Rethink of Open Access Regime

Report to Clean Energy Investor Group

February 2022

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Definitions

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
CMM	Congestion Management Model
ESB	Energy Security Board
EOI	Expression of Interest
ERCOT	Electric Reliability Council of Texas
CAISO	California Independent System Operator
CEIG	Clean Energy Investor Group
COGATI	Coordination of Generation and Transmission Investment
ISP	Integrated System Plan
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator
NEM	National Electricity Market
NYISO	New York Independent System Operator
PJM	Pennsylvania, New Jersey, and Maryland
RE	Renewable Energy
REZ	Renewable Energy Zone
SPP	Southwest Power Pool
SRMC	Short-run marginal cost
VRE	Variable Renewable Energy

1 Introduction

This paper responds to the ESB's request for comment on its Congestion Management Model/Renewable Energy Zones (CMM/REZ) proposal and for alternative approaches to achieving transmission access reform.

We start by refining the definition of the problem that CMM attempts to solve to reflect the needs and the context of the broader energy transition challenge facing Australia. In particular, we consider how the energy transition detailed in the Australian Electricity Market Operator's (AEMO) Integrated System Plan (ISP) will impact the ESB's stated goals for transmission access reform.

We then set out alternative mechanisms for reforming grid access which are consistent with the requirements of the energy transition and future needs of an increasingly renewables-based energy market. We believe two key measures would best meet ESB's objectives while minimizing unintended consequences and risks:

- Modifying existing National Electricity Rules (NER) for open access to transmission (Chapter 5, Part B) to incorporate queuing for transmission capacity to create a substantial protection of incumbent access
- Modifying existing NER rules for Central Dispatch and Spot Market Operation (Chapter 3.8) so that instead of pro-rata dispatch in the event of tied priced bids, Renewable Energy (RE)[1] generators—including wind, solar, and hydropower—are always dispatched before thermal generators where consistent with system security requirements. Dispatching RE ahead of thermal generation as a "tie-break" will prevent "race to the bottom" disorderly bidding.

As part of our analysis, we compare this alternative approach to the proposed CMM mechanism and explain why the alternative proposal can achieve the ESB's objectives more effectively than the CMM proposal. Finally, we provide worked examples of how our alternative proposal would function in practice.

[1] We define RE in line with the Energy Information Agency of the USA as an "energy from sources that are naturally replenishing but flow-limited; renewable resources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time." This includes wind, solar, and hydropower. Source: https://www.eia.gov/energyexplained/renewable-sources/

2 Problem Definition in the Context of Energy Transition

In this section, we will lay out how Australia's ongoing energy transition, reflected in AEMO's ISP, will affect the challenges and the needs of transmission access. ESB sets out the following objectives for transmission access reform:

- Efficient locational signals for generators—better signals for generators to locate in areas where there is available transmission capacity. These include, but are not necessarily limited to, the REZs that are being delivered through the ISP and state government policies
- Efficient locational signals for storage and demand side management—establishing a framework that rewards storage and demand side resources for locating where they are needed most and operating in ways that benefit the broader system
- Measures to give investors confidence that their investments will not be undermined by inefficient subsequent connections
- Efficient dispatch—achieving efficient dispatch through eliminating disorderly bidding.[2]

The rapid change in energy technologies, and in particular the rise of variable renewable energy (VRE) and energy storage, will fundamentally re-shape both the geography and the market dynamics of the NEM. To consider how each transmission access objective may best be achieved, it is important to anticipate how the electricity market may be changed by the energy transition and how these changes will be addressed in the transmission access reform. We recognize that we are still some way from complete energy transition. However, it is essential that reforms which may be designed to address historical problems do not themselves delay and complicate the transition, and that they continue to be relevant as the market evolves.

2.1 Defining Energy Transition and the Challenges it Presents

The essence of energy transition is that by around 2040, Australia can expect to have an energy system with no baseload thermal generation and only a small amount of thermal generation remaining for providing firming and peaking capacity. Instead, the majority of electricity will be provided by near zero Short Run Marginal Cost (SRMC) wind and solar generation[3] and energy storage located in REZs. As we explain below, the nature of competition and the market challenges in such a system will be very different to competition for dispatch between thermal generators

[2]Collyer, A. Et. Al. "Transmission access reform Project initiation paper" Energy Security Board. November, 2021 Accessed at: https://esb-post2025-market-design.aemc.gov.au/32572/1637195631-access-reform-project-initiation-document-nov-2021-final.pdf

