# TECHNICAL WORKING GROUP

## OPERATIONAL SUBGROUP

ENERGY SECURITY BOARD

17 NOVEMBER 2022

# AGENDA



| Time | Topic |
| --- | --- |
| **2:00** | Welcome, objectives and agenda |
| **2:05** | Open forum – discussion of Directions Paper |
| **2:45** | • Overview of the modelling approach<br>○ Scope<br>○ PLEXOS set up<br>○ Model limitations<br>○ Scenarios<br>• Overview of results (2023-24)<br>○ Aggregate outcomes (cost, RRP and profit changes)<br>○ Detailed snapshot (dispatch and financial outcomes under CRM/CMM variants) |
| **3:55** | Next steps |
| **4:00** | Close |

# MODELLING

## Overview of modelling approach

# MODEL SCOPE



*The purpose of the modelling exercise is to show the differences in outcomes for market participants between options (including do nothing) rather than to replicate all the complexity of the NEM.*

**Model scope**

The ESB has contracted NERA Economic Consulting (NERA) to perform an iterative market modelling exercise to quantify the outcomes resulting from different congestion management design options, focused on the operational timeframes.

The purpose of the modelling is to:

- consider the impact of the proposed design choices on the bidding incentives faced by market participants
- model the impact of changed bidding behaviour on dispatch and pricing outcomes
- present the market outcomes from different design options for different groups of market participants, including:
    - different types of plant (e.g. by fuel type, or scheduled versus semi scheduled)
    - generators who are eligible to receive congestion rebates versus those who are not
    - generators who are located in congested and uncongested locations.

**Initial questions for modelling**

- Does cost reflective bidding achieve a more cost-efficient outcome compared to today's disorderly bidding?
- What are the profit outcomes at an individual generator level, from the CRM design and CMM rebate allocation methods?
- How similar are these profit outcomes to today's market design?
- What is the system cost impact if there is partial participation in the CRM?
- How much profit gain can batteries achieve when charging at the LMP (versus RRP)?
- How do the results change over the modelled time horizon?

# OPENING MESSAGES



*Preliminary draft results are shared for discussion today, but key insights are pending further model outputs.*

- Initial draft results are shared for 2023-24 only. Key insights and conclusions are pending 2033-34 outcomes.
- 2023-24 is not the planned date of reform implementation. It provides a baseline of results to analyse the impact of the model options on today's generation fleet and transmission network.
- Cost-reflective bidding achieves a more cost-efficient outcome compared to today's disorderly bidding.
- Disorderly bidding exacerbates congestion and counter-price flows.
- Modelled outcomes can be difficult to understand at face value because of the complexities of the physical system and market design.
- LMPs give participants more transparency about why distorted market outcomes arise in the event of congestion.
- Modelled RRPs change between the cost-reflective and disorderly bidding scenarios. However, the RRP outcomes should not be given weight given the model scope and limitations.

**We want to draw on TWG insights as part of our quality review of the modelling results.**

# DISCUSSION OF RESULTS



**Thursday 17 November, 2022 (today's TWG)**

- 2023-24 aggregate results
  - Cost outcomes
  - RRP outcomes
  - Profit changes
- Dispatch and financial outcomes for detailed snapshot of congestion in south west NSW including:
  - Counter price flows
  - CMM access allocations
  - CRM trading outcomes.

**Thursday 1 December, 2022**

- 2033-34 aggregate results (and comparison to 2023-24)
- Detailed snapshot of congestion in 2033-34
- Sensitivities/scenario analysis including:
  - CRM partial participation
  - Analysis of battery profits settling at RRP vs LMP
  - Exclusion of out-of-merit generators from CMM rebate allocation methods.

# PLEXOS MODELLING



*PLEXOS enables a simulation of dispatch and pricing outcomes at half-hourly intervals. It adopts a cost-minimization approach with inputs and assumptions from the ISP 2022. PLEXOS defines a nodal network in order to simulate the impacts of congestion for market participants.*

### PLEXOS modelling software

- cost-minimising market-modelling and system planning software package
- optimises the short-term optimal dispatch patterns in the nodal framework
- dispatch and pricing outcomes in each half hour of the modelling horizon in order to determine outcomes under different scenarios

### Defining the nodal network

- based on the ESOO and ISP 2022 generation and transmission outlook
- modified based on AEMO locational data and ISP 2022 Step Change scenario
- 1,068 nodes and 1,942 lines

**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 |

### Forecast demand

- based on ISP 2022 forecast demand (POE 10)
- allocate load to nodes based on 'load participation factors' derived from AEMO data

### Forecast capacity and storage mix

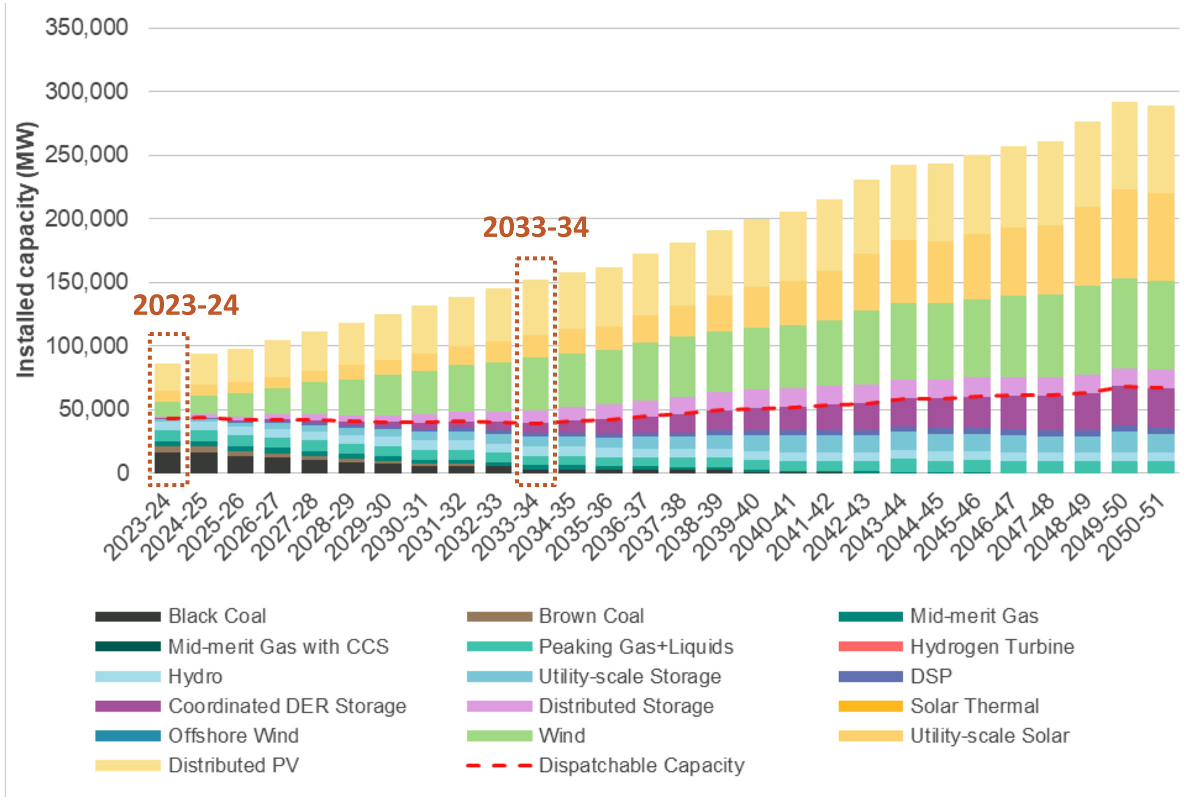
- recreate ISP 2022 capacity outlook in a nodal dimension
- cap on new capacity by technology based on ISP capacity outlook
- generator and battery properties from 2022 Inputs and Assumptions Workbook
- updated with additional ESOO properties for short-term dispatch e.g. minimum up time, must-run units, fixed load, min load, max ramp up, max ramp down, forced outage rate, outage factor, min time to repair.
- availability of renewable plants based on traces from ISP 2022 databases for solar and wind plants

