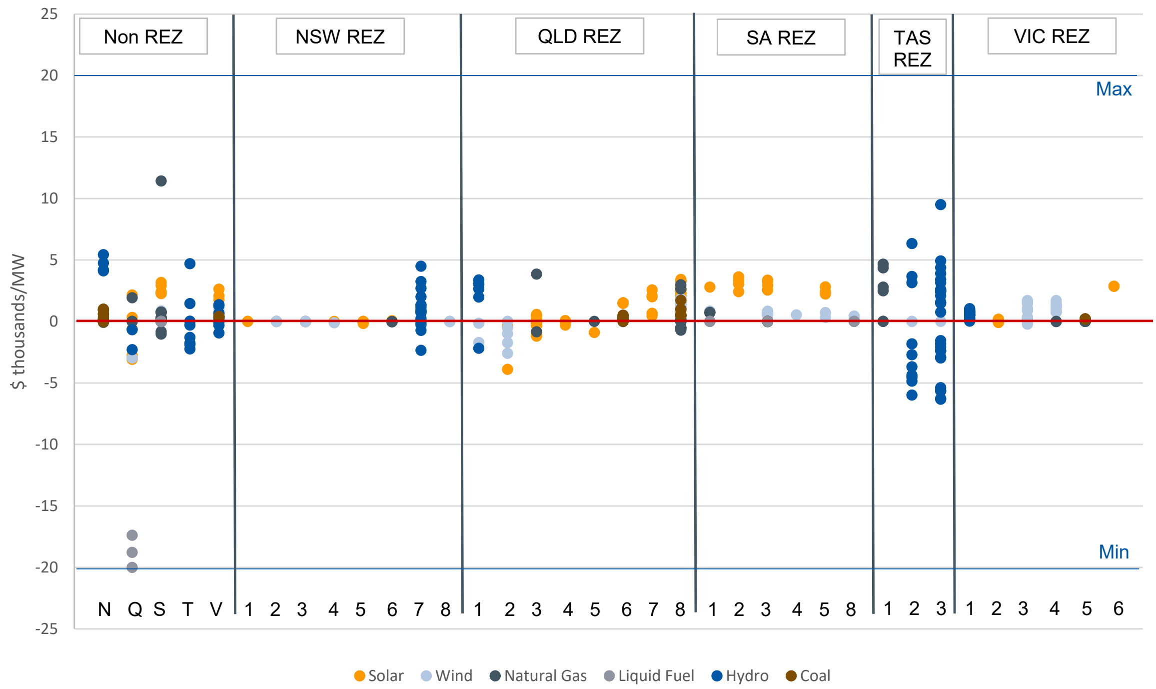
- The impact on profits due to a change in dispatch, due to efficient cost-reflective bidding (DE).
- The impact of the change in RRPs between each option and the status quo (DP); and
- The impact of a change in access, as access is allocated based on a different calculation under each option (DA).

Each data point represents the profit deviation per unit of capacity relative to the disorderly status quo for a generator. Plants are colour-coded by technology type and organised in columns each representing a location. The left side shows plants located in non-REZ nodes by region in alphabetical order (NSW to VIC). Similarly, REZ nodes are organised alphabetically and numerically (N1-N8, Q1-Q9, S1-S9, T1-T3, V1-V6). Please refer to Appendix C for a more detailed list of REZs and map.

To manage the scale of the illustrative charts, profit differentials per unit are capped at +/-$25,000/MW. Generators on the top and bottom line are therefore "outliers" that earn disproportionately high or low profits relative to their capacity.

We first look at the distribution of profit differentials due to dispatch, shown below in Figure 4.4. This component of profit differentials is the same across all the policy options considered, as we assume plants are dispatched in the same cost-reflective pattern.

Figure 4.4: Profit Differential Due to Change in Dispatch by (DE) by Technology and REZ – All Cost-Reflective Scenarios v. Status Quo Disorderly ($thousands/MW)



Source: NERA analysis of PLEXOS outputs. Note: missing REZs (e.g. S6-S7) do not have any capacity installed in the year 2023/24 under the ISP 2022 Step Change assumptions

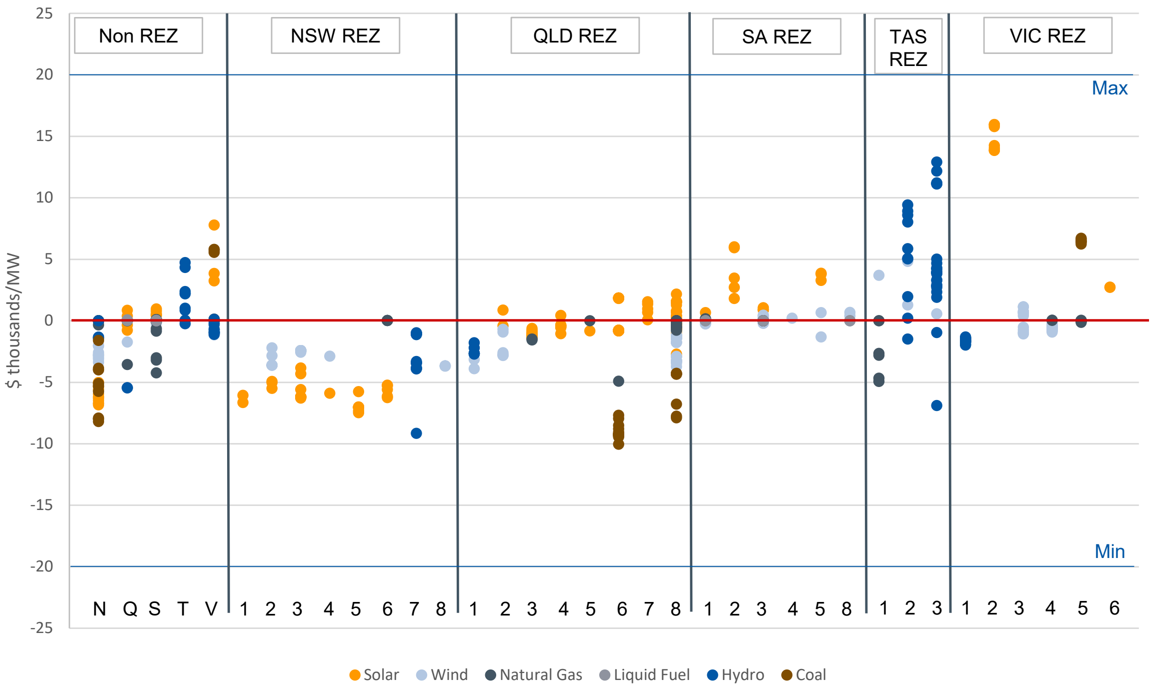
We can observe that across the system generators tend to be moderately better off compared to the disorderly status quo – i.e. they receive an "efficiency dividend" from more efficient dispatch. The trend persists across the NEM for thermal, wind and solar generators, which engage in disorderly bidding in the status quo (with the exception of the Q1 and Q2 REZs).[36]

In our modelling design, hydro plants do not bid disorderly; they therefore see more variation in their "DE" outcomes, as can be seen for generators in Tasmania or in the N7 "Tumut" REZ. We also do not directly value the difference in use of water resources between the cost-reflective and disorderly dispatch cases, which could affect plants' costs in reality. We discuss the potential impact of these modelling assumptions on our results in more detail in Chapter 5.

Figure 4.5 shows the profit difference component due to changes in the RRPs (DP).

36 As explained in Section 4.4, under the reform options the "DE" component is generally positive, as plants are either a) dispatched more under the cost-reflective scenario and exploit the LMP at their node above their marginal cost, or b) dispatched less but still have a positive profit component as their costs decrease more than their revenues. This holds for all plants unless they are constrained on in certain instances (as is the case for some thermal plants with must-run constraints) or as a result of our adjustment of LMPs in 2022-23 to reconcile with congestion, as is likely the case in the Q1 and Q2 REZs.

Figure 4.5: Profit Differential Due to Change in RRPs (DP) by Technology and REZ – All Cost-Reflective Scenarios v. Status Quo Disorderly ($thousands/MW)



Source: NERA analysis of PLEXOS outputs.

We know from the aggregate results in Table 4.6 that this component results in an overall negative profit differential for the reform options compared to the disorderly status quo. We can see from the distribution of the effects by location that the negative impact comes primarily from NSW and QLD, where different technologies are uniformly worse off compared to the status quo – in both REZ and non-REZ locations. Most areas in SA, TAS and VIC, on the other hand, see an increase in profits relative to the status quo.

This outcome is consistent with the trend in RRPs in each region under cost-reflective and disorderly assumptions. As explained above, our calculation of the “DP” component relies on comparing RRPs weighted by generation in the (disorderly) status quo, to keep dispatch constant. Table 4.10 below shows that RRPs in NSW and QLD, both time-weighted and weighted by status quo generation, are lower under cost-reflective bidding than under disorderly bidding. Conversely, in SA and TAS RRPs are higher under cost reflective bidding and most generators enjoy a positive “DP” profit differential. In the case of Victoria, time-weighted RRPs are higher under cost-reflective bidding by almost $2/MWh but weighted RRPs are slightly lower.

Table 4.10: RRPs by Region, Cost-Reflective v. Disorderly (Status Quo) Run ($/MWh)

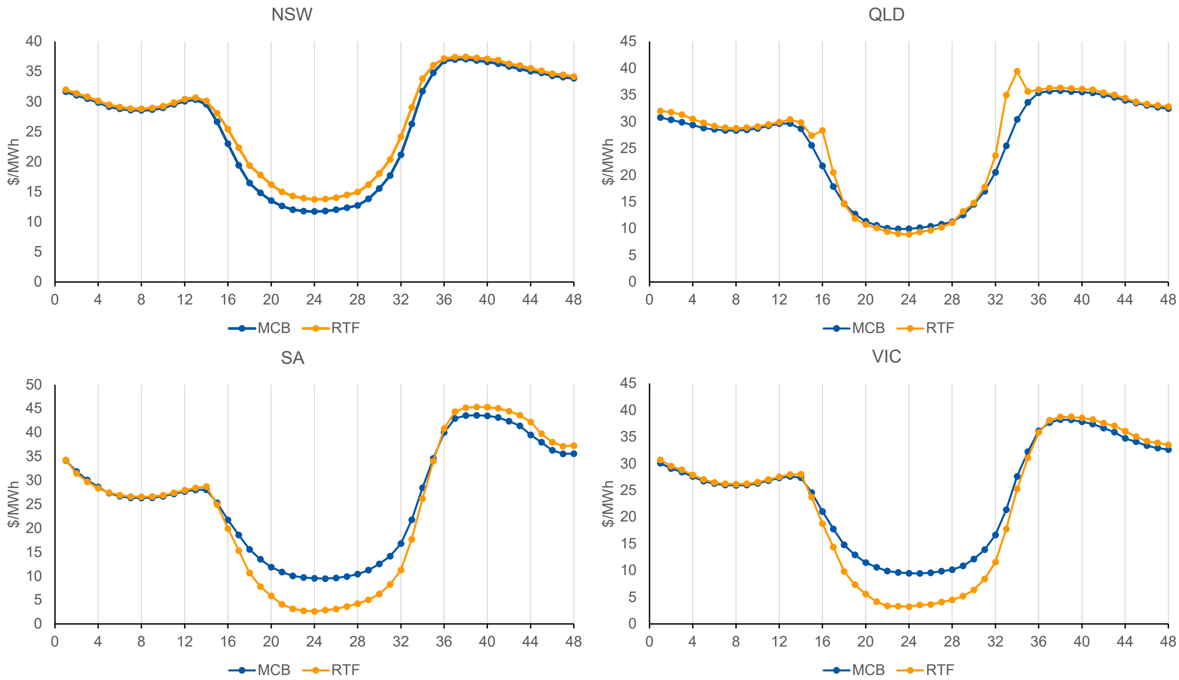
	Time-Weighted RRPs		RRPs Weighted by SQ (Disorderly) Generation	
Region	**Cost-reflective**	**Disorderly (SQ)**	**Cost-reflective**	**Disorderly**
NSW	26.05	27.28	27.03	28.50
QLD	24.95	25.29	26.64	27.90
SA	25.95	24.27	26.24	25.90
TAs	20.45	19.55	20.12	19.23
VIC	24.22	22.42	25.95	25.16

Source: NERA analysis of PLEXOS outputs

The RRP differences between scenarios also influence the difference in outcomes by technology type. Figure 4.6 below shows the average daily profile for disorderly and cost-reflective RRPs by region. We can observe that for NSW, SA and VIC the most significant spread between the two scenarios occurs in the middle of the day, therefore it principally affects the solar plants (as shown in Figure 4.5). Solar plants are therefore worse off compared to the status quo in NSW, where cost-reflective RRPs are lower during the day, and better off in SA and VIC, where they are higher.

On the other hand, in QLD we observe price spreads at peak times in the evening, which impact thermal plants and hydro negatively compared to the status quo. The price spread in Tasmania is more uniform throughout the day and is therefore not shown below.

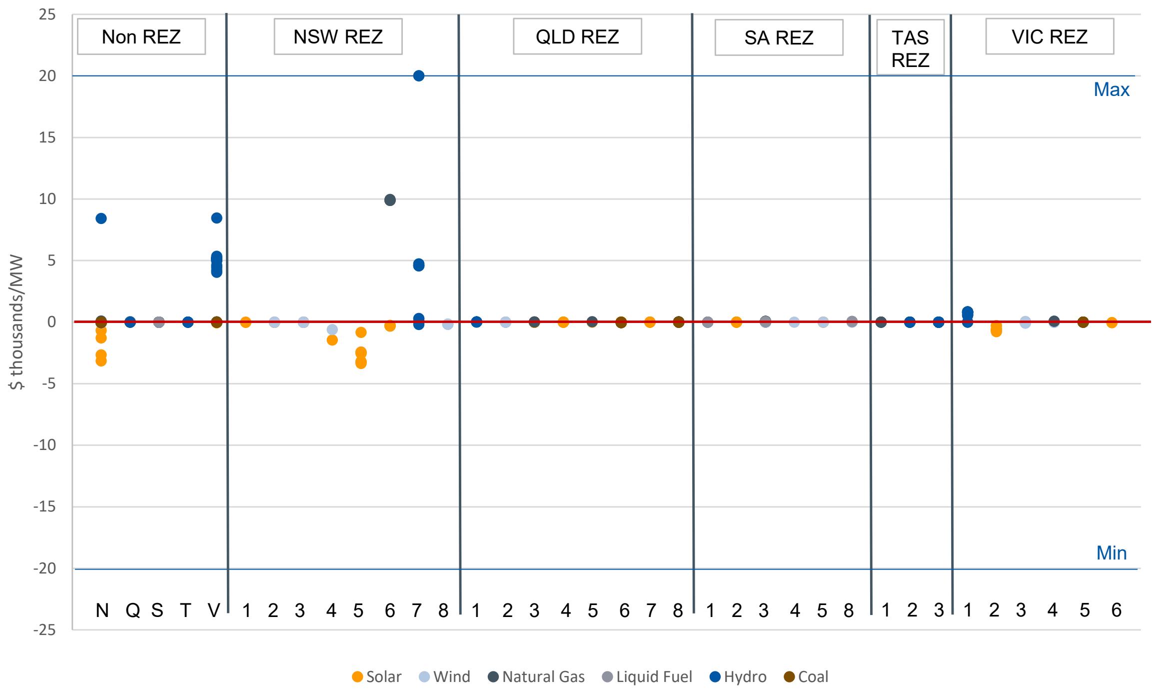
Figure 4.6: Average Daily RRP Profile by Region ($/MWh)



Source: NERA analysis of PLEXOS outputs

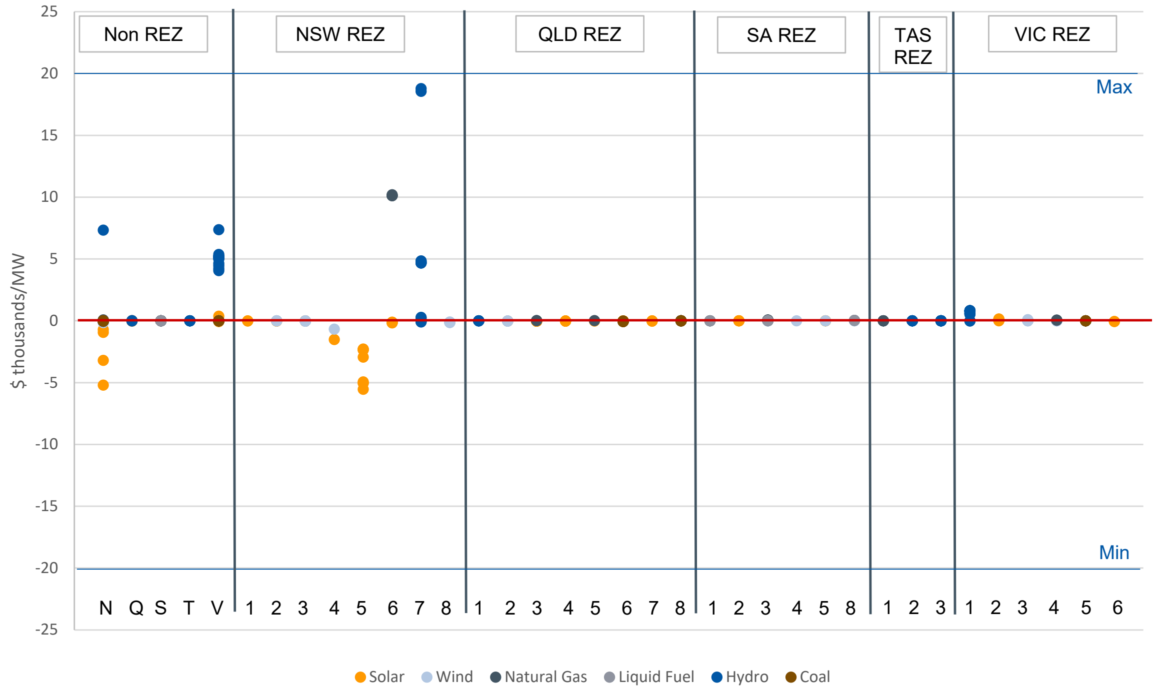
We now look at the "DA" component that comprises the changes in profits from the status quo due to the changes in access. Figure 4.7, Figure 4.8 and Figure 4.9 below show the distribution of the "DA" component for the pro-rata access, pro-rata entitlement and inferred economic dispatch options, respectively. As detailed in Section 4.5, for the winner-takes-all and CRM options this element of the profit difference is equal to zero, since access under these options is represented by dispatch under the status quo.