[3] We use the term near zero SRMC renewable generation to refer to the large amounts of wind and solar generation that will join the NEM in the coming years. The SRMC of wind and solar is significantly lower than any competing thermal generation. In fact, the SRMC of solar generation is zero. However, wind power does have a very small SRMC—estimated by AEMO to be A$2.71 per MWh. For this reason, we refer to these generators as "near zero" for the sake of accuracy. Source: AEMO. 2019 Input and Assumptions workbook. 5 July 2020. Tab: Generator Summary -Existing, Committed and Anticipated Generators.

which is the key determinant of market outcomes at present. The expected energy transition is well represented in AEMO's Draft 2022 Integrated System Plan. In particular, the step-change scenario—identified as the most likely scenario by AEMO—makes clear that market conditions will change dramatically in the near future.

The key challenges presented by the energy transition detailed in the step-change scenario are:

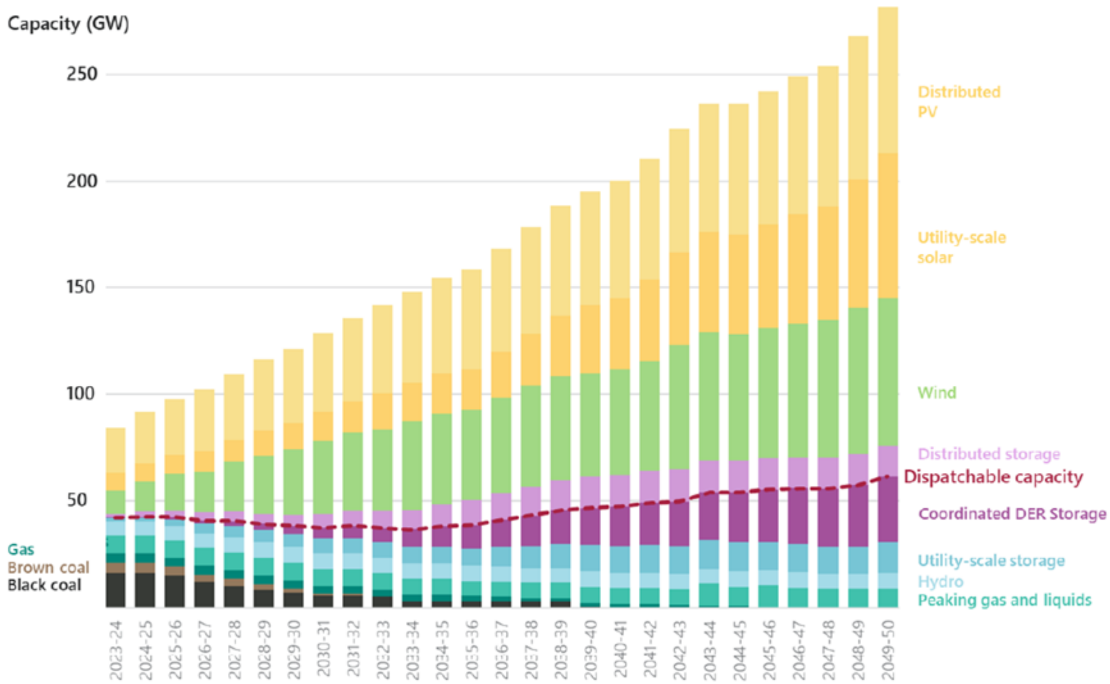
- Mobilizing the extraordinary amount of capital required to achieve energy transition over a relatively short period of time—shifting the electricity generation mix dramatically away from thermal generation to electricity generated from VRE will require mobilizing A$208 billion in capital
- Addressing grid access issues created by VRE locating in REZs—the energy transition will result in the location of electricity generators shifting from thermal generators located close to load and transmission capacity to generation located in Renewable Energy Zones (REZs) which are located far from load centers and transmission capacity.

The energy transition requires mobilizing massive amounts of capital to build VRE and upgrade transmission

Under the step-change scenario, "all brown coal generation and over two-thirds of black coal generation are expected to withdraw by 2032"—with the remainder phasing out before 2040—leaving only a small amount of peaking and firming gas turbine capacity. Further, the ISP expects that the market will "triple VRE capacity by 2030 – then almost double it again by 2040, and again by 2050."[4] Figure 2.1 illustrates the speed and scale of the investment AEMO expects will be required in the energy transition.

