Level 15, 459 Collins Street, Melbourne, 3000

Mr Benn Barr
CEO, Australian Energy Market Commission
Lodged on AEMC website

19 October 2020

Dear Mr Barr,

Response to Interim Report on *Transmission access reform: Updated technical specifications and cost-benefit analysis*

On 7 September 2020, the Australian Energy Market Commission (AEMC) published an Interim Report on *Transmission access reform: Updated technical specifications and cost-benefit analysis* (the Interim Report). The Interim Report represents a further iteration on the AEMC's proposal to introduce locational marginal pricing and financial transmission rights (the COGATI Proposal). The Clean Energy Investor Group (CEIG) welcomes the opportunity to provide feedback on the AEMC's COGATI Proposal.

CEIG represents domestic and global renewable energy developers and investors, with around 5GW of installed renewable energy capacity across 49 power stations and a combined portfolio value of over $9 billion. CEIG strongly advocates for an efficient transition to a clean energy system from the perspective of the stakeholders who will provide the low cost capital needed to achieve it.

CEIG agrees that reform is needed to ensure that the regulatory framework for the National Electricity Market (NEM) is fit-for-purpose and that the necessary clean energy transition can be achieved at the lowest cost.

A number of policy and regulatory measures currently underway have started to address some of the current issues around the lack of transmission investment and the associated congestion in the grid:

- improved transparency of information on the capacity of existing, withdrawn, committed, and proposed generation projects in the NEM, led by the Australian Energy Market Operator (AEMO);
- improvements to the Regulatory investment test for transmission (RIT-T) process to make it more robust, efficient and timely, recently implemented by the Australian Energy Regulator (AER);
- AEMO's Integrated System Plan (ISP);
- introduction of the ISP Rules to enable actionable projects; and
- Energy Security Board (ESB)'s Renewable Energy Zone (REZ) Framework.

CEIG firmly believes that the AEMC's COGATI Proposal is not required now as it does not address the current issues around lack of transmission capacity and congestion. In fact, the introduction of COGATI would jeopardise the transition to a clean energy system by increasing the cost of capital, triggering negative flow-on impacts on the level of investment in clean energy and wholesale electricity prices ultimately paid by consumers.

CEIG also finds that the AEMC has failed to appropriately account for broader economic impacts that would be associated with COGATI including impacts on the Power Purchase Agreement (PPA) market (a major decarbonisation tool for governments and corporates) and REZ development policy (a key enabler for coordinated investment in generation and transmission capacity).

CEIG is urging the AEMC to defer further consideration of its COGATI Proposal. Instead, market bodies should focus on measures that address current problems through the ISP process, the design of a robust REZ framework - as already initiated by the ESB - and continuing consumer protections from transmission overbuild.

THE INTRODUCTION OF COGATI WOULD INCREASE THE COST OF CAPITAL FOR EXISTING AND FUTURE GENERATION AND STORAGE PROJECTS

CEIG has commissioned modelling to quantify the impacts of an increase in the cost of capital due to COGATI

CEIG fundamentally disagrees with the AEMC's treatment of the cost of capital in the NERA modelling and argues that the introduction of COGATI would increase the cost of capital.

CEIG has commissioned electricity market modelling from Baringa Partners to quantify the impacts of the increase in the cost of capital that would occur if COGATI was implemented. CEIG discusses key modelling results in its submission, with more details available in Attachment 1.

The AEMC's assumptions on the cost of capital do not reflect real-world financing.

The AEMC modelling assumes a weighted average cost of capital (WACC) of 5.9% in both the No-Reform and Reform scenarios. Notwithstanding CEIG's disagreement with the chosen WACC which does not reflect current financing rates (our modelling is based on an 8.4% WACC in the Base Case scenario), CEIG fundamentally disagrees with the AEMC's assessment of the impacts of the COGATI Proposal on the cost of capital:

> *"Attendees queried how the investor survey results have been used. The project team noted that the survey was undertaken at a particular point in time when there was an earlier Financial Transmission Right design and so the survey results are not reflective of the current proposal as set out in the March technical paper."* (AEMC Technical Working Group #6 minutes[1] – June 2020)

Investors hold a unanimous view that the implementation of COGATI would increase the cost of capital. While some design features have been amended through the various iterations, the fundamental premise of COGATI – the introduction of locational marginal pricing (LMP) and Financial

[1] https://www.aemc.gov.au/sites/default/files/2020-06/COGATI TWG%236 minutes 2020_06_10.PDf

Transmission Right (FTRs) - has not changed and concerns that the COGATI Proposal would increase the cost of capital have remained alive with investors.

In fact, by increasing the level of uncertainty for generators, changes to design features made over various iterations have worsened the impacts on the cost of capital with for example, decisions to remove long-term signals for transmission investment, move to dynamic loss factors (DyLFs) with no ability to hedge, limit the number of FTR nodes, limit grandfathering and limit the availability of FTRs.

That COGATI would increase the cost of capital is also one of the findings of a June 2020 *Financing Cost Survey*[2] where all investors surveyed (Independent developers, Project financiers and Existing gentailers), across all technology types, found that the COGATI Proposal would increase the WACC by 150-200 bps per annum.

COGATI would increase the cost of capital

The implementation of COGATI would increase the cost of capital for existing and new projects from two key reasons:

1. Generators would need to purchase new financial instruments - FTRs - to regain revenue lost from the introduction of LMP and avoid being exposed to revenues that are more volatile and difficult to forecast

- Compared to the existing NEM settlement process, for each five-minute interval and for a given volume of generation, the introduction of LMP and DyLFs would impact a generator's revenue:
  - due to differences between the Regional Reference Price (RRP) and the LMP whenever those differ (impact of congestion); and
  - due to differences between the static marginal loss factor (MLF) and DyLF values (impact of losses).

- Introducing LMPs and DyLFs would also make revenue inherently difficult to forecast, both at the time of financial investment decision (FID) and during the life of the plant.
  - Under an LMP model, spot prices could suddenly change if a transmission constraint were to bind on a particular transmission line. This would increase revenue uncertainty, particularly for generators exposed to merchant risk.
  - Because of the physical characteristics of power flows, a congested line could also cause variations in LMPs elsewhere in the grid.

- FTRs would need to be purchased by generators, at prices that would be inherently difficult to forecast for the life of the asset.

2. The lack of FTR firmness does not provide sufficient revenue certainty:

- The FTRs as currently designed only provide an imperfect hedge for those additional costs and uncertainty over the life of an asset (including not providing a hedge for losses).

[2] Rai, A. and Nelson, T. (2020) 'Financing costs and barriers to entry in Australia's electricity market', SSRN, pp. 12–15. Available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3692295

- CEIG further discusses the FTR design principles and how they are not appropriate below in the submission.

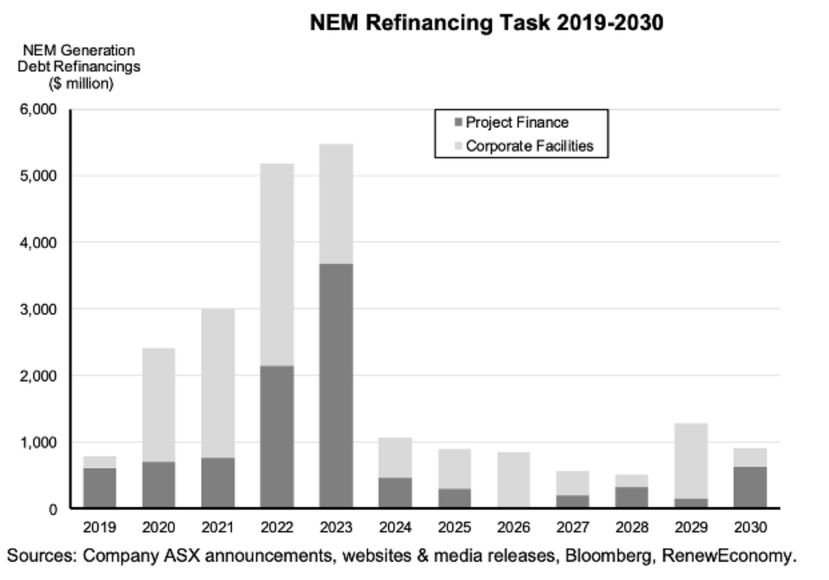
The increase in cost of capital due to the implementation of COGATI would ultimately flow through to higher wholesale prices

To counteract the increasing uncertainty, volatility and the higher costs that their projects would face under COGATI, investors would be led to apply a risk premium and increase their cost of capital. In return, a project's long-run marginal cost would increase which would ultimately flow through to an increase in wholesale prices paid by consumers.

This mechanism would be exacerbated in the absence of appropriate grandfathering measures for existing projects as it would effectively signal a willingness of the Australian energy market bodies to 'punish' generators' for past siting decisions and to allow sudden changes in profitability.

The increased cost of capital could also be felt through a 'refinancing' channel. If the industry felt that COGATI was due to be implemented (for example through a formal decision by Energy Ministers in June 2021 to proceed with COGATI), the effect on wholesale prices could start to be felt prior to 2025 as up to $18b of existing renewables projects due to be refinanced over the next five years would start to reflect the expected higher cost of capital (Figure 1).

Figure 1 – NEM Refinancing Task 2019-2030



Source: Simshauser, P. and Gilmore, J. (2020)[3].

Modelling results of a 150bps rise in the cost of capital

CEIG has commissioned modelling from Baringa to quantify the impacts of an increase in the cost of capital of 150bps per annum due to the introduction of COGATI.

[3] Simshauser, P. and Gilmore, J. (2020) 'Is the NEM broken? Policy discontinuity and the 2017-2020 investment megacycle', University of Cambridge, pp26-27. Available at: https://www.eprg.group.cam.ac.uk/wp-content/uploads/2020/05/2014-Text_UPD.pdf

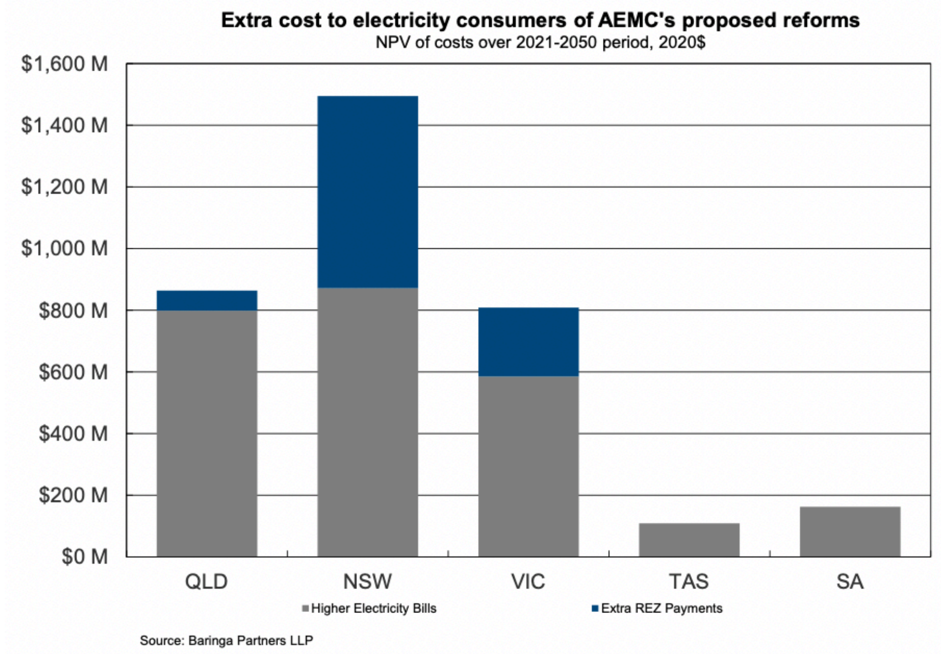
The modelling assessed:

- no-Reform scenario (or 'Base Case' where COGATI is not implemented); and
- Reform scenario (or 'Higher WACC' where COGATI is implemented).

Overall, the modelling found that the increase in WACC between the no-Reform and Reform scenarios leads to increased consumer costs of $3.4 billion (in present value terms) over the 2021-2050 period across the NEM (Figure 2):

- $2.5 billion of this (77 per cent) reflects increased electricity bills due to an average 3.5% increase in wholesale electricity prices under Reform;
- The remaining $0.9 billion of consumer costs comes from the additional payments required to achieve State-based renewable energy targets (RETs) under Reform. This cost is ultimately borne by electricity consumers within those States. Without these payments State-based RETs would not be achieved; and
- Relative to no-Reform, electricity consumers in Victoria (VIC), New South Wales (NSW) and South Australia face the biggest increases in costs under Reform. For VIC and NSW consumers, increased costs are due to:
  - higher electricity prices, and
  - payments to utility-scale renewables to offset the higher WACC imposed on renewables under Reform, so as to enable achievement of their State-based renewable energy targets.

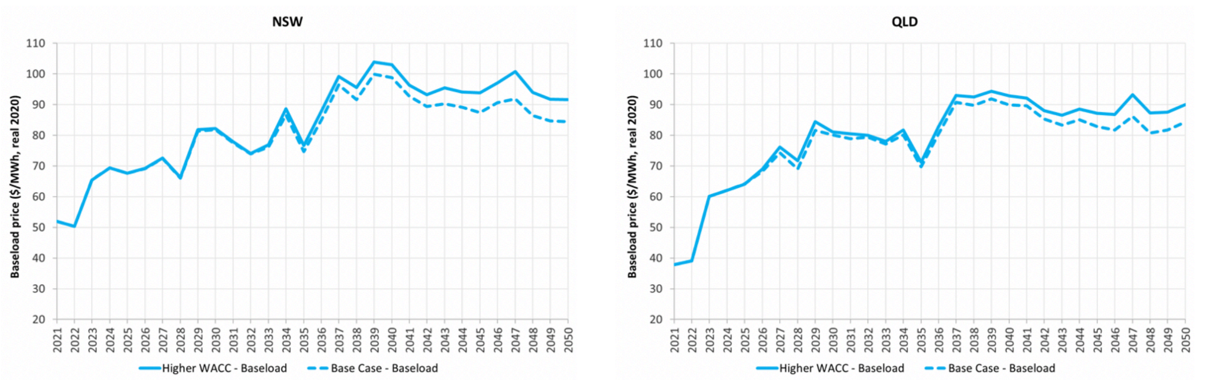
Figure 2 – Extra cost to electricity consumers from COGATI Proposal



By increasing expected break-even spot prices, a higher WACC reduces the volume of new-entrant capacity unless and until spot prices rise to equal expected break-even prices. With the exception of Queensland (QLD), spot prices under Reform start to rise above no-Reform prices from the mid-2030s.