Figure 4.7: Profit Differential Due to Change in Access (DA) by Technology and REZ – Pro-Rata Access ($thousands/MW)



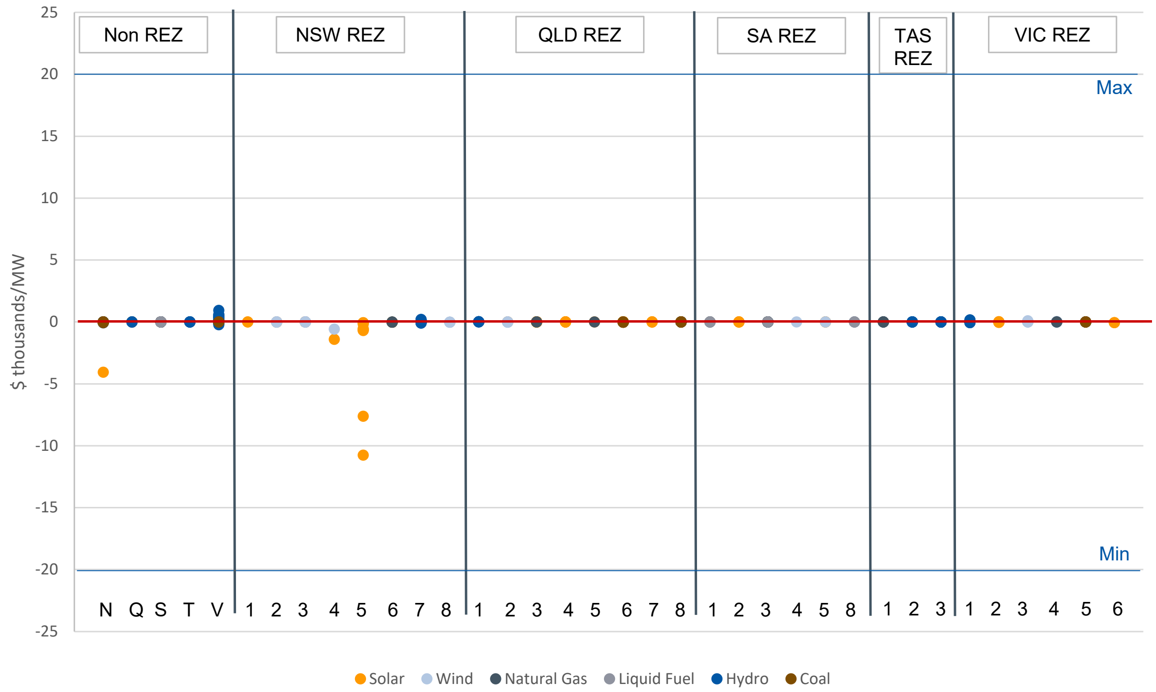
Source: NERA analysis of PLEXOS outputs.

Figure 4.8: Profit Differential Due to Change in Access (DA) by Technology and REZ – Pro-Rata Entitlement ($thousands/MW)



Source: NERA analysis of PLEXOS outputs.

Figure 4.9: Profit Differential Due to Change in Access (DA) by Technology and REZ – Inferred Economic Dispatch ($thousands/MW)



Source: NERA analysis of PLEXOS outputs.

As the figures show, there is minimal variation in profits due to access across the NEM. Across the three options, we see some relative losses for solar plants in NSW, in particular for the N5 REZ (South-West NSW) which is near the highly congested area on the border of NSW and VIC. The solar plants in this REZ are dispatched comparatively less than in the status quo, as cost-reflective bidding efficiently reallocates dispatch to the NSW-VIC interconnector. The DA differential with the status quo for South-West NSW is smaller under the pro-rata CMM options than under inferred economic dispatch. The pro rata options share access based on availability and constraint coefficients. Inferred economic dispatch allocates access to plant in order of cost effectiveness for the system as a whole based on cost reflective bidding. Inferred economic dispatch may therefore result in more binary outcomes by awarding access to some capacity and not others.

The pro-rata access and entitlement options also record high profits by hydro plants across the system compared to the status quo; however, as mentioned above, these additional profits are not inclusive of the change in water value between the disorderly and cost-reflective case.

4.7.2. Solar Plants Are the Highest Earners under Reform Compared to Disorderly Bidding

Table 4.11 represents the five largest beneficiaries, on the basis of the change in profit per MW by node, for the cost-reflective scenarios of each reform option versus the disorderly status quo.

The table shows that the "winning" nodes, across the four CMM scenarios, are in the Murray River REZ. We have seen in Table 4.3 how Victorian RRPs are higher under cost-reflective dispatch, in particular during the daytime where solar plants can increase their profits relative to the status quo.

In terms of technology, solar dominates the list across all five CMM scenarios. The RRP_{NEM} CRM, on the other hand, rewards a more diverse set of technologies, with solar still among the "winners". We have excluded nodes with hydro capacity from the "winners" in this option, as we have mentioned that the profits for these plants are not inclusive of the value of water.

Table 4.11: Highest Profits per Unit by Node v. Disorderly Status Quo

	#	Difference ($k/MW)	Node[37]	REZ	REZ Name	Technology
Status quo Cost-Reflective	1	15.84	Alpha	V2	*Murray River*	Solar
	2	15.73	Beta	V2	*Murray River*	Solar
	3	15.40	Gamma	V2	*Murray River*	Solar
	4	14.25	Delta	V2	*Murray River*	Solar
	5	14.07	Epsilon	V2	*Murray River*	Solar
Pro-Rata Access	1	15.16	Alpha	V2	*Murray River*	Solar
	2	14.98	Beta	V2	*Murray River*	Solar
	3	14.74	Gamma	V2	*Murray River*	Solar
	4	13.75	Epsilon	V2	*Murray River*	Solar
	5	13.74	Zeta	V2	*Murray River*	Solar
Pro-Rata Entitlement	1	15.91	Alpha	V2	*Murray River*	Solar
	2	15.76	Beta	V2	*Murray River*	Solar
	3	15.56	Gamma	V2	*Murray River*	Solar
	4	14.31	Delta	V2	*Murray River*	Solar
	5	14.11	Epsilon	V2	*Murray River*	Solar
Winner-Takes-All	1	15.87	Alpha	V2	*Murray River*	Solar
	2	15.75	Beta	V2	*Murray River*	Solar
	3	15.40	Gamma	V2	*Murray River*	Solar
	4	14.25	Delta	V2	*Murray River*	Solar
	5	14.04	Epsilon	V2	*Murray River*	Solar
Inferred Economic Dispatch	1	15.84	Alpha	V2	*Murray River*	Solar
	2	15.73	Beta	V2	*Murray River*	Solar
	3	15.40	Gamma	V2	*Murray River*	Solar
	4	14.25	Delta	V2	*Murray River*	Solar
	5	14.07	Epsilon	V2	*Murray River*	Solar
CRM RRP_{NEM} - 100% opt-in	1	3.58	Eta	QLD	*QLD Non-REZ*	Large-Scale Battery, Solar
	2	3.36	Theta	S3	*Mid-North SA*	Solar
	3	3.34	Iota	S2	*Riverland*	Solar
	4	3.26	Kappa	S3	*Mid-North SA*	Solar
	5	3.24	Lambda	T1	*North-East Tasmania*	Aggregated Distributed Storage, Natural Gas

Source: NERA analysis of PLEXOS outputs. Notes: the RRPCRM scenario with 100% participation is equivalent to the Winner-Takes-All option and is therefore not displayed. The nodes in the RRPNEM scenario with the highest profits are hydro nodes and therefore not displayed.

[37] Each node has been anonymised and assigned a unique identifier. We keep this unique identifier across Table 4.11, Table 4.12, Table 5.11 and Table 5.12.

Conversely, [Table 4.12] shows the five largest negative changes in profits, on a per MW basis, compared to the disorderly status quo for the same scenarios. While there is a less consistent pattern in their locational distribution compared to the “winners”, we can see more thermal nodes and hydro nodes among the “losers”, with some solar and wind nodes in addition. Thermal nodes lose profitability compared to the disorderly status quo. In addition, some storages also lose the opportunity to profit based on the price spread between high prices and negative prices under disorderly bidding.

Note also the presence of nodes in the South-West NSW REZ and non-REZ NSW among the “losers”. Congestion in these areas adversely affects the dispatch of solar farms, decreasing their profits. The size of the profit differential with the status quo and the individual nodes affected depends on the CMM option, as observed above in Section 4.7.1.

Table 4.12: Lowest Profits per Unit by Node v. Status Quo Disorderly

	#	Difference ($k/MW)	Node	REZ	REZ Name	Technology
Status quo Cost-Reflective	1	-18.72	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	2	-14.29	Node Mu	N5	*South-West NSW*	Solar
	3	-10.86	Node Nu	NSW	*NSW Non-REZ*	Solar
	4	-9.75	Node Chi	S4	*Yorke Peninsula*	
	5	-9.20	Node C	Q6	*Fitzroy*	Solar, Coal
Pro-Rata Access	1	-18.69	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	2	-10.30	Node Xi	N5	*South-West NSW*	Solar
	3	-10.22	Omicron	N5	*South-West NSW*	Solar
	4	-9.97	Node Nu	NSW	*NSW Non-REZ*	Solar
	5	-9.65	Node Pi	N5	*South-West NSW*	Solar
Pro-Rata Entitlement	1	-18.70	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	2	-12.08	Node Xi	N5	*South-West NSW*	Solar
	3	-12.00	Node Nu	NSW	*NSW Non-REZ*	Solar
	4	-11.98	Omicron	N5	*South-West NSW*	Solar
	5	-9.90	Node Rho	NSW	*NSW Non-REZ*	Solar
Winner-Takes-All	1	-18.73	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	2	-9.34	Node Chi	S4	*Yorke Peninsula*	Large-Scale Battery
	3	-9.20	Node C	Q6	*Fitzroy*	Solar, Coal
	4	-8.94	Sigma	Q6	*Fitzroy*	Coal, Solar
	5	-8.90	Node Tau	N7	*Tumut*	Hydro
Inferred Economic Dispatch	1	-18.72	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	2	-14.29	Node Mu	N5	*South-West NSW*	Solar
	3	-10.86	Node Nu	NSW	*NSW Non-REZ*	Solar
	4	-9.34	Node Chi	S4	*Yorke Peninsula*	Large-Scale Battery
	5	-9.20	Node C	Q6	*Fitzroy*	Solar, Coal
RRP_{NEM} - 100% opt-in	1	-18.78	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	2	-9.34	Node Chi	S4	*Yorke Peninsula*	Large-Scale Battery
	3	-5.98	Node U	T2	*North-West Tasmania*	Hydro
	4	-5.85	Upsilon	T3	*Central Highlands*	Hydro
	5	-4.95	Node Phi	V3	*Western Victoria*	Large-Scale Battery

Source: NERA analysis of PLEXOS outputs. Note: the RRPCRM scenario with 100% participation is equivalent to the Winner-Takes-All option and is therefore not displayed.

4.8. Illustration: Impact on Storage

The theory behind the CMM logic is that batteries would benefit from the introduction of CMM or CRM with higher profit arbitrage. Batteries can charge at the (lower) LMP rather than the RRP under the NEM status quo. The profit difference can be estimated by comparing the profits of a battery located at the reference node versus at a REZ node, where it might be facing constraints and therefore be able to benefit from more significant variation in LMPs.

An obstacle to estimating the impact of CMM/CRM on storage based on PLEXOS results is that our PLEXOS simulation dispatches batteries according to a cost-minimisation logic. In practice, a battery would attempt to optimise its charging and discharging pattern to be able to arbitrage over the spread in prices over a “cycle” of charge and discharge.

To illustrate the profit potential of different locations for a battery that arbitrage on the LMP spread, we perform a post-modelling calculation simulating a simple arbitrage-based operation of storage rather than the cost-minimisation operation that PLEXOS performs:

- We collect half-hourly LMPs for selected nodes.[38] For each region, we choose a selection of nodes (3-4 per region) including the RRN and more remote nodes located in REZs. We focus on 1) nodes that are sufficiently distant from the RRN to observe the effect of locating in a remote area; and 2) nodes that we have shown to have plants connected to them that appear to be significantly better off compared to the status quo, as shown in Section 4.7.2.

- We then use the LMPs to model a simplified operation pattern for sample 1 MW storages. We assume 92 per cent charging efficiency and 92 per cent discharging efficiency for every battery, as assumed by the 2022 ISP Step Change model for large-scale batteries. This implies, for instance, that a 2-hour battery would need to charge for 2/0.92 hours to discharge 2*0.92 MWh of electricity.

- For simplicity, assume no more than once cycle per day, where the battery, if profitable, would optimise by charging in the 2/0.92 hours of each day with lowest prices, and discharging in the 2*0.92 most expensive hours. The battery would pay and receive the LMP for these periods.

- We then calculate profits for the sample batteries and compare results between the RRN and the more remote locations for every region.

- When a day’s profit is negative according to our calculation (e.g. when there is little or no difference in prices in the day) we assume that the battery does not cycle and earns a profit of zero.

- We introduce a modification of the LMPs derived from our PLEXOS run to incorporate the impact of the LGC unit subsidy scheme for renewable plants.[39] Plants connected until 2030 receive renewable energy credits for the energy generated (we assume the level in 2023/24 is $60/MWh based on current forward curves). We assume that plants would be incorporating the value of the LGC into their bids, effectively being willing to submit a negative bid as it is offset by the tariff. As most of the renewable plants in the energy mix

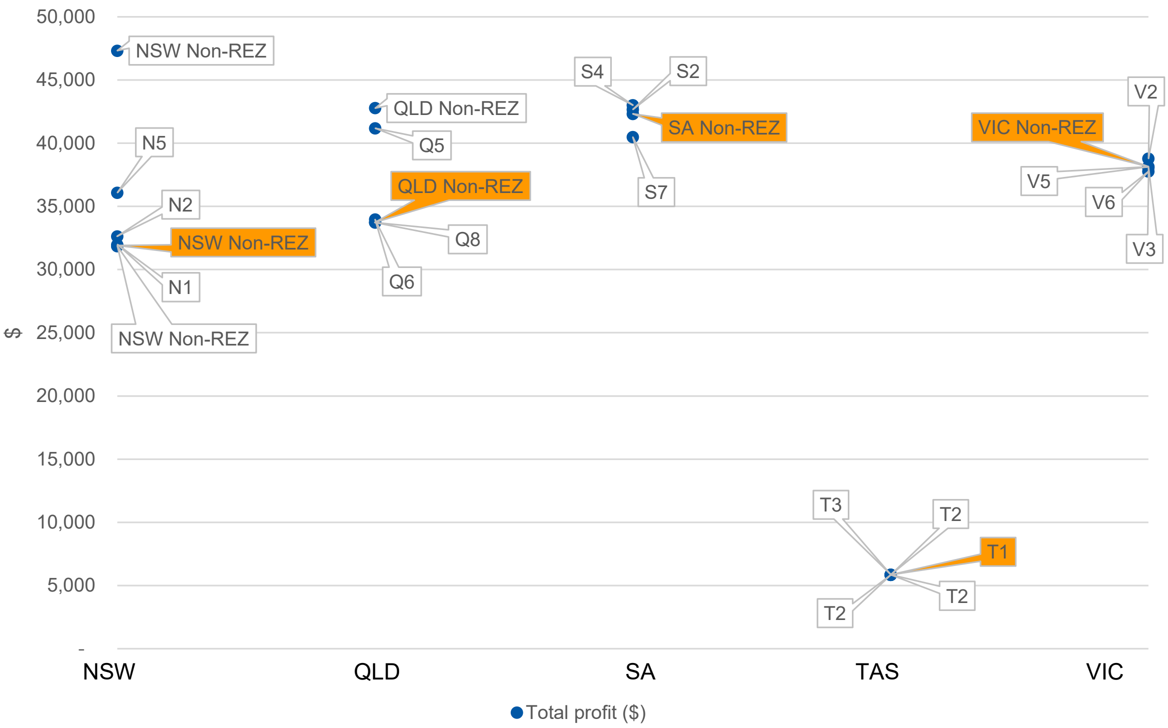
[38] For simplicity, we do not adjust these LMPs to reconcile with congestion, as this exercise is particularly relevant to the calculation of entitlements and revenues under pro-rata reform options, rather than to the operation of storage.

[39] Clean Energy Regulator website (accessed 12 November 2022), URL: https://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/qcmr/june-quarter-2022/Large-scale-generation-certificates-(LGCs).aspx

for the 2023/24 fiscal year would be receiving the credits, we replace instances of zero prices with a negative price of $-60/MWh. This allows batteries located at nodes with high concentration of renewables to arbitrage on a wider price spread.

Figure 4.10 below illustrates the difference in profits by node under the cost-reflective bidding case for a 2-hour, 1 MW battery.

Figure 4.10: LMP Profits for 2-hour, 1 MW Battery by Location ($)



Source: NERA analysis.
Note: *Nodes are organised by region; the regional reference node is highlighted in yellow for each region. The full name of REZs can be found in Table C.1.*

The evidence on the nodes considered is varied. Profit differences between the RRNs and external nodes in SA, TAS and VIC are minimal based on the nodes chosen for this illustration. On the other hand, some nodes in areas of QLD and NSW with high renewable generation allow batteries to better exploit the price spread created by the LGC and achieve profits about 50 per cent above those recorded at the RRN for a comparable battery. These nodes are shown to be overall "winners" under the different CMM and CRM options considered.

