TRANSMISSION ACCESS REFORM

PUBLIC FORUM ON QUANTITATIVE ANALYSIS

17 SEPTEMBER 2020

AEMC

Agenda

1.	Introduction and ground rules – Victoria Mollard *(5 mins)*
2.	Welcome – Merryn York *(5 mins)*
3.	Overview of quantitative analysis – Russell Pendlebury *(15 mins)*
4.	NERA modelling – George Antsey & Will Taylor *(90 mins)* Q&A
5.	Close and next steps – Allison Warburton *(5 mins)*

Format for the forum

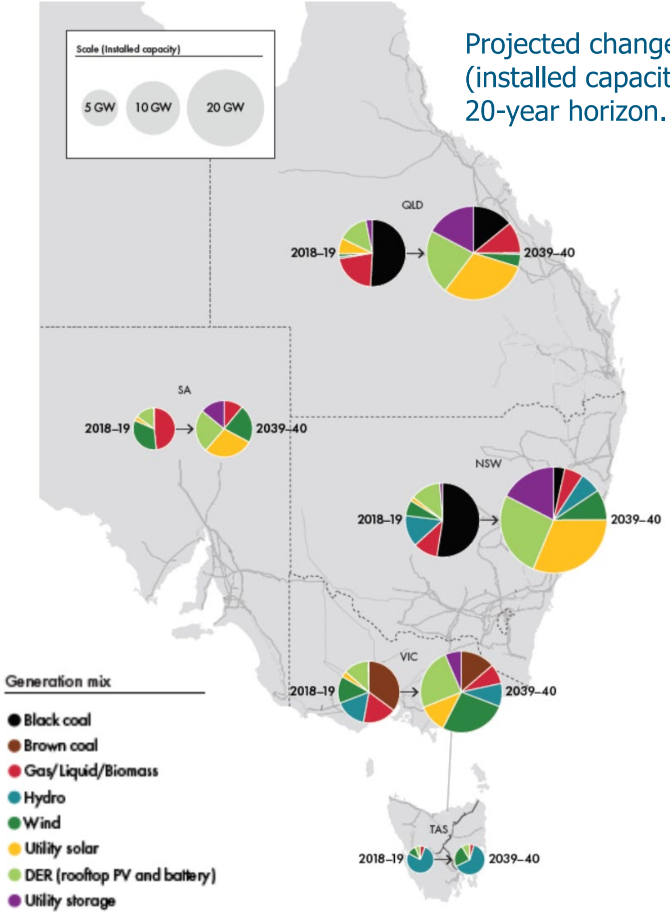
- You will have the option to make comments or ask questions via the Q and A function on your screen.
- When asking questions or presenting comments, please relate them to the purpose and scope of the meeting.
- In the Q and A area please first indicate whether you are asking a question or making a comment, then add your remarks, and then finally please include your name and organisation at the end.
- We will attempt to answer all questions during the scheduled Q and A sessions - if we don’t get to your question during the forum, we will follow up after the event.
- Comments will also be raised during the Q and A sessions. Where possible, and time permitting, participants will be invited to present their comments - if this happens, your mic will be taken off mute, and you will be asked by the presenter to make your comment.

WELCOME

MERRYN YORK – ACTING CHAIR

What is the problem that needs to be addressed?

Projected change in generation resource mix (installed capacity) by NEM region over the 20-year horizon.



The NEM will replace most of its generation stock by 2040. Given changing generation mix, signals about where to locate in the transmission network and the ability to manage congestion are more important than they used to be.

OVERVIEW OF THE MODELLING

RUSSELL PENDLEBURY

The task set for NERA

- In January of this year the AEMC tasked NERA with assisting in the analysis of the benefits of transmission access reform in the NEM.
- This work was divided into two stages:
  - **Stage 1**:
    - A benchmarking study of the benefits, costs and learnings based on similar reforms applied overseas – published in March 2020
    - Covered ten overseas markets
    - Recognised limitations of benchmarking, but will help to refine later NEM specific modelling
  - **Stage 2**:
    - Specific modelling of the reforms as applied to the NEM – published in September 2020
    - Provide evidence for the reforms in the specific context of the NEM
    - It required the creation of a detailed nodal model reflecting the characteristics of the NEM and the comparison of this nodal model with the existing functioning of the NEM

The benefits addressed by NERA

- The key categories of impact that we asked NERA to analyse were:
  - **Changes to dispatch** including modelling the impact of race to the floor bidding on the efficiency of dispatch
  - **Changes to investment decisions** or a different capital cost development pathway for generation and transmission investment
  - **Competition** effects
  - **Cost of capital** changes
- The **distributional impacts** of access reform.
- NERA was also asked to look at the potential impact on **contract market liquidity.**
- Core assumptions were to be taken from other modelling processes in the NEM (ESOO, ISP)
- All assumptions and proposed methodology were discussed with the COGATI technical working group on 18 June 2020, as well as with market bodies
- The output of this work, presented by NERA today, is a comparison of the costs faced by industry and consumers in the two different worlds, assuming implementation of the reform in the middle of the decade, and assessing the net impact out to 2040.