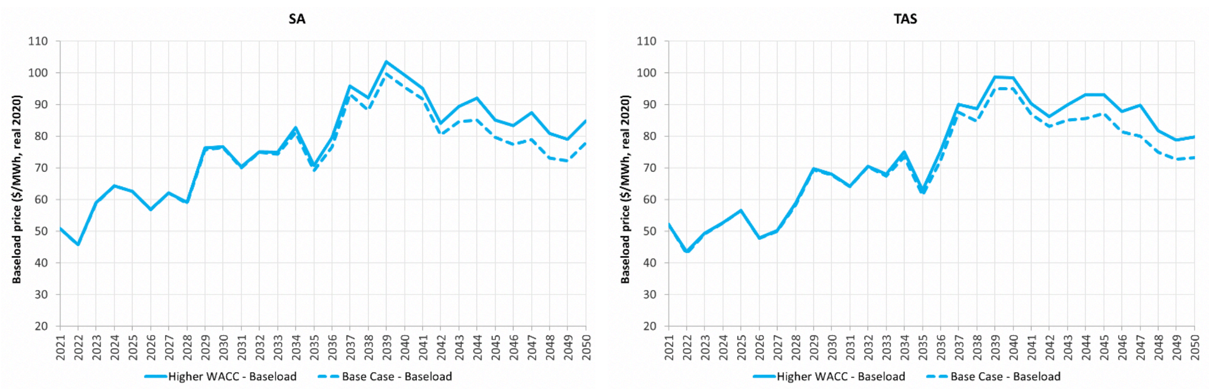
By 2050, spot prices in each region are around $6-7/MWh higher under the Reform scenario – an 8% increase on spot prices compared to no-Reform (Figures 3-5).

Figure 3 – Prices in NSW and QLD under Reform and no-Reform



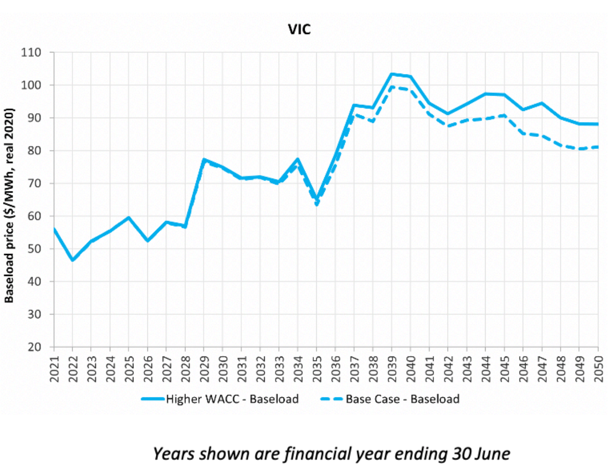
Source: Baringa Partners

Figure 4 – Prices in SA and TAS under Reform and no-Reform



Source: Baringa Partners

Figure 5 – Prices in VIC under Reform and no-Reform

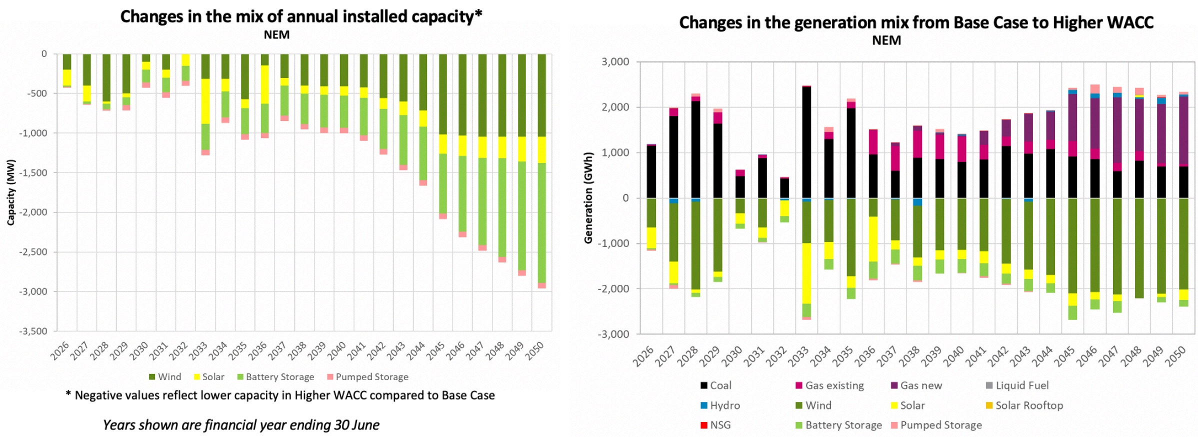


Source: Baringa Partners

Installed capacity is around 3GW lower under Reform compared to no-Reform as a higher WACC impacts the economics of utility-scale battery storage. Across the NEM, the magnitude of reduced volumes of new-entrant capacity under the Reform scenario becomes progressively larger from the mid-2030s as that new-entrant capacity is most needed from a price and affordability perspective to replace retiring coal plants (Figure 6).

Reduced new-entrant capacity results in increased output from incumbent thermal plant, both coal and gas powered generators (GPGs). Compared to no-Reform, existing coal plants increase their output by 3-4%, while incumbent GPGs increase their output by an average of 9%.

Figure 6 – Change in capacity and generation mix under Reform and no-Reform



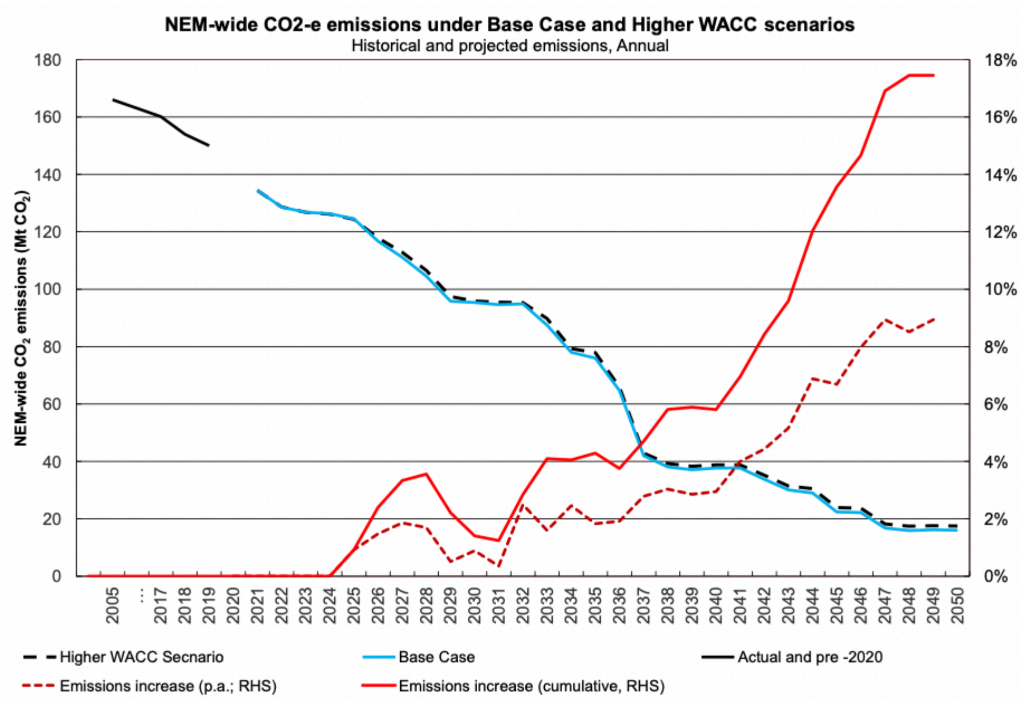
Source: Baringa Partners

Consequently, the level of CO2-e emissions across the NEM in the Reform scenario are higher than in the no-Reform scenario with a cumulative increase of 18% compared to NEM-wide CO2-e emissions under no-Reform.This equates to a $0.5 billion increase in social costs using a social cost of carbon of $15/tonne (Figure 7). These costs are additional to those noted above.

Emissions are higher especially from the mid-2030s under Reform due to:

- lower entry of renewables following coal plant exits, which results in more gas generation (and in turn higher emissions) than under no-Reform; and
- increased coal and gas generation, with gas plants' output further rising following the greater than 16GW of coal plant retirement by the mid-2030s.

Figure 7 – NEM-wide CO2-2e emissions under Reform and no-Reform



Source: Baringa Partners

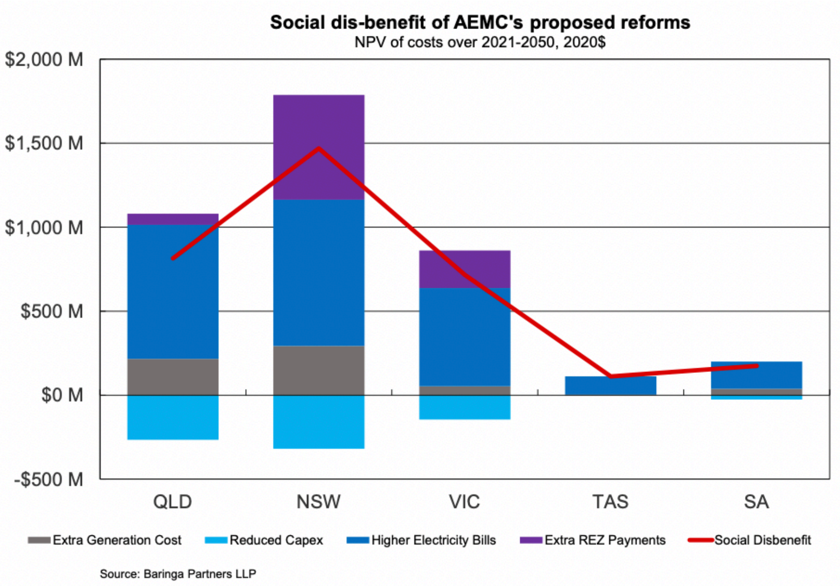
Overall, electricity consumers in each State experience social dis-benefits from the COGATI Proposal (Figure 8).

The prior modelling results reveal consumers are worse off (noting that price impacts provide the best indicator of consumer impacts):

- A higher WACC reduces the amount of new-entrant capacity, which results in reduced system costs (namely, reduced expenditure on capital expenditure intensive plants like utility-scale solar PV and onshore wind). However, contrary to NERA's assertions yet consistent with NERA's price outcomes, these lower system costs do not pass through to consumers;
- Instead, the beneficiaries under Reform are existing plants, especially thermal plants, which make windfall gains. The reduction in system costs under Reform results in incumbent generators enjoying higher profits – not consumers enjoying lower prices;
- Prices for consumers actually higher; and
- State Governments need to pay renewables to enter the NEM,in order to achieve State renewable energy targets and to offset the negative effect on investment caused by a higher WACC. This is

relevant to NSW, VIC and QLD governments - and by extension their electricity consumers. In the absence of these payments, State Governments are projected to not achieve their renewable energy targets.

Figure 8 – Social dis-benefits by State



Source: Baringa Partners

THE AEMC'S ANALYSIS OMITS BROADER COSTS TO THE ECONOMY AT A CRITICAL TIME FOR THE CLEAN ENERGY TRANSITION

The introduction of COGATI could jeopardise the necessary short and medium term investment in clean energy generation capacity

AEMO's 2020 ISP has found that 26-50 GW of new utility-scale wind and solar capacity is needed in the National Electricity Market (NEM) by 2040 for the optimal development of the power system at lowest cost to consumers.

With investment at a three year low and major issues with the grid connection and commissioning process already dampening investor sentiment in the NEM, investor confidence is paramount to deliver the required generation capacity in the short and medium term. Investment certainty is required in this early stage of the energy transition. Otherwise, a lesser quantum of investment could translate into missed opportunities and significantly lower levels of economic and regional development and job creation.

A rise in uncertainty from the introduction of COGATI would lead to lower levels of investment, especially in the short and medium term, at a time when investment in clean energy generation capacity is necessary:

- in the context of the economic recession induced by COVID-19 and the opportunity to promote jobs, economic growth, regional development and investment;

- in the context of the quantum of emission reductions that need to be achieved between now and 2050 for Australia to meet its commitments under the Paris Agreement;
- to ensure low prices for customers through the build out of the lowest-cost generation capacity;
- to ensure that the investment is funded at the lowest-cost capital available so that consumers do not pay an unnecessary premium; and
- to ensure that there is sufficient generation capacity in place ahead of coal-fired stations retirement (particularly if closures occur earlier than planned which AEMO and ESB have been warning about).

Impacts on Power Purchase Agreements (PPAs)

Some longer-term contracts already in existence (particularly PPAs) would likely need to be reopened if COGATI was implemented.

PPAs have tended to use the RRP as the strike price. A material change in market design and/or pricing methodology – such as the introduction of LMP – would likely cause the re-opening of PPA pricing to re-assess which counterparty should take on that price risk. In terms of mechanism, this might be triggered by 'Change in law' or 'COGATI/ Grid Access' clauses, depending on the terms and conditions of each contract.

A large range of PPAs would be in scope to be re-opened:

- the majority of State and Territory Governments would be impacted through recent auctions and individual Support Agreements;
- a number of local governments and Universities have recently procured renewable energy through long-term PPAs to meet emission reduction targets; and
- the corporate sector has supported projects with a combined capacity of over 5GW.