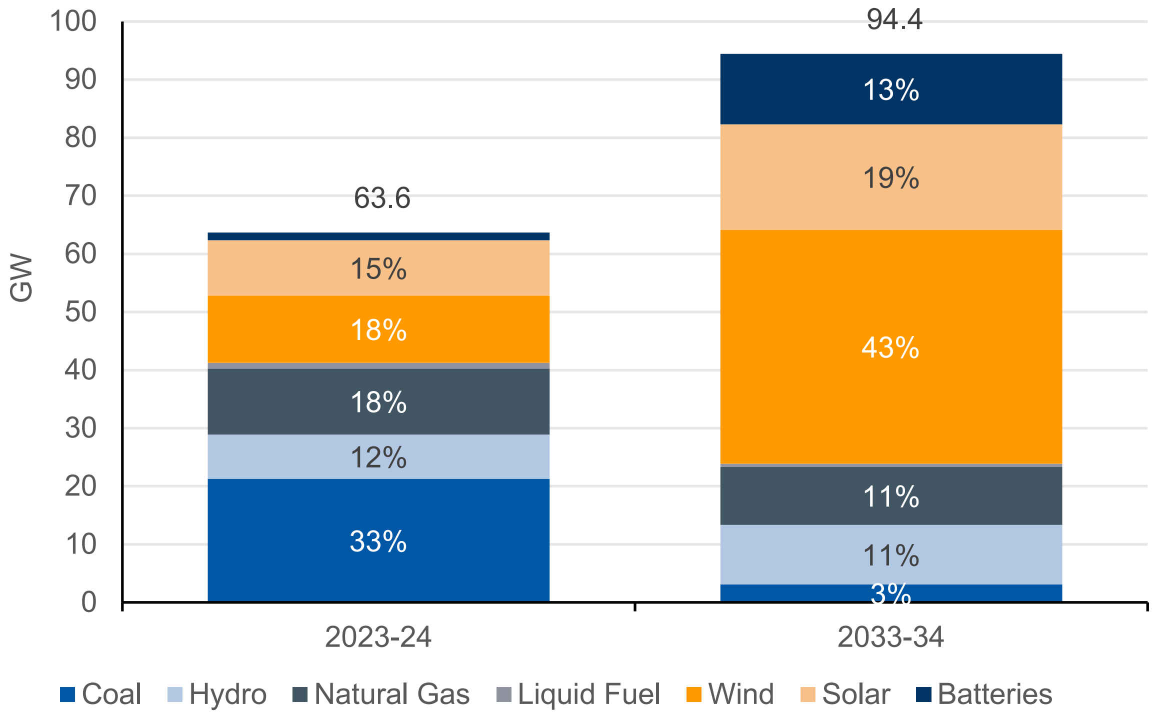
We have separately tested sensitivities for different battery capacities (1 and 4-hour capacity), with similar results.

5. Main Results for the 2033-34 Fiscal Year

5.1. For Fiscal Year 2033-34, We Remove Intervals with Unreliable Results

The 2033-34 fiscal year presents a more complex optimisation problem compared to 2023-24. Firstly, the capacity online in the system significantly increases, especially with respect to renewables and storage, as shown below in Figure 5.1. In particular, the system now includes larger amounts of multi-day storage (such as the Snowy Hydro complex) that requires optimisation over multiple daily steps. The network is likely to evolve in by 2033 and the full features of the network design (such the precise operation and planning of the 132kV and 330kV network) are not fully visible in the ISP.

Figure 5.1: Generation Capacity in 2023-24 and 2033-34 runs (GW)



Source: NERA analysis of PLEXOS inputs.

The larger and more complex capacity mix, combined with the extremely detailed short-term representation of the transmission network that is required for our modelling exercise, leads to our PLEXOS model failing to optimise certain steps under the same modelling settings adopted in 2023-24. This leads to "infeasible" daily steps; PLEXOS can repair these infeasibilities by changing the solution constraints bounds (i.e. lower and/or upper bounds), or fail to repair them. In both cases, we can observe counter-intuitive results such as excessive amount of lost load and/or curtailed load, or the demand and supply equation not holding in certain intervals. Additionally, PLEXOS sometimes uses input load from previous feasible steps to repair an infeasible step. As the infeasibilities do not occur at the same time in the cost-reflective and disorderly modelling run, the two runs might have to serve different load for the same half-hourly interval, preventing a like-for-like comparison of dispatch, costs and prices between the two runs.

To remedy this issue and preserve comparability with 2023-24 results, we opt to exclude periods where we identify the issues described above from the results. In total, we exclude 2,609 half-hourly periods out of 17,520 (around 15 per cent).

To present representative results for the full financial year 2033-34, we apply a regional scaling factor to the results to the results for the 14,911 remaining periods. We determine the scaling factor based on input demand per interval (i.e. input load), provided in the ISP 2022 Step Change PLEXOS model. Input demand is the same across the cost-reflective and disorderly run.

As presented in Table 5.1, we calculate the percentage of total input load related to the 2,609 excluded periods. We then determine the scaling factor from the percentage of excluded input load.

Table 5.1: Determination of Regional Scaling Factors

Region	Percentage of Total Load Associated with Excluded Hours(A)	Regional Scaling Factor (100%/(100% - A)
NSW	16.12%	1.1921
QLD	15.28%	1.1804
SA	16.35%	1.1955
TAS	15.53%	1.1838
VIC	16.42%	1.1965

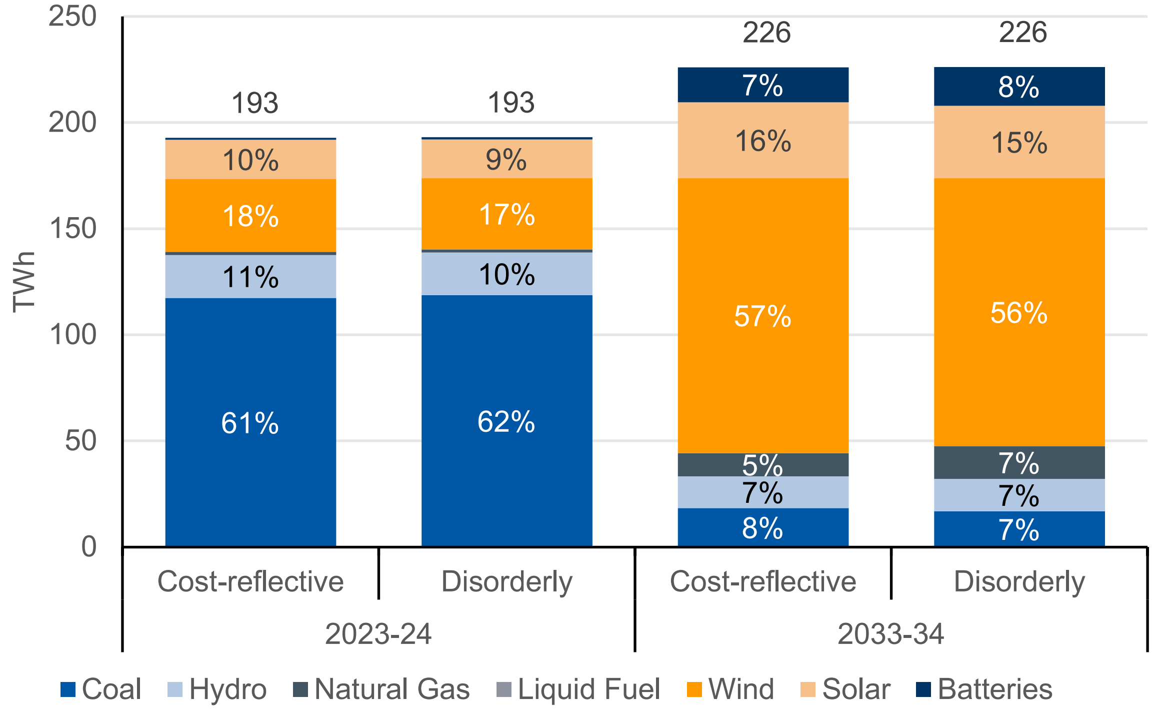
Source: NERA analysis of PLEXOS inputs.

We scale up costs, revenues, generation, flows and load at the regional level.[40]

Figure 5.2 presents the generation mix for the selected periods of 2033-34, scaled up according to the regional scaling factors presented above. Compared to 2023-24, the contribution of coal is significantly diminished, while renewables, storage and gas make up the majority of total generation. We present a further breakdown of the generation mix by region in Figure 5.3.

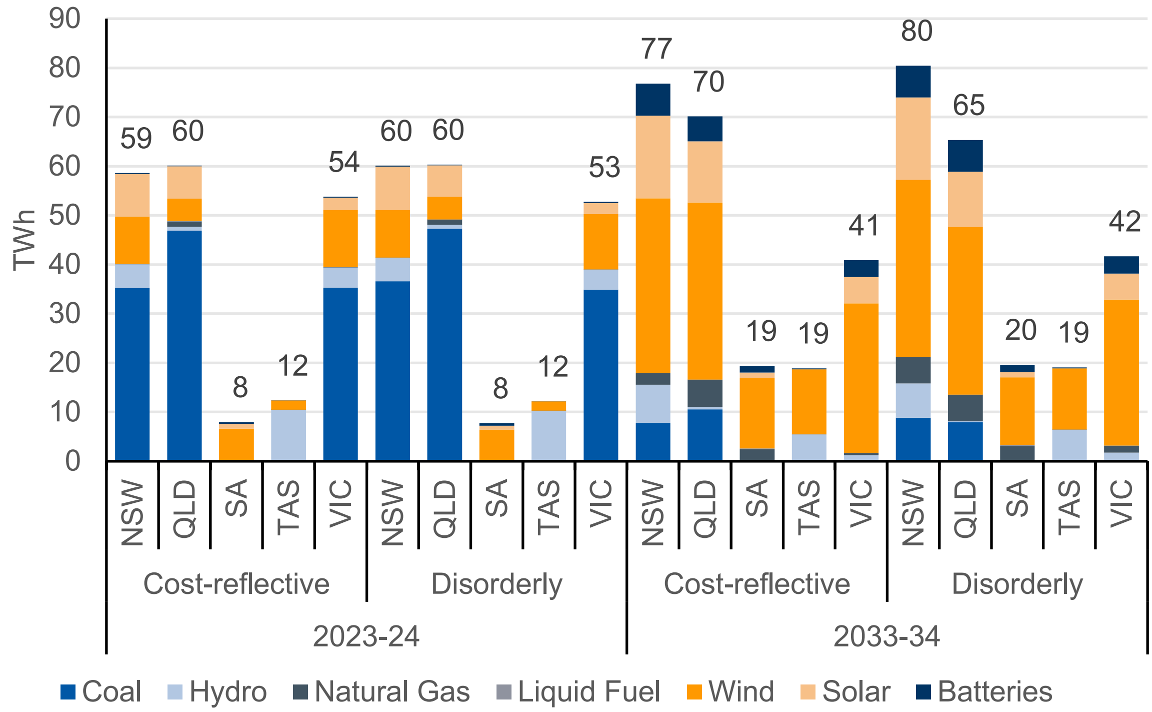
40 Specifically for inter-regional flows, we scale up the flows according to the destination region. For example, if electricity flows from NSW to SA, we apply the SA scaling factor; conversely if electricity flows from SA to NSW, we apply the NSW scaling factor.

Figure 5.2: Generation Mix in 2023-24 and 2033-34 runs, Cost-Reflective v. Disorderly Case (TWh)



Source: NERA analysis of PLEXOS outputs.

Figure 5.3: Generation Mix by Region in 2023-24 and 2033-34 runs (TWh)



Source: NERA analysis of PLEXOS outputs.

Table 5.2 provides an overview of congested lines and congestion prices in the cost-reflective and disorderly runs. In 2033-34, more lines experience instances of congestion than in 2023-24, particularly under the disorderly case. As in 2023-24, we can observe that the key areas of congestion are along the NSW-QLD border (New England, Fitzroy, Darling Downs REZs) and NSW-VIC border (the “N7” Tumut REZ, where the large pump storage project of Snowy Hydro is located). Please refer to Appendix C for a detailed list and map of REZs.

Table 5.2: Congested Lines in the Cost-Reflective v. Disorderly run in 2033-34

			Cost-Reflective				Disorderly			
	Region, REZ		Number Periods Congested		Avg. Congestion Price ($/MWh)		Number Periods Congested		Avg. Congestion Price ($/MWh)	
Line (Node 1-Node 2)	Node 1	Node 2	Flow	Flow Back	Flow	Flow Back	Flow	Flow Back	Flow	Flow Back
Woolooga-Palmwoods	QLD, Q7	QLD, Non-REZ	2,931	4	77.34	0.00	3,384	9	2,410.15	0.00
Bannaby-Sydney West	NSW, Non-REZ	NSW, Non-REZ	2,095	15	187.28	1.34	1,890	19	108.55	0.10
Keylor-Sydenham	VIC, Non-REZ	VIC, Non-REZ	141	1,349	0.01	39.79	102	1,559	0.06	41.99
Dumaresq-Sapphire Windfarm	NSW, Non-REZ	NSW, N2	12	123	0.00	12.94	8	1,422	0.01	307.51
Tumut1/2-Murray	NSW, N7	VIC, N7	1,259	1,281	88.14	76.81	316	872	36.27	53.53
Canowie-Robertstown	SA, S3	SA, S3	29	622	0.00	27.10	15	649	0.00	431.98
Heywood-South East (Mount Gambier)	VIC, V4	SA, S1	30	463	0.02	10.12	33	491	1.87	22.51
Tumut1/2-Maragle	NSW, N7	NSW, Non-REZ	980	306	74.50	10.43	188	94	23.28	1.13
Armidale-Tamworth	NSW, N2	NSW, Non-REZ	2,444	-	62.63	-	231	1	35.19	0.00
Davenport-Olympic Dam West	SA, S5	SA, S7	103	2	17,490.99	0.00	225	3	12,880.24	0.00
South Pine-Blackwall	QLD, Non-REZ	QLD, Non-REZ	33	18	2.56	0.72	29	61	65.93	23.72
Rocklea-Blackwall	QLD, Non-REZ	QLD, Non-REZ	18	25	0.00	8.27	16	64	0.00	187.16
Tumut3-Maragle	NSW, N7	NSW, Non-REZ	271	67	43.45	0.41	46	7	140.52	0.03
Dederang-Murray	VIC, V1	VIC, N7	69	52	4.49	36.00	14	1	18.79	0.11
Mount Piper-Wellington	NSW, Non-REZ	NSW, N3	2	51	0.00	97.68	1	14	0.00	1,501.96
Brinkworth-Templers West	SA, S3	SA, S3	-	-	-	-	12	-	96.95	-
Wandoan South-Yuleba North	QLD, Non-REZ	NSW, Non-REZ	-	-	-	-	12	-	-	-
Blyth West-Stown	SA, S3	SA, S4	-	-	-	-	8	-	-	-
Para Reservoir (Gould Creek)-Torrens A	SA, S3	SA, Non-REZ	-	-	-	-	8	-	-	-

	Region, REZ		Cost-Reflective Number Periods Congested		Cost-Reflective Avg. Congestion Price ($/MWh)		Disorderly Number Periods Congested		Disorderly Avg. Congestion Price ($/MWh)	
Line	**Node 1**	**Node 2**	**Flow**	**Flow Back**	**Flow**	**Flow Back**	**Flow**	**Flow Back**	**Flow**	**Flow Back**
Para Reservoir (Gould Creek)-Templers West	SA, S3	SA, S3	-	-	-	-	-	6	-	12.93
Middle Ridge-Greenbank	QLD, Q8	QLD, Non-REZ	2	-	0.00	-	5	-	84.00	-
Wellington-Wollar	NSW, N3	NSW, Non-REZ	3	-	0.00	-	5	-	623.22	-
East Terrace-Macgill	SA, Non-REZ	SA, Non-REZ	-	-	-	-	5	-	16.98	-
South Pine-Palmwoods	QLD, Non-REZ	QLD, Non-REZ	-	-	-	-	3	-	-	-
Tumut3-Wagga Wagga	NSW, N7	NSW, N6	2	1	0.00	0.00	-	2	-	20.95
Black Range-Tailem Bend	SA, S1	SA, S1	-	-	-	-	1	1	0.26	0.00
Abermain-Blackstone	QLD, Non-REZ	QLD, Non-REZ	-	-	-	-	2	-	-	-
Darling Downs Solar Farm-Braemar	QLD, Q8	QLD, Q8	-	-	-	-	2	-	0.03	-
Black Range-South East (Mount Gambier)	SA, S1	SA, S1	-	-	-	-	1	-	0.00	-
Wurdong-Calliope River	QLD, Q6	QLD, Q6	-	-	-	-	1	-	0.10	-
Bulli Creek-Dumaresq West	QLD, Q8	NSW, Non-REZ	-	-	-	-	1	-	12.50	-
Armidale-Sapphire Windfarm	NSW, N2	NSW, N2	1	-	0.05	-	-	-	-	-
Avon Lake-Campbelltown	NSW, Non-REZ	NSW, Non-REZ	-	-	-	-	-	-	-	-
Canberra-Yass	NSW, Non-REZ	NSW, Non-REZ	1	-	0.00	-	-	-	-	-
Dederang-South Morang	VIC, V1	VIC, Non-REZ	7	16	22.47	2.05	-	-	-	-

Source: NERA analysis of PLEXOS outputs. This table reports congested lines only for the 14,911 included periods. Lines are sorted from most often to least often congested in the disorderly scenario.
Notes: "Flow" indicates a flow from Node 1 to Node 2. "Flow Back" indicates a flow from Node 2 to Node 1

5.2. Cost-Reflective Bidding Achieves Lower System Costs than Disorderly Bidding

The calculation below in Table 5.3 includes total system costs of generators and storages (mainly fuel costs and variable O&M costs).