# TIME HORIZONS



*Two time periods are modelled for 2023-24 and 2033-34, which adopt the generation and transmission assumptions of the ISP 2022.*

**Forecast NEM capacity to 2050, Step Change, CDP12**




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

Scenarios modelled for two annual snapshots; 2023-24 and 2033-34 (latter results are pending).

**ISP projects**

| 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 |
| QNI Connect | Future | 2032-33 |
| Facilitating Power to Central QLD (Stage 1) | Future | 2033-34 |
| 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.*

# BIDDING ASSUMPTIONS



*'Cost reflective' bidding and 'disorderly' bidding are critical assumptions that define the scenarios. Disorderly bidding is only applied to in-merit generators that are facing a binding constraint (it is not applied to all market participants).*

**Cost reflective bidding**

All generators bid their short-run marginal cost as an offer price and PLEXOS selects the cost-minimising dispatch.

*Assumptions*

- Thermal - ISP 2022 assumptions on fuel prices
- Variable renewable energy - ISP 2022 assumptions
- Hydro - PLEXOS optimises the dispatch of hydro plant over a one-year horizon i.e. considers the marginal value of storage based on the global hydro resource availability for the year
- Batteries – a 'medium term' optimisation run is executed before the short-term one. This simulation models a schedule of charging and discharging and passes the information onto the short-term model run.

**Disorderly bidding**

In-merit generators facing a binding constraint have an incentive to bid to the market floor price (-$1,000/MWh) in order to secure dispatch and earn the RRP.

*Assumptions*

- Identify generators for disorderly bidding from the cost-reflective run:
  - short-run marginal cost < RRP, by more than $1/MWh;
  - LMP < RRP, by more than $1/MWh.
- All other generators bid at short run marginal cost.

In scope (for disorderly bidding)

- Coal
- Gas
- Solar
- Wind

Out of scope (always cost reflective)

- Battery
- Hydro

# MODEL LIMITATIONS



*Modelled outcomes must be interpreted carefully given the model limitations.*

### Simplification of PLEXOS simulation

- No modelling of stability constraints
- No modelling of transmission losses

### Limitations on bidding behaviour

- No disorderly bidding for hydro and batteries
- No strategic bidding beyond bidding at cost or market price floor

### No clamping for counter price flows

- There are instances of counter-price flows between regions in the PLEXOS model i.e. energy flows from a high-priced region to a flow-priced region.
- In practice, when the accrued value of counter-price flows across an interconnector exceeds $100,000, AEMO "clamps" the interconnector i.e. intervenes in dispatch so that the counter-price flow ceases to avoid large negative inter-regional settlement residues.
- PLEXOS modelling does not simulate this clamping procedure.

### Value and volume of counter price flows

| | | Cost-reflective | | Disorderly | |
|---|---|---|---|---|---|
| Interconnector | | Value $'000s | Flow GWh | Value $'000s | Flow GWh |
| **NSW-VIC** | | **-204** | **-5,047** | **-46,404** | **-3,411** |
| | NSW to VIC | -131 | 1,383 | -46,313 | 2,490 |
| | VIC to NSW | -73 | 6,430 | -91 | 5,901 |
| **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 |

**DRAFT results (17 Nov 2022)**

# SCENARIOS

ENERGY SECURITY BOARD

*Bidding assumptions are tailored to each CRM and CMM scenario.*

| | Base case | CRM scenarios | | | CMM scenarios | | | |
|---|---|---|---|---|---|---|---|---|
| **Field** | Status quo | 100% opt in with $RRP_{NEM}$ | 100% opt in with $RRP_{CRM}$ | Partial opt in with $RRP_{NEM}$ | Pro rata access | Pro rata entitlement | 'Winner takes all' | Inferred economic dispatch |
| Bidding – energy market | | | | | | | | |
| Unconstrained and/or out of merit generators | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost |
| Constrained in-merit generators | **Market floor price** | **Market floor price** | **Market floor price** | **Market floor price** | **Short run marginal cost** | **Short run marginal cost** | **Short run marginal cost** | **Short run marginal cost** |
| Bidding – CRM | | | | | | | | |
| All generators | n/a | **Short run marginal cost** | **Short run marginal cost** | **Short run marginal cost** | n/a | n/a | n/a | n/a |

# SCENARIOS



*CRM scenarios reflect a design choice from the Directions Paper about the calculation of RRP (based on the energy market, or the CRM).*

| | Base case | CRM scenarios | | | CMM scenarios | | | |
|---|---|---|---|---|---|---|---|---|
| **Field** | Status quo | 100% opt in with $RRP_{NEM}$ | 100% opt in with $RRP_{CRM}$ | Partial opt in with $RRP_{NEM}$ | Pro rata access | Pro rata entitlement | 'Winner takes all' | Inferred economic dispatch |
| Bidding – energy market | | | | | | | | |
| Unconstrained and/or out of merit generators | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost |
| Constrained in-merit generators | Market floor price | Market floor price | Market floor price | Market floor price | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost |
| Bidding – CRM | | | | | | | | |
| All generators | n/a | Short run marginal cost | Short run marginal cost | Short run marginal cost | n/a | n/a | n/a | n/a |

The Directions Paper includes a design choice as to whether the RRP is based on the energy market or CRM.