With regards to the cost of re-opening PPAs, the AEMC has only quantified the cost of legal fees (up to $5m, at up to $20k per contract). CEIG considers that this cost is vastly under-estimated, especially when considering the likelihood of disputes between parties as to who should bear the additional risk and cost imposed by COGATI. More importantly however, the impacts of re-negotiating PPA prices - with the potential need to flow through a higher cost of capital - can be expected to be material and have not been accounted for by the AEMC. There could also be an impact on future PPAs whereby generators would need to incorporate a higher risk premium in their PPA prices to account for the difficulty in assessing FTR prices and revenue more generally.

Although it is less likely to be an issue because their electricity supply contracts tend to be shorter term, some retailers could be impacted too (for example through the bundled contracts with maturities to 2030 held to manage their Large-scale Renewable Energy Target liability). AEMC has assumed that those contracts would no longer be in existence by the time COGATI commences (est. 2025-26). However, there would likely be a price impact from the new COGATI arrangements (including to reflect the higher WACC) into retailers' contracts going forward.

Impacts on REZ developments

Various State governments have started developing REZ policies, partly to speed up the clean energy transition and benefit from the associated economic and regional activity, partly to address

REZ-specific issues and be able to tailor their policies accordingly (for example tailor policy for 'brownfield' vs. 'greenfield' REZs).

As granular regional data was not provided as part of the NERA modelling results, it is not clear whether by 2040 the COGATI Proposal would ultimately deliver the same outcomes as those currently anticipated through the ISP in terms of REZ development (for example in terms of MW of generation capacity installed in a particular REZ but also where new generation would be ultimately located). This could cause some State governments to have to intervene if the COGATI Proposal led to mis-alignment or counteracted their State's REZ policies. At a minimum, the AEMC should conduct some analysis to assess the scale of those potential impacts on State policies and on the associated investment levels.

If COGATI was implemented from around 2025-26, it is also unclear how existing 'REZ access rights' acquired through the ESB's REZ Framework would be safeguarded and whether State governments would ultimately be required to cover the costs of grandfathering any such rights.

THE PROPOSED COGATI MARKET DESIGN IS NOT APPROPRIATE AND CAN BE EXPECTED TO INCREASE COSTS

The FTR design principles and grandfathering provisions are not appropriate
The FTR design principles proposed by the AEMC do not provide sufficient hedging options for generators and do not provide sufficient certainty at FID over what share of total revenue can be hedged. This is likely to translate into hedging being only available for a relatively small share of a plant's output, which can in turn be expected to translate into higher pricing.

The following FTR design features, when combined, limit the ability to know at FID how much revenue can be hedged:

- FTRs to only be available at "a relatively small number of pre-defined nodes" (with the AEMC yet to finalise its methodology). The basis risk created by the introduction of LMP cannot therefore be fully hedged;
- FTRs to not be firm, with payouts able to be reduced if there are revenue shortfalls;
- FTRs to not cover transmission losses;
- FTRs to be available for up to 10 years in advance for parts of the network;
- Tranches of FTRs to only be progressively released over time; and
- lack of clarity around how the expanding number of 'FTR nodes' is treated over time and how existing FTRs would be transitioned.

In summary, the theoretical FTR framework is so complex that to come up with a solution that could be practically implemented, the AEMC have derived a partial non-firm FTR model which provides limited benefits while retaining all of the costs and complexity.

The proposed grandfathering provisions are insufficient as transitional FTRs are not fully backed and the total 5 year sculpting timeframe for transitional FTRs is too aggressive. As the AEMC has not finalised its methodology for allocating transitional FTRs, the impacts on existing investors could also be worse.

Overall, this could combine to create a sovereign risk whereby investors lose faith in the NEM, its Rules and its regulators as they feel that an unreasonable amount of value is given to consumers without respect for recent investment decisions.

The COGATI Proposal could create new barriers to entry

The COGATI Proposal as currently designed is unnecessarily complex and could create new barriers to entry, particularly for smaller players. While some design features intend to simplify market operation - for example limiting the number of 'FTR nodes' - they could actually increase complexity and uncertainty as the value of FTRs becomes harder to forecast, market competition decreases and ultimately, the proposed FTR design creates new barriers to entry.

If complexity is too great and hedging also becomes too expensive or too difficult to price in, market participants, particularly smaller players with less resources, may also have to rely on less effective contracting hedges which would ultimately lead to cost increases that are passed through as higher wholesale prices.

CEIG has reservations around NERA's modelling methodology as it underestimates or ignores key costs.

<u>Some assumptions in the NERA modelling are not sufficiently robust</u>

- By using an unrealistic low WACC in its net present value calculation, NERA mechanically overstates the benefits as future cash flows (particularly in late years) are only discounted by a low amount. This holds true without even questioning the quantum of benefits modelled by NERA.

- The benefits from 'Eliminating Race to the Floor bidding' appear to have only been modelled in 2025-26 and then extrapolated. The impact of race to the floor bidding is based on the assumed behaviour of coal fired generators and has not been modelled explicitly over the long-term to account for the transition to more renewable energy generation with lower marginal costs.

- It is unclear why wind and solar generation are treated differently in how REZs are assumed to be built out. NERA states that:

  > *"We understand from discussions with the AEMC and AEMO that the REZs are established as optimal areas for renewable build, and therefore it is not realistic/profitable to expect investors to build wind plants outside of those boundaries. Solar, on the other hand, is more versatile, so we allow for build outside the REZ."*

  As the modelling is based on the ISP assumptions which enables the building of REZs, solar is bound to be disadvantaged by being sited outside of REZs (with presumably greater congestion as those areas do not benefit from ISP investment), compounding any negative impacts in the No-Reform scenario.

- NERA advised that the analysis has not applied the REZ build limits defined by AEMO in the ISP ignoring the physical constraints in the system and potentially resulting in incorrectly locating new generation and subsequent congestion outcomes.

- It is unclear what MLF values have been assumed by NERA for the modelling of DyLFs in 2025-26.

- It is not clear whether NERA have re-calculated the MLF for each generator each year of the No-Reform Case. Despite its limitations, the MLF framework provides a strong locational signal and extended periods of congestion result in increased losses which typically result in material reductions to MLFs. If the NERA analysis has not recalculated MLFs each year in the No-Reform Case, there is a risk that the benefits of the Reform Case have been materially overstated.

- It is unclear what type of behaviour change has been assumed (or not) by NERA around:
  - bidding behaviour changes in response to the proposed LMP framework and what impact this could have on the results; and
  - how the proposed FTR grandfathering framework could impact on the results.

The modelled 'Competition related wealth transfer from generators/retailers to consumers' may be overstated as:

- FTRs are assumed in NERA's modelling to be firm whereas the reform does not propose that they would be firm, hence FTRs would be less effective;
- the increased complexity of participating in the FTR market will be a barrier to entry, particularly for smaller players; and
- it is unclear whether NERA has considered whether the Reform could reduce competition rather than increase it. For example, the New Zealand market has traditionally operated under limited liquidity as the only three existing 'FTR nodes' did not align well with load location, creating basis risk for most participants.

<u>The modelling results are not provided at a sufficiently granular level to assess the impacts of the COGATI Proposal</u>

To conduct a more fulsome assessment of the costs and benefits of the COGATI Proposal, it would be useful to have access to granular data to assess the impacts of any distributional impacts and cross-subsidies.

There is potential for material wealth transfers across various consumer categories based on:

- their type (for example large vs. small consumers);
- the electricity tariff they are on (for example whether they are subject to a demand charge); and
- their location (across and within NEM regions).

There could also be the potential for divergence in regional outcomes in the Reform and No-Reform scenarios:

- economic outcomes including jobs and regional development (across and within NEM regions);

- local economic impacts (for example if the introduction of COGATI diverts jobs and investment away from regions currently earmarked through the ISP and/or State government policies).
- emission reduction outcomes in various NEM regions;
- potential for wealth transfers across various regions including:
  - through variations in wholesale price outcomes; and
  - through disadvantages for regions with the cheapest generation in the form of lower LMPs if they cannot export to other regions (importance of inter-connectors).

The cost estimates to implement the COGATI Proposal are too low

CEIG agrees with the AEMC that its estimate for implementation costs is currently too low. AEMC should consider not only the IT costs of implementing COGATI, but also the broader staff-related costs to implement this major piece of market reform such as training and upskilling staff (including some transitory and some ongoing costs).

THE COGATI PROPOSAL SHOULD BE PUT ON HOLD AS IT IS NOT REQUIRED NOW

The COGATI Proposal does not solve current and future grid access issues

A key issue currently faced by generators is the deficiency in transmission capacity due to a previous lack of investment in the transmission network. CEIG strongly believes that the COGATI Proposal needs to be put on hold to avoid compounding those live issues.

Instead, CEIG firmly believes that the market bodies' focus should be on continuing to implement the initiatives already underway that address the current problems being faced by market participants around the lack of transmission investment:

- the biennial ISP process and the ISP Rules to enable actionable projects;
- the development of the ESB's REZ Framework;
- maintaining AEMO's register of information on generation projects; and
- maintaining existing consumer protections from transmission overbuild, as implemented by the AER through the RIT-T process.

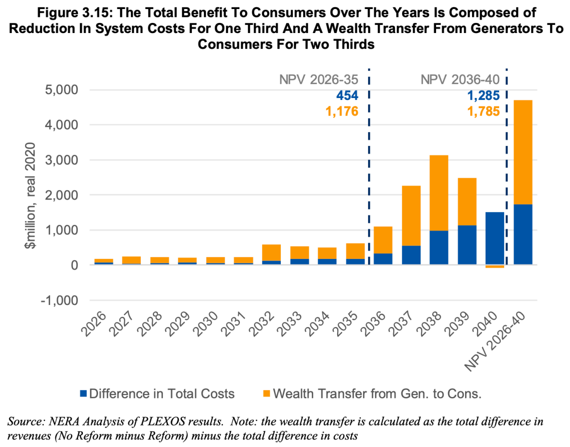
Another reason to put COGATI on hold is that it no longer provides a market signal for future transmission network investment through FTRs as this market design feature was removed in the October 2019 iteration. There is no longer a direct signal for additional transmission network investment since there is no longer a link between the planning and coordination of transmission investment and the price of FTRs.

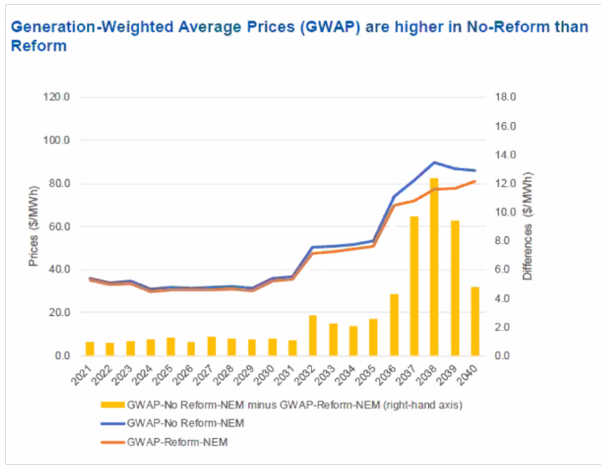
There are material risks that net benefits to consumers are minimal in the early years.

CEIG has reservations around the NERA modelling as it is skewed towards the quantification of benefits, without properly accounting for all costs including the impacts on the cost of capital as demonstrated above. Notwithstanding those material reservations, CEIG is concerned that the implementation of COGATI could be progressed on the basis of what are minimal consumer benefits in the early years.

The majority of consumers benefits as modelled by NERA come from 'Savings on system costs' and 'Wealth transfers from generators to consumers'. The benefits from those two categories - which together account for 57-76% of total benefits over the period 2026 to 2040 - are minimal before 2031 and largely accrue post 2035 (see Fig 3.15, NERA report – reproduced below). Prior to 2035, NERA has also modelled that prices to consumers would only be lower by $0.9 to $2.8 per MWh p.a. (Figure 9).

Figure 9 – NERA modelling results





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

Source: NERA modelling presentation – Sep-20

CEIG'S ALTERNATIVE SOLUTION FOCUSES ON ADDRESSING CURRENT PROBLEMS

CEIG supports applying the ESB's proposed REZ Planning Framework on a permanent rather than interim basis.

Investors seek a more predictable and less volatile siting signal that is known at the time when investors make their final investment decision. This mitigates any increase in the cost of capital that would be necessary if investors had to factor in volatile and/or uncertain future revenue streams. CEIG argues that the COGATI Proposal, by increasing uncertainty around future revenue streams, does not provide a sufficiently robust signal at FID and is therefore not necessary nor useful.

In its submission to the ESB's *REZ framework - Step 1 (Planning)* paper, CEIG noted that the REZ Framework would provide regulatory clarity so that REZs assessed for priority development by AEMO in its ISPs are able to be developed quickly. This is important in the context of the scale of the energy transition and the level of investment required to ensure that the energy system remains reliable, secure and affordable as will continue to be detailed through AEMO's ISPs.

CEIG supports a grid access framework that creates a robust investment environment to enable the efficient investment in new generation, storage and transmission capacity imperative to achieving the long-term customer outcomes set out in the National Electricity Objective. To create this investment environment, it is important that the regulatory reform process is undertaken in a coordinated manner that avoids unnecessary complexity and volatility and the associated risk premiums.

CEIG has also argued through the ESB consultation process that the REZ framework needs to be in place for the entire duration of the NEM energy transition (rather than being replaced with COGATI in 2025-26). In CEIG's opinion, withdrawing a REZ framework and implementing an alternative solution in a few years' time would create unnecessary uncertainty for investors, ultimately increasing the risks of a more volatile, costlier and less reliable energy transition.

CEIG looks forward to assessing the ESB's proposed cost sharing arrangements between generators, consumers and REZ proponents (including governments) for investments in transmission infrastructure. The level of investor interest that can be generated through those arrangements will be largely influenced by the extent of the firmness of access rights that they will provide to generators.