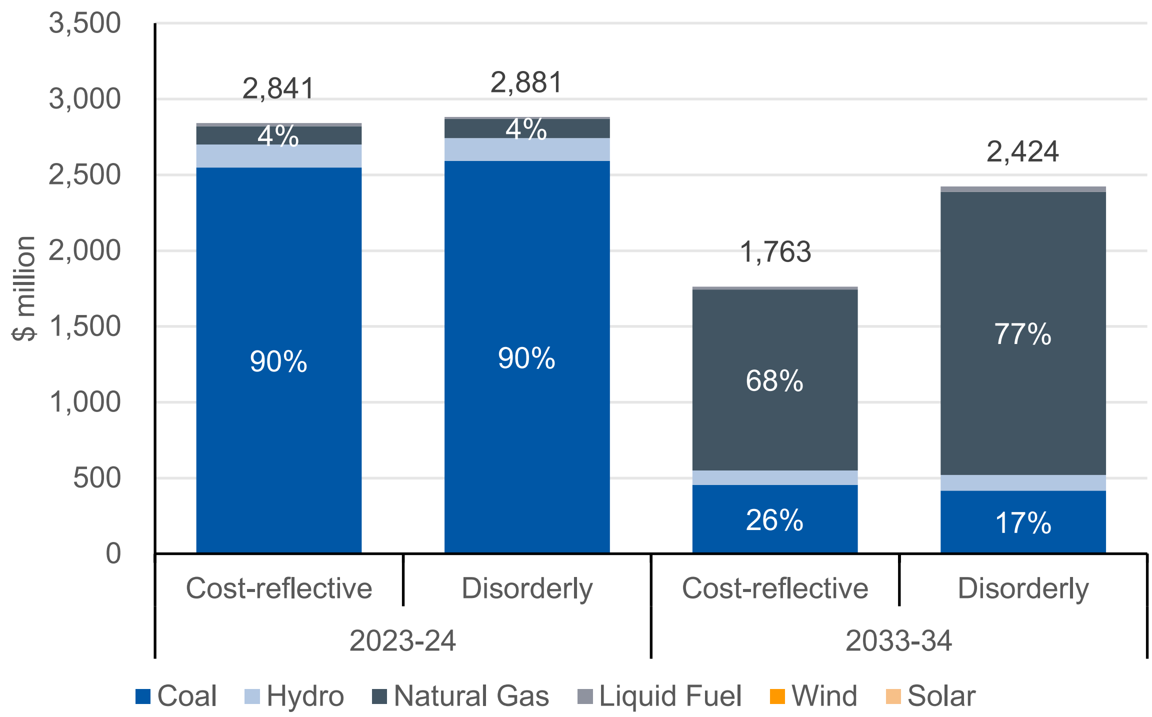
Table 5.3: System Costs Modelled, Cost-Reflective v. Disorderly case ($m)

Model Run	Generation Cost 2033-34
Cost-Reflective	1,561
Disorderly	2,176
Difference (Cost-Reflective - Disorderly)	-615
	(-28.3%)

Source: NERA analysis of PLEXOS outputs

In 2033-34, generation costs under cost-reflective bidding are lower than those in disorderly bidding by around $615 million (-28.3 per cent), a significantly larger margin than the 1.4 per cent difference observed in 2023-24 (see Table 4.2 above). Similarly to the 2023-24 results, the lower costs of the cost-reflective case reflect the increased efficiency of dispatch.

Figure 5.4: System Costs Modelled by Technology, Cost-Reflective v. Disorderly case in 2023-24 and 2033-34 ($m)



Source: NERA analysis of PLEXOS outputs

Compared to the 2023-24 results, the system costs in the cost-reflective and disorderly runs are lower, because of the deployment of wind and solar capacities in REZ and the decommission of must-run coal plants. Indeed, as seen above in Figure 5.2, in 2033-34 wind generation amounts to about 56 per cent of total generation in the disorderly run and 57 per cent in the cost-reflective run, against 17 and 18 per cent of the total in 2023-24, respectively. The same reasoning stands for solar generation: solar generation represents about 15 per cent (in the disorderly run) and 16 per cent (in the cost-reflective) of total generation in 2033-34, against 9-10 per cent of total generation in 2023-24, respectively.

In 2033-34, the higher amounts of gas generation in the disorderly run (15.4 TWh versus 10.9 TWh in the cost-reflective) explains most of the difference in system costs of 28.3 per cent, whereas the difference between cost-reflective and disorderly in the 2023-24 was only 1.4 per cent. Gas is more often at the margin in 2033-34, as most of must-run coal capacity from 2023-24 has retired. As a more expensive form of generation, a difference in dispatch between the two runs translates into a larger difference in system costs than might occur for other technologies.

Altogether, we can identify two key points that drive the differences in generation system costs between 2023-24 and 2033-34. On the one hand, gas must complement intermittent renewables generation in 2033-34 as a flexible generation by being at the margin because the renewables capacity is larger in 2033-34 compared to 2023-24. Therefore, the combination of the higher gas generation (from 1 per cent to 5-7 per cent) and higher operational costs associated to gas technology lead to higher generation system costs attributable to gas generation. On the other hand, the optimal capacity expansion obtained in the model is based on cost-reflective bidding, where gas generation accommodates intermittent renewables generation as a source of flexible generation. However, disorderly bidding introduces a distortion by influencing the merit order and exacerbating "counter-price" flows from high-price to low-price regions. This dynamic can force more expensive capacity into merit and increase system costs. Consequently, the disorderly dispatch results are inefficient, but also aim to accommodate the capacity expansion distortion between cost-reflective bidding (optimal) and disorderly bidding.

Our analysis of the benefits of reform in 2033-34 reflects the generation capacity mix in the ISP. AEMO produces the ISP based on the optimal generation mix as would be developed by a benevolent and omniscient central planner. In practice, absent reform, the market may deliver more gas plant than the ISP indicates and therefore could result in higher overall costs in our disorderly bidding case than our results suggest due to increased capital costs, which are not the subject of this report. In other words, given the distorted capacity mix that may develop in the absence of reform, the benefits of reform may be greater in 2033-34 than our results suggest.

5.3. CMM Revenues Are Lower Than Status Quo

As Table 5.4 shows, in 2033-34 the RRPs are higher on average in the disorderly run than in the cost-reflective run, across different weighting methodology. The relationship holds at the regional level for all regions except Queensland.

Table 5.4: Overview of RRPs per region ($/MWh)

	Time-Weighted RRPs		Load-Weighted RRPs		Gen.-weighted RRPs	
Region	**Cost-Ref.**	**Disorderly**	**Cost-Ref.**	**Disorderly**	**Cost-Ref.**	**Disorderly**
NSW	53.77	75.72	62.22	85.80	53.49	77.29
QLD	39.43	37.75	44.34	41.93	41.99	40.31
SA	45.60	51.16	57.80	63.68	51.45	61.37
TAS	33.21	37.85	34.26	39.08	35.22	43.47
VIC	47.34	51.78	55.64	59.63	39.64	43.88
NEM avg.	43.12	48.13	49.55	53.81	45.70	56.17

Source: NERA analysis of PLEXOS outputs.

We have seen in Table 5.2 that the areas near the QLD-NSW border are particularly congested in 2033-34, especially under disorderly bidding. Congestion and disorderly bidding can cause flows to be directed from NSW to QLD, forcing the QLD price down and NSW up. We discuss the impact of these "counter-price" flows in more detail in Section 6.1.

Table 5.5 below shows total revenues, costs and profits for the status quo and the cost-reflective reform options in 2033-34. As described in Section 3.1.4, these results use unadjusted LMPs from PLEXOS. We discuss the impact of adjusted and unadjusted LMPs on the two pro-rata options later in Section 5.4.

Table 5.5: Overview of Revenues, Costs and Profits by Cost-Reflective Scenarios ($m)

Scenario	**Model Run**	**Total Revenues**	**Total Costs**	**Profits (Rev. - Costs)**	**Profit diff. with Status quo disorderly**	
Status Quo	Disorderly	12,589	2,858	9,731	-	-
CMM Scenarios						
Pro-Rata Access	Cost-Reflective	10,100	2,050	8,050	-1,681	-17.3%
Pro-Rata Entitlement		10,101	2,050	8,051	-1,680	-17.3%
Winner-Takes-All		10,378	2,050	8,327	-1,403	-14.4%
Inferred Economic Dispatch		10,204	2,050	8,154	-1,577	-16.2%
CRM scenarios						
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	10,378	2,050	8,327	-1,403	-14.4%
RRP_{NEM} - 100% opt-in		12,320	2,050	10,269	538	5.5%

Source: NERA analysis of PLEXOS outputs.

As shown in the table above, most scenarios are less profitable for generators and batteries by around 14-17 per cent. Only the CRM scenario with RRPs from the energy market (RRP_{NEM}) is narrowly more profitable (by 5.5 per cent) than the status quo, as revenues are calculated in the CRM methodology using RRPs from the disorderly run and the more efficient dispatch of the cost-reflective run. We review the impact of dispatch, RRPs and access on the profitability of each scenario in Section 5.4.

In the cost-reflective CMM scenarios where OOM generators do not get access (see below in Table 5.6), the costs remain unchanged compared to the scenarios where OOM generators get access (Table 5.5), but we see variation in revenues.

Table 5.6: Overview of Revenues, Costs and Profits by Cost-Reflective Scenarios with OOM Generators Excluded from RRP Access Allocation ($m)

Scenario	Model Run	Total Revenues	Total Costs	Profits (Rev. - Costs) (Diff. with "default")	Profit diff. with Status quo disorderly	
Status Quo	Disorderly	12,589	2,858	9,731	-	-
CMM Scenarios						
Pro-Rata Access	Cost-Reflective excl. OOM	10,059	2,050	8,009 (-41)	-1,722	-17.7%
Pro-Rata Entitlement		10,058	2,050	8,008 (-43)	-1,723	-17.7%
Winner-Takes-All		10,370	2,050	8,319 (-8)	-1,411	-14.5%
Inferred Economic Dispatch		10,204	2,050	8,154 (0)	-1,577	-16.2%

Source: NERA analysis of PLEXOS outputs. The difference with the default case refers to the results in 5.4 above.

In the pro-rata access and pro-rata entitlement scenarios revenues are lower than the cases giving access to OOM generators, respectively by $41 million and $43 million.

The revenues in the inferred economic dispatch option remain unchanged under this sensitivity. As we mentioned in the case of 2023-24 results, OOM generators are not dispatched in the "default" case and therefore do not receive access. In the case of winner-takes-all, unlike in 2023-24 we observe a more marked difference between the default case and the sensitivity excluding OOM generators from access. This occurs because out-of-merit gas plants can in some rare instances receive access under disorderly bidding (i.e. under the default case) due to must run constraints or when constrained-on due to congestion. Therefore, they have positive access in the default case and their revenue changes in the scenario when they are no longer given access and are settled at their LMP, which is higher than the RRP in constrained-on instances.[41]

As discussed in Section 3.1.3, our modelling approach does not redistribute access from OOM to in-merit generators once OOM generators are excluded from the access allocation. In practice, the revenue lost from OOM generators quantified above will not be lost in aggregate, with the exception of the reallocation of part of the revenue to interconnectors (see Section 3.1.6).

41 The difference in profits between the default winner-takes-all and the sensitivity excluding OOM generators from access for an OOM plant is the sum of the following value over every interval: (RRP – LMP) * Disorderly generation, obtained after taking differentials of the respective revenue formulas.

5.4. The Change in Access Explains the Difference in Profit Change Across the CMM and CRM scenarios

In the same way as for 2023-24 (see Section 4.4), we decompose the profit change with the status quo disorderly scenario into three components and we add a component for modelling error:

- The profit change due to change in dispatch (“DE”);
- The profit change due to change in RRP (“DP”);
- The profit change due to change in access (“DA”). We adjust LMPs that do not reflect the congestion prices for pro-rata access and pro-rata entitlement dispatch scenarios (see Section 3.1.4). For other CMM scenarios “DA” component reflects the profit change due to change in access with unadjusted LMPs; and
- The profit change due to discrepancies between the LMPs and the congestion prices (“DX”), described in Section 3.1.4 above. The “DX” component is the difference in “DA” components when calculated with unadjusted and adjusted LMPs. We calculate this component for the two pro-rata options (pro-rata access and pro-rata entitlement) as these are the two options in which we allocate access and entitlement based on each plant’s contribution to a transmission constraint. For the other CMM options, the PLEXOS reporting discrepancy does not affect our modelling results as the access is inferred from alternative dispatch runs rather than calculated based on congestion prices. Therefore the DX component is zero for all other scenarios.

Table 5.7 breaks down the profit differential between each cost-reflective reform option and the disorderly status quo.

Table 5.7: Decomposition of the Profit Change v Status Quo Disorderly by Cost-Reflective Reform Option ($m)

Scenario	Model Run	DE	DA	Profit Change	DP	DX	Total Profit Change
CMM Scenarios							
Pro-Rata Access	Cost-Reflective	538.5	-26.6	511.9	-1,941.9	-250.7	-1,680.7
Pro-Rata Entitlement		538.5	-24.2	514.3	-1,941.9	-252.4	-1,680.0
Winner-Takes-All		538.5	-	538.5	-1,941.9	-	-1,403.4
Inferred Economic Dispatch		538.5	-173.8	364.7	-1,941.9	-	-1,577.2
CRM scenarios							
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	538.5	-	538.5	-1,941.9	-	-1,403.4
RRP_{NEM} - 100% opt-in		538.5	-	538.5	-	-	538.5

Source: NERA analysis of PLEXOS outputs. Notes: Profit Change = DE+DA. Total Profit Change = DE+DP+DA+DX.

The effect of change in dispatch on profit change remains identical across all cost-reflective CMM and CRM scenarios, as they all reflect dispatch under the same cost-reflective bidding assumptions. The effect of the change in dispatch is positive, as plants are dispatched more efficiently under cost-reflective bidding, and amounts to $538.5 million (32-38.4 per cent of total differential versus 13.6-17.6 per cent in 2023-24, as detailed in Table 4.6). Consequently, compared to 2023-24, we can observe that improving dispatch efficiency has a larger profit impact in the 2033-34 system. Indeed, the generation capacity in 2033-34 includes larger shares of variable renewable energy, together with the decommission of must-run coal plants and higher deployment of gas plants that operate as peaking plants compared to 2023-24, as seen in Figure 5.2. The difference between lowest-cost plants and higher cost plants is therefore starker than in the first year of results, increasing the positive "efficiency dividend" for plants.

The "DA" component is now negative for all three scenarios that have different access allocation from the status quo (pro-rata access, pro-rata entitlement and inferred economic dispatch). Like in 2023-24, the impact on the inferred economic dispatch scenario is larger than in the two pro-rata options.

The "DP" component reflecting the change in profits due to different RRPs is constant across all scenarios except the CRM with RRPs from the energy market (RRP_{NEM}), where the RRPs are unchanged from the status quo. The impact on profits is overall negative, since in all regions except QLD generation-weighted RRPs are lower in the cost-reflective case than in the disorderly one. As is the case for 2023-24, this component represents the largest share of the profit differential (between 116 and 138 per cent), though its share relative to the other components decreases in pro-rata access and pro-rata entitlement sensitivities compared to 2023-24 (142 per cent). The impact on single technologies and areas depends on the time-of-day distribution of the price differential; we provide more insight in 5.7.1.

The "DX" component representing the impact of the modelling discrepancy between the LMPs and congestion prices is negative and only affects the two pro-rata options. As we discussed above, this is an artefact of the modelling and we do not expect the profit impact of this component to manifest in reality. Our results reflect the allocation of Interregional Settlement Residuals (IRSR) under the CMM and CRM. In reality, clamping would prevent large counterprice flows that would result in large negative settlement residuals. We discuss the impact of clamping and counterprice flows in greater detail in Section 6.1.

5.5. The Settlement Residue is Higher Under CMM Scenarios

Table 5.8 presents the settlement residue calculation for the cost-reflective reform options and the status quo. The calculation of customer load, revenues and costs to charge storage follow the same methodology used in 2023-24 (see Section 4.5). In the status quo, storages (both pump hydro and batteries) earn and pay the RRP to charge, while in the CMM/CRM options they are exposed to the LMP. Customer in all scenarios pay the RRP associated with the dispatch scenario, therefore they are constant across all CMM options and the RRP_{CRM} CRM; the customer payments in the RRP_{NEM} CRM are analogous to those of the status quo disorderly, as the two scenarios use the same RRPs and customer load is constant between the cost-reflective and disorderly modelling run.

Table 5.8: NEM-Wide Settlement Residue by Reform Option ($m)

Scenario	Cust. Payment	Storage Cost to charge	Gen. Revenue	Batt. Revenue	NEM SR
	[1]	[2]	[3]	[4]	[5]=[1]+[2]-[3]-[4]
Status Quo Disorderly	12,106	682	11,649	939	199
Status Quo Cost-Reflective	10,398	517	9,382	844	689
CMM scenarios					
Pro-rata Access	10,398	489	9,279	822	787
Pro-rata Entitlement	10,398	489	9,279	822	786
Winner-Takes-All	10,398	489	9,556	822	510
Inferred Economic Dispatch	10,398	489	9,382	822	683
CRM scenarios					
RRP_{CRM} - 100% opt-in	10,398	489	9,556	822	510
RRP_{NEM} - 100% opt-in	12,106	489	11,498	822	276

Source: NERA analysis of PLEXOS outputs.

As seen in 2023-24, the NEM-wide settlement residue for all reform options compared to the status quo increases. The smallest increase occurs for the RRP_{NEM} CRM, whose assumptions are the closest to the status quo.

Table 5.9 presents results for the cost-reflective sensitivity where OOM generators do not receive access. The settlement residue for this sensitivity is higher than the "default" cost-reflective counterpart for most options, at least as modelled (including, for instance, that our modelling does not recycle OOM access to in-merit generators). As we have seen in Table 5.6, this sensitivity erodes total revenues. Results for the inferred economic dispatch are unchanged, as OOM generators do not receive access in the "default" option either. The settlement residue for the winner-takes-all option is slightly higher due to the small difference in revenues between sensitivities resulting from our exclusion of periods.