[4] "Draft 2022 Integrated System Plan." AEMO. December 2021

Figure 2.1: Forecast NEM capacity to 2050, Step Change scenario, with transmission



Source: *Draft 2022 Integrated System Plan AEMO*

This will require mobilizing massive amounts of capital. Further, the ISP makes clear that it expects "much of this resource will be built in renewable energy zones."[5] The REZs are intended both to coordinate network and renewable investment and to reflect the reality of where most renewable investment is likely to be technically and economically viable. As a result of the large additions in VRE capacity in REZs, the ISP anticipates and guides large investments in transmission capacity to serve REZs.

Table 2.1 provides an estimate of the state-by-state breakdown of the investments in VRE and transmission capacity to serve REZs. Total investment need will require mobilizing A$208 billion in capital.

[5] "Draft 2022 Integrated System Plan." AEMO. December 2021

Table 2.1: New VRE and Associated Transmission Augmentation Expected in the Energy Transition

State	Period	New VRE Generation[6]	Expected Generation Investment Cost ($ billion)*	Expected Transmission Investment Cost ($ billion) [7]
NSW	by 2050	38GW	52.06	13.4-17.5
Queensland	by 2050	47GW	64.39	2.8-8.3
South Australia	by 2050	15GW	20.55	1.8-4.6
Tasmania	by 2030	2.5GW	3.425	.70-.86
Victoria	by 2050	23GW	31.51	2.6-5.3

Source: Draft 2022 Integrated System Plan
**Clean Energy Investor Principles August 2021 Unlocking low-cost capital for clean energy investment According to the report, the cost of 1GW of new VRE is approximately $1.37b.*

The energy transition will alter the transmission grid by moving generation far from load

The energy transition will place a much greater emphasis on efficiently using transmission capacity—mostly radial lines—that serve REZs and on resolving congestion in the radial elements of the transmission network. In other words, the transmission access issues that need to be resolved are not abstract concerns about hypothetical optimal efficiency but, for the most part, a set of specific issues relating to:

- Optimally aligning REZ transmission and VRE and storage generation investment decisions to efficiently use transmission capacity
- Minimizing the cost of capital that must be mobilized through addressing unnecessary risks which result from the regulatory and market design shortcomings.

The ISP calls for constructing many transmission spurs leading off from the meshed grid that serves the NEM's major load centers to REZs. The spurs to serve REZ's are necessarry to reach REZ areas carefully selected for characteristics favorable to VRE development—namely cheap land and good wind resources—instead of their proximity to load. Further, these spurs will serve areas where likely all or almost all new generation capacity will be VRE, with no adjacent thermal generation. Thus, there will be limited competition for dispatch between thermal generators and VRE. However, VRE generators' propensity to all want to dispatch at the same time as the wind blows or the sun shines means that there will be competition for capacity on the transmission lines that serve REZs during peak periods.

[6] Draft 2022 Integrated System Plan, Appendix 3. Renewable energy zones

[7] 2021 Inputs and assumptions workbook/Rez Augmentation Options

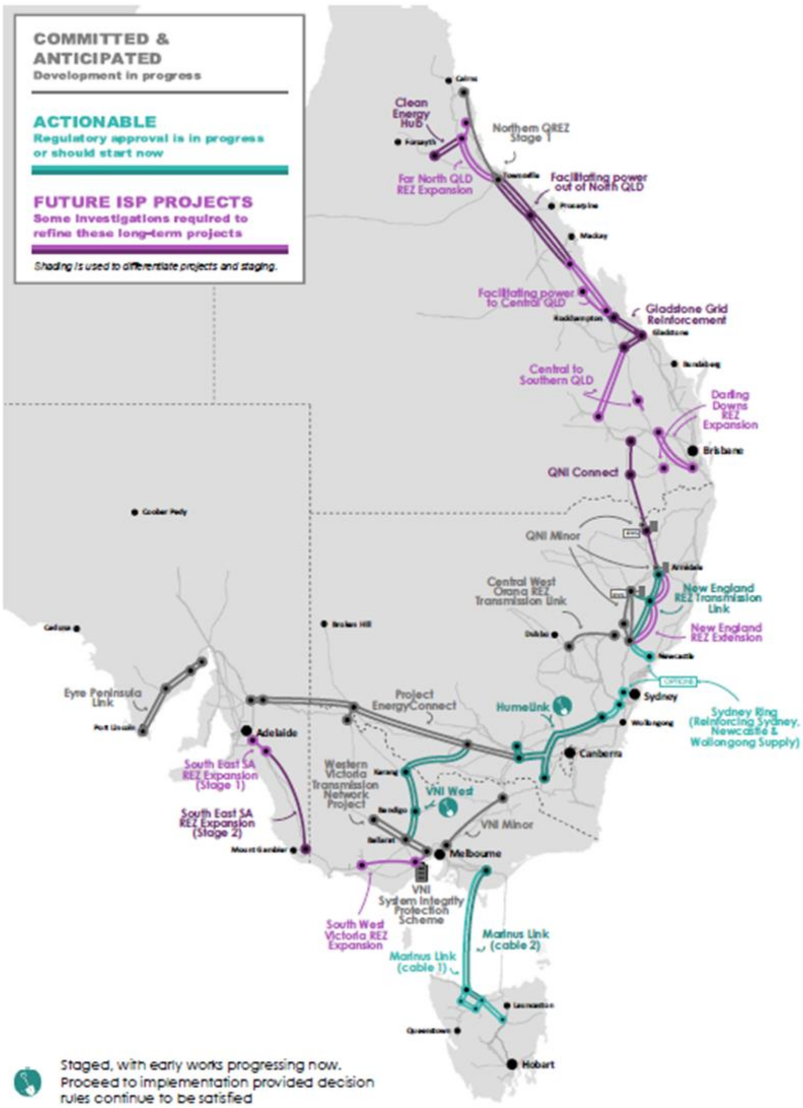
As we explain in more detail below, competition for dispatch among VRE generators does not serve the same social purpose of competition between thermal generators with different fuel costs and heat efficiencies. There may be some efficiencies to over-building VRE capacity compared to local transmission capacity, and hence efficient to curtail. However, there is likely to be limited efficiency benefits to allocating the dispatch capacity among VRE generators on the basis of 5-minute bids.