In principle, investors will value:
- firm access to the transmission network;
- knowledge of transmission access parameters at FID (such as risk of curtailment, system strength risks, expected level of grid losses);
- a guarantee that is either physical (for example, no new generator connection above the capacity of a transmission line) or financial (for example, if a generator contributes to an investment in transmission, its associated FTRs would be valid for the life of the generator's asset, to the value of the RRP);
- ability to fund transmission network capacity in the REZ itself; and
- third parties being able to build new transmission capacity (noting that the grid access framework may need to be different on radial vs. mesh lines).

CEIG is also cognisant that cost sharing arrangements within REZs will not eliminate the risk that some generators may site their infrastructure outside a REZ to benefit from the investment in transmission upgrades without sharing the costs. CEIG is interested in working with the ESB and State Governments to mitigate those impacts.

Overall, a well-designed REZ framework would address contract liquidity and transmission build cost issues and would give sufficient certainty for investors when combined with the rigour of the ISP process already in place. In this context, the introduction of LMP would not be required as the REZ Framework would give a sufficient signal to investors to encourage the appropriate siting of new generation capacity.

In the future, outstanding problems in the NEM design of the time could be re-assessed. The costs and benefits of the COGATI proposal and/or other options that could address those problems could be reconsidered then if there were material net benefits.

Thank you for giving the energy industry an opportunity to provide feedback on the COGATI Proposal; CEIG looks forward to continued engagement with the AEMC. For completeness, this submission has also been attached to CEIG's response to the ESB's Post 2025 Market Design Consultation Paper.

Please contact us at secretariat@ceig.org.au if you would like to discuss any elements of this submission.

Yours sincerely,

Simon Corbell
Chairperson
Clean Energy Investor Group

Attachment 1 – The impact of higher financing costs from the AEMC's proposed transmission access reforms (Baringa Partners)

Baringa
Brighter together

The impact of higher financing costs from the AEMC's proposed transmission access reforms

Final Report

The Clean Energy Investor Group
19 October 2020

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Executive Summary [1]

The Clean Energy Investor Group (CEIG) engaged Baringa to conduct electricity market modelling to quantify the impact of higher financing costs on the estimated net benefits of the AEMC's transmission access reform proposal

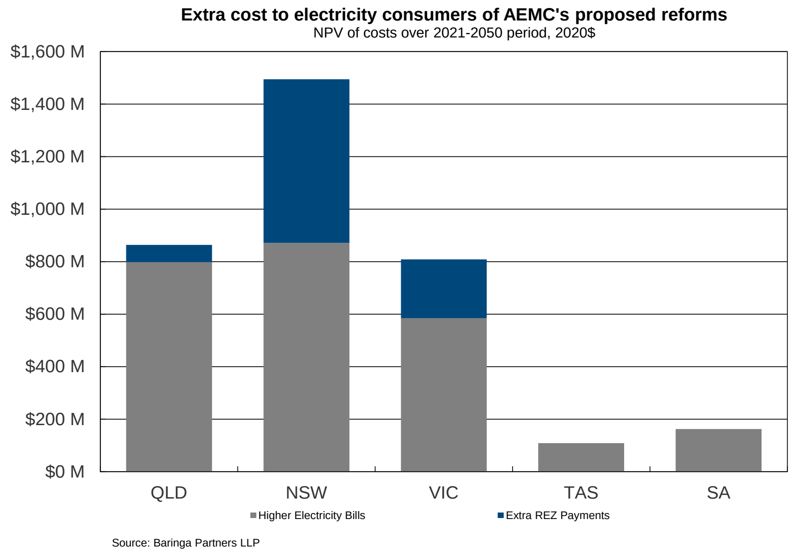
- On 07 September 2020, NERA Economic Consulting published a report (**NERA report**) for the Australian Energy Market Commission (AEMC), examining the costs and benefits of the AEMC's proposed transmission access reforms (*Reform*)

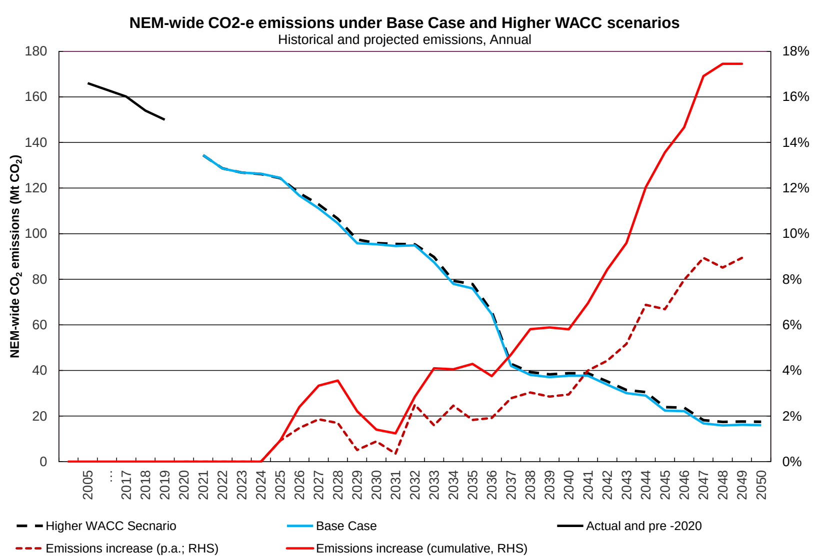
- The CEIG engaged Baringa to assist it by undertaking market modelling to estimate the impact of a higher weighted average cost of capital (WACC) on the estimated net benefits provided in the NERA report. The CEIG also engaged Baringa to provide a critique of the WACC used in the NERA report

- With respect to the WACC assumptions, we find the following:
  - NERA's WACC assumption of 5.9% p.a. in the no-Reform scenario is demonstrably too low – other studies suggest a WACC is in the order of 8-10% p.a. is appropriate. We use a WACC of 8.4% p.a. for the no-Reform scenario.
  - NERA's assumption that the WACC remains constant under no-Reform and Reform is also at odds with evidence from an AEMC investor survey. We use a WACC of 9.9% p.a. for Reform (i.e. an uplift of 1.5% on the no-Reform WACC).
  - Insufficient FTR firmness is key to understanding why the WACC is higher under Reform. Moving to nodal pricing will increase spot price volatility and in turn increase revenue volatility for generators (especially variable renewables like wind and solar PV). A lack of FTR firmness means this volatility remains unhedgeable, and therefore a higher WACC is required by investors to compensate them for the additional risks posed by the reforms

Executive Summary [2]

The Clean Energy Investor Group (CEIG) engaged Baringa to conduct electricity market modelling to quantify the impact of higher financing costs on the estimated net benefits of the AEMC's transmission access reform proposal





- With respect to the modelling, we find the following results when comparing market outcomes under Reform vs no-Reform:
  - The increase in WACC leads to increased consumer costs of **$3.4 billion** (in PV terms) over the 2021-2050 period across the NEM (see top LHS graph):
    - $2.5 billion of this is due to higher electricity bills
    - $0.9 billion of consumer costs comes from additional payments required to achieve State-based RETs under Reform
  - Relative to no-Reform, electricity consumers in VIC, NSW and SA face the biggest increases in costs under Reform. For VIC and NSW consumers, increased costs are due to: (i) higher electricity prices, and (ii) payments to utility-scale renewables to offset the impact of a higher WACC
  - Without payments to utility-scale renewables, State-based renewable energy targets (including targeted REZ build outs) would **not** be achieved
  - Reform results in higher emissions than no-Reform. By 2050, cumulative emissions in the NEM are **18% higher** under Reform (see bottom LHS graph). This equates to a **$0.5 billion** increase in social costs using a very conservative social carbon cost of $15/t. These costs are additional to those reported above
  - Emissions are higher especially from the mid-2030s under Reform due to:
    - lower entry of renewables following coal plant exits, which results in more gas generation (and in turn higher emissions) than under no-Reform
    - gas generators increase their output following the bulk of coal plants closures (from mid-2030s), which means emissions are higher

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Baringa

Introduction to the project [1]

The AEMC's proposed transmission access reforms: a "three-legged stool" of locational marginal prices, hedging contracts, and consequential changes to IT dispatch and settlement systems

Background

- On 07 September 2020, NERA Economic Consulting published a report (**NERA report**) for the Australian Energy Market Commission (AEMC), examining the costs and benefits of the AEMC's proposed transmission access reforms*

- The AEMC's proposed transmission access reforms consists of the following four elements:

  1. Moving away from the existing pricing of wholesale spot electricity based on the price at the regional reference node (RRN), to locational marginal prices (LMPs), where wholesale spot prices are allowed to differ by transmission node identifier
  2. LMPs are to be paid to scheduled and semi-scheduled generators, and paid by scheduled loads. In contrast, non-scheduled generators and non-scheduled loads will face a region-wide price, namely a volume-weighted average of individual LMPs (VWAPs)
  3. Hedging instruments, known as 'financial transmission rights' (FTRs), are available for purchase by market participants (both loads and generators). FTRs serve to can hedge the difference in prices between the load's/generator's transmission node and the price at any other node (including the RRN)
  4. Consequential changes to AEMO and market participants' dispatch and settlement systems, to enable LMPs (VWAPs) to be paid (received) by load (generators)

- Two other related reports were published by the AEMC on the same day:

  – An AEMC interim report (*AEMC technical specifications report*) with the following elements:

    - AEMC arguments for the need for reform to the existing regional
    - how the AEMC's proposed reforms relate to the ESB's 2025 market design work
    - changes to the AEMC's preferred design since the prior AEMC report on transmission access reform, and
    - an overview of the NERA report's cost-benefit analysis

  – A report by consultants HARD software providing preliminary indications of the implementation costs of the reform (*HARD software report*)

* Source: NERA Economic Consulting, *Cost Benefit Analysis of Access Reform: Modelling Report*, Prepared for the Australian Energy Market Commission, 07 September 2020, Available at: https://www.aemc.gov.au/sites/default/files/2020-09/NERA%20report%20Cost%20Benefit%20of%20Access%20Reform%202020_09_07%20%28excl.%20George%20changes%29.PDF

Introduction to the project [2]

The Clean Energy Investor Group (CEIG) engaged Baringa to conduct electricity market modelling to quantify the impact of a higher financing costs on the estimated net benefits of the AEMC's transmission access reform proposal

- The CEIG engaged Baringa to assist it by undertaking market modelling to estimate the impact of a higher weighted average cost of capital (WACC) on the estimated net benefits provided in the NERA report
- Baringa has modelled price and volume outcomes under a Base Case scenario, and also similar outcomes under a bespoke market s cenario. The description of the bespoke scenario is as follows:
  - The set of input assumptions used in Baringa's Base case forms the bulk of the input assumptions for the bespoke scenario (input assumptions are discussed further on in this deck)
  - The one and only change to the base case is a **150 basis point increase** in the WACC for new-entrant wind and solar PV from FY2026 onward
  - The increase in WACC in the bespoke market scenario is based on a prior AEMC survey of generation sector investors, which asked for survey participants' views on the potential change to their WACC from the introduction of the AEMC's proposed transmission access re forms
- Baringa has then compared the differences between the bespoke scenario and the base case in terms of:
  - the impact on system costs (i.e. changes in the costs of generating electricity)
  - wholesale electricity prices (changes in which provides an indication of changes in consumer prices)
  - the composition of the capacity mix and composition of the associated generation mix, and
  - The level of CO_2-e emissions across the NEM
- With this change in WACC, Baringa has re-run its long-term investment model to determine optimal capacity mix, and re-run their short-term dispatch model to determine spot prices and optimal generation mix
  - FY2026 is chosen to coincide with the start of the proposed transmission access reforms (and hence the start of the modelling period) as per the NERA report

Introduction to the project [3]

The Clean Energy Investor Group (CEIG) engaged Baringa to conduct electricity market modelling to quantify the impact of a higher financing costs on the estimated net benefits of the AEMC's transmission access reform proposal

- Baringa's Base Case broadly corresponds with the NERA report's No-Reform scenario
  - there are differences in the input assumptions between these two scenarios – in addition to differences in projected demand and projected network augmentation, two key differences in input assumptions relate to:
    - the WACC used in the Baringa Base Case is higher than in No-Reform
    - the "locational subsidy" in the no-Reform case leads to a large decline in NERA's technology cost assumptions relative to Draft ISP 2020 technology costs. The NERA report notes this subsidy is up to $20/MWh for wind and solar PV – this would represent **one-third to two-fifths** of wind and solar PV LCOEs in 2040
- These differences in approach and input assumptions are discussed in more detail in Section D
- The CEIG also engaged Baringa to provide a critique of the following three arguments:
  1. The note to Table 3.2 in the NERA report which states an assumed WACC of 5.9% p.a. in both the no-Reform and Reform scenarios
  2. Investors' views on the AEMC's proposed transmission access reforms
  3. A justification for why WACCs are expected to rise under the existing nodal pricing design, with reference to the following excerpt from the minutes of the AEMC's Grid access reform (COGATI) review – technical working group #6*:

  "The project team noted that the survey was undertaken at a particular point in time when there was an earlier FTR design and so the survey results are not reflective of the current proposal as set out in the March technical paper. We are open to detailed and specific feedback from stakeholders on whether and why the cost of capital would increase under the specification of the reform set out in the March technical paper."