Table 5.9: NEM-Wide Settlement Residue by Scenario with OOM Generators settled at LMP ($m)

Scenario	Cust. Payment	Storage Cost to charge	Gen. Revenue	Batt. Revenue	Diff. IRSR with Cost-ref.	NEM SR (Diff with Table 5.8)
Status Quo Disorderly	12,106	682	11,649	939		199
CMM scenarios						
Pro-rata Access	10,398	489	9,237	822	471	357 (+41.2)
Pro-rata Entitlement	10,398	489	9,237	822	471	358 (+42.8)
Winner-Takes-All	10,398	489	9,548	822	471	46 (+7.8)
Inferred Economic Dispatch	10,398	489	9,382	822	471	212 (0)

Source: NERA analysis of PLEXOS outputs.

5.6. Like in 2023-24, Partial Participation in the CRM Helps to Achieve Lower System Costs

Table 5.10 shows generation costs for the partial participation CRM sensitivity (with RRP based on the energy market, i.e. RRP_{NEM}). We adopt the same adjustment methodology as in 2023-24. As detailed in Section 3.2.2, we assume that 50 per cent of renewable generation in the year opts into the relief market; in addition, around 40 per cent of thermal and all of hydro and storage capacity also opt in, amounting to a total of 56 per cent of generation opting in and the remaining 44 per cent maintaining the dispatch outcomes of the disorderly status quo.

Table 5.10: Generation Costs by Level of CRM Opt-In ($m)

	0% opt in (SQ Disorderly)	Partial opt-in	100% opt-in
Generation Costs	2,176	1,908	1,561
Diff. w/ SQ Disorderly		-268 (-12.3%)	-615 (-28.3%)

Source: NERA analysis of PLEXOS outputs

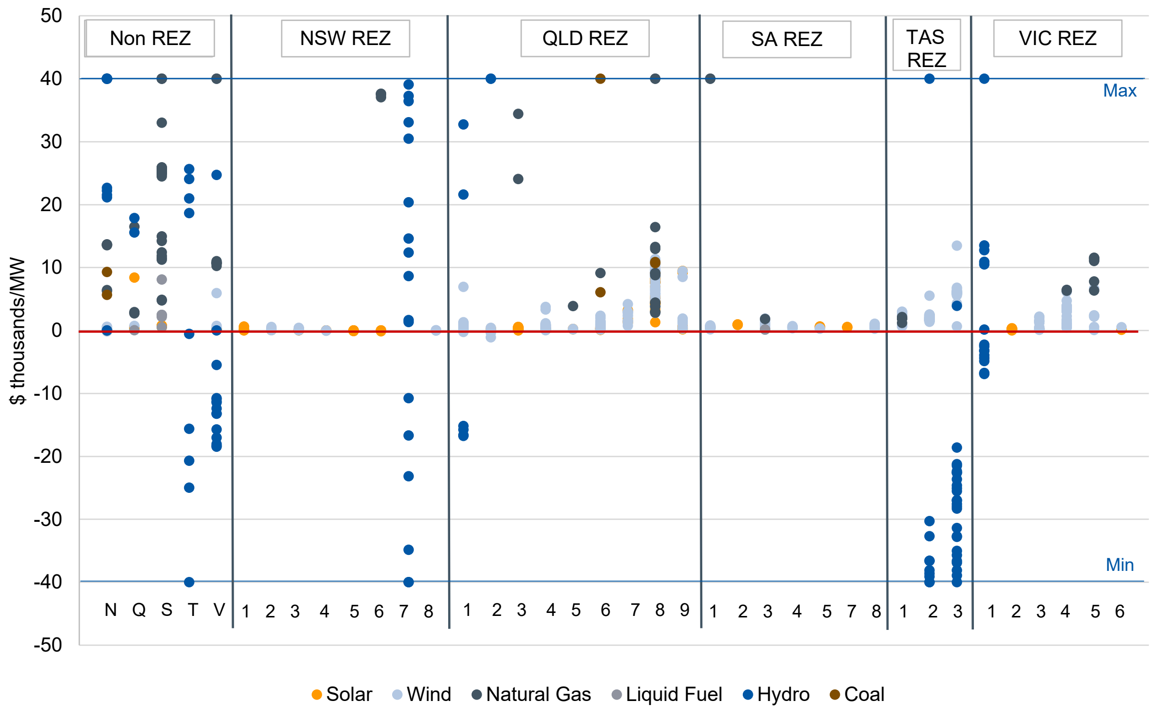
We can see that also in 2033-34 partial participation helps reduce system costs for generation by re-dispatching the opt-in plants under cost-reflective assumptions. While in 2023-24 the partial participation case already achieved cost savings very close to those of full participation (see Table 4.9), in 2033-34 the overall lower level of opt-in leads to savings of 12.3 per cent relative to the status quo compared to 28.3 per cent under full participation. The lower reduction in operating cost is consistent with the lower variable costs of plant on the electricity system in 2033-34.

5.7. The Difference in RRPs Between Cost-Reflective and Disorderly Options Determines "Winners" and "Losers" Among Technologies and Locations

5.7.1. We Review Profit Differentials By REZs

Figure 5.5 shows the distribution of the "DE" component by technology and location of generators, per unit of installed capacity. The chart layout is analogous to that described for 2023-24 in Section 4.7.1.

Figure 5.5: Profit Differential Due to Change in Dispatch by (DE) by Technology and REZ – All Cost-Reflective Scenarios v. Status Quo Disorderly ($thousands/MW)



Source: NERA analysis of PLEXOS outputs. Note: missing REZs (e.g. S6) do not have any capacity installed in the year 2033/34 under the ISP 2022 Step Change assumptions

We know from the aggregate results in Table 5.7 that this component results in a net positive profit differential with the status quo across the NEM. This remains true at the individual level for most locations and technologies, with the exception of hydro plants, whose profitability varies significantly compared to the status quo, as we have seen is the case for 2023-24.

As explained above, the formula for the calculation of the "DE" component is:

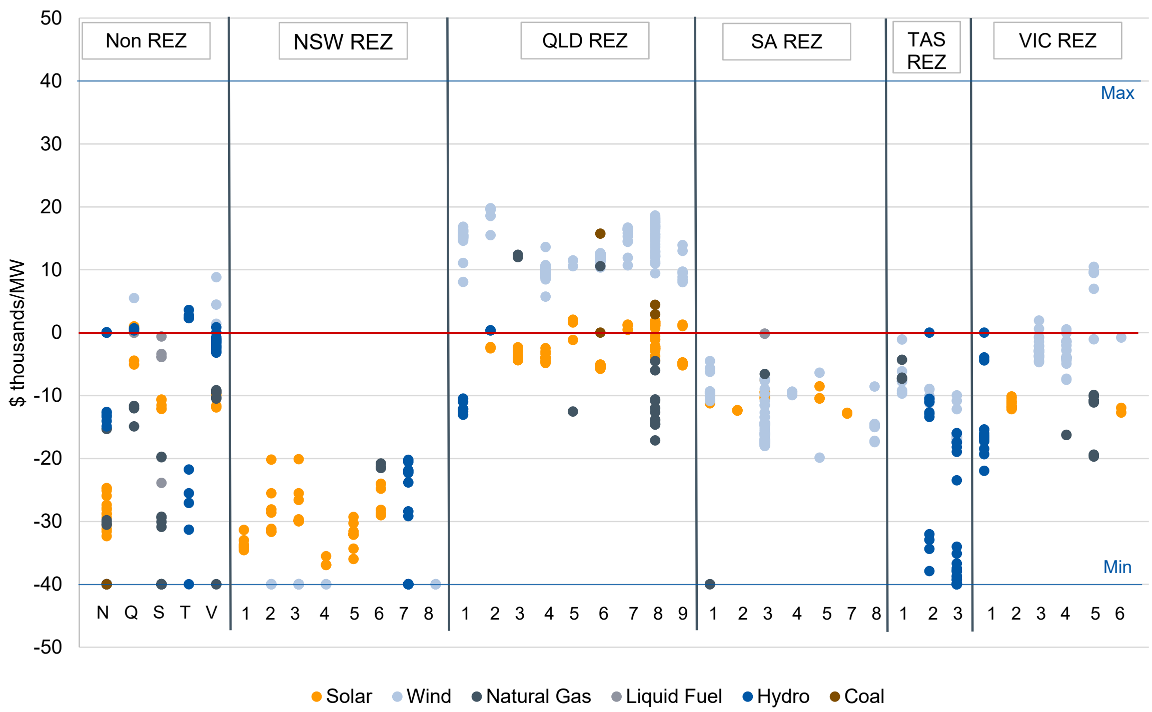
$$\mathrm{DE} = (\mathrm{LMP}_{\mathrm{CMM,CRM}} - \text{Marginal Cost}\ \ ) \times (\mathrm{Gen}_{\mathrm{CMM,CRM}} - \mathrm{Gen}_{\mathrm{SQ\ disorderly}})$$

Therefore, for a given plant, the "DE" component is positive if either (a) it is dispatched more in the cost-reflective case than in the disorderly status quo and the LMPs at its node are overall higher than its marginal cost over the year; or b) it is dispatched less than in the status quo but its LMPs are overall lower than its marginal cost over the year.

For most plants, a positive "DE" correlates with increased dispatch in the cost reflective case, i.e. they run more as they are not undercut by more expensive capacity that engages in disorderly bidding. On the other hand, some plants (e.g. some wind plants in congested QLD REZs such as Q7 and Q8) have a positive "DE" when they generate less than the disorderly status quo given that they are exposed to negative LMPs in some daytime periods. By bidding at cost in the CRM, these plants are able to profit by facing an LMP lower than marginal cost even when cost-reflective bidding reduces their dispatch compared to disorderly bidding. The dispatch of hydro in our simulation is determined by medium-term constraints on the water resources and storage targets, therefore they might face a reduction in profits due to changes in dispatch under these conditions.

Figure 5.6 presents the distribution of the "DP" component, or the change in profit per MW relative to the status quo due to the change in RRPs between cost-reflective and disorderly bidding.

Figure 5.6: Profit Differential Due to Change in RRPs (DP) by Technology and REZ – All Cost-Reflective Scenarios v. Status Quo Disorderly ($thousands/MW)

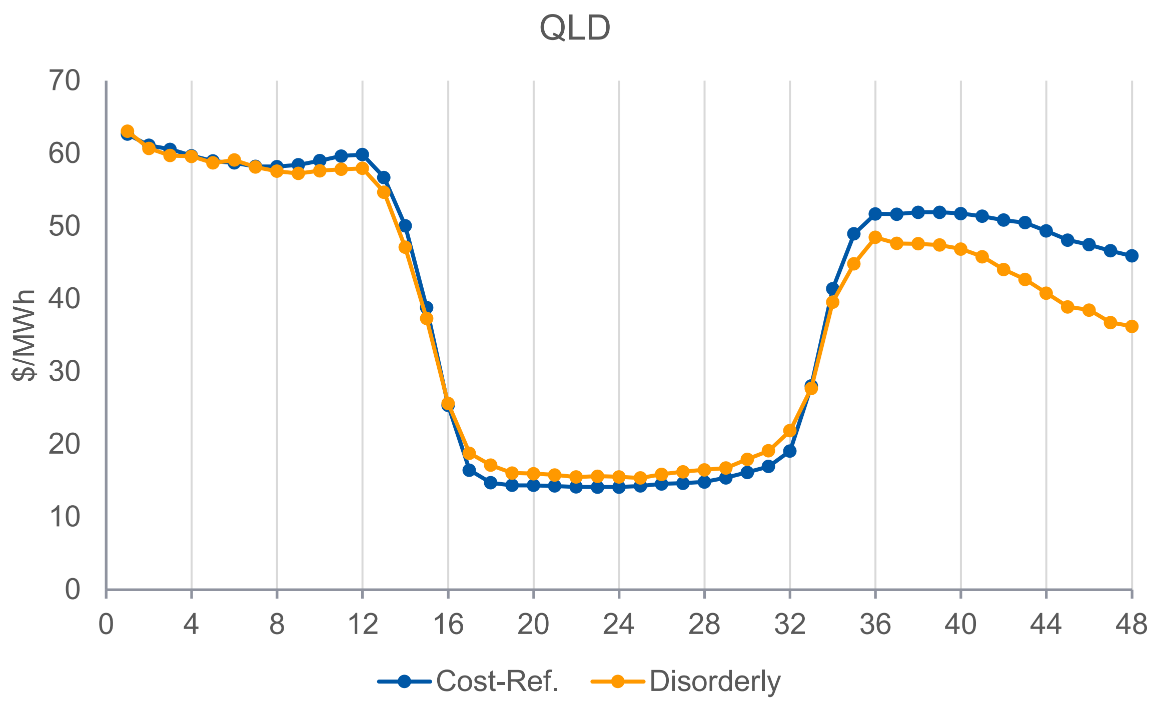


Source: NERA analysis of PLEXOS outputs.

We have seen in the aggregate results presented above in Table 5.7 that this component of the profit differential is the largest in absolute value and negative compared to the status quo. The net negative result is driven by SA, VIC, TAS and especially NSW, which experiences the largest difference in RRPs between the cost-reflective and disorderly bidding case (see Table 5.3).

While the negative difference with the status quo is fairly homogeneous across technologies in these four regions, in QLD we see that wind is overall better off relative to the status quo, leading to an overall positive "DP" component for QLD. On the other hand, most of solar, thermal and hydro capacity is overall worse off. To understand the difference in outcome across location, we look at the time-of-day average RRP in QLD for the cost-reflective and disorderly case. Figure 5.7 presents the results for an average day. We only consider the periods of the year selected according to the methodology described in Section 5.1.

Figure 5.7: Average Daily RRP Profile in QLD ($/MWh)

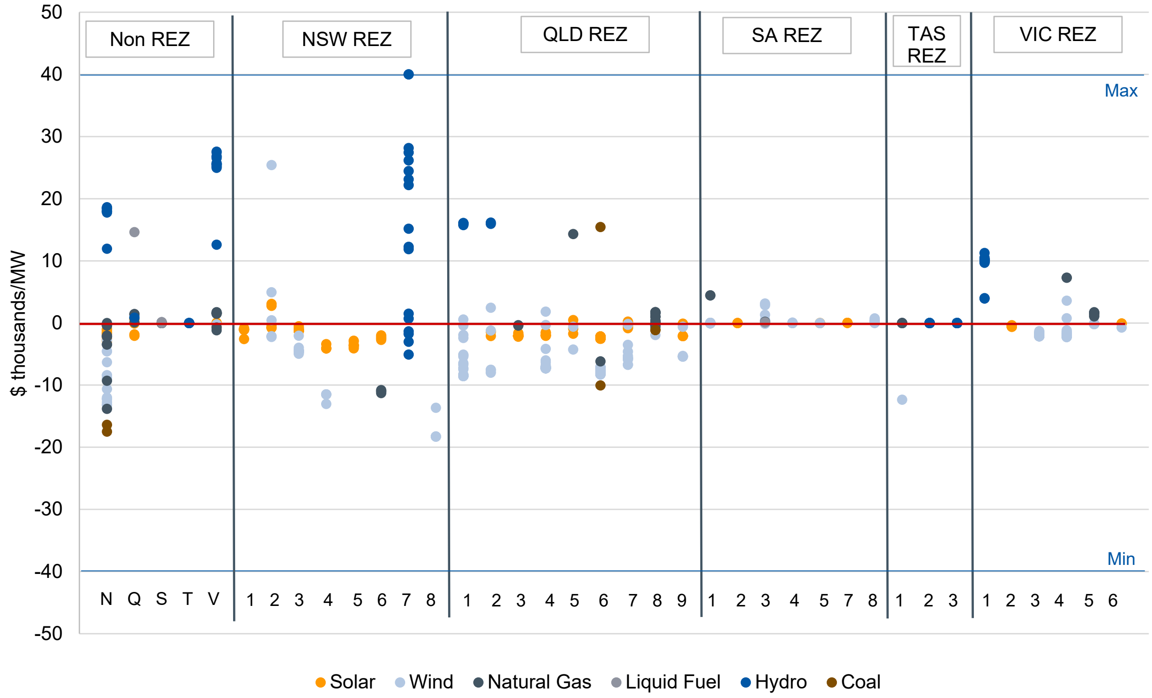


Source: NERA analysis of PLEXOS outputs.

As the figure shows, the positive spread in RRPs in favour of the cost-reflective option occurs predominantly in the evening, where wind can generate. During the morning and afternoon peaks, the difference in RRPs is very narrow, and in the middle of the day is narrowly in favour of the disorderly case, putting solar at disadvantage.

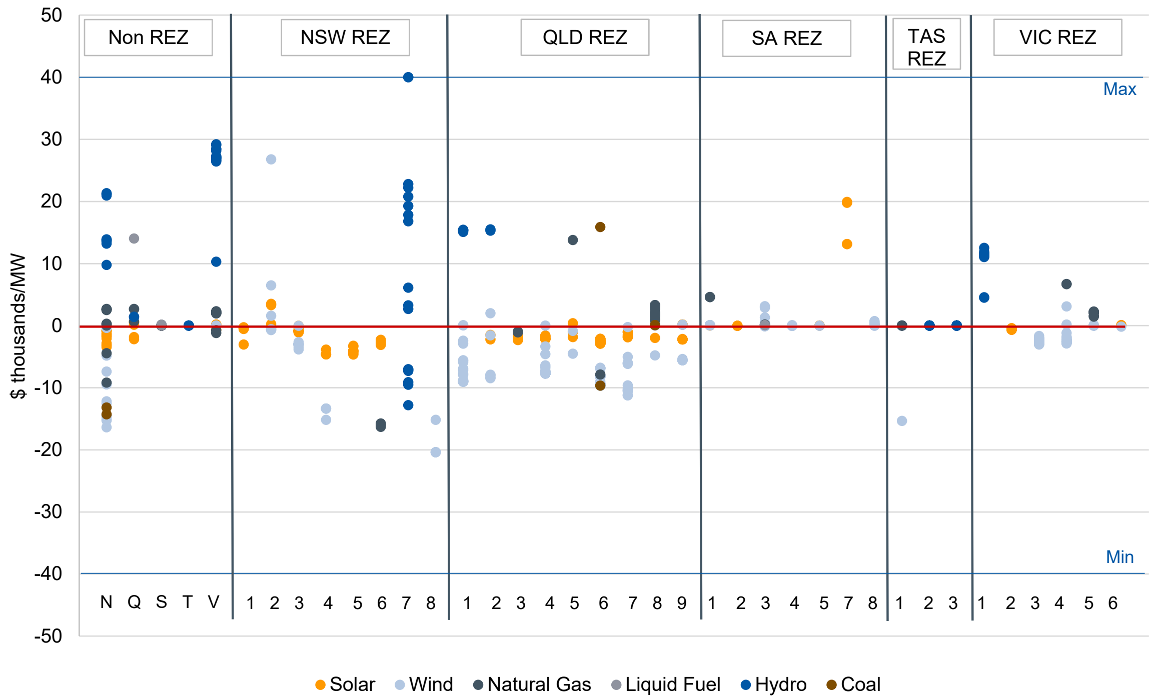
Figure 5.8, Figure 5.9 and Figure 5.10 present the distribution of the "DA" component for the pro-rata access, pro-rata entitlement and inferred economic dispatch option, respectively. As is the case for the 2023-24 results, the winner-takes-all and CRM options have the same access as the disorderly status quo, therefore their "DA" component is equal to zero. We discussed above that we show a "DA" component using adjusted LMPs for the pro-rata options and one using unadjusted LMPs for inferred economic dispatch.