$RRP_{NEM}$ where the RRP is based on the energy market, as it is currently calculated.

$RRP_{CRM}$ where the RRP is based on the CRM i.e. the marginal cost of an additional unit of load at the RRN in the CRM.

# SCENARIOS



*CMM scenarios refer to the four rebate allocation methods previously discussed with the TWG.*

| | Base case | CRM scenarios | | | CMM scenarios | | | |
|---|---|---|---|---|---|---|---|---|
| **Field** | Status quo | 100% opt in with $RRP_{NEM}$ | 100% opt in with $RRP_{CRM}$ | Partial opt in with $RRP_{NEM}$ | Pro rata access | Pro rata entitlement | 'Winner takes all' | Inferred economic dispatch |
| Bidding – energy market | | | | | | | | |
| Unconstrained generators | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost |
| Constrained generators | Market floor price | Market floor price | Market floor price | Market floor price | Short run marginal cost | Short run marginal cost | Short run marginal cost | Short run marginal cost |
| Bidding – CRM | | | | | | | | |
| All generators | n/a | Short run marginal cost | Short run marginal cost | Short run marginal cost | n/a | n/a | n/a | n/a |

**Pro-rata access** – based on offered availability. It allocates access to each generator in proportion to their available capacity in each interval.

**Pro-rata entitlement** – based on a combination of constraint coefficients and offered availability. It allocates entitlements (access x coefficient) (rather than access) in proportion to availability.

**'Winner takes all'** – assigns access 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.

**Inferred economic dispatch** - allocates access on a combination of constraint coefficients and inferred marginal costs.

# MODELLING

## Overview of results (2023-24)

# OVERVIEW OF RESULTS



**Cost reflective bidding achieves lower system costs than disorderly bidding**

| | Total system costs $m | |
|---|---|---|
| **Model run** | **2023-24** | **2033-34** |
| Disorderly (status quo) | 2,881 | *tba* |
| Cost-reflective (CRM/CMM) | 2,841 | *tba* |
| Difference | 40<br>(1.4%) | *tba* |

DRAFT results (17 Nov 2022)

# OVERVIEW OF RESULTS



**RRPs are affected by the change in bidding strategies, but it is complex to model and PLEXOS does not include AEMO's procedures for clamping**

*Draft results redacted given results have been superseded.*

*Final model outcomes will be published online.*

**Model limitations**

- No clamping of counter price flows.

  Clamping could significantly change RRP outcomes. The impact of RRP changes is separately itemised (see overleaf).
- No modelling of stability constraints (thermal constraints only)
- No strategic bidding
- Draft results provided for 2023-24 only (direction and size of RRP changes may vary over time, 2033-34 pending)

**There are three key components to the change in profits between status quo (disorderly) and the CRM/CMM (cost reflective) scenarios**

Profit change$ = DE$ + DA$ + DP$:

where:

DE$ = $\Delta$G x (LMP – cost) = profit change due to a change in ***dispatch***

DA$ = $\Delta$A x ($RRP_{SCEN}$ – LMP) = profit change due to changes in ***access***

DP$ = $\Delta$RRP x $G_{SQ}$ = profit change due to changes in ***RRP***

Notes:

G = dispatched output
A = access
SQ means status quo
$\Delta$ means change
$A_{SQ} = G_{SQ}$

**Decomposition of the profit change by reform option/scenarios**

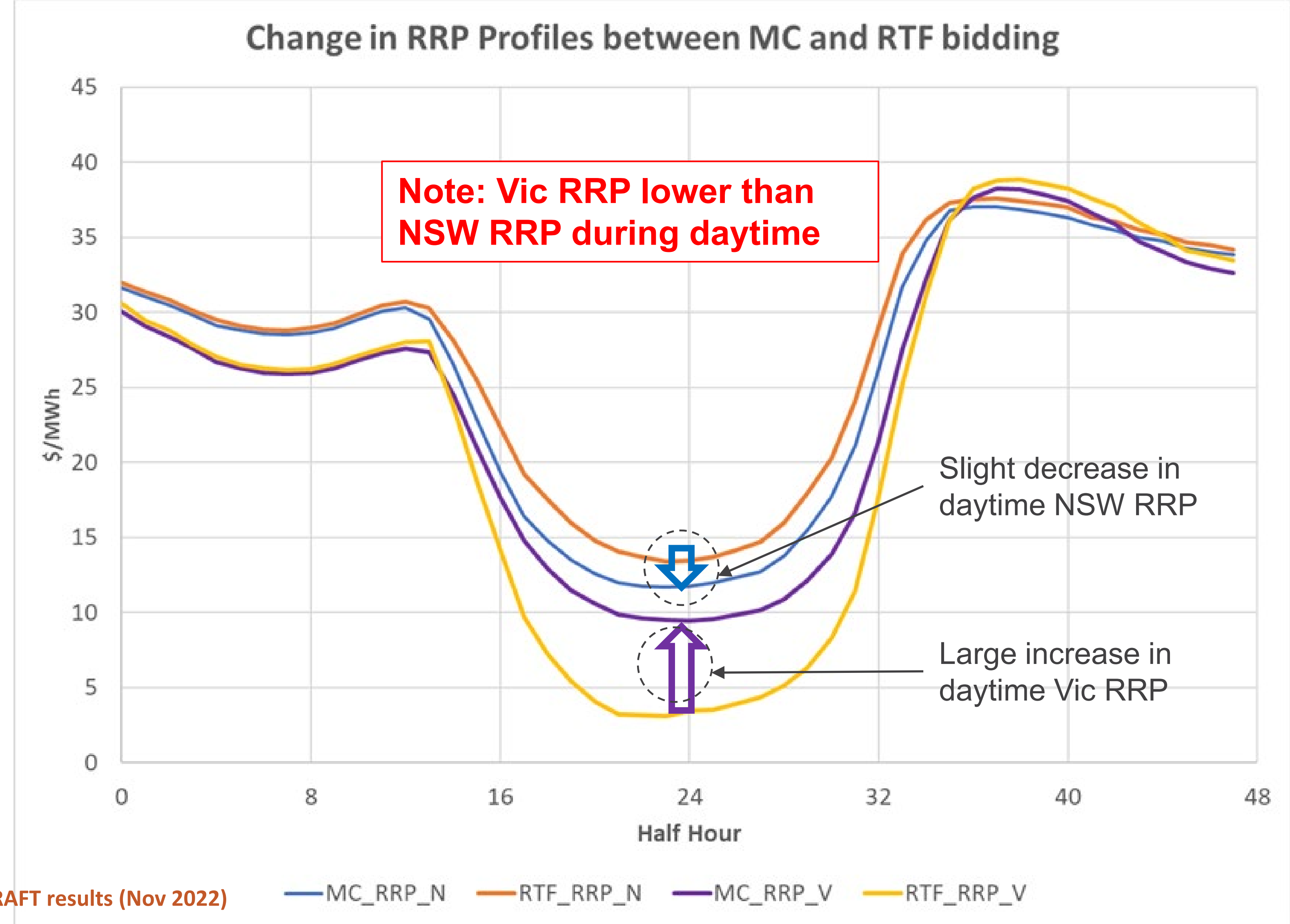
*Draft results redacted given results have been superseded. Final model outcomes will be published online.*