Ongoing work into the costs of implementing the reform

NERA do not model the implementation costs

To obtain preliminary cost figures to inform transmission access reform design decisions, we engaged **Hard Software to assess the IT costs** of transmission access reform for both AEMO and market participants at a high-level.

Hard Software assessed IT costs associated with different transmission access reform options:

- Option 1 – retaining NEMDE, the RRP and static marginal loss factors
- Option 2 – retaining NEMDE and static marginal loss factors, but using VWAP
- Option 3 – using a new security constrained dispatch engine that would facilitate both VWAP and dynamic losses

	Option 1	Option 2	Option 3
AEMO	$34,000,000	$46,000,000	$71,000,000
Participant	$28,000,000	$34,000,000	$34,000,000
Total	**$62,000,000**	**$80,000,000**	**$105,000,000**

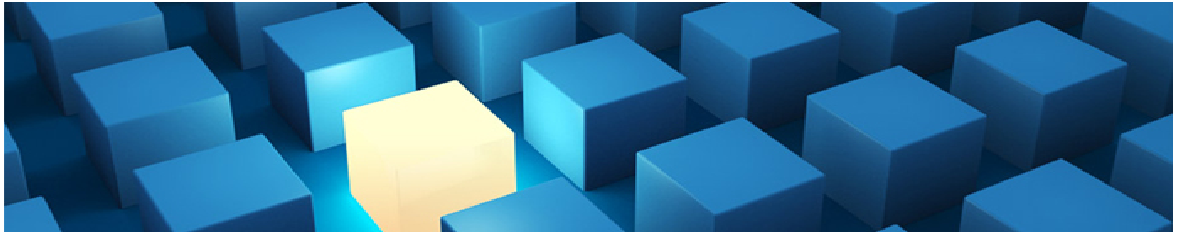
NPV of Costs for 20-Year period for each LMP option in Real 2024 AUD currency.

The Hard Software report is published on the AEMC website alongside the NERA cost benefit analysis

The AEMC also carried out a high-level assessment of the possible costs of **reopening contracts** that would not expire during the implementation period. Using publicly-available information we estimated that legal costs relating to contract reopenings could total up to **$5.4m**.

Altogether, these preliminary figures suggest that implementing transmission access reform could cost around **$110m**

We suggest that these costs are relatively low – although still a magnitude less than the estimated benefits. We will be working with AEMO and participants to obtain more detailed numbers over the coming months



ACCESS REFORM
OVERVIEW OF MODELLING RESULTS

17 SEPTEMBER 2020

George Anstey
Director

Will Taylor
Associate Director

London, Auckland and Sydney

CONFIDENTIALITY

Agenda and Overview of Benefits

- Overview of Approach
- Capital and fuel cost savings from more efficient locational decisions
- Q+A

- Improved efficiency of dispatch from eliminating race to the floor bidding
- Introduction of dynamic losses
- Q+A

- Impacts on consumer prices from LMP
- Impacts on competition from FTRs
- Summary
- Q+A

1 Overall Approach

We developed a nodal PLEXOS model of the NEM building on the publicly-available Electricity Statement of Opportunities (ESOO) model

The foundation of our model is AEMO's 2019 ESOO Model

The ESOO (Electricity Statement of Opportunities) Model simulates a system with regional settlement and is the main data source for:

- Generator information and properties (capacity, units, ratings, costs)
- Demand traces following AEMO Input and assumptions for planning and forecasting at **base year 2017/2018**

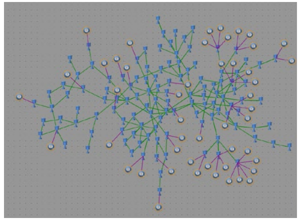
Following the ESOO model's baseline settings we adopt **"Central"** assumptions on growth and evolution of the system

We coordinated with the AEMC to add a nodal infrastructure to the regional model

The AEMC provided:

- A list of nodes with defined voltage properties
- Lines and interconnectors with properties (resistance, reactance, load constraints)
- Instructions for modifications to the line and node structure to introduce "priority" projects from AEMO's 2020 Integrated System Plan between 2020 and 2025

Central Scenario	
Economic growth	Moderate
Take-up of Rooftop PV and EV	Moderate
Average temperature rise by 2050	3.0 - 4.5 ^{o}C
Hydro inflow reduction by 2050	-14%
Renewable build cost trajectory	CSIRO 4 degree
Gas prices	Core Energy 19, Neutral
Coal prices	WoodMackenzie 19, Neutral
Outages "All Average"	
Forced outages	Average across reference years 2015/16 to 2018/19



PLEXOS representation of Victoria's nodal network

We estimate the impact of reform by taking the difference in costs (or prices) between a PLEXOS run intended to reflect a Reform and a No-Reform scenario

We have used PLEXOS to model four sources of benefit for consumers of the COGATI reforms

1 Capital and fuel cost savings from more efficient locational decisions

- Paying generators at oversupplied nodes the Regional Reference Price (RRP) provides a subsidy to locate in inefficient locations on the grid.
- We estimate the locational subsidy under the status quo and use it to determine which plant would be built, given the price signals they face.