Figure 5.8: Profit Differential Due to Change in Access (DA) by Technology and REZ – Pro-Rata Access ($thousands/MW)



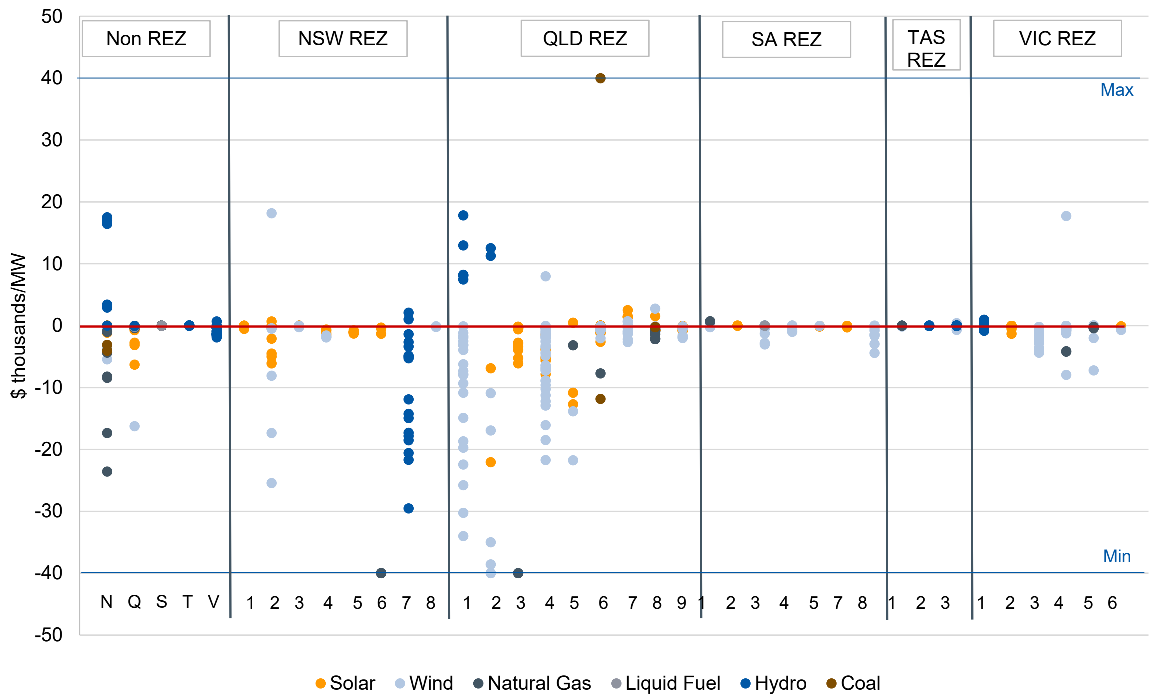
Source: NERA analysis of PLEXOS outputs.

Figure 5.9: Profit Differential Due to Change in Access (DA) by Technology and REZ – Pro-Rata Entitlement ($thousands/MW)



Source: NERA analysis of PLEXOS outputs.

Figure 5.10: Profit Differential Due to Change in Access (DA) by Technology and REZ – Inferred Economic Dispatch ($thousands/MW)



Source: NERA analysis of PLEXOS outputs.

The negative net results appear to be driven mostly by plants in NSW and QLD across all three options considered.

5.7.2. Renewables Nodes in QLD Are the "Winners" in CMM Scenarios Compared to the Status Quo

Table 5.11 presents the five nodes with the highest profit differential per MW compared to the disorderly status quo for each reform option. As done in 2023-24, we have excluded hydro nodes from the list as the high variance in profitability across the plants does not take into account the shadow value of water.

We can observe that in CMM scenarios all "winning" nodes are in Queensland REZs. As described in the previous section, this region is the only one in the NEM where plants can benefit from a higher RRP relative to the status quo. As the RRP differential appears to be the largest driver of profit differentials, QLD plants are among the most profitable relative to the status quo. The RRPNEM CRM, on the other hand, uses the same RRPs as the status quo, and therefore displays more variety in the location of high earners.

Table 5.11: Highest Profits per Unit by Node v. Disorderly Status Quo

	#	Difference ($k/MW)	Node	REZ	REZ Name	Technology
Status quo Cost-Reflective	1	78.87	Node C	Q6	*Fitzroy*	Coal, Solar, Wind
	2	64.02	Node K	Q2	*North Qld Clean Energy Hub*	Wind, Hydro
	3	28.17	Node H	Q8	*Darling Downs*	Wind, Solar
	4	25.09	Node B	Q1	*Far North QLD*	Hydro, Wind
	5	24.92	Node R	Q4	*Isaac*	Wind
Pro-Rata Access	1	84.82	Node K	Q2	*North Qld Clean Energy Hub*	Wind, Hydro
	2	58.47	Node C	Q6	*Fitzroy*	Coal, Solar, Wind
	3	33.41	Node L	T1	*Gippsland*	Wind
	4	32.59	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	5	28.92	Node H	Q8	*Darling Downs*	Wind, Solar
Pro-Rata Entitlement	1	83.07	Node K	Q2	*North Qld Clean Energy Hub*	Wind, Hydro
	2	58.99	Node C	Q6	*Fitzroy*	Coal, Solar, Wind
	3	34.43	Node L	T1	*Gippsland*	Wind
	4	31.17	Node M	QLD	*QLD Non-REZ*	Liquid Fuel
	5	29.25	Node H	Q8	*Darling Downs*	Wind, Solar
Winner-Takes-All	1	86.53	Node K	Q2	*North Qld Clean Energy Hub*	Wind, Hydro
	2	63.77	Node C	Q6	*Fitzroy*	Coal, Solar, Wind
	3	28.56	Node H	Q8	*Darling Downs*	Wind, Solar
	4	23.72	Node Y	Q8	*Darling Downs*	Solar, Wind
	5	23.03	Node T	Q8	*Darling Downs*	Solar, Wind
Inferred Economic Dispatch	1	78.87	Node C	Q6	*Fitzroy*	Coal, Solar, Wind
	2	75.99	Node K	Q2	*North Qld Clean Energy Hub*	Wind, Hydro
	3	28.17	Node H	Q8	*Darling Downs*	Wind, Solar
	4	25.09	Node B	Q1	*Far North QLD*	Hydro, Wind
	5	24.92	Node R	Q4	*Isaac*	Wind
RRP_{NEM} - 100% opt-in	1	79.76	Node K	Q2	*North Qld Clean Energy Hub*	Wind, Hydro
	2	70.95	Node S	NSW	*NSW Non-REZ*	Natural Gas
	3	67.36	Node N	VIC	*VIC Non-REZ*	Natural Gas
	4	56.35	Node C	Q6	*Fitzroy*	Coal, Solar, Wind
	5	48.24	Node A	NSW	*NSW Non-REZ*	Natural Gas

Source: NERA analysis of PLEXOS outputs. Notes: the RRP_{CRM} scenario with 100% participation is equivalent to the Winner-Takes-All option and is therefore not displayed. The hydro-only nodes with the highest profits are not displayed in this ranking.

Table 5.12 shows the nodes with the largest negative profit differentials with the status quo.

Table 5.12: Lowest Profits per Unit by Node v. Status Quo Disorderly

	#	Difference ($k/MW)	Node	REZ	REZ Name	Technology
Status quo Cost-Reflective	1	-163.12	Node P	NSW	*NSW Non-REZ*	Coal, Wind
	2	-97.27	Node G	N2	*New England*	Solar, Wind
	3	-89.94	Node W	N2	*New England*	Wind, Solar
	4	-85.87	Node F	N2	*New England*	Wind, Solar
	5	-83.90	Node E	NSW	*NSW Non-REZ*	Wind
Pro-Rata Access	1	-179.74	Node P	NSW	*NSW Non-REZ*	Coal, Wind
	2	-106.84	Node G	N2	*New England*	Solar, Wind
	3	-100.16	Node Z	N8	*Cooma-Monaro*	Wind
	4	-100.13	Node X	N8	*Cooma-Monaro*	Wind
	5	-98.99	Node O	N8	*Cooma-Monaro*	Wind
Pro-Rata Entitlement	1	-176.41	Node P	NSW	*NSW Non-REZ*	Coal, Wind
	2	-104.09	Node G	N2	*New England*	Solar, Wind
	3	-102.41	Node Z	N8	*Cooma-Monaro*	Wind
	4	-102.38	Node X	N8	*Cooma-Monaro*	Wind
	5	-101.20	Node O	N8	*Cooma-Monaro*	Wind
Winner-Takes-All	1	-159.71	Node P	N0	*NSW Non-REZ*	Coal, Wind
	2	-90.69	Node G	N2	*New England*	Solar, Wind
	3	-85.42	Node F	N2	*New England*	Wind, Solar
	4	-83.88	Node E	N0	*NSW Non-REZ*	Wind
	5	-83.87	Node D	NSW	*NSW Non-REZ*	Wind
Inferred Economic Dispatch	1	-163.12	Node P	NSW	*NSW Non-REZ*	Coal, Wind
	2	-97.27	Node G	N2	*New England*	Solar, Wind
	3	-89.94	Node W	N2	*New England*	Wind, Solar
	4	-85.87	Node F	N2	*New England*	Wind, Solar
	5	-83.90	Node E	NSW	*NSW Non-REZ*	Wind
RRP_{NEM} - 100% opt-in	1	-28.03	Node Q	T3	*Central Highlands*	Hydro, Wind
	2	-25.47	Node U	T2	*North-West Tasmania*	Hydro, Wind
	3	-24.70	Node J	T2	*North-West Tasmania*	Hydro, Wind
	4	-24.58	Node V	T2	*North-West Tasmania*	Hydro, Wind
	5	-24.20	Node I	T2	*North-West Tasmania*	Hydro, Wind

Source: NERA analysis of PLEXOS outputs. Note: the RRP_{CRM} scenario with 100% participation is equivalent to the Winner-Takes-All option and is therefore not displayed. The hydro-only nodes with the lowest profits are not displayed in this ranking.

The RRP differences between the status quo and the CMM scenario also play a key role in determining the "losers" among the nodes: we can see that most nodes shown in the table are in NSW, which experiences the largest negative profit difference with the status quo (over $20/MWh on average). In particular, the "loser" nodes are on the northern border with Queensland (New England) and in the south near the border with Victoria (Cooma-Monaro) where prices are affected by congestion.

5.8. Illustration: Impact on Storage

Using the same methodology described in Section 4.8, we derive profits of batteries when they charge at the LMP, either at the Regional Reference Node or in different nodes in each region. We account for the inconsistencies in PLEXOS results by applying the exclusion of the 2,609 half-hourly periods. However, the exclusion of the 2,609 half-hourly periods implies that a total of 59 days in this fiscal year does not report LMPs for at least one half-hourly period. As it is complex to optimise charging and discharging in days with partially missing LMPs, we exclude the 59 days from the analysis and scale results upwards on the 306 remaining full days. This approach has limitations because it most likely eliminates days with high price spreads, and therefore potentially lowers the profitability of battery storage.

We do not apply the regional scaling factor set out in Section 5.1 as this calculation does not depend on input load. The scaling factor is time-weighted and equal to 1.19[42].

We also do not adjust LMPs to ensure consistency with congestion price, following the methodology applied to the calculation of revenues for this fiscal year in the rest of the chapter.

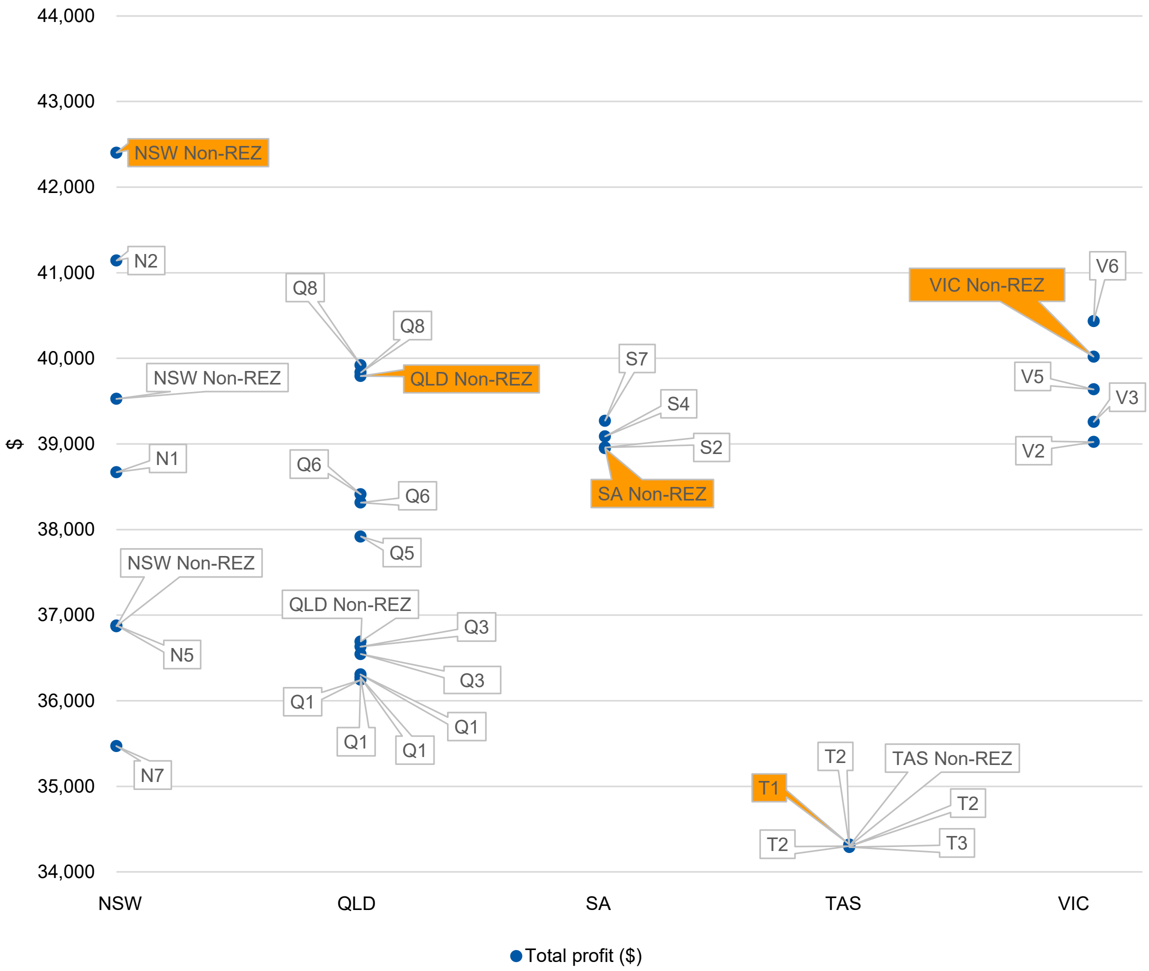
For our analysis, we choose all five reference nodes and the same "remote" nodes as in Section 4.8, as well as the "winner" nodes listed in Table 5.11.

In Section 4.8, we introduce the LGC unit subsidy scheme for renewable plants, set up at \$60/MWh. This subsidy scheme runs until 2030,[43] in conjunction with the national Large-Scale Renewable Energy Target (LRET). Therefore, in 2033-34 we no longer modify LMPs of zero to incorporate the value of the subsidy. This leads to batteries getting overall lower profits in 2033/34 compared to 2023/24. In 2023/24, batteries located at nodes with a higher concentration of renewables benefit from the wider price spread due to the LGC unit subsidy. For example, the node in NSW Non-REZ (not the reference node), connected to a solar farm, is the most profitable battery among the sampled nodes in NSW in 2023/24 (see Figure 4.10). Without the LGC unit subsidy, this same node in NSW Non-REZ is the least profitable battery among the sampled NSW nodes in 2033/34 (Figure 5.11).