* Source: AEMC, *Grid access reform (COGATI) review – technical working group #6,* 05 June 2020, Available at: https://www.aemc.gov.au/sites/default/files/2020-06/COGATI%20TWG%236%20minutes%202020_06_10.PDF

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Baringa

WACC is an important aspect of NERA's cost-benefit analysis

Impacts both present and future value of benefits of Reform

Impacts of a higher WACC in each of the NERA report's Reform and no-Reform scenarios

- A higher WACC in both scenarios would impact various aspects of NERA's cost-benefit analysis:
  - would lower the present value of the benefits of Reform, *assuming future value of the benefits are unchanged,* and this would apply for all aspects of NERA's benefit categories
  - would lower the *future* value of certain benefits, such as the size of NERA-estimated generator-to-consumer wealth transfers. Since generator earnings/EBITDA would need to be higher to compensate for the higher risks faced under a higher WACC, a higher WACC would, all else equal, reduce the size of any generator economic profits in both no-Reform and Reform scenario → in turn, reducing the size of estimated wealth transfers

Impact of a higher WACC specifically in the Reform scenario (i.e. an increase in WACC between no-Reform and Reform)

- An increase in WACC between the Reform and no-Reform scenarios would reduce the size of the benefits in the NERA report:
  - as for the above, a higher WACC would lower the present value of the benefits of Reform, *assuming future value of the benefits are unchanged*
  - would lower the *future* value of all benefit categories, as the system cost of new generation capacity under Reform would be higher than under a lower WACC. If the WACC increase was sufficiently large, the consumer benefit of a lower amount of generation capacity under Reform vs. no-Reform would be more than offset by the consumer dis-benefit from higher system costs associated with that low capacity
- We discuss these different impacts from a higher WACC in Sections C and D

Estimates of generator WACCs, and other considerations

NERA's assumptions appear too low

- Table 3.2 of the NERA report notes that a WACC of 5.9% p.a. has been assumed, while Table 1 of the NERA report refers to a 7% p.a. discount rate
- Since the WACC should be *the* discount rate, NERA does not specify how their "WACC of 5.9% p.a." relates to their "discount rate of 7% p.a."
- Even with a 7% p.a. discount rate, the WACC is too low
  - In Baringa's market and transaction advisory services,* a WACC of **8.4% p.a.**, on a real pre-tax basis is used for merchant generation projects
  - This is based on a more realistic cost of debt (4% p.a.) and cost of equity (15% p.a.)
- This is within the range of reported WACCs for merchant projects
  - One study† reported WACCs for merchant projects in the NEM are in a 10-13% p.a. range on a pre-tax, nominal basis – or 7.8-10.8% p.a. on real, pre-tax basis. Another study†† reported a real pre-tax WACC of 8.5% p.a.
- There are other sources of upwards bias in NERA's estimates of benefits; namely, NERA's analysis ignores the locational signals existing under no-Reform:
  - locational signal for losses is marginal loss factors (MLFs)
  - locational signals for congestion are the:
    - optimal development paths in AEMO's biannual ISP process, and how these plans feed through into individual TNSP network planning reports and investment decisions given the extensive work done to "action" the ISP, and
    - congestion projections done by prospective new-entrant generators as a requisite for obtaining debt and equity financing. Prospective congestion has come under increasing scrutiny by lenders during project due diligence processes, with the risk of future congestion impacting a project's economics through its impacts on the extent of financial leverage that a generation project can bear
- Allowing for a higher WACC under Reform, and accounting for the locational signals provided to generators, and their response to these signals, under no-Reform will reduce the extent of "wasted" capacity under no-Reform, and in turn reduce the benefits of Reform

* For more details, see https://www.baringa.com/en/markets/power-reports/

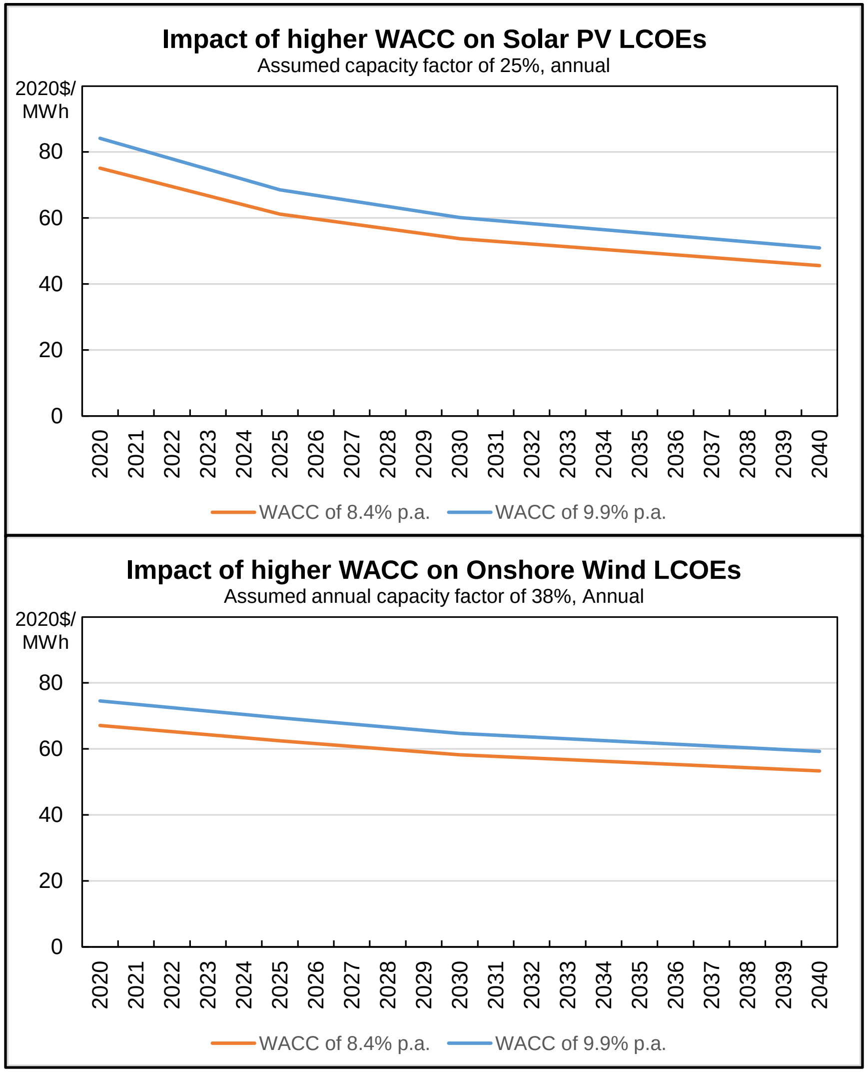
† Rai, A., and Nelson, T., 2020, *Financing costs and barriers to entry in Australia's national electricity market,* available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3692295

†† Simshauser, P., and J. Gilmore, 2020, *Is the NEM broken? Policy discontinuity and the 2017-2020 investment megacycle,* available at https://ideas.repec.org/p/enp/wpaper/eprg2014.html

Impact of a higher WACC

A higher, more realistic, WACC reduces the *future* value of NERA's estimated benefits

- A higher WACC also reduces the size of NERA's estimated future benefits. Using the benefit categories in the NERA report, the impact of a higher WACC would be as follows:
  - *Competition-related wealth transfers*: this benefit would decline, due to a higher WACC raising the cost of <u>new-entrant capacity</u> and therefore raising barriers to entry into the generation sector
  - *Generator-to-consumer wealth transfers*: wealth transfer from existing generators to consumers would fall, as a higher WACC under no-Reform reduces the size of economic profits existing prior to Reform
  - *Capital and fuel cost savings from more efficient locational decisions*: these would also be lower than NERA's estimates, as the higher WACC under Reform vs. no-Reform would increase the system costs of the capacity entering under Reform
- In all three of these instances, the reduction in benefits under Reform can be estimated from the increase in LCOE of generation capacity under Reform vs. no-Reform
  - The LCOE of both new-entrant and existing generation capacity would increase, the latter due to the increased cost associated with debt refinancing
  - For Solar PV, a 1.5 ppt increase in the WACC results in a $9.1/MWh increase (or 12%) in LCOEs for new-entrant capacity in FY2020. For new-entrant capacity in FY2040, the LCOE increases by $5.3/MWh (see RHS graph, top panel)
  - For Onshore Wind, a 1.5 ppt increase in the WACC results in a $7.3/MWh increase (or 11%) in LCOEs for new-entrant capacity in FY2020. For new-entrant capacity in FY2040, the LCOE increases by $6/MWh (see RHS graph, bottom panel)



Source: Baringa analysis

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Why may a higher WACC be expected? [1]

Concerns around firmness of FTRs

- In the absence of FTRs, nodal pricing will result in increased price and in turn revenue volatility for generators, as their settlement price will incorporate two time-varying components:
  - dynamic loss factors: essentially, MLFs that vary every thirty minutes (and every five minutes, when five-minute settlement commences in October 2021)
  - congestion between the RRN and the generator's node
- FTRs can serve to hedge the LMP-RRP price basis risk, with the effectiveness of this hedge linked to the firmness of the FTRs
  - the firmer the FTRs, the more that nodal price volatility can be reduced down towards the price volatility under regional reference-based pricing
  - while the AEMC has proposed various measures to enhance FTR firmness, it has not committed to measures that would otherwise ensure FTR firmness (discussed on next slide)
  - In turn, concerns about a lack of requisite FTR firmness drives investors' expectations of higher WACCs under nodal pricing, given the consequent increase in revenue volatility under nodal pricing
- We note the *AEMC technical specifications report* notes FTRs would **not** hedge for dynamic losses
  - As dynamic loss factors (DLFs) are inherently more volatile than MLFs, moving to DLFs must result in higher revenue volatility
  - Since FTRs would not provide a hedge for this greater revenue volatility, this risk remains unhedgeable, and therefore a higher WACC is required by investors to compensate them for the additional risks posed by dynamic losses

Why may a higher WACC be expected? [2]

Ways to enhance FTR firmness

- NERA notes their analysis presumes FTRs are firm (see p63 of their report)
- This assumption provides the answer for why they consider WACCs to not be greater under Reform vs. No-Reform
- The *AEMC technical specifications report* notes, relative to the prior design, the latest iteration of the design of the transmission access reforms contains the following elements considered by the AEMC to enhance FTR firmness:
  - use of proceeds from FTR auctions, in addition to settlement residues, to back FTRs
  - allowing non-physical participants to participate in FTR auctioning – this greater participation is argued by the AEMC to decrease "FTR competition issues", increase FTR firmness, and also improve FTR secondary market liquidity
  - settling (non-scheduled) loads on the basis of volume-weighted average prices (VWAPs) rather than regional reference prices
  - allowing FTRs to not hedge losses, which is argued by the AEMC to be firmness-enhancing
- Baringa considers that, fundamentally, the best way to enhance FTR firmness would be for FTRs to be guaranteed to be "revenue adequate"
  - "Revenue adequacy" is the extent to which an FTR's promised payouts can actually be paid in practice out of the residue pool
  - To guarantee revenue adequacy, any shortfalls in settlement residues (i.e. any negative residues) need to be funded, by definition, outside of the residue pool (i.e. by a third-party). In overseas nodal markets, this outside funding is often provided by the transmission network service provider (TNSP)
  - However, Baringa understands the AEMC remains opposed to third-party funding of residue shortfalls, in turn implying a lack of firmness in the FTRs. Furthermore, the *AEMC technical specifications report* notes FTRs would **not** hedge for dynamic losses
  - In Baringa's view, the AEMC's proposed enhancements to FTR firmness would provide limited additional firmness compared to an explicit commitment to fund any shortfall between the level of promised FTR payouts and settlement residues
- A credible and explicit commitment to fund any FTR shortfalls would have the beneficial impact of increasing generators' willingness to pay for FTRs
  - in turn, and somewhat paradoxically, this could *decrease* the chance of having to actually make good on these payment shortfalls, as increased FTR prices can increase the amount of funds available for FTR payouts
  - at the very least, a cost-benefit analysis of nodal pricing and FTRs should consider the costs and benefits of providing such an explicit commitment, and more generally, the costs and benefits of providing differing degrees of firmness – rather than the approach of assuming the answer

Why may a higher WACC be expected? [3]

Loss of automatic & free access to intra-regional settlement residues

- Under zonal/regional reference-based pricing, generators receive the congestion component of intra-regional settlement residues automatically and for free. Moving to nodal pricing and FTRs would require generators to pay for these residues via purchase of FTRs
- Existing generators would seek to recover payment for these FTRs by increasing their bids into the energy market
- Prospective generators would seek to recover these payments by requiring a higher break-even electricity price to incentivise entry
  - a higher WACC is one mechanism by which a higher break-even price can be set
- Prospective and existing generators may be unable to seek to recover these costs from consumers if there was increased competition in the market under Reform
  - this is the presumption in the NERA and AEMC reports – the "wealth transfers" from generators to consumers reflect reductions in prices to consumers that outstrip reductions in costs (or conversely, an increase in costs that are not passed through to consumers)
  - however, given the sheer complexity of the proposed nodal pricing reforms, it is highly debatable if competition would be enhanced under Reform. A higher WACC would reflect concerns about the potential increase in barriers to entry under Reform
- Furthermore, the NERA analysis shows generators do not exit following an effective decrease in their profitability from having to pay for these residues
  - this requires there to be a level of economic profit under no-Reform that are eroded under Reform (this erosion in turn reflecting the "competition-related wealth transfer" in the NERA report)
  - however, the NERA report does not contain any analysis of generator profits under no-Reform and Reform, to aid in determining the level of any economic profit existing under either scenario
- Moreover, we note the bulk of assessments on the effectiveness of competition in generation and retail markets – including assessments done by the AEMC – generally conclude these markets to be workably competitive, such that there are limited (or no) economic profits being earned, at least on a sustained/non-transitory, structural basis
  - this means increased costs associated with being required to pay for FTRs is likely to be passed through to consumers, as there is limited economic profits to erode without impacting generator entry and exit decisions
  - as noted above, the complexity of the proposed nodal pricing reforms means it is highly questionable if competition *would* be enhanced under Reform, and therefore whether any generator-to-consumer "wealth transfers" would arise

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Methodology and input assumptions [1]