2 Benefits of more efficient dispatch (elimination of the race to the floor)

- Generators behind supply constraints with marginal costs below the RRP have an incentive to **"race to the floor"** to capture that RRP.
- Such generators share output rather than allocate it to the lowest-cost generator, which increases system costs.
- We estimate the resulting change in system costs.

3 Introduction of dynamic losses

- Plant in the NEM are currently paid (and therefore dispatched) based on static loss factors determined by AEMO in advance rather than underlying losses in real time.
- Our estimate of the benefit of introducing dynamic losses is the "size of pie" from dispatching based on dynamic losses, before any mitigation that AEMO may already implicitly undertake.

4 Wealth transfer from generators to consumers

- Under the status quo, consumers pay generators RRP for their output, including any congestion rent between the generator's node and the reference node.
- Under the access reform, consumers will pay generators for the locational value of their power and retain the congestion rent.
- We estimate the transfer to consumers from the change in total revenue paid to generators.

Q&A

2

Reduced Capital Cost of Generation, Transmission and Storage

1

We estimate the reduced capital costs of generation, transmission and storage resulting from distorted investment signals

We use PLEXOS to estimate costs and benefits for generation and storage

1. **Run 1:** Long-term Expansion to 2040 to identify optimal system build. New entrants are input as infinitesimal units at eligible nodes to estimate load factors and subsidies by location
2. Two runs using the same build schedule: **Run 2a:** Dispatch run with **regional** settlement for generators/batteries **Run 2b**: Dispatch run with **LMP** settlement
3. **Subsidy calculation:** We compute the difference in annual revenue for each generator between Run 2a and 2b (and cap it at the cost of the best new entrant)
4. **Run 3:** Long-term expansion to 2040 with the annual "subsidy" added (subtracted) to each entrant generator's fixed costs
5. **Run 4:** Dispatch run to 2040 using the build plan from Run 3. **The benefit/cost quantification is the difference in total costs (variable and fixed) between Runs 1+2 and 3+4**

Steps 1–2: Estimate investment and dispatch in the **Reform** world

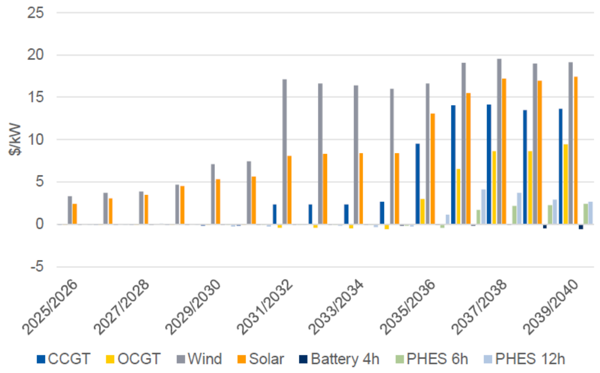
Steps 2–3: Estimate distorted market signal

Steps 4–5: Estimate investment and dispatch in the **No-reform** world

No-reform results in $1.7 billion in excess costs, mostly in later years

	Reform Run 1+2 *Optimal Build Schedule*	No Reform Run 3+4 *"Subsidised" Sub-optimal build*	Savings *NR - R*
Total System Costs 2026-2040 ($m)	40,634	42,373	**1,738**

Average Locational Subsidies under Reform ($/kW)