| Scenario | Bidding | DE \$m | DA \$m | **Subtotal \$m - profit change versus status quo disorderly** | DP \$m | **Total \$m - Profit change versus status quo disorderly** |
|---|---|---|---|---|---|---|
| CRM scenarios | | | | | | |
| $RRP_{CRM}$ - 100% part. | Energy market disorderly, CRM cost-reflective | tbc | tbc | tbc | tbc | tbc |
| $RRP_{NEM}$ - 100% part. | | tbc | tbc | tbc | tbc | tbc |
| CMM scenarios | | | | | | |
| Pro-rata access | Cost-reflective | tbc | tbc | tbc | tbc | tbc |
| Pro-rata entitlement | | tbc | tbc | tbc | tbc | tbc |
| Winner-takes-all | | tbc | tbc | tbc | tbc | tbc |
| Inferred economic dispatch | | tbc | tbc | tbc | tbc | tbc |

**DRAFT results (16 Nov 2022)**

where:
DE\$ = profit change due to a change in dispatch DA\$ = profit change due to changes in access DP\$ = profit change due to changes in RRP

# 2023 DISPATCH RESULTS



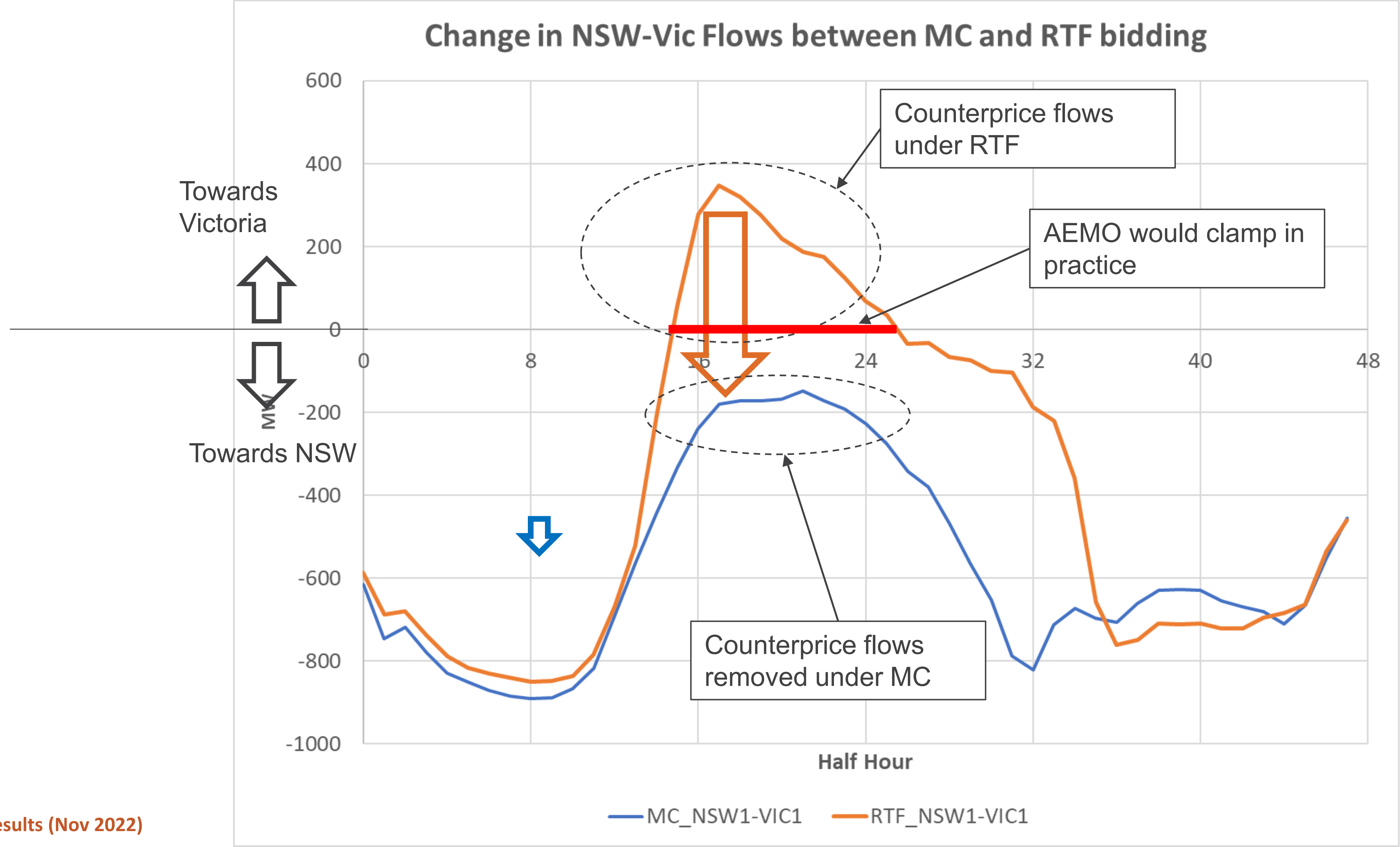

DRAFT results (Nov 2022)

RTF = "Race-to-the-floor"

⇩

MC = Marginal Cost

# 2023 DISPATCH RESULTS




DRAFT results (Nov 2022)