Summary of key input assumptions used in this study

Driver	Assumption	Base Case
Policy	Carbon price	None
	Reliability Guarantee	Implemented, but does not impact on wholesale market participant bidding behaviour
	Integrated System Plan	New interconnection and transmission implemented as per AEMO's Final ISP 2020 (which impacts maximum build limits at a REZ-level)
	State-based renewable energy targets	Assumed first 2-3 rounds of VRET and QRET auctions proceed. Also, we assume that the central west NSW REZ is accelerated as per NSW government announcements.
Demand	Demand and peak demand	AEMO Neutral Case (ESOO 2020)
	Rooftop solar, residential storage and Electric Vehicles (EVs)	AEMO Neutral Case (ESOO 2020)
Commodity prices	Gas prices	LNG netback prices (latest ACCC LNG netback series, then US Henry Hub prices)
	Coal prices	Asian coal export price for 'uncontracted' plant (Japan coal prices less transport costs)
Capacity mix	Coal plant retirements	Retire coal plant at end of 50 year life (subject to economic test), or earlier if there is a public announcement
	Gas plant retirements	Aligned with AEMO assumptions (taken from AEMO ISP 2019 Inputs and Assumption workbook)
	Technology costs	Baringa internal cost assumptions
Bidding behaviour	Scarcity uplift	Scarcity function calibrated to historic bidding behaviour

Methodology and input assumptions [2]

The bespoke market scenario differs from the Base Case in only one respect: the assumed WACC for new-entrant plant

Market modelling

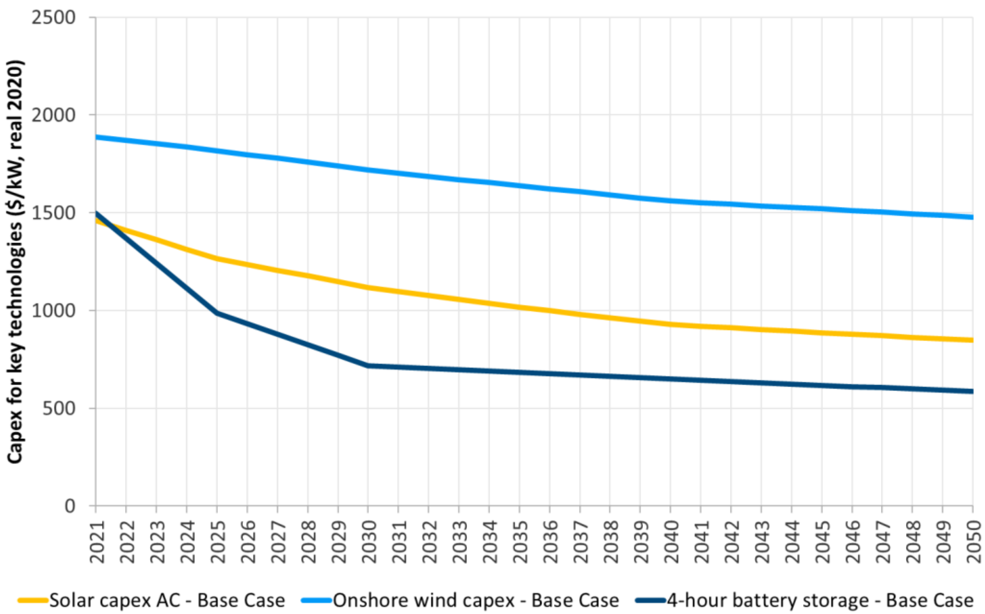
- Baringa has constructed a bespoke market scenario as requested by the Client. The bespoke scenario is defined as follows:
  - The Base Case (see input assumptions on previous slide) used as the basis for the bespoke scenario
  - The one and only change to the Base Case is a **150 basis point increase** in the WACC for new-entrant wind and solar PV from FY2026 onward
  - The increase in WACC in the bespoke scenario is based on a prior AEMC survey of generation sector investors, which asked for survey participants' views on the potential change to their WACC from the introduction of the AEMC's proposed transmission access reforms
- With this change in WACC, Baringa has re-run its long-term investment model to determine optimal capacity mix, and re-run its short-term dispatch model to determine spot prices and optimal generation mix
  - FY2026 is chosen to coincide with the start of the modelling period in the NERA report for the AEMC
- Baringa has then compared the differences between the bespoke scenario and the base case in terms of:
  - the impact on system costs (i.e. changes in the costs of generating electricity)
  - wholesale electricity prices (changes in which directly indicates consumer impacts)
  - the composition of the capacity mix and composition of the associated generation mix, and
  - the level of CO_2-e emissions in the NEM
- Details on Baringa's modelling approach is provided in the **Appendix**

Technology costs and LCOEs

Baringa

Base case technology cost assumptions for stand-alone onshore wind, solar PV, and 4-hour battery storage

Renewable technology costs



Our methodology

- Our cost assumptions are based on an internal Baringa database of global cost elements (e.g. Panels, turbines, battery cells) and local cost elements (e.g. BOP, grid costs), which is regularly benchmarked against data seen in our due-diligence work
- Our global experience suggests that this approach yields much more realistic results compared to a reliance on public numbers (which can fall out of date quickly)
- As previously noted, the WACC in Baringa's Base Case is set at a pre-tax, inflation-adjusted, rate of 8.4% p.a.
- The below table shows levelised cost of energy (LCOE) for new-entrant wind and solar PV, with the range in LCOEs reflecting the range in capacity/load factors

Table 1: Technology costs and LCOEs for 2021 for hypothetical new-entrant merchant project (i.e. no long-term PPA)

Technology	All-in capex ($/kW)	Opex ($/kW/yr)	Load factor (%)^	Equity hurdle rate (% nominal)	Gearing (%)	Cost of debt (% nominal)	WACC (pre-tax real)	LCOE* ($/MWh)
Onshore wind	1,889	45	36 – 40%	15%	40%	4.0%	8.4%	$62-69/MWh
Solar PV (AC)	1,460	20	23 – 27%	15%	40%	4.0%	8.4%	$65-77/MWh

^ Degradation of 0.4% pa has been assumed for these calculations
* LCOE: levelised cost of electricity

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Baringa

A caveat with respect to comparability

While our modelling approach is similar to that used by NERA, differences do exist and hence our results are not directly comparable to NERA's

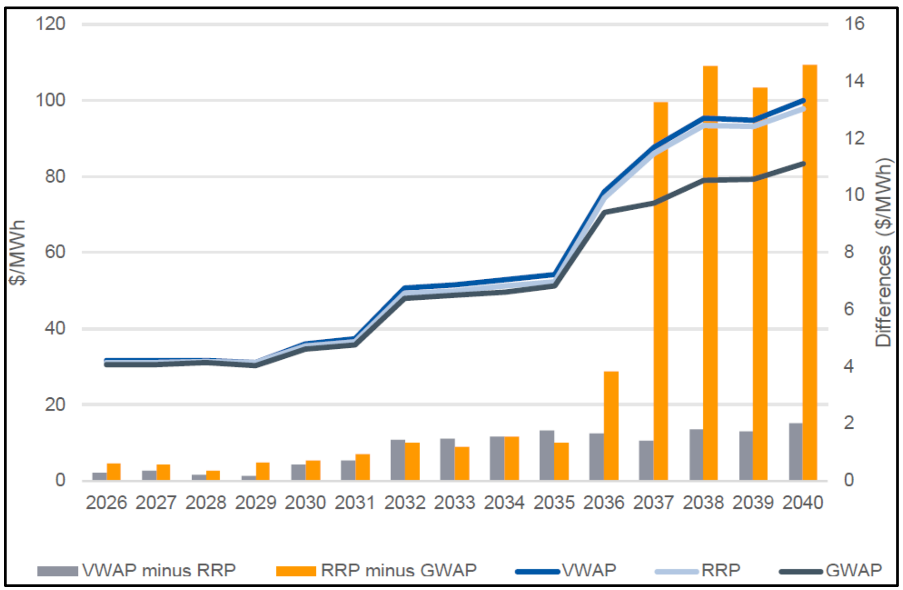
- Baringa's Base Case broadly corresponds with the NERA report's No-Reform scenario. However, there are differences in input assumptions:
  - NERA's demand assumptions are from AEMO's ESOO 2019; Baringa's is from ESOO 2020
  - the WACC used in the Base Case is higher than in No-Reform
  - the "locational subsidy" in the no-Reform case leads to a large decline in NERA's technology cost assumptions relative to Draft ISP 2020 technology costs
- NERA notes it completed "offline calculations in order to mimic the market signals sent under current access arrangements" (see page ii of NERA report)
  - Baringa has no knowledge of the nature of these 'offline' calculations and the extent to which these calculations impact NERA's final estimated benefits vs. the estimates of benefits obtained solely from the PLEXOS outputs
  - this applies to both the estimated overall benefits and the estimates of benefits for each of the individual NERA-identified benefit categories
- As our modelling approach and input assumptions are not exactly the same as those in the NERA report, some caution is advised in offsetting (i.e. netting off) our estimates of the consumer dis-benefit of implementing the proposed access reforms against the estimated benefits in the NERA report
- Ultimately, the most appropriate way to address this issue would be for the costs of the proposed reforms to be explicitly considered in the NERA report's market modelling
  - these costs include the potential impact on financing costs, IT and other system implementation costs, legal costs, and costs due to reduced contract market liquidity
  - the *Hard software* report, released by the AEMC on the same day as the NERA report, contained estimates of the IT-related costs of implementing the proposed transmission access reforms
  - in addition, the *AEMC technical specifications report* quoted costs of $5,000-$20,000 per PPA for the legal work needed to reopen contracts prior to commencement of the proposed reforms
  - yet, despite being titled a "Cost benefit analysis", the NERA report does not consider these costs

Price changes are the best measure of consumer impact

Price changes between no-Reform and Reform tells us the portion of system costs borne by consumers vs. generators

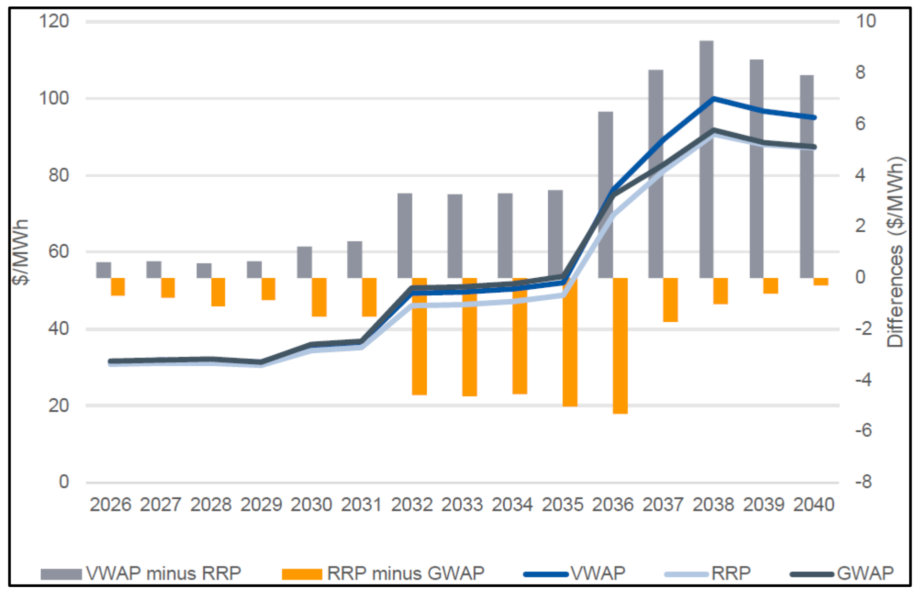
- NERA defines consumer benefits in terms of avoided system *costs* – this assumes system cost savings under Reform are all passed through to consumers
- Yet, the best measure of consumer impact is the change in electricity *prices* – changes in prices relative to changes in system costs indicates the extent to which changes in system costs are allocated to consumers vs. generators
- NERA projects moving from no-Reform to Reform will result in higher system costs, but a ~$3-4/MWh *fall* in year-2040 wholesale prices (see below graphs from NERA report)
  - this means the higher system costs under no-Reform are actually incurred by *generators*, not consumers; that is, consumers actually *benefit* under no-Reform, from the extra ~20GW installed capacity, with the system costs of this extra capacity borne by incumbent and new-entrant generators
- Therefore, we question the validity of NERA's analysis given their assumption that system cost savings are passed through to consumers when, in fact, their price modelling shows the opposite result i.e. NERA assumes consumers benefit under Reform, but their modelling shows consumers are worse off

NERA-modelled wholesale electricity prices in the Reform scenario



Source: Figure 3.3 in the NERA report

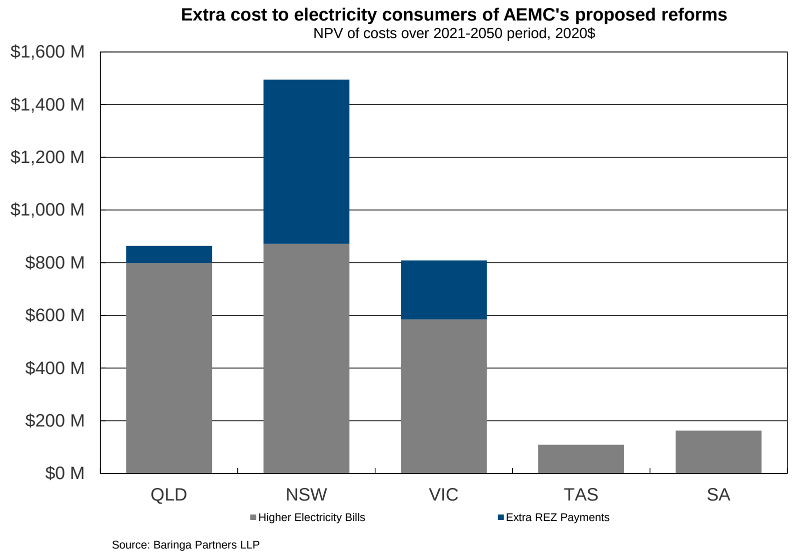
NERA-modelled wholesale electricity prices in the no-Reform scenario