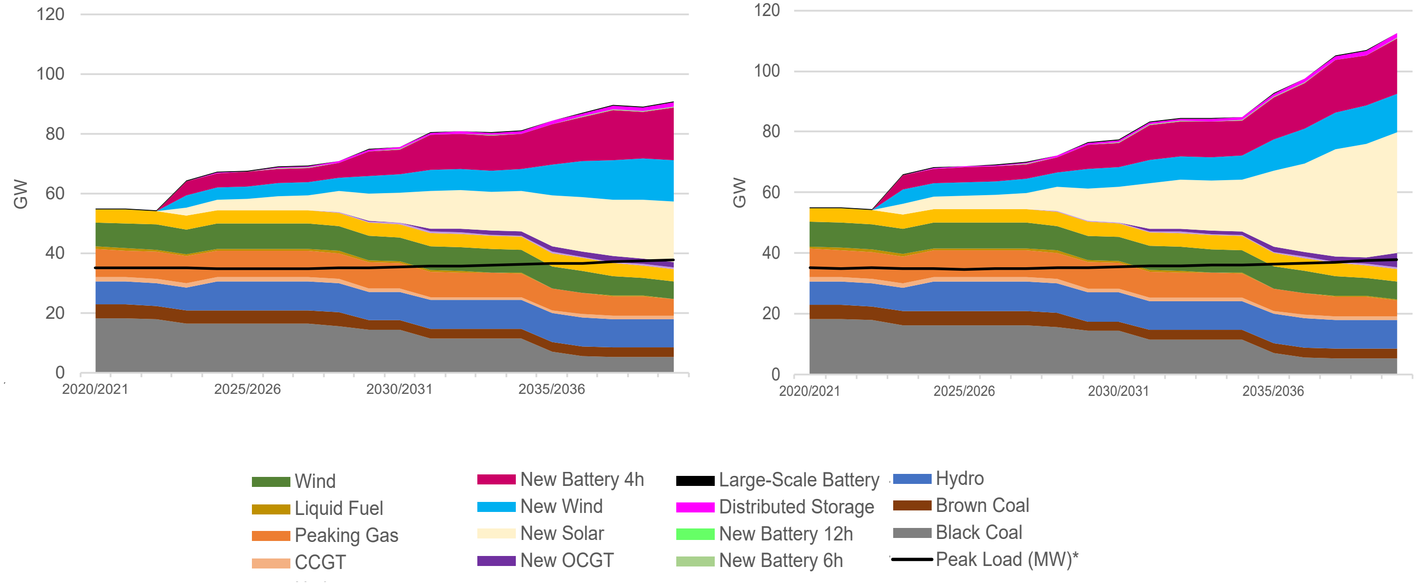


Source: NERA calculation

The No-Reform world results in more investment in capacity, mostly from the mid 2030s once the bulk of coal plant retires

Capacity Mix: Reform (Optimal Build)

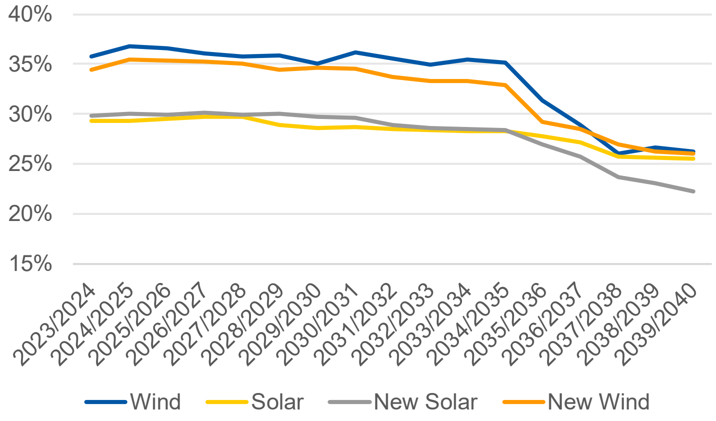
Capacity Mix: No Reform (Sub-Optimal Build)



By the end of the period, our modelling suggests that consumers would pay for around 20 GW of additional capacity, largely consisting of solar plant

The higher capacity on the system and same assumed load means that the load factors of existing plant would be lower in the No-Reform scenario, including for renewable plant

Load factors for renewable plants in the No-reform scenario fall towards the end of the modelling horizon



Difference in load factor after 2032 (No-reform minus reform state)

	2032/ 2033	2033/ 2034	2034/ 2035	2035/ 2036	2036/ 2037	2037/ 2038	2038/ 2039	2039/ 2040
Black Coal	-0.05	-0.05	-0.05	-0.07	-0.07	-0.07	-0.07	-0.07
Brown Coal	-0.02	-0.02	-0.02	-0.07	-0.09	-0.13	-0.13	-0.14
Hydro	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
CCGT	0.00	-0.01	-0.01	-0.05	-0.04	-0.05	-0.07	-0.08
Peaking Gas	0.00	0.00	0.00	-0.02	0.00	0.02	0.00	0.00
Liquid Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01
Wind	-0.01	-0.01	-0.01	-0.03	-0.05	-0.08	-0.08	-0.09
Solar	-0.01	-0.01	-0.01	-0.02	-0.02	-0.04	-0.04	-0.04
New CCGT	-0.01	-0.01	-0.01	-0.05	-0.04	-0.04	-0.08	-0.11
New OCGT	0.00	0.00	0.00	0.00	0.01	0.02	0.00	-0.04
New Solar	-0.01	-0.01	-0.01	-0.02	-0.04	-0.06	-0.06	-0.07
New Wind	-0.02	-0.02	-0.02	-0.05	-0.06	-0.07	-0.08	-0.08
New Battery 4h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Battery 6h	0.00	0.00	0.00	-0.01	0.01	0.01	0.01	-0.01
New Battery 12h	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.00
Distributed Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Large-Scale Battery	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.00	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.02

The large expansion in capacity from 2035/36 causes load factors for wind and solar plant to fall by 4-9 percentage points by the end of the modelling period