42 The scaling factor is equal to (number of days in fiscal year)/(number of full days)=365/306.

43 Clean Energy Regulator website (accessed 12 November 2022), URL: https://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/qcmr/june-quarter-2022/Large-scale-generation-certificates-(LGCs).aspx

Figure 5.11: LMP Profits for 2-hour, 1 MW Battery by Location ($)



Source: NERA analysis. ***Note:*** *Nodes are organised by region; the regional reference node is highlighted in yellow for each region. The full name of REZs can be found in Table C.1.*

6. Estimated Impact of Modelling Assumptions and Simplifications

6.1. In Reality, AEMO's Clamping of Counter-Price Flows Would Influence Outcomes

In our PLEXOS model we observe instances of counter-price flows between regions, where energy flows from a high-price region to a low-price region ("against" the RRP differential). Flows in PLEXOS are expressed with respect to a "reference" direction, e.g. flow on the NSW-VIC interconnector has a positive sign when energy is flowing from NSW to VIC, and negative vice versa. In any given interval, we identify flow on an interconnector as "counter-price" when net flow on the interconnector and the difference between destination and origin RRP have opposite sign. The value of the counter-price flow is the product of net flow on the interconnector and the RRP differential. Table 6.1 shows the annual value of all counter-price flow by interconnector in the cost-reflective and disorderly run for 2023-24, broken down by direction of flow. The sign on the net flow for each interconnector follows the NEM convention, that is, a positive sign indicates a net flow north and a negative sign a net flow south.

For the 2023-24 fiscal year, the PLEXOS database contains 15 cross-regional lines, i.e. lines that transport energy from a node in one region to a node in another region. For simplicity, in Table 6.1 we aggregate them based on region of origin and region of destination into five unique bi-directional interconnectors.

Table 6.1: Overview of Counter-Price Flows by Interconnector in 2023-24 (Cost-reflective v. Disorderly Run)

Interconn.	Direction	Cost-reflective Counter-price flow value ($ thousands)	Flow (GWh)	Disorderly Counter-price flow value ($ thousands)	Flow (GWh)
VIC-NSW		**-204**	**5,047**	**-46,404**	**3,411**
	VIC to NSW	-73	6,430	-91	5,901
	NSW to VIC	-131	-1,383	-46,313	-2,490
TAS-VIC		**-0**	**1,364**	**-0**	**1,175**
	TAS to VIC	-0	2,470	-0	2,413
	VIC to TAS	-0	-1,106	-0	-1,238
NSW-QLD		**-75**	**-3,096**	**-6,883**	**-3,200**
	NSW to QLD	-12	1,866	-13	1,623
	QLD to NSW	-63	-4,962	-6,869	-4,823
NSW-SA		**-**	**-**	**-**	**-**
	NSW to SA	-	-	-	-
	SA to NSW	-	-	-	-
VIC-SA		**-24**	**4,537**	**-1,237**	**4,907**
	VIC to SA	-22	5,035	-1,235	5,309
	SA to VIC	-2	-499	-2	-402

Source: NERA analysis of PLEXOS outputs.

Table 6.2 shows the value and quantity of counter-price flows in 2033-34. In this fiscal year, the value of counter-price flows increases due to overall higher RRPs. Under disorderly bidding, we observe that counter-price flows go from NSW to QLD, while under cost-reflective bidding they travel from QLD to NSW. The value of these flows is much higher under disorderly bidding given the large (negative) difference in prices between NSW and QLD.

Table 6.2: Overview of Counter-Price Flows by Interconnector in 2033-34 (Cost-reflective v. Disorderly Run)

Interconn.	Direction	Cost-reflective Counter-price flow value ($ thousands)	Flow (GWh)	Disorderly Counter-price flow value ($ thousands)	Flow (GWh)
VIC-NSW		**-14,473**	**144**	**-78,108**	**1,036**
	VIC to NSW	-3,970	7,363	-1,486	6,413
	NSW to VIC	-10,502	-7,219	-76,622	-5,377
TAS-VIC		**-533**	**7,805**	**-1,597**	**7,958**
	TAS to VIC	-17	8,765	-296	8,924
	VIC to TAS	-516	-960	-1,301	-966
NSW-QLD		**-20,607**	**-4,007**	**-390,515**	**2,956**
	NSW to QLD	-20,584	3,911	-388,822	7,403
	QLD to NSW	-22	-7,918	-1,694	-4,447
NSW-SA		**-8,105**	**-1,387**	**-39,087**	**-1,305**
	NSW to SA	-6,726	1,027	-38,970	1,207
	SA to NSW	-1,379	-2,414	-117	-2,512
VIC-SA		**-2,438**	**-3,694**	**-8,207**	**-3,776**
	VIC to SA	-538	374	-1,241	361
	SA to VIC	-1,899	-4,068	-6,966	-4,137

Source: NERA analysis of PLEXOS outputs.

Under current arrangements, the market operator would prevent counter-price flows by clamping these flows and dispatching different capacity in the low-price area. The absence of counter-price flows will likely increase system costs measured by the total bids accepted as more costly capacity would tend to be dispatched instead of importing energy. Whether true underlying system costs increase as a result of clamping is less clear: under the status quo arrangements, markets participants with high marginal costs may bid to the market price floor to ensure dispatch (when they have the incentive to do so), whilst the clamped dispatch may bring on rival plant with lower cost but with lesser or no incentive to bid to the market price floor.

Counter-price flows happen in instances where there are discrepancies between RRP and LMPs across regions, where a node in region A might have less expensive generation connected to it than another node in the neighbouring Region B, but the RRP of Region A is higher than the RRP of Region B in the same interval. Therefore, the PLEXOS engine finds it optimal to export energy from the node in Region A to Region B, despite the RRP in Region A being higher.

Preventing counter-price flows will also affect the customer payments and generator revenues through changes in prices across the network. For instance, we can observe in our review of RRPs for 2023-24 presented in Table 4.3 that under disorderly bidding (where counter price flows are more consistent) we see higher RRPs in the northern regions of NSW and QLD and lower in the three southern regions. In the status quo, congestion and disorderly bidding combine to create counter-price flows towards Victoria, lowering the southern RRPs and raising the northern RRPs. A similar dynamic occurs in 2033-34 both with flows from NSW to VIC and from NSW to QLD. We know in practice that AEMO would clamp these flows, mitigating this price effect and impacting revenue outcomes. It is complex to assess these impacts without explicit modelling of the clamping effect.

6.2. We Do Not Account for Strategic Bidding in PLEXOS

"Strategic bidding" denotes any strategic behaviour by market participants beyond the race-to-the-floor bidding logic. For instance, a company owning multiple generation assets might withhold capacity from one asset to favour another, or a generator bidding more than their marginal cost because they are at the margin. The significant complexity of our model does not allow us to estimate the impact of such behaviour as it dispatches either under perfect cost-reflective logic or under our distorted logic for disorderly bidding. The lack of strategic bidding has several consequences for our modelling:

- Our prices, cost to consumers and generator revenues are likely to be on the low side in both the status quo and CMM/CRM scenarios because they do not take account of market power;
- Generally, the impact of facing the LMP at the margin is that it does not increase *locational* market power, it merely reveals it. If a generator is required at a particular location then it will ensure it extracts its value from the system operator, even in markets which are settled by zone or jurisdiction. The Australian system limits the extent to which generators can do this in practice, by paying a fixed (high) price for generators which are directed to produce by the system operator;
- As a result, the lack of strategic bidding in our modelling does not have clear directional effect on the costs and benefits for consumers and generators for the CMM/CRM;
- As an opt-in framework, the CRM may create opportunities for participants with market power to increase their allocation of rents in the relief market, which may dampen participation and reduce the modelled economic benefits. However, the scope to do so depends on the size of the individual participants.

6.3. Network Settings and Operation in Our PLEXOS Simulation Include Simplifying Assumptions

6.3.1. No Stability Constraints

Our PLEXOS model does not incorporate stability constraints for thermal generators, renewable generators or network assets, such as minimum up/down times. In reality, where the system operator has to account for these constraints, the system could have more congestion than the PLEXOS model leading to increased opportunity for disorderly bidding. However, congestion will only increase in circumstances where wider constraints were correlated with network flows. This could lead to an under-estimation of savings from marginal cost bidding.

6.3.2. No Loss Modelling

Our model does not include explicit modelling of transmission losses. The absence of loss modelling would affect revenues and the settlement residue marginally, since generators in reality earn a price adjusted by their marginal loss factor. This affects both the Cost reflective and Disorderly runs to the same extent.

Storage assets may be particularly affected by losses. Where LMPs are loss adjusted, they could be affected to a greater extent during peak hours (where loss factors tend to be higher) than off peak hours. As a result, the arbitrage revenue available to the battery may be compressed. It is not possible to quantify this effect without additional runs which included explicit modelling of losses.

The impact of losses on the CMM outcomes in practice would depend on how exactly the losses will be implemented in the CMM logic in determining allocation of access under each option. We do not provide a sensitivity estimate of CMM outcomes that accounts for losses in this report.

6.3.3. Hydro Excluded from Disorderly Bidding Log

In our model hydro plants (both run-of-river and pumped storages) do not engage in disorderly bidding in the disorderly run. The reason for this modelling choice is that our PLEXOS model is set up to optimise the hydro system over a one-year period and to pass down the storage constraints and targets to shorter-term daily models. Under such constraints any additional disorderly bid prices will conflict with the storage constraints, resulting in unrealistic dispatch outcomes.

In reality, we expect that hydro would bid at the floor, however only in the very limited number of instances when the RRP is higher than the shadow value of water. Therefore we believe that our approximation is not unreasonable.

6.4. We Do Not Quantify the Impact of Occasional Inconsistencies Between RRPs of Different Regions

We have observed in example periods that the RRPs in two connected regions differ even in the absence of reported congestion between these regions. Therefore in these periods the RRPs and congestion prices of the relevant interconnectors do not reconcile across regions.

On the other hand, given the reported data from PLEXOS, we are not able to determine whether the issue lies in the RRPs or the congestion prices – that is, whether there is under-reported congestion affecting the RRP spread or whether the lack of congestion is genuine and the RRPs should therefore be equal in the two connected regions. It is therefore difficult to apply an adjustment to either element, or to comment on whether an adjustment would increase or reduce the gap in profitability between the status quo and the reform options.

We have described in Section 3.1.4 the adjustment we apply to LMPs in 2023-24 where they are not consistent with the congestion price and RRP. The consistency between LMPs within a region and their RRP is the primary driver for the CMM outcomes; we ensure that it holds with our adjustments to LMPs. In 2033-34, we only adjust LMPs when calculating the impact of access on profitability for pro-rata options (See Section 3.1.4 and Chapter 5) and quantify the impact of the discrepancy between LMP and RRP through the “DX” component of the profit differential.

7. Conclusions

For this modelling study, we have constructed a detailed simulation of the NEM based on published assumptions by AEMO, following the capacity/transmission outlook of the Step Change scenario of the 2022 ISP. We have modelled different options for the proposed CMM based on different allocations of access (pro-rated on availability or entitlements, based on economic dispatch, or ordering by participation factor) and the voluntary CRM. We estimate the change in prices, costs to the system, revenues and profits of participants, and costs and revenues for storages for the reform options and a "status quo" that maintains the current market arrangements. We have reviewed results for 2023-24 and 2033-34, to observe the change in outcomes as the system transitions to predominantly zero-cost renewable capacity.

Overall, we find that under the CMM and CRM proposed options there are cost savings in the system due to more efficient dispatch, as the reform incentivises cost-reflective bidding. This finding holds in both 2023-24 and 2033-34. The difference in system costs between the reform and status quo increases in 2033-34 as most coal plants operating in 2023-24 retire, leaving the marginal position to zero-cost renewables and more costly natural gas – therefore, dispatching the lowest cost capacity achieves greater savings.

On the other hand, in aggregate across the NEM, the CMM options achieve lower revenues and profits for market participants compared to the status quo. The positive gains due to dispatch are offset by lost revenues due to reduced RRPs in the CMM. The results are more pronounced in 2033-34 as gas sets the price more often and prices increase.

A proportion of the efficiency gain from dispatch flows through to generators as an "efficiency dividend" and the remainder is a settlement residue (including both intra-regional and inter-regional settlement residues). However, there are model limitations to the allocation of the efficiency gain given there is no clamping applied to counter-price flows in PLEXOS which affects the inter-regional settlement residues. In addition, the RRP effect might be more modest in real-world outcomes. In the absence of clamping of counter-price flows by the market operator (see Section 6.1) and strategic bidding calculations by market participants (see Section 6.2), our PLEXOS representation faces model limitations which could affect RRPs outcomes significantly in practice.

The reduced RRPs shown in our modelling under the reform lead to a reduction in customer payments. However, the combination of lower costs to charge (as storage faces the RRP under the CMM/CRM) and the reduction in revenues leads to an increase in the NEM-wide settlement residue compared to the status quo.

The CRM with RRPs from the disorderly market is the only option reviewed that achieves more profitability overall. Under this option, participants do not experience the loss of profits due to overall lower RRPs compared to the status quo; furthermore, participants can opt into the CRM and be re-dispatched more efficiently according to cost-reflective logic. At full participation, in 2023-24 and 2033-34 profits are 3 and 5 per cent higher than the status quo, respectively. We also observe that partial participation is sufficient to achieve significant cost savings, however the extent of these cost savings depends on the technology and location of generators opting in, as these characteristics affect the efficiency of a re-dispatch under the CRM.

After reviewing results for both 2023-24 and 2033-34, we can compare different CMM options. We have discussed that the difference in outcomes for cost-reflective options lays in the method for allocating access, as all CMM options share the same dispatch and pricing assumptions. Within this framework, the two pro-rata options, which allocate access and entitlements based on availability, respectively, appear to mitigate the effects of congestion in aggregate by pro-rating access between participants behind a certain constraint. The winner-takes-all and inferred economic dispatch options, on the other hand, order dispatch either according to cost-effective dispatch or according to a plant's participation factor to a constraint. These methods imply that some plants will receive the entirety of access and others will receive none if they are less cost-efficient or have a higher participation factor, respectively. If the CMM design is chosen over the CRM, the policy design for the reform will have to weigh the mitigation of overall profit impacts against prioritising cost-effectiveness or low congestion impact when allocating access.

We have also addressed how in real life part of the price differences within a modelling run (between RRPs and LMPs in a region) and across the two modelling runs might be mitigated by clamping of counter-price interconnector flow. While it is complex to fully estimate the effect of clamping on our modelling results, we can envisage that it might mitigate part of the differences in profitability between the status quo and the reform options; this is particularly relevant in 2033-34, where the difference in revenues, costs and profits between scenario widens as the capacity mix of the NEM evolves.

Appendix A. Results for CMM Disorderly Sensitivities in 2023-24

Table A.1 shows the financial outcomes of CMM disorderly sensitivities compared to the status quo disorderly scenario. Costs remain unchanged across the sensitivities, as the dispatch is the same. All CMM disorderly sensitivities are less profitable compared to the status quo disorderly scenario.

Table A.1: Overview of Revenues, Costs and Profits by Disorderly Scenarios ($m)

Scenario	Model Run	Total Revenues	Total Costs	Profits (Rev. - Costs)	Profit diff. with Status quo disorderly	
Status Quo	Disorderly	4,924	2,900	2,025	-	-
CMM Scenarios						
Pro-Rata Access	Disorderly	4,633	2,900	1,733	-291.7	-14.4%
Pro-Rata Entitlement		4,633	2,900	1,733	-291.9	-14.4%
Winner-Takes-All		4,924	2,900	2,024	-0.6	0.0%
Inferred Economic Dispatch		4,751	2,900	1,851	-173.7	-8.6%

Source: NERA analysis of PLEXOS outputs.

Table A.2 shows that customer payments are identical across disorderly scenarios.

On the storage revenues and costs, the cost to charge of batteries and pump units are valued at the LMP for CMM scenarios and RRP for status quo scenarios. In disorderly sensitivities, the RRPs in SA and VIC are negative during more than 800 intervals whereas they are negative only during 7 intervals in VIC and always positive in SA in the cost-reflective scenarios. Therefore, the status quo disorderly sensitivity has lower storage cost to load compared to the status cost-reflective scenario ($18.2 million vs. $25.2 million).

The same effect takes place in CMM scenarios. With LMPs being negative in more intervals in the disorderly scenarios than in the status quo cost-reflective scenario (more than 1,000 intervals in some nodes in the disorderly scenario vs. 0-7 intervals in the cost-reflective scenario), the cost to charge drops to $15.2 million in the CMM scenarios because of the negative LMPs. The same reasoning holds for batteries revenues: batteries revenues are lower under the CMM disorderly sensitivities because of the negative LMPs compared to the CMM cost-reflective scenarios (Table 4.7), and the status quo disorderly scenario is lower than the status quo cost-reflective scenario because of negative RRPs.

The settlement revenue remains the highest in pro-rata access and pro-rata entitlement scenarios, where the revenues are the lowest among CMM scenarios ($4,608 million).

Table A.2: NEM-Wide SR Differentials by Disorderly Scenarios ($m)

Scenario	Customer Payments	Storage Cost to charge	Generators Revenues	Batt Revenues	NEM Settlement revenue
	[1]	[2]	[3]	[4]	[5]=[1]+[2]-[3]-[4]
Status Quo Disorderly	4,995	18.2	4,899	25.4	89
Status Quo Cost-Reflective	4,897	25.2	4,766	27.1	129
CMM scenarios					
Pro-rata Access	4,995	15.2	4,608	24.8	378
Pro-rata Entitlement	4,995	15.2	4,608	24.8	378
Winner-Takes-All	4,995	15.2	4,899	24.8	87
Inferred Economic Dispatch	4,995	15.2	4,726	24.8	260

Source: NERA analysis of PLEXOS outputs.

Appendix B. Results for CMM Disorderly Sensitivities in 2033-34

We provide the scaled-up results for CMM disorderly sensitivities.

Table B.1 below presents total revenues, costs and profits for the status quo and the disorderly reform options in 2033-34. Pro-rata access and pro-rata entitlement options are around 30 per cent less profitable than the status quo. The inferred economic dispatch scenario is less profitable than the status quo by 4.5 per cent (v. 16.2 per cent in the cost-reflective sensitivity in Table 5.5). Unlike the cost-reflective scenario result (Table 5.5), the winner-takes-all dispatch scenario is more profitable in the disorderly model run by 7.8 per cent.