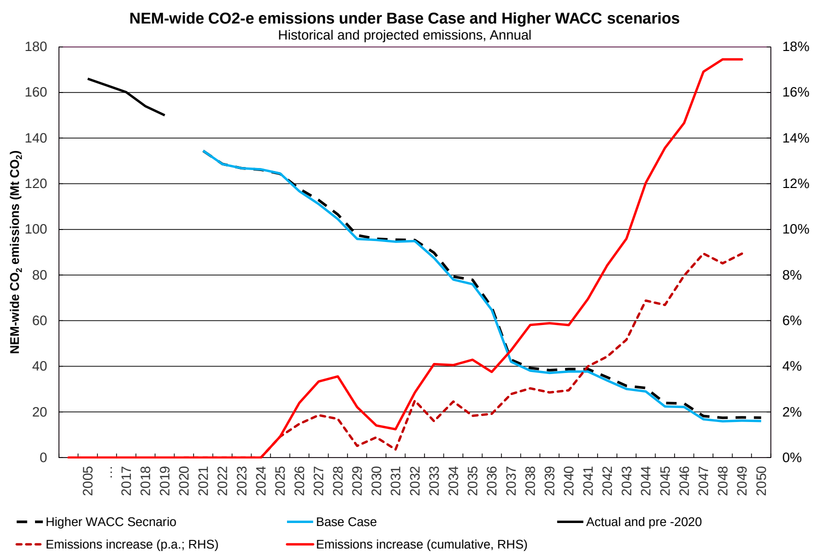


Source: Figure 3.11 in the NERA report

Summary of Baringa's market modelling outcomes

Cost of the AEMC's proposed transmission access reforms to electricity consumers

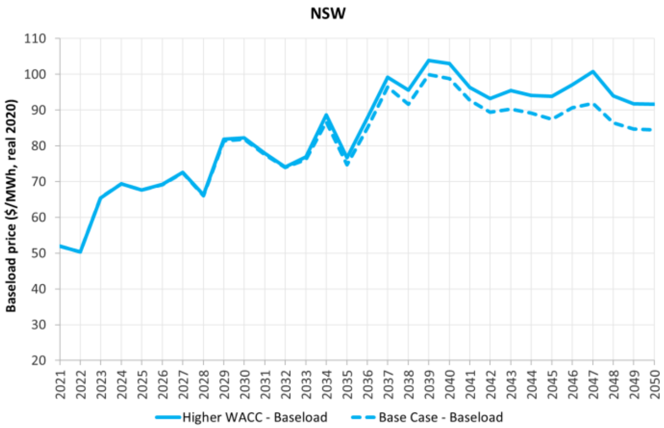


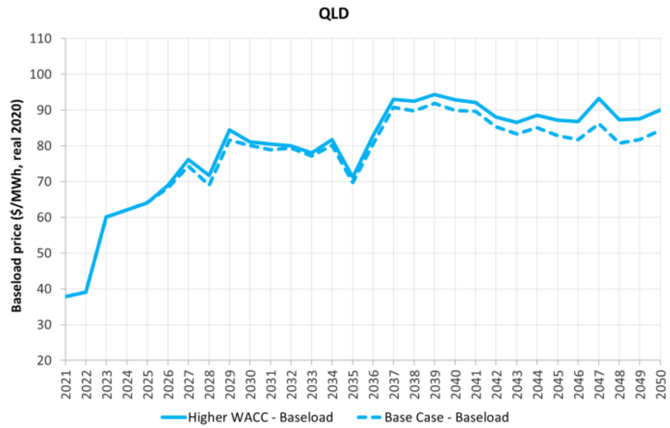


- The increase in WACC between the no-Reform and Reform scenarios leads to increased consumer costs of **$3.4 billion** (in PV terms) over the 2021-2050 period across the NEM (see top LHS graph)
- $2.5 billion of this (77 per cent) reflects increased electricity bills due to an average 3.5% increase in wholesale electricity prices under Reform
- The remaining $0.9 billion of consumer costs comes from the additional payments required to achieve State-based renewable energy targets under Reform. This cost is ultimately borne by electricity consumers within those States. Without these payments State-based RETs would **not** be achieved
- Relative to no-Reform, electricity consumers in Victoria, NSW and South Australia face the biggest increases in costs under Reform. For Victorian and NSW consumers, increased costs are due to:
  - higher electricity prices, and
  - payments to utility-scale renewables to offset the higher WACC imposed on renewables under Reform, so as to enable achievement of their State-based renewable energy targets
- Reform results in higher emissions than no-Reform by 2050, cumulative emissions in the NEM are **18% higher** under Reform (see bottom RHS graph)
  - this equates to a **$0.5 billion** increase in social costs using a social cost of carbon of $15/tonne. These costs are additional to those in the top graph
- Emissions are higher especially from the mid-2030s under Reform due to:
  - lower entry of renewables following coal plant exits, which results in more gas generation (and in turn higher emissions) than under no-Reform
  - increased coal and gas generation, with gas plants' output further rising following the >16GW of coal plant retirement by the mid-2030s

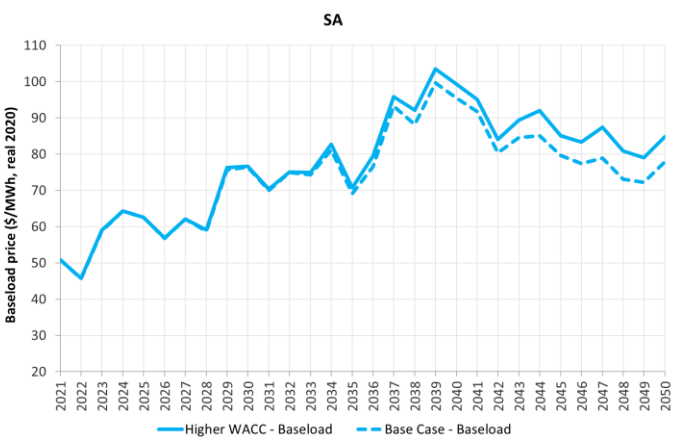
Baringa's market modelling outcomes [1]

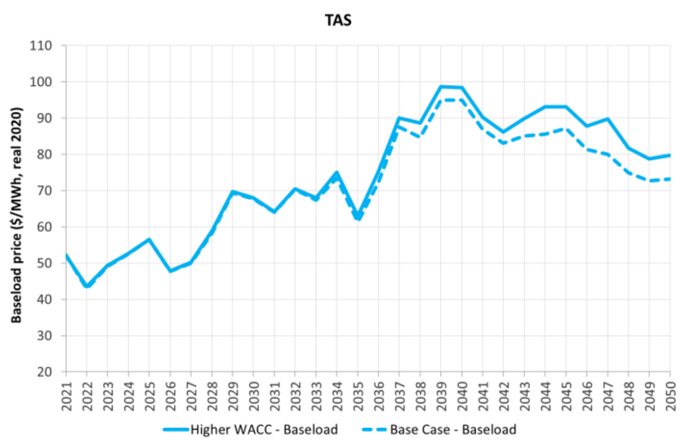
Annual-average settlement ('baseload') spot prices under Base Case vs Higher WACC scenarios

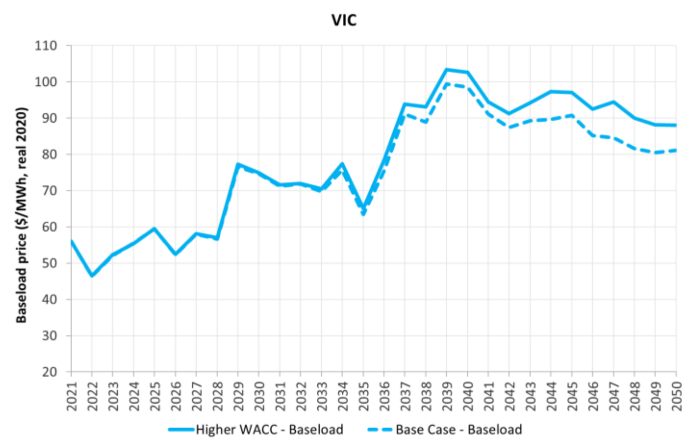




- By increasing expected break-even spot prices, a higher WACC reduces the volume of new-entrant capacity unless and until spot prices rise to equal expected break-even prices
- With the exception of QLD, spot prices under Higher WACC start to rise above Base Case prices from the mid-2030s. QLD spot prices rise above Base Case levels from the mid-2020s
- The mid-2030s timeframe reflects the higher cost to entice new-entrants to replace >10GW of coal plant capacity exiting during those years
- By 2050, spot prices in each region are around $6-7/MWh higher under Higher WACC scenario – a 8% increase on spot prices under Base Case







Years shown are financial year ending 30 June

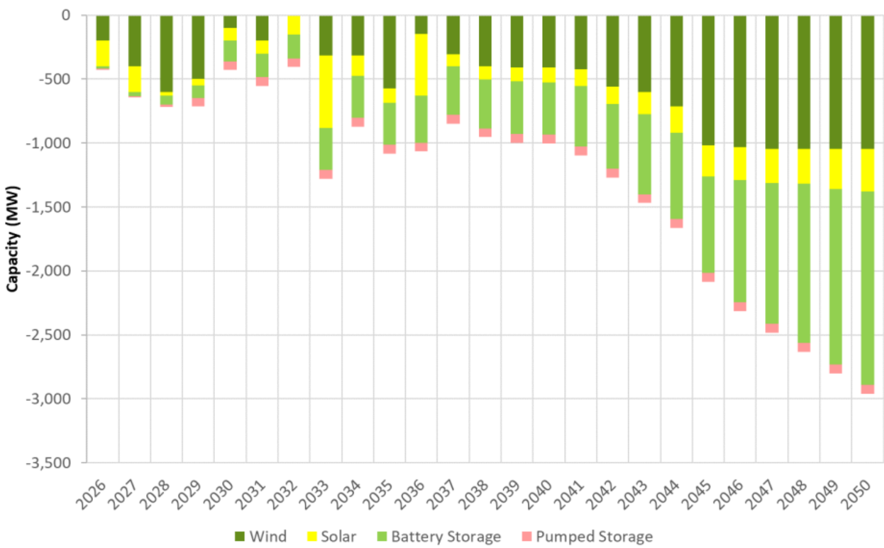
Baringa's market modelling outcomes [2]

Changes in capacity mix and generation mix between Base Case and Higher WACC scenarios

- Installed capacity is around 3GW lower under the higher WACC scenario compared to the Base Case – a higher WACC especially impacts the economics of utility-scale battery storage (NB: the increase in WACC for utility-scale storage is sourced from the AEMC's February 2020 investor survey)
- Across the NEM, the magnitude of reduced volumes of new-entrant capacity under Higher WACC becomes progressively larger from the mid-2030s – just when that new-entrant capacity is most needed from a price and affordability perspective: to replace retiring coal plants
- Reduced new-entrant capacity results in increased output from incumbent thermal plant, both coal and gas powered generators (GPGs). Compared to Base Case, existing coal plants increase their output by 3-4%, while incumbent GPGs increase their output by an average of 9%
- Consequently, the level of CO_2-e emissions across the NEM are higher than in the Base Case – with a cumulative increase of 18% compared to NEM-wide CO_2-e emissions under the Base Case

Changes in the mix of annual installed capacity*

NEM

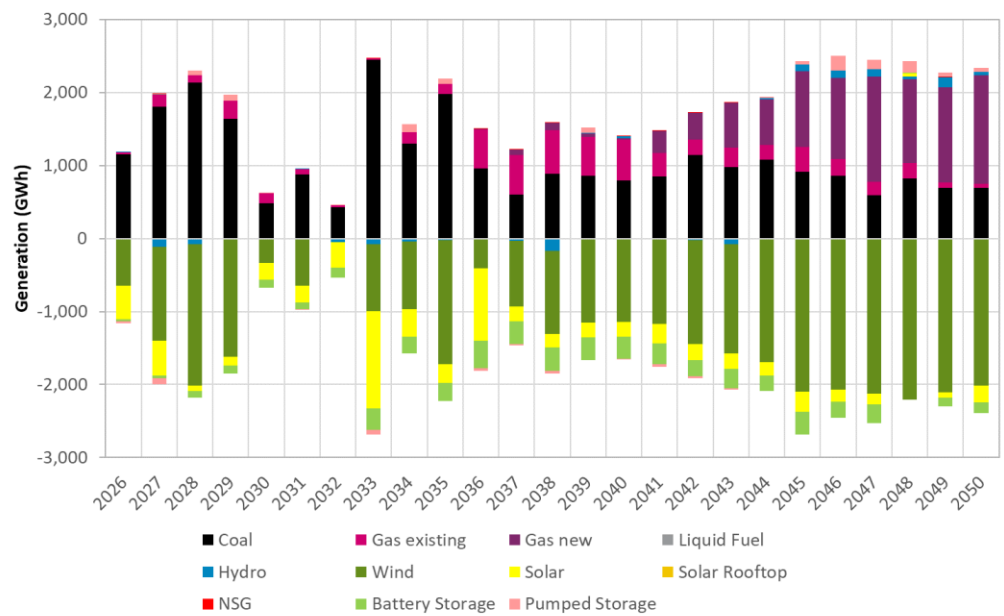


* Negative values reflect lower capacity in Higher WACC compared to Base Case

Years shown are financial year ending 30 June

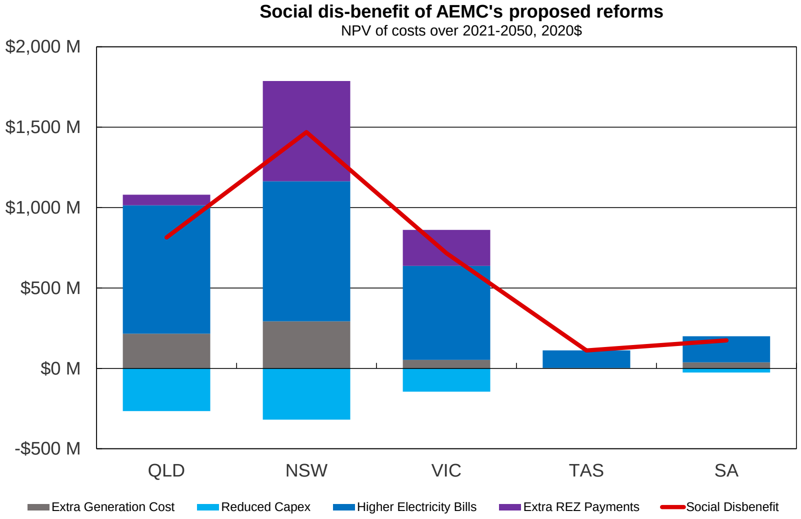
Changes in the generation mix from Base Case to Higher WACC