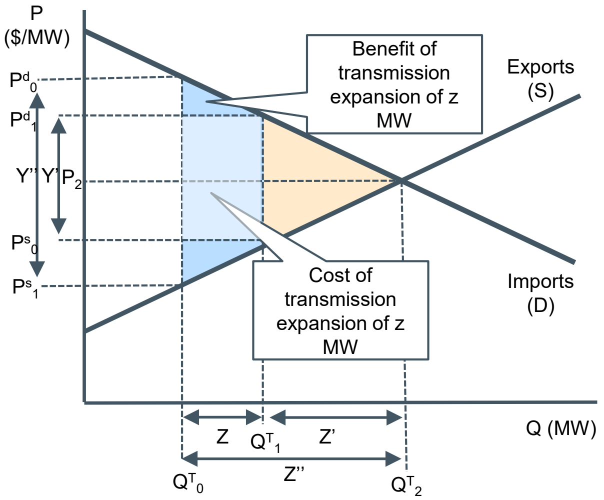
In principle, transmission investment could mitigate or worsen the inefficiency resulting from inefficiently-located investment in generation and storage under the status quo

The benefits of transmission investment are likely to be higher if the network is more constrained but additional transmission investment could encourage further investment in generation in inefficient locations

We estimate costs and benefits of transmission expansion based on our PLEXOS results

1. Take results on prices at each node from PLEXOS runs for investment in new generation and storage as market before transmission investment
2. Conduct a short-term run in PLEXOS as if the NEM were a copper plate with no constraints to find Q^T_2 and P^T_2 for both Access Reform and Status Quo.
3. Calculate the length of each line using GPS data and ascribe a transmission cost (e.g. $2,000/km)
4. Calculate the benefits of transmission investment (blue trapezium) and the costs (blue rectangle representing costs x expansion)

Diagrammatic representation of costs and benefits of transmission expansion



In practice, our (simplified) analysis suggests that the impact of transmission investment on the benefits of reform is small, at least after the construction of new generation and storage, and we have omitted these impacts from our final results

Q&A

3

Increased efficiency of dispatch

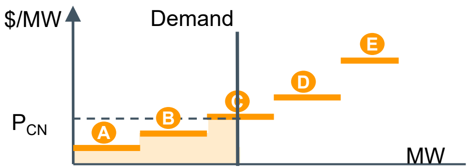
Elimination of Race to the Floor Bidding

2

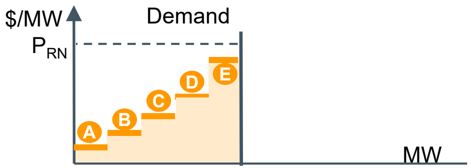
Katzen and Leslie had previously estimated the "total overcompensation" in the NEM – in other words the transfer from consumers to generators under the current structure

Race to the Floor Bidding results in an inefficient pattern of dispatch

Locational Marginal Pricing Results in Efficient Dispatch

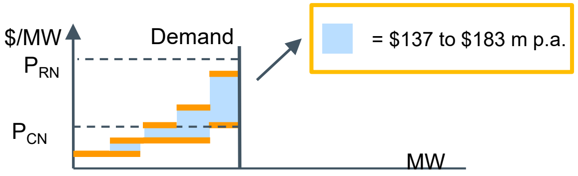


Race to Floor Bidding results in High-Cost plant sharing output



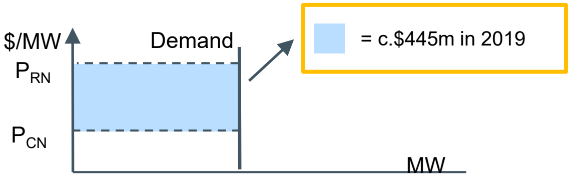
Our method estimates the change in total system costs

Forward looking (models the ideal nodal state)



Katzen and Leslie's measure of "overcompensation" is a difference in prices

Backward looking (estimate based on observed behaviour in the NEM)



Our quantification of the benefit represents the *social* costs between the two different market designs

Our modelling of distorted behaviour predicts that the elimination of race-to-the-floor bidding would result in $137 to $183 million in overall savings in 2025/26

We use marginal costs and prices received by generators to distort bids

1 **Run 1:** model a base case scenario in which generators submit bids at their marginal cost.

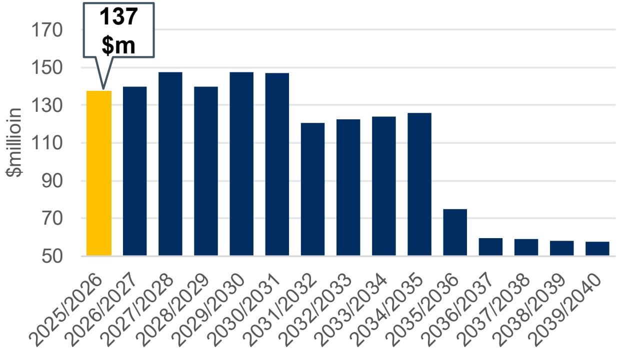
2 In every period, we constrain generators (excluding PHES) to bid -1,000 $/MWh if:

a) Their generation < their available capacity; and
b) Their short-run marginal cost is lower than their price received (RRP*Marginal loss factor); and
c) They are not located at the regional reference node; or
d) They satisfy b) and c), not a) but another a generator at a) does

3 **Run 2:** we run the model with distorted bids and compare it to the base case.