## MAIN POINTS OF CONGESTION

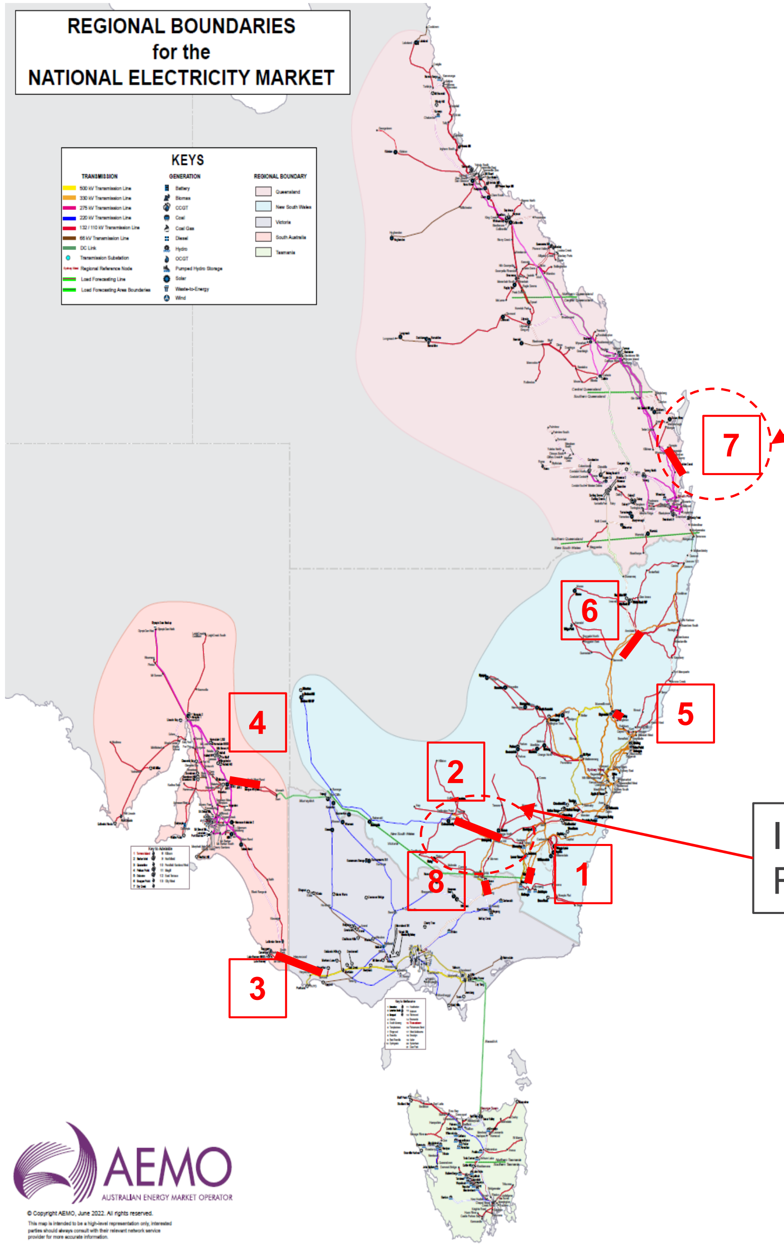
Key congestion

Higher congestion prices due to MPF bids

| Index | From Node | To Node | region | #DIs MC | #DIs RTF | total MC ($k) | total RTF ($k) |
|---|---|---|---|---|---|---|---|
| 1 | Tumut1_2 | Murray | NSW | 5064 | 4375 | 52 | 39 |
| 2 | Darlington Pt | Wagga330 | NSW | 2309 | 2292 | 20 | 777 |
| 3 | Heywood | South East | Vic | 1691 | 1464 | 6.3 | 4.6 |
| 4 | Tailem Bend | Tungkillo | SA | 785 | 771 | 1.8 | 2.1 |
| 5 | Bayswatr | Liddell | NSW | 303 | 174 | 0.5 | 0.4 |
| 6 | Armidale | Tamworth | NSW | 206 | 88 | 0.7 | 0.5 |
| 7 | Woolooga | Palmwoods | Qld | 76 | 527 | 0.3 | 603.3 |
| 8 | Dederang | Wodonga | Vic | 11 | 357 | 0.0 | 21.1 |

DRAFT results (Nov 2022)