NEM

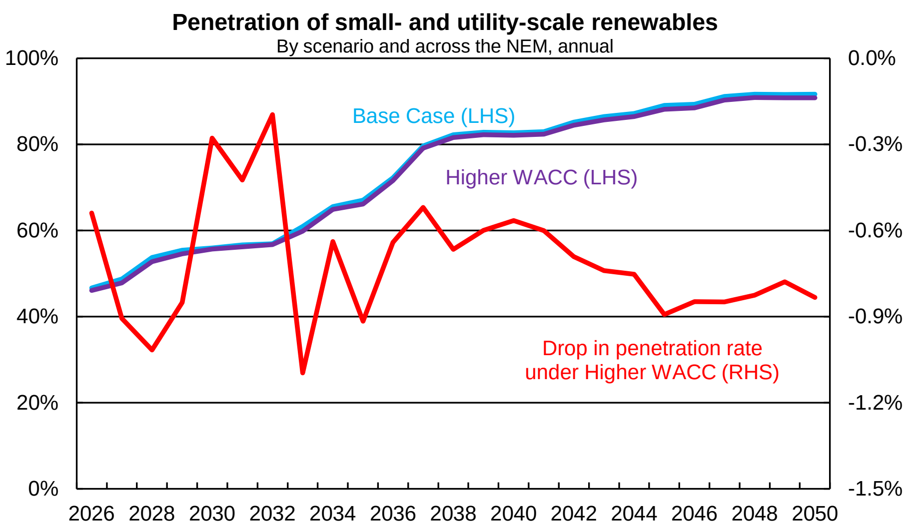


Consumer impact from a higher WACC

Applying the market modelling results to the estimated benefits in the NERA report



Source: Baringa Partners LLP



Source: Baringa Partners LLP

- The prior modelling results reveal consumers are worse off (noting, again, that price impacts provide the best indicator of consumer impacts)
- A higher WACC reduces the amount of new-entrant capacity, which results in reduced system costs (namely, reduced expenditure on capex-intensive plant like utility-scale solar PV and onshore wind)
- However, contrary to NERA's assertions yet consistent with NERA's price outcomes, these lower system costs do *not* pass through to consumers
- Instead, the beneficiaries under Reform are existing plants, especially thermal plant, which make windfall gains. The reduction in system costs under Reform results in incumbent generators enjoying higher profits – not consumers enjoying lower prices
- Worse for consumers, prices are actually *higher,* which adds further uplift to incumbent generators' profits
- And, to compound matters, State Governments need to pay renewables to enter the NEM, in order to achieve State renewable energy targets and to offset the negative effect on investment caused by a higher WACC
  - this is relevant to NSW, VIC and QLD governments – and by extension their electricity consumers
  - without these payments State-based RETs would **not** be achieved
- In the absence of these payments, State Governments are projected to *not* achieve their renewable energy targets
  - even if these renewable energy targets achieved under the AEMC's reforms, renewables penetration across the NEM would still be lower (see bottom graph)

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Baringa Overview

Baringa

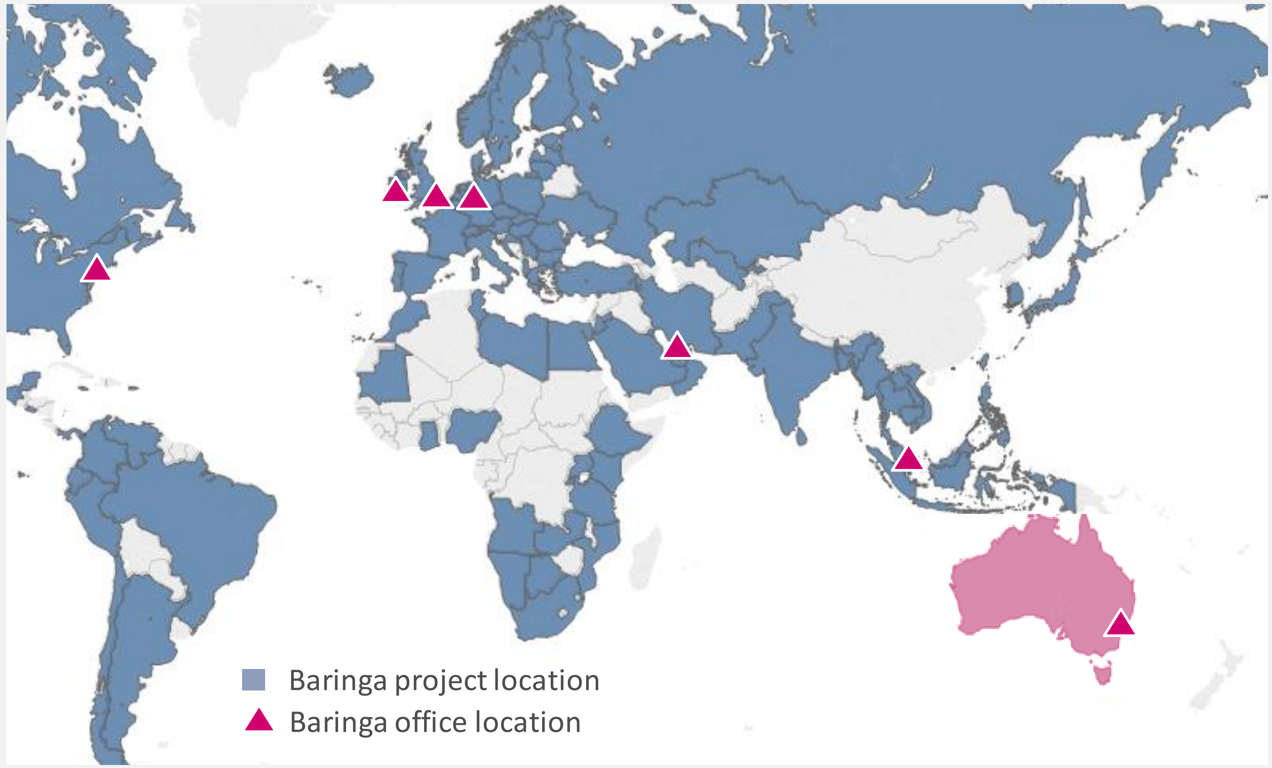
We help clients in the energy industry run more effective businesses, launch new businesses and reach new markets, understand and navigate industry change

70 Partners : 750 Employees

7 Offices Worldwide
London head office, with offices in Ireland, Germany, USA, UAE, Australia and Singapore, delivering projects globally

Unique Experience
Our clients tell us that they enjoy the distinctive experience of partnering with Baringa

Great Place To Work
Voted top 10 'Great Places to Work' for 12 years running...this creates a highly motivated, engaged and passionate consulting team



Upstream/ Generation → Trading / Sourcing → T&D → Distributed Energy → Retail / Supply → Customer

Energy Markets: offerings and capabilities

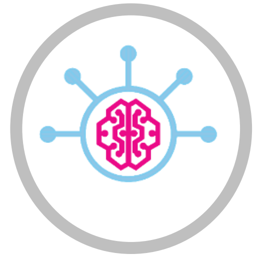
We support our client base with leading edge analytics and market insights

Our offerings

We offer our clients insights and analysis to support business decisions and solve complex problems

- Market reports
- Price projections
- Transaction advisory
- Commercial due diligence
- Opportunity screening
- Business case development
- Offtake and purchase agreements
- Decarbonisation pathways
- Energy system model deployment
- Market design
- Regulatory strategy and submissions
- Expert opinion

Our capabilities



We have a multi-lingual, multi-disciplinary team with expertise in economics, business, science, engineering and analytics

- Strategy development
- Scenario development
- Financial modelling
- Macro-economics
- Regulatory economics
- Econometrics
- Operational research
- Market and asset modelling
- Data science and analytics
- Market research
- Innovation thinking

Our tools

Our analysis is supported by rich data and leading edge analytical tools

- Power market models
- Whole energy system models
- Energy asset models
- Energy asset databases
- Network simulation and investment models
- Business case templates

Overview of our NEM model

Our model produces half-hourly wholesale prices for each of the five regions of the NEM

Key inputs

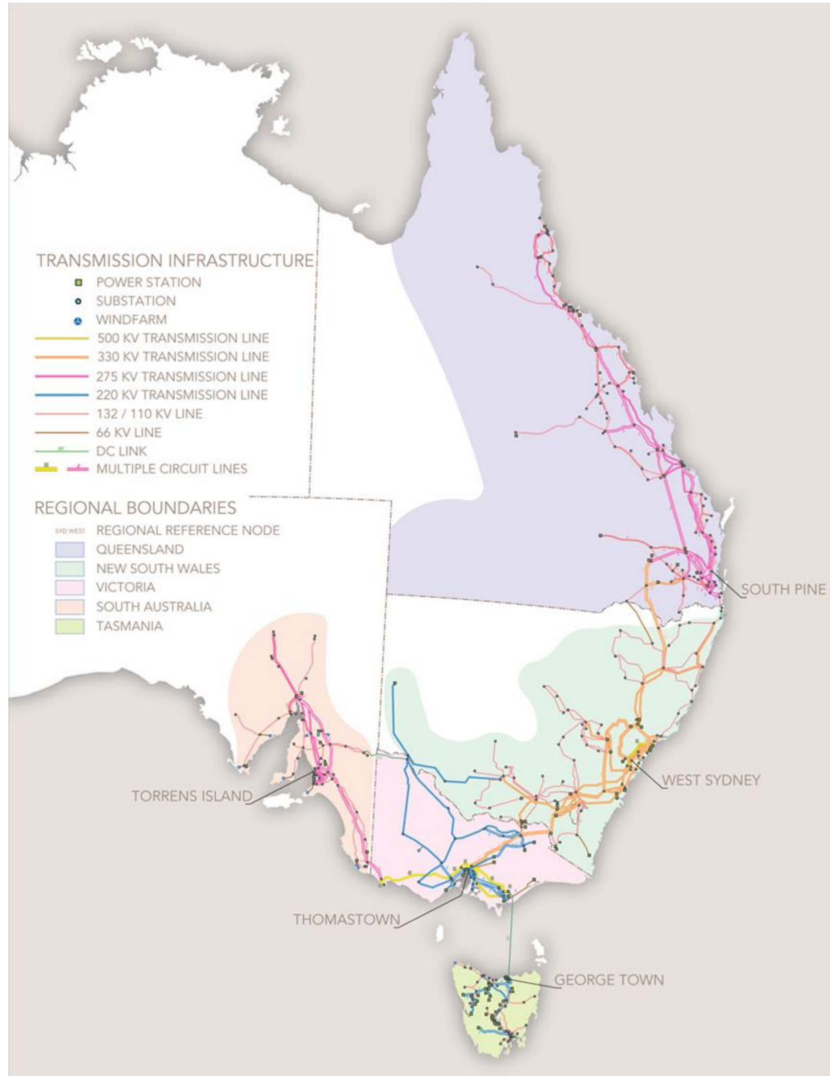
- Scenario inputs: policy, fuel prices, technology costs, demand, BtM deployment, plant retirement
- Detailed plant level database (from AEMO): installed capacity, efficiencies, operating costs, operating constraints
- Investment decision model for new build capacity
- Cross-regional interconnector capacity
- Detailed hourly wind and solar profiles

Model engine

- Half hourly dispatch, least-cost optimisation framework using the PLEXOS platform
- Optimisation of operational constraints including start costs, ramp rates, heat rates
- Maintenance scheduling and unplanned outages

Key outputs

- HH wholesale electricity prices (by region)
- Generation schedules
- Generation weighted-average prices (GWA)
- Asset energy revenues and gross margins
- Carbon Emissions
- Interconnector flows (imports / exports)



Baringa long-term investment and dispatch model

Baringa

Baringa's NEM market modelling consists of three phases: input/assumption preparation/update, long-term capacity mix projection and generation and price dispatch projections

Baringa scenario inputs

Assumptions

- Fuel & carbon prices
- Demand (growth & shape)

Baringa generator dataset

Detailed plant-level database

- All existing & committed plants
- Installed Capacity
- Efficiencies
- Operating costs
- Operational constraints
- Hourly wind and solar profiles based on historic data

Baringa new build assumptions

Cost and characteristics for generic plants

- Build and fixed operating and maintenance cost
- Variable operating costs, efficiencies
- Capacity build limits
- Capacity reserve margin requirements
- Other revenues

PLEXOS long-term investment plan

Simple generation dispatch model

- 60 day samples per year
- Model inter-region interconnection
- Optimisation of operational constraints such as start costs, and simple heat rate curves
- Hydro and pumped storage
- Simplified-average scheduling of outages

Outputs – capacity mix

- Capacity build:
- Solar (per zone)
- Wind (per zone)
- Battery and pumped storage (per region)
- Gas-fired plants (per region)

PLEXOS price-dispatch model

Detailed generation dispatch model

- Half-hourly generation dispatch
- Model inter-region interconnection
- Optimisation of operational constraints such as start costs, ramp rates and heat rate curves
- Hydro and pumped storage
- Scheduling of maintenance and unplanned outages

Outputs - dispatch

- Power prices
- Generation schedules
- Emissions
- Dispatch costs
- Wholesale revenues and gross margins
- Imports & exports

About Baringa Partners

Baringa Partners is an independent business and technology consultancy.

We help businesses run more effectively, reach new markets and navigate industry shifts. We use our industry insights, pragmatism and original thought to help each client transform their business.

Collaboration runs through everything we do. Collaboration is the essence of our strategy and culture. It means the brightest and the best enjoy working here. Baringa. Brighter Together.

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