	Base	Upper Bound		Lower Bound	
	Run 1	Run 2a	Savings	Run 2b	Savings
	Bids at marginal cost	*Bids at SRMC or floor*	*2a - 1*	*Bids at SRMC or floor*	*2b - 1*
System Costs 2025/26 ($m)	2,650	2,833	**183**	2,787	**137**
System Costs 2026 – 2040 ($m, NPV to 2020)	14,972	16,004	**1,032**	15,748	**776**

Typically, racing to the floor would result in sharing of output between in-merit and out-of-merit plant. Our upper bound has black coal displacing renewable generation (wind and solar). Our lower bound assumes that *no renewable plant is displaced*.



Costs in our lower bound alternative

Around 90 per cent of the benefits from eliminating racing to the floor in the sample year come from coal plant, so we index the assumed annual benefits to the variable costs of coal in each year.

4 | Dynamic Losses

We estimated the benefit of dynamic MLFs by modelling savings in total system costs in 2025/6

Our estimated benefits derive from cheaper procurement of energy based on dynamically modelled losses and constitute an upper bound

Our modelling process consists of three runs

1 We model the system with the **static MLFs** provided to determine an appropriate **dispatch pattern (Kirchhoff's Laws hold).**

2 We **impose the dispatch decisions from run 1** onto a run with dynamic losses and calculate total system costs, including of lost energy.

3 We compare scenario 2 with a 3rd run using **dynamic MLFs**, but allowing **efficient dispatch** decisions.

We estimate maximum cost savings from dynamic MLFs of $102m with this method

	Dynamic Loss Factors (Run 3)	Fixed Generation (Run 2)	Saving (Run 3 – Run 2)
Variable Costs – generators	3,155.9	2,362.9	
Variable Costs – batteries	0.7	0.3	
Cost of Unserved Energy and Demand Curtailed	-	895.2	
Total	3,156.6	3,258.4	**101.8**

Notes: *We value unserved energy and curtailed demand recorded in Run 2 at the average load-weighted price in the NEM for the sample year

$102m is an upper bound estimate

- Our modelling captures two potential sources of inefficiency resulting from relying on static losses:
  - **Price effect:** Dispatching the wrong plant to meet demand based on static rather than dynamic signals;
  - **Volume effect:** Dispatching sufficient generation to cover dynamic, rather than static losses.
- In practice, we understand AEMO currently forecasts gross demand, including (but not separating out) losses, in real time by node. If AEMO's forecasts would not improve after introducing dynamic losses, the only benefit of introducing dynamic losses would be the price effect.

The benefits which would be realised in practice would be a fraction of the above estimate since the system operator is likely to correct for a proportion of the inefficient dispatch decisions that we model

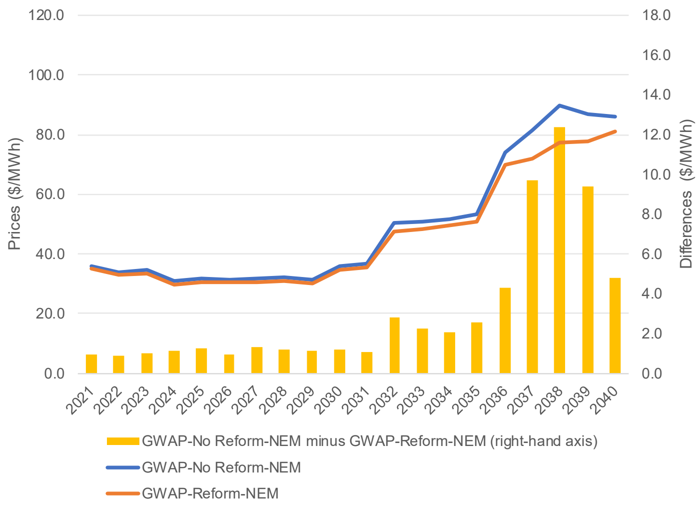
Q&A

5 | Impacts of Locational Marginal Pricing on Consumers

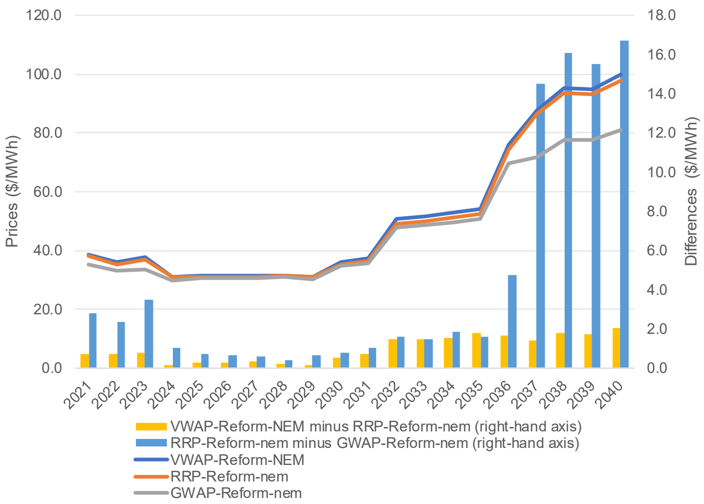
4

The final cost of power to consumers after settlement residues is the Generation-Weighted Average Price (GWAP), defined by Locational Marginal Prices in Reform and the RRP in No-Reform