## CONGESTED LOCATIONS

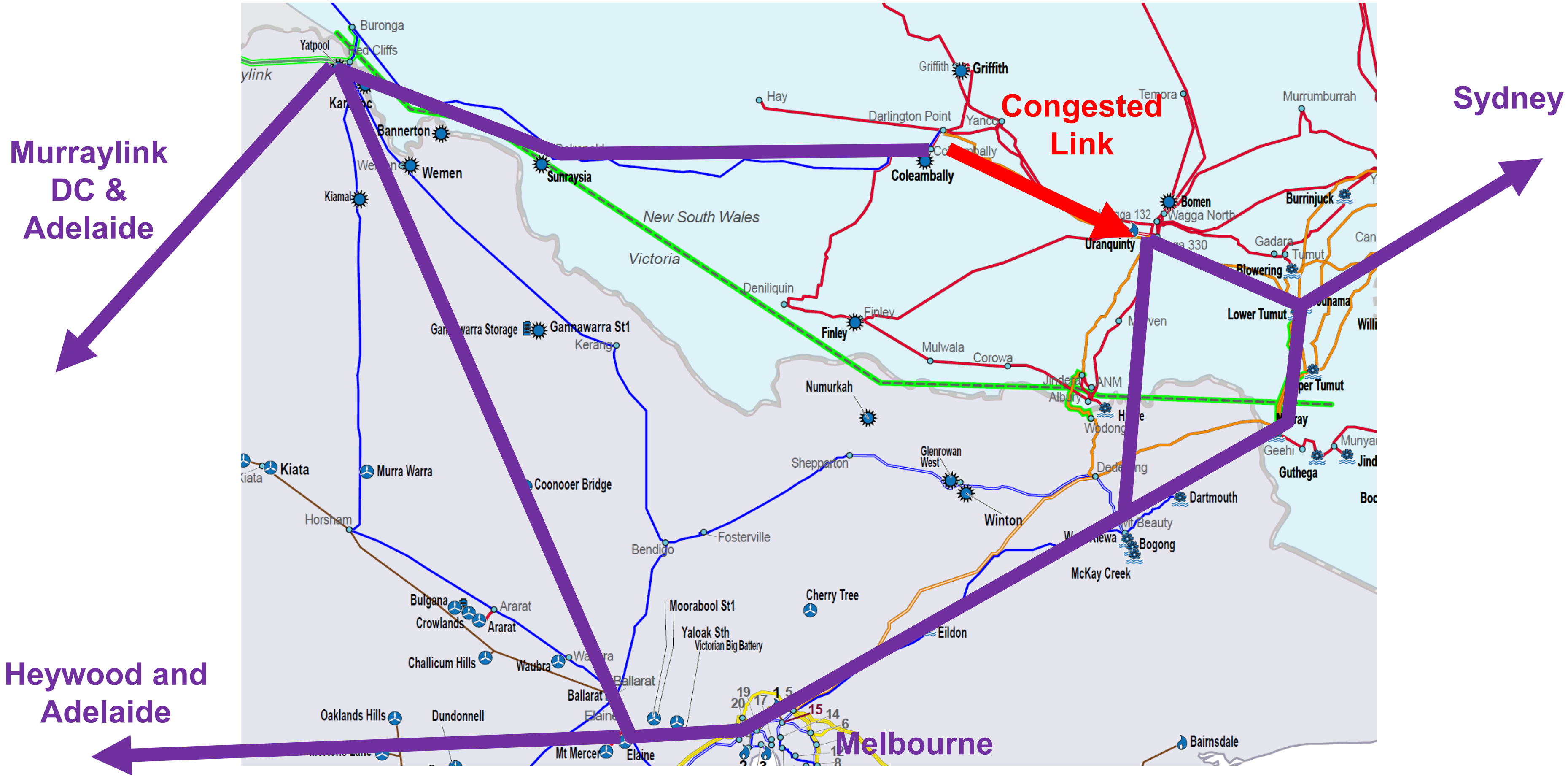



Intra-regional loop: RTF only

Intra-regional loop: MC and RTF

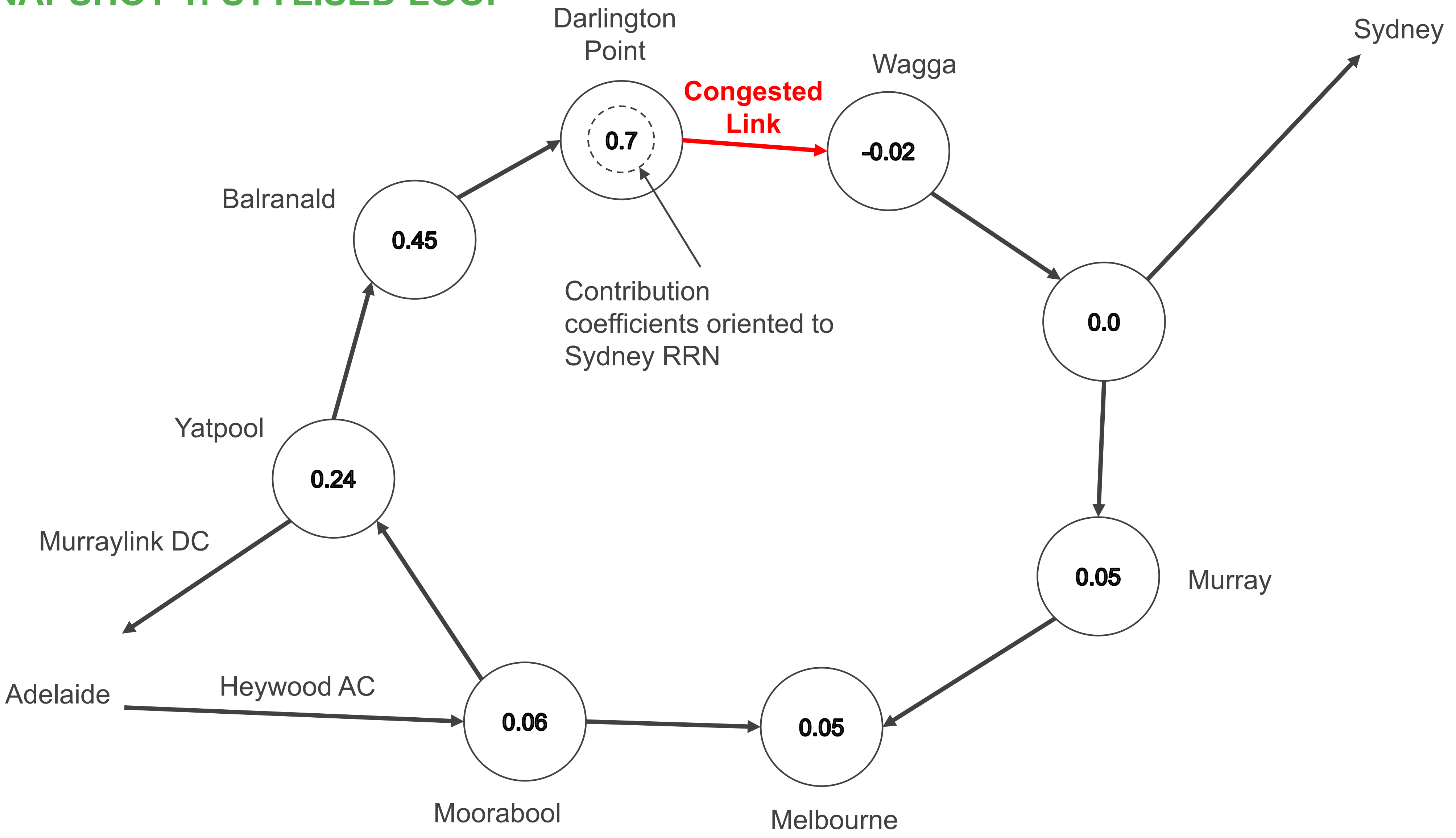
## SNAPSHOT 1: CONGESTION IN SW NSW, EAST OF DARLINGTON POINT