In the ISP:

- Three out of eight committed and anticipated transmission investments are directly for servicing REZs,
- Four out of five actionable projects are linked to REZ development (with Hume Link key for unlocking large amounts of energy storage)
- Nine out of 11 future transmission investments are directly linked to developing REZs.

The figure below shows the ISPs plan for committed & anticipated, actionable, and future transmission investments. The many spurs serving REZs illustrate the impact that the energy transition will have on the transmission grid.

Figure 2.2: Transmission Investments in the ISP



Source: AEMO ISP

2.2 Impact of the Energy Transition on Achieving the ESB's Objectives

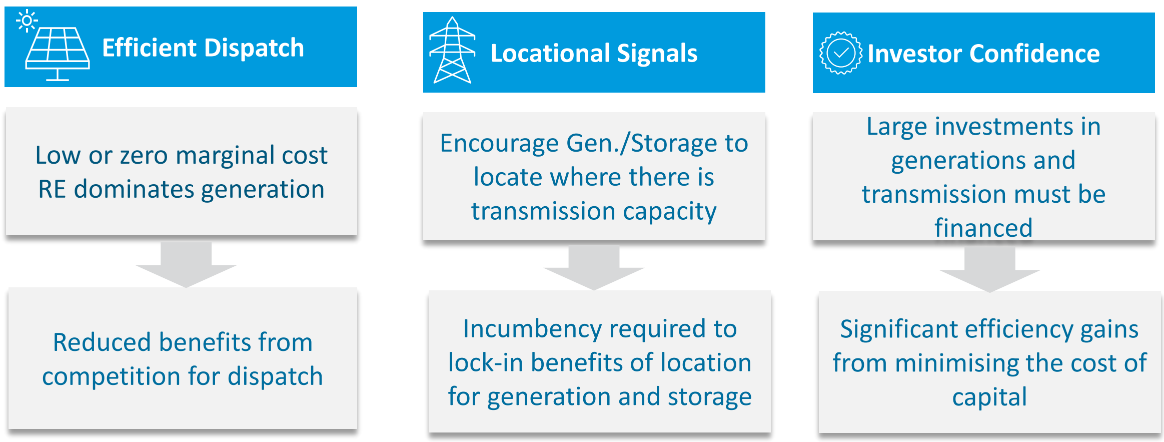
The two key challenges posed by the energy transition will have a large impact on how the ESB should approach achieving its objectives in reforming grid access. Further, the challenges presented by the energy transition mean that decreasing both the volume and the cost of capital become paramount to achieve the overall National Electricity Objective of achieving efficient investment in electricity services in the long-term interest of reducing cost for consumers.

- Locational signals that promote efficient location of generators and use of transmission capacity reduce the volume of capital required
- Increasing investor confidence reduces the cost of mobilizing the massive amounts of capital required

Meanwhile, achieving efficient dispatch becomes less important as the benefits of competition for dispatch are diminished.

Figure 2.3 shows the relationship between the key changes that result from the energy transition and their impact on the ESB's objectives.