Generation-Weighted Average Prices (GWAP) are higher in No-Reform than Reform



Regional Reference Prices are below but close to Volume-Weighted Average Prices, whilst both are higher than GWAP due to congestion rents



Prices diverge between the Reform and No Reform scenarios as the supply and demand balance tightens in the mid-2030s: Consumers ultimately pay lower prices by $0.9 to $2.8/MWh prior to 2035 and by as much as $12.4/MWh in 2038

6

Improved competition due to introduction of FTRs

Replacing SRA units with FTRs could improve inter-regional competition if:

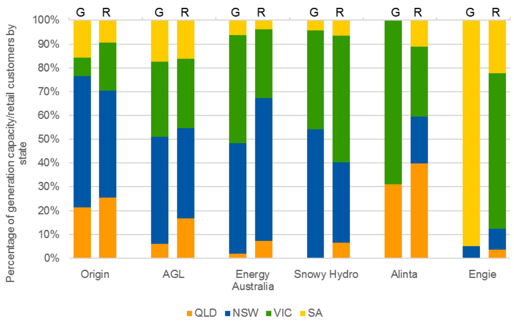
Existing competition concerns

ACCC AUSTRALIAN COMPETITION & CONSUMER COMMISSION

AER AUSTRALIAN ENERGY REGULATOR

AEMC AUSTRALIAN ENERGY MARKET COMMISSION

Evidence inter-regional risk is distorting behaviour



Room for entry/expansion

- **Generation**
  - 2020 ISP = up to **45 GW** of new capacity needed by 2040 compared to **61GW** today
  - 69% of new capacity 2018 outside of "big 3"
- **Retail**
  - ACCC REPI found no significant barriers to entry in retail

FTRs material improvement in inter-regional risk management

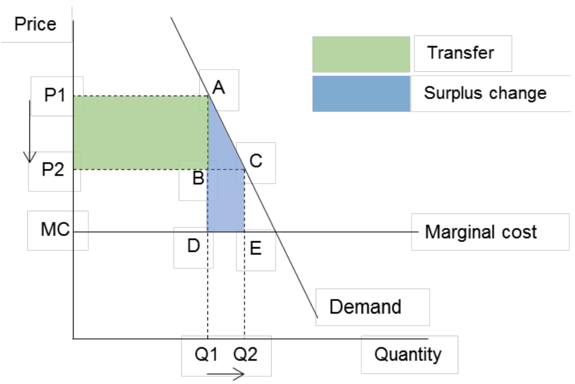
- In theory, FTRs are firmer than SRAs
  - Counter price flows can lead to no settlement residue when there is price separation
- Magnitude of improvement moving from SRAs to FTRs unclear

Quantification

What did we quantify?

- **Allocative efficiency:** increased consumption due to lower prices
  - assumed price decrease range of 0 – 0.5% (EA assumption = 0.5% - 1%)
- **Productive efficiency:** lower costs due to increased competition
  - Assume variable costs fall by 0 – 0.5% (EA assumption = 0.5% - 1%)
- Calculated using outputs from PLEXOS modelling.
- More conservative assumptions than NZ due to different starting points and lack of conclusive evidence demonstrating strong impact

Illustration of allocative efficiency benefit from lower prices



Results (2026-2040 NPV, $2020)

	Allocative efficiency benefit		Productive efficiency benefit		Wealth transfers	
	min	max	min	max	min	Max
Generation market	$0	$12.4m	$0	$68.6m	$0	$333.2m
Retail market	$0	$20.7m	$0	$107.1m	$0	$1,354.0m
Total	**$0**	**$33.1m**	**$0**	**$175.6m**	**$0**	**$1,687.2m**

7 Overall Conclusions

Our analysis suggests that the overall benefits of reform to society and consumers are up to $8.2 billion by 2040 in Net Present Value terms