Table B.1: Overview of Revenues, Costs and Profits by Disorderly Scenarios ($m)

Scenario	Model Run	Total Revenues	Total Costs	Profits (Rev. - Costs)	Profit diff. with Status quo disorderly	
Status Quo	Disorderly	12,589	2,858	9,731	-	-
CMM Scenarios						
Pro-Rata Access	Disorderly	8,542	1,809	6,733	-2,997	-30.8%
Pro-Rata Entitlement		8,660	1,809	6,851	-2,880	-29.6%
Winner-Takes-All		12,294	1,809	10,485	754	7.8%
Inferred Economic Dispatch		11,103	1,809	9,294	-436	-4.5%

Source: NERA analysis of PLEXOS outputs

Table B.2 below shows the settlement residue calculation for the status quo and the disorderly reform options.

Customers pay the RRP associated with the disorderly model run (column [1]), therefore the customers pay the same amount of $12,106 million across all CMM options, i.e., $1,708 million more than in the cost-reflective CMM options (Table 5.8).

In the status quo, storages charge at the cost of RRP, while storages pay the LMP under the CMM options. In the disorderly model run, the storage charging costs are negative (column [2]). Indeed, the LMP at nodes attached to the QLD pump units Kidston and Wivenhoe are negative respectively during 3,683 periods and 509 periods, while the QLD reference node is never negative. Consequently, the negative LMPs result in negative charging costs for pump QLD pump units in the CMM sensitivities. The same effect occurs for battery nodes in SA and QLD where batteries get negative charging costs because of the negative LMPs.

Batteries revenues are remunerated at the LMP and constant across all CMM scenarios. For the same reason as storage charging costs, batteries are remunerated at a negative LMP at their respective nodes during specific periods, which results in lower batteries revenues in the

CMM scenarios compared to the status quo ($644.1 million v. $939.4 million in the status quo).

Similarly to the cost-reflective scenarios (Table 5.8), the disorderly CMM reform options offer lower revenues for the generators (column [3]) compared to the status quo, in particular for pro-rata access and pro-rata entitlement scenarios.

In total, the lower generator revenues in the pro-rata access and pro-rata entitlement scenarios compared to the status quo offers an increase in the settlement residue (respectively $3,197 million and $3,079 million v. $199 million in the status quo). Conversely, the higher generator revenues in the winner-takes-all and inferred economic dispatch scenarios lead to lower and even negative settlement residues in these two CMM sensitivities (respectively -$555 million v. $636 million) compared to the status quo.

Table B.2: NEM-Wide SR Differentials by Disorderly Scenarios ($m)

Scenario	Customer Payments	Storage Cost to charge	Generators Revenues	Batt Revenues	NEM Settlement revenue
	[1]	[2]	[3]	[4]	[5]=[1]+[2]-[3]-[4]
Status Quo Disorderly	12,106	682.2	11,649	939.4	199
Status Quo Cost-Reflective	10,398	516.8	9,382	843.8	689
CMM Scenarios					
Pro-rata Access	12,106	-367.3	7,898	644.1	3,197
Pro-rata Entitlement	12,106	-367.3	8,015	644.1	3,079
Winner-Takes-All	12,106	-367.3	11,649	644.1	-555
Inferred Economic Dispatch	12,106	-367.3	10,459	644.1	636

Source: NERA analysis of PLEXOS outputs

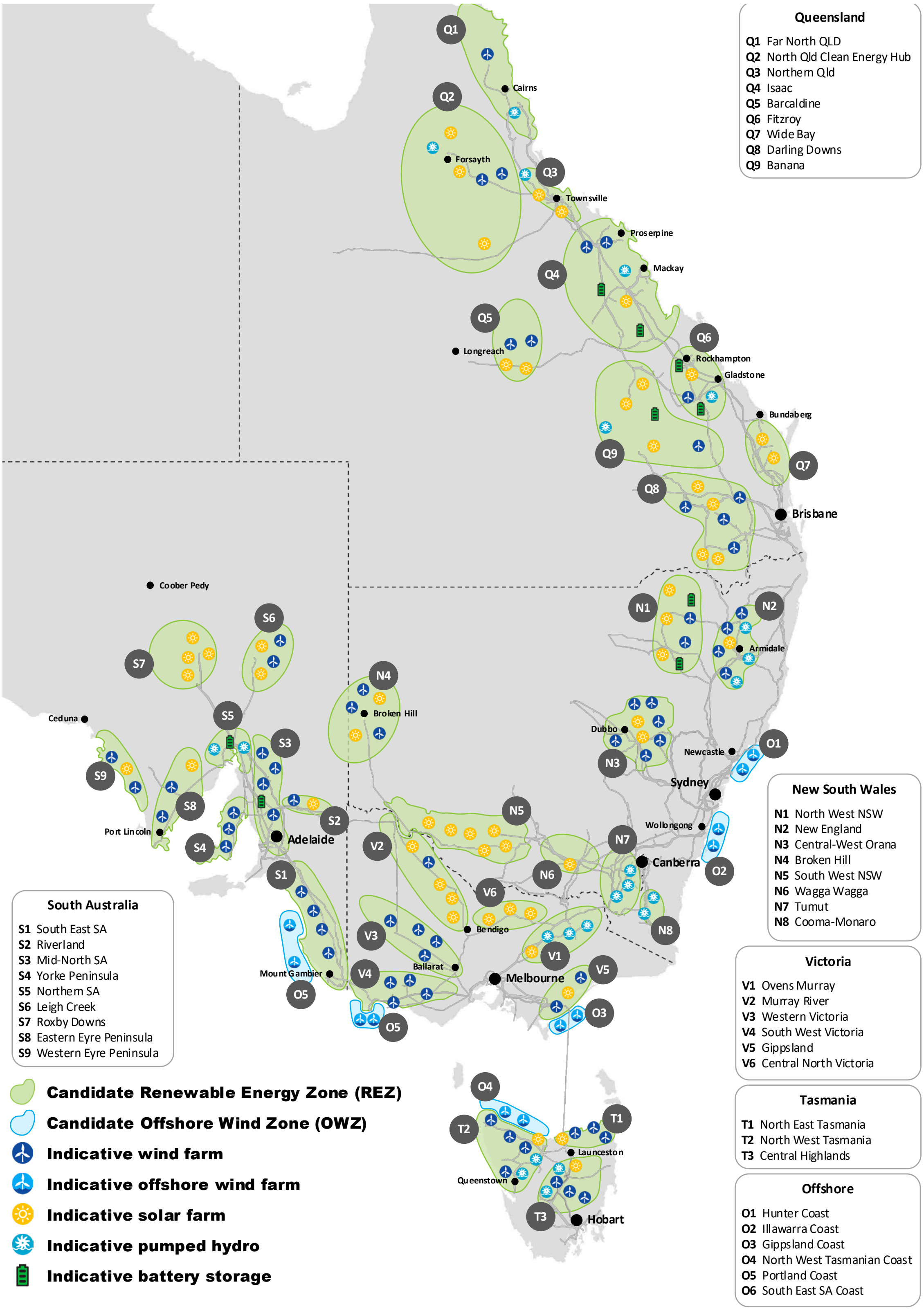
Appendix C. REZ List and Map

Table C.1: List of Renewable Energy Zones

Code	REZ Name	NEM Region	ISP Sub-Region
Q1	Far North QLD	QLD	CNQ
Q2	North Qld Clean Energy Hub	QLD	CNQ
Q3	Northern Qld	QLD	CNQ
Q4	Isaac	QLD	CNQ
Q5	Barcaldine	QLD	CNQ
Q6	Fitzroy	QLD	CNQ
Q7	Wide Bay	QLD	SQ
Q8	Darling Downs	QLD	SQ
Q9	Banana	QLD	SQ
N1	North West NSW	NSW	NNSW
N2	New England	NSW	NNSW
N3	Central-West Orana	NSW	CNSW
N4	Broken Hill	NSW	SNSW
N5	South West NSW	NSW	SNSW
N6	Wagga Wagga	NSW	SNSW
N7	Tumut	NSW	SNSW
N8	Cooma-Monaro	NSW	SNSW
V1	Ovens Murray	VIC	VIC
V2	Murray River	VIC	VIC
V3	Western Victoria	VIC	VIC
V4	South West Victoria	VIC	VIC
V5	Gippsland	VIC	VIC
V6	Central North Vic	VIC	VIC
S1	South East SA	SA	SA
S2	Riverland	SA	SA
S3	Mid-North SA	SA	SA
S4	Yorke Peninsula	SA	SA
S5	Northern SA	SA	SA
S6	Leigh Creek	SA	SA
S7	Roxby Downs	SA	SA
S8	Eastern Eyre Peninsula	SA	SA
S9	Western Eyre Peninsula	SA	SA
T1	North East Tasmania	TAS	TAS
T2	North West Tasmania	TAS	TAS
T2	Central Highlands	TAS	TAS

Source: AEMO (2022) – 2022 Inputs, Assumptions and Scenario Workbook

Figure C.1: REZ Map



Source: AEMO (2022) – 2022 Inputs, Assumptions and Scenario Workbook

Appendix D. List of ISP Projects Implemented in PLEXOS Nodal Model

Below we list the ISP projects represented in our PLEXOS nodal model. We follow the "Optimal Development Path" for the Step Change Scenario. The first section of the table shows projects present in our 2023/24 simulation and the second sections the additional projects present in the 2033/34 simulation. Please refer to the 2022 ISP for further detail on the projects.

Table D.1: ISP Projects Implemented in PLEXOS Nodal Model

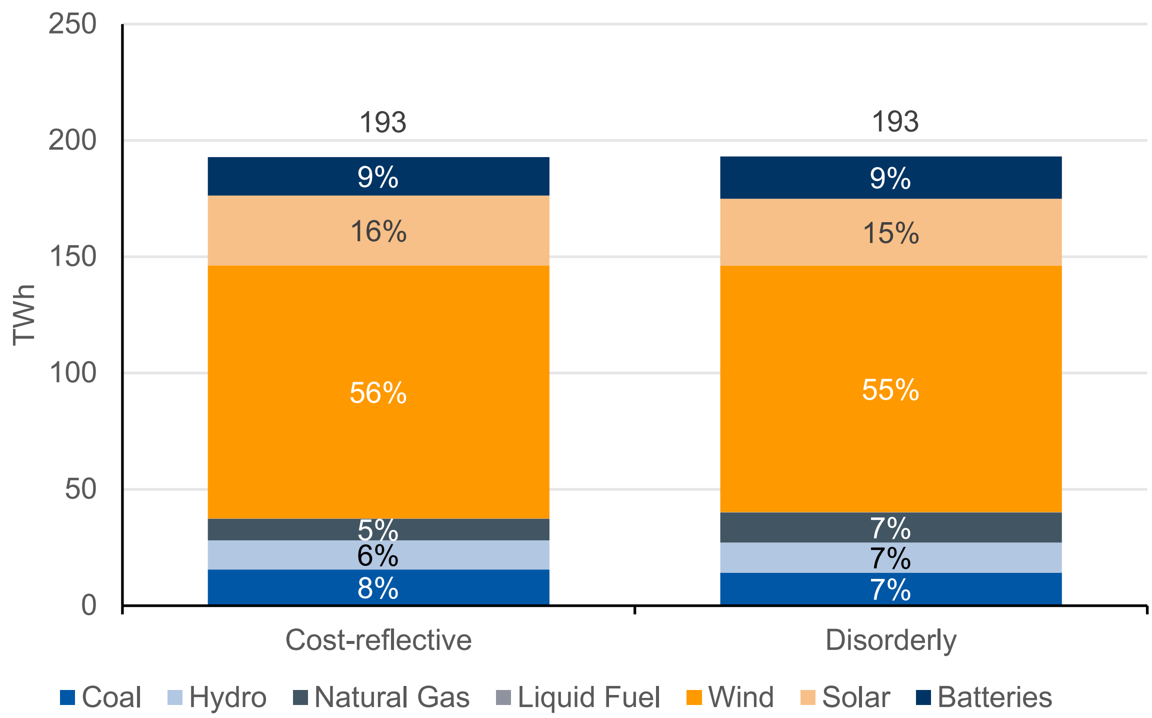
Project Name	ISP Status	Timing (Step Change)
QNI Minor	Committed	Mid-2023
Eyre Peninsula Link	Committed	Early 2023
VNI Minor	Committed	November 2022
Northern QLD REZ (Stage 1)	Anticipated	September 2023
Project EnergyConnect	Anticipated	July 2026
Central West Orana REZ Transm. Link	Anticipated	Mid-2025
Western Renewables Link	Anticipated	July 2026
New England REZ Transm. Link	Actionable	July 2027
Sydney Ring (reinforcement)	Actionable	July 2027
HumeLink (Stage 2)	Actionable	July 2026
Marinus Link Cable 1	Actionable	July 2029
Marinus Link Cable 2	Actionable	July 2031
VNI West (Stage 2, via Kerang)	Actionable	July 2031
Central to Southern QLD (Stage 1)	Future	2028-29
Darling Downs REZ Expansion (Stage 1)	Future	2028-29
South-East SA REZ Expansion	Future	2028-29
Gladstone Grid Reinforcement	Future	2030-31
Facilitating Power to Central QLD (Stage 1)	Future	2033-34
QNI Connect	Future	2032-33
South-West VIC REZ Expansion (Stage 1)	Future	2033-34
Mid-North SA REZ Expansion (Stage 1)	Future	2033-34

Source: AEMO (30 June 2022), 2022 Integrated System Plan – Appendix 5: Network Investments.

Appendix E. Non-Scaled Results For 2033-34

We present in this Appendix the 2033-34 results before the application of the regional scaling factors.

Figure E.1: Non-Scaled Generation Mix in 2033-34



Source: NERA analysis of PLEXOS outputs.

Table E.1: System Costs Modelled, Cost-Reflective v. Disorderly case ($m)

Model Run	Generation Cost
Cost-Reflective	1,314
Disorderly	1,829
Difference (Cost-Reflective - Disorderly)	-515
	-28.1%

Source: NERA analysis of PLEXOS outputs.

Table E.2: Overview of Revenues, Costs and Profits by Cost-Reflective Scenarios ($m)

Scenario	Model Run	Total Revenues	Total Costs	Profits (Rev. - Costs)	Profit diff. with Status quo disorderly	
Status Quo	Disorderly	10,578	2,402	8,176	-	-
CMM Scenarios						
Pro-Rata Access	Cost-Reflective	8,492	1,725	6,767	-1,409	-17.2%
Pro-Rata Entitlement		8,492	1,725	6,767	-1,409	-17.2%
Winner-Takes-All		8,726	1,725	7,001	-1,175	-14.4%
Inferred Economic Dispatch		8,580	1,725	6,855	-1,321	-16.2%
CRM scenarios						
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	8,726	1,725	7,001	-1,175	-14.4%
RRP_{NEM} - 100% opt-in		10,354	1,725	8,629	453	5.5%

Source: NERA analysis of PLEXOS outputs.

Table E.3: Overview of Revenues, Costs and Profits by Cost-Reflective Scenarios with OOM Generators settled at LMP ($m)

Scenario	Model Run	Total Revenues	Total Costs	Profits (Rev. - Costs)	Profit diff. with Status quo disorderly	
Status Quo	Disorderly	10,578	2,402	8,176	-	-
CMM Scenarios						
Pro-Rata Access	Cost-Reflective excl. OOM	8,457	1,725	6732 (-35)	-1,444	-17.7%
Pro-Rata Entitlement		8,456	1,725	6731 (-36)	-1,445	-17.7%
Winner-Takes-All		8,719	1,725	6995 (-7)	-1,181	-14.5%
Inferred Economic Dispatch		8,580	1,725	6855 (0)	-1,321	-16.2%

Source: NERA analysis of PLEXOS outputs. The difference with the default case refers to the results in Table E.2: Overview of Revenues, Costs and Profits by Cost-Reflective Scenarios ($m) above.

Table E.4: Decomposition of the Profit Change by Cost-Reflective Reform Option ($m)

Scenario	Model Run	DE	DP	DA	DX	Profit Change v. Status Quo Disorderly
CMM Scenarios						
Pro-Rata Access	Cost-Reflective	453.0	-1,627.9	-22.8	-211.6	-1,409.2
Pro-Rata Entitlement		453.0	-1,627.9	-20.8	-213.1	-1,408.8
Winner-Takes-All		453.0	-1,627.9	-	-	-1,174.9
Inferred Economic Dispatch		453.0	-1,627.9	-146.2	-	-1,321.1
CRM scenarios						
RRP_{CRM} - 100% opt-in	Energy market disorderly, CRM cost-reflective	453.0	-1,627.9	-	-	-1,174.9
RRP_{NEM} - 100% opt-in		453.0	-	-	-	453.0

Source: NERA analysis of PLEXOS outputs.

Table E.5: NEM-Wide Settlement Residue by Reform Option ($m)

Scenario	Cust. Payment	Storage Cost to charge	Gen. Revenue	Batt. Revenue	NEM SR
	[1]	[2]	[3]	[4]	[5]=[1]+[2]-[3]-[4]
Status Quo Disorderly	10,167	573	9,789	789	162
Status Quo Cost-Reflective	8,736	434	7,889	709	571
CMM Scenarios					
Pro-rata Access	8,736	411	7,801	690	655
Pro-rata Entitlement	8,736	411	7,802	690	655
Winner-Takes-All	8,736	411	8,036	690	421
Inferred Economic Dispatch	8,736	411	7,889	690	567
CRM Scenarios					
RRP_{CRM} - 100% opt-in	8,736	411	8,036	690	421
RRP_{NEM} - 100% opt-in	10,167	411	9,664	690	224

Source: NERA analysis of PLEXOS outputs.

Table E.6: NEM-Wide Settlement Residue by Scenario with OOM Generators settled at LMP ($m)

Scenario	Cust. Payment	Storage Cost to charge	Gen. Revenue	Batt. Revenue	NEM SR (Diff with Table E.5)
Status Quo Disorderly	10,167	573	9,789	789	162
CMM scenarios					
Pro-rata Access	8,736	411	7,767	690	690 (+34.6)
Pro-rata Entitlement	8,736	411	7,766	690	691 (+36)
Winner-Takes-All	8,736	411	8,029	690	427 (+6.6)
Inferred Economic Dispatch	8,736	411	7,889	690	567 (0)

Source: NERA analysis of PLEXOS outputs.

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