Figure 2.3: Nature of the Energy Market Post Energy Transition



The dominance of RE with near-zero SRMC cost in the generation mix will dramatically reduce the benefits achieved from encouraging competition for dispatch. In a near-zero SRMC environment, there will be many periods where all bidders have near-zero SRMC and so there is no social benefit to dispatching any particular unit ahead of another, even though the dispatch order—or rather the risk of non-dispatch—will of course be important to each investor. Further, this does not mean, at least not in the short term, that there will not continue to be periods where thermal generation and RE will compete; however, as the energy transition advances instances where thermal generation and RE compete will reduce as a result of:

- The simple fact that there will be less thermal generation in the NEM as made clear by the step-change scenario
- The location of most VRE in REZs far from remaining thermal generation means there will be very limited competition between thermal generators and VRE
- The remaining thermal generation will mostly be firming or peaking capacity. By its very nature firming and peaking units are intended to run when RE is not able to meet demand. Thus, it is very unlikely that these units would be generating at a time when they would be competing with RE for transmission capacity.

If there are no efficiency gains from competition for dispatch during each bidding period, then it becomes more important to provide generation and storage investors with greater certainty about their future ability to dispatch at the time of the investment decision. The economic nature of the right to open access to transmission changes with energy transition. What matters is no longer the right to enter the competitive arena during every 5-minute period but rather the right to secure some degree of protection from being crowded out by generators with the same SRMC. This also comes with the obligation not to crowd out others. This requires an end to Australia's extreme form of open access and the introduction of some form of rationing access to the existing or planned capacity on the transmission grid, with the corollary of incumbency protection that locks-in the benefits of locating in areas with transmission capacity.

The large investments in generation and transmission capacity and diminished importance of fuel cost in generating electricity mean that volume of capital—the amount of generation and transmission built—and cost of capital—which is essentially a measure of investor risk—will become the key driver of the cost of electricity. As a result, reducing risk of inefficient crowding out for renewable and storage investors through structured changes to transmission access will have the greatest impact on lowering the overall cost of electricity production.

Reducing the risk of inefficient crowding out reduces the volume of capital by preventing inefficient overbuild of generation in areas where there is insufficient transmission capacity. It also simultaneously encourages generators to locate where there is available transmission capacity which better utilizes transmission capacity. Reducing inefficient crowding out also reduces the cost of capital, because the risk of curtailment due to crowding is the key uncertainty that is driving up the cost of capital.

In summary, ensuring that the right generation and energy storage capacity is built in areas with existing or planned transmission capacity and is financed with the lowest possible cost of capital is a challenge that cannot be primarily addressed through a further refinement of the spot market. Rather, as the order of dispatch becomes less significant in ensuring overall efficiency, the focus must shift to ensuring stability and predictability of the investment environment. As the ISP transmission projects are approved and implemented, the location of generation investment will become increasingly driven by planning decisions rather than by notional market signals. Any market signals and transmission access rules should work in tandem with the ISP planning processes rather than against them.

2.2.1 Efficient dispatch after energy transition

The existing dispatch algorithm is designed to dispatch generation units in merit order based on their bids, which in a competitive market should be primarily determined by each generator's SRMC. The fuel cost is the main driver of SRMC. As a result, the SRMC of thermal generation will almost always be higher than the SRMC of RE and, as a result, RE should be able to compete away thermal energy.[8] However, the dispatch algorithm will struggle to differentiate between RE generators with an equal SRMC and with an incentive to bid the price floor to be dispatched.

The economic dispatch model based on bid price is critical to minimizing the fuel costs of the existing fleet. It also sends an important signal to investors as they can anticipate where they will sit in the merit order and hence evaluate their investment from the perspective of the overall generation portfolio. However, in a situation where both new generation and energy storage have near zero SRMC characteristics, the 5-minute dispatch model is likely to play an increasingly minor role in achieving efficient utilization of the fleet[9].

Once the system is overwhelmingly VRE with near-zero SRMC, there will be little or no efficiency to be gained from optimizing the order of dispatch. Additional renewable investors will also be less able to assess how their project fits into the overall system on the basis of the merit order of their plant. Rather, they will be mainly focused on assessing the risk of being physically constrained off at times when they are able to generate.

In this context, it is likely that, energy storage will eventually eliminate price arbitrage between time periods. The key factor here is that storage has the same near-zero SRMC characteristics as RE. The current view is that investors in storage can make money by charging at low or zero cost during periods when RE units are generating—since REs will bid at zero or below in order to be dispatched—and then selling energy once REs are not generating (e.g., after dark). However, once there is enough storage in the system and storage providers compete for the opportunity to dispatch, they too will have an incentive to bid at zero