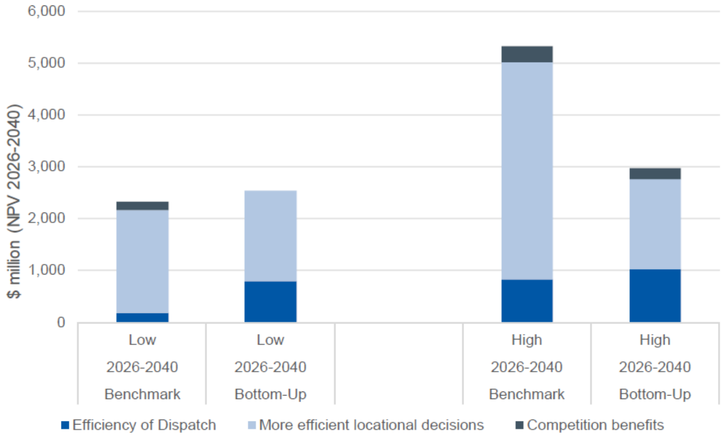
		Annual benefits 2026 (2026 $m)		NPV of Benefits (discounted at 7 per cent per year, 2020$m)					
				2026-2035		2036-2040		2026-2040	
		Low	High	Low	High	Low	High	Low	High
1	Capital and fuel cost savings from more efficient locational decisions	66		454		1,285		1,738	
2	Improved dispatch efficiency from eliminating Race to the Floor bidding	141	181	700	898	95	122	795	1,020
3	Introduction of dynamic losses	102		510		151		661	
4	Competition benefit	0	9	0	140	0	68	0	209
5	**Total social benefit**	**308**	**358**	**1,663**	**2,002**	**1,531**	**1,626**	**3,194**	**3,629**
6	*Social benefit (w/o dynamic losses)*	*207*	*256*	*1,153*	*1,492*	*1,380*	*1,475*	*2,533*	*2,967*
7	Wealth transfer from generators to consumers	105		1,176		1,785		2,961	
8	Competition related wealth transfer from generators/retailers to consumers*	*0*	*200*	*0*	*1,119*	*0*	*536*	*0*	*1,655*
9	**Total consumer benefit**	**414**	**662**	**2,839**	**4,297**	**3,316**	**3,948**	**6,155**	**8,245**
10	*Consumer benefit (w/o dyn. losses)*	*312*	*561*	*2,329*	*3,787*	*3,165*	*3,796*	*5,494*	*7,583*

Source: NERA Analysis

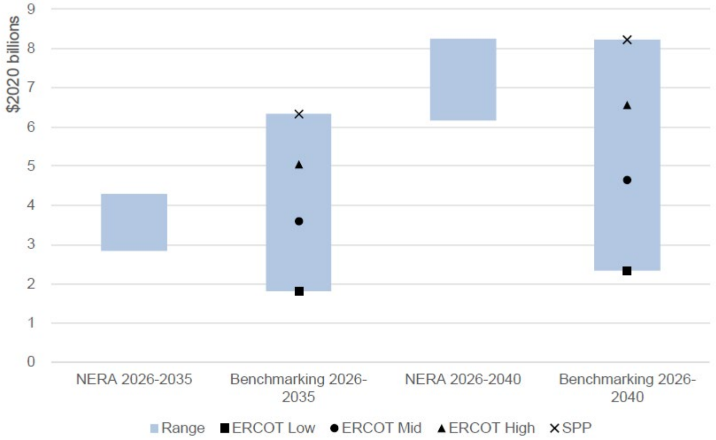
In our modelling, around half of benefits (depending on the measure) occur from 2036 to 2040, prompted by the retirement of coal plant: Earlier retirement would bring the benefits forward

Our estimates are broadly consistent with our top-down results from our international benchmarking in our Phase 1 report

Our estimated social benefits are broadly in line with international benchmarks

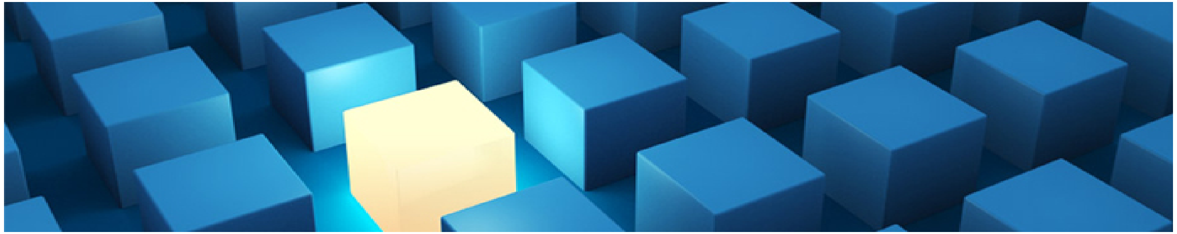


Our estimated wealth transfers to consumers are at the higher end of international benchmarks for the full period



Q&A

NERA
ECONOMIC CONSULTING



CONTACT US

George Anstey
NERA
London: +44 7917 032 584
George.Anstey@nera.com

Will Taylor
NERA
Auckland/Sydney: +61 2 8864 6535
Will.Taylor@nera.com

CLOSING REMARKS

ALLISON WARBURTON - COMMISSIONER

We want to hear your views on the modelling

- Submissions are due on 19 October 2020
- We are always happy to chat – reach out to one of the team
- One more upcoming public forum, register on AEMC website (www.aemc.gov.au):
  - Simplified model – 22 Sept


AEMC

Australian Energy Market Commission

INTERIM REPORT

TRANSMISSION ACCESS REFORM: UPDATED TECHNICAL SPECIFICATIONS AND COST-BENEFIT ANALYSIS

7 SEPTEMBER 2020

REVIEW