29/10/2023 12:00

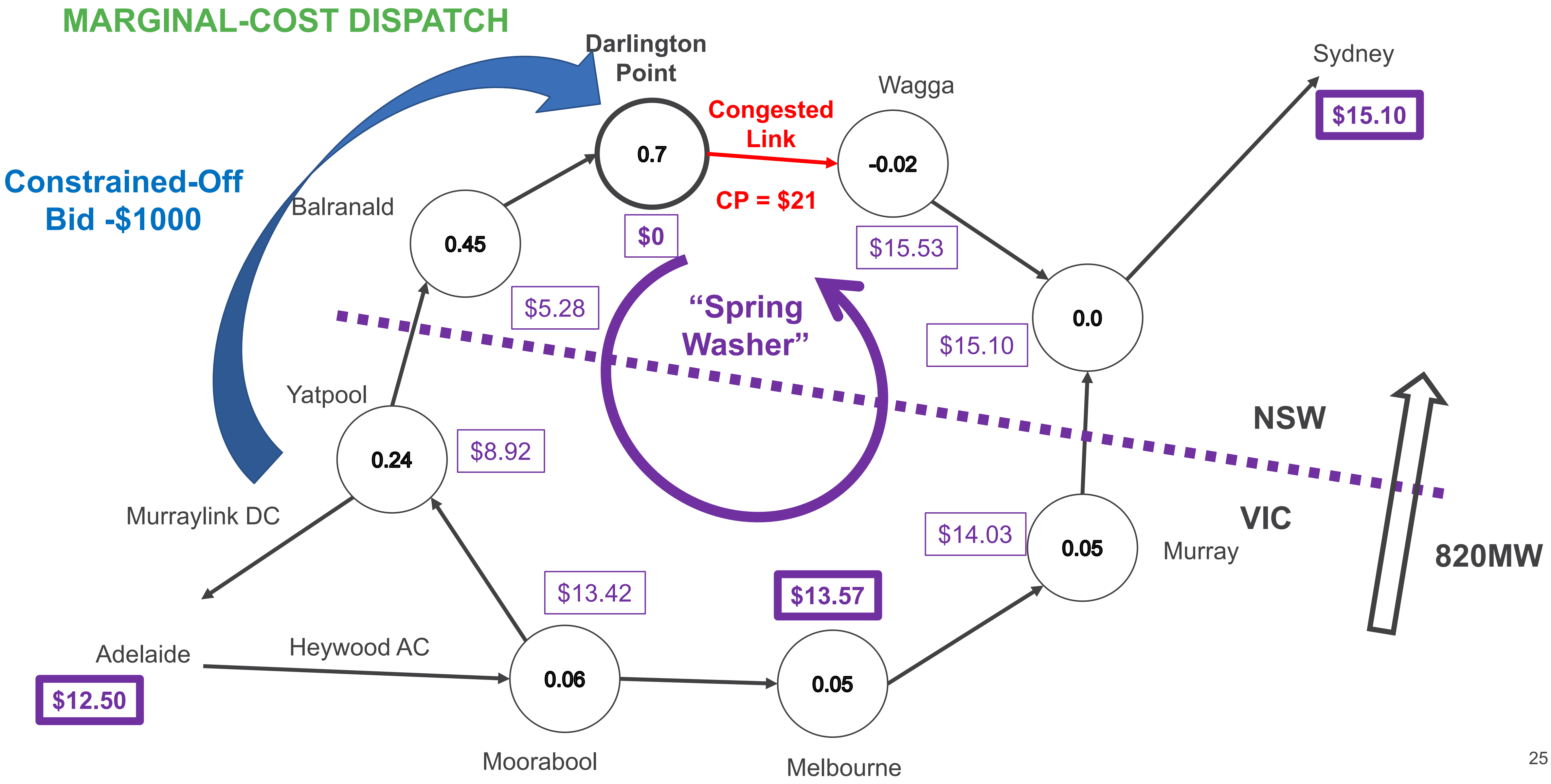


# SNAPSHOT: SUNDAY 29TH OCTOBER 2023 12:00PM

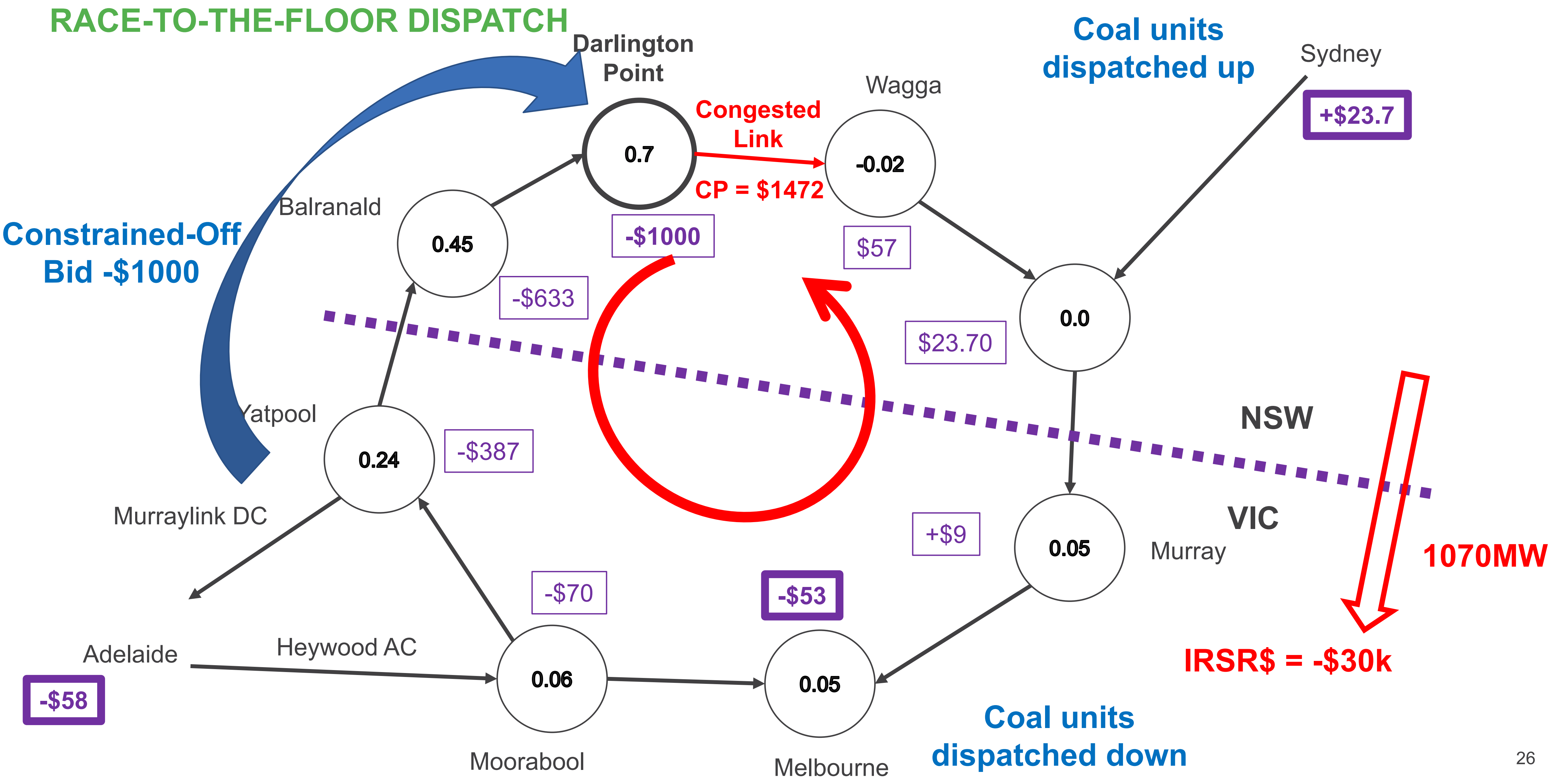
## SNAPSHOT 1: STYLISED LOOP



# SNAPSHOT: SUNDAY 29TH OCTOBER 2023 12:00PM



# SNAPSHOT: SUNDAY 29TH OCTOBER 2023 12:00PM



# SNAPSHOT: SUNDAY 29TH OCTOBER 2023 12:00PM

## CRM TRADING OUTCOMES: SELECTED GENS

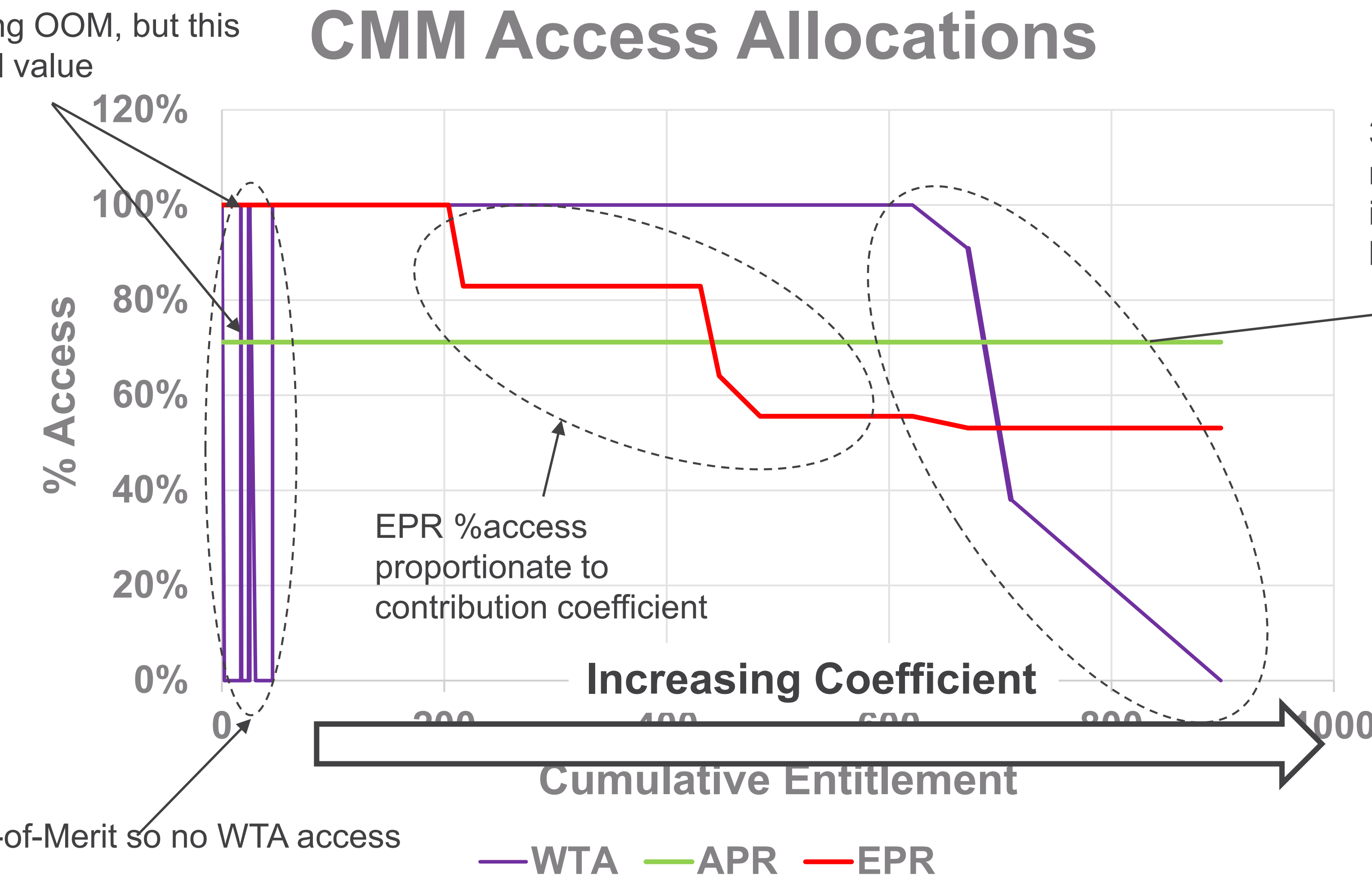
Change between RTF dispatch and MC dispatch

| Gen | Region | Traded MW | Traded CR | CRM price | inferred cost | CRM profit | Comments |
|---|---|---|---|---|---|---|---|
| Bayswater 1 | NSW | -396 | 0 | 15.15 | 11.18 | -1568 | Apparent loss, since LMP>cost[1] |
| Callide B2 | QLD | -91 | 0 | 16.10 | 12.40 | -337 | Apparent loss, since LMP>cost[1] |
| Loy Yang B1 | VIC | +110 | 0 | 13.57 | 6.84 | 739 | Profitably increase output[2] |
| Darlington SF | NSW | -139 | -97 | 0.00 | 0.00 | 0 | Reduce output to zero at cost[3] |
| Glenrowan SF | VIC | +86 | [illegible] | 14.07 | 0.00 | 1212 | Profitably Increase Output |
| Bungala SF2 | SA | +97 | [illegible] | 12.44 | 0.00 | 1208 | Profitably Increase Output |
| Stockyard Hill WF | VIC | +24 | [illegible] | 13.44 | 0.00 | 318 | Profitably Increase Output |
| NSW-Vic Interconnector | n/a | -1890 | +98[5] | 1.5 | 0 | 0[6] | But does not offset |

1. NSW and Qld coal gens are de-loaded in MC dispatch, despite RRP being above cost
2. Vic coal gens increase output to full load and have RRP > cost
3. Darlington SF is the marginal generator and so has LMP=cost and is profit-neutral from CRM trading
4. The NSW-Vic interconnector changes from 1070MW south (counterprice) to 820MW north
5. The interconnector has a participation of 0.05 in the binding constraint: so 0.05 x 1890 = 98
6. AC interconnectors receive no CRM profit because their "cost" is equal to their "LMP"

## CMM ACCESS ALLOCATIONS

Snowy Receives CMM access despite being OOM, but this has minimal value




EPR %access proportionate to contribution coefficient

3 solar Farms at Darlington Point node are constrained off. Tapering is due to Plexos not having a tie-break algorithm like NEMDE

**WTA Winner Takes All**
**APR Access Pro Rata**
**EPR Entitlement Pro Rata**

Snowy Out-of-Merit so no WTA access

**Contact details** Energy Security Board
Level 15, 60 Castlereagh St
Sydney NSW 2000
**Email** info@esb.org.au
**Website** http://www.energyministers.gov.au/market-bodies/energy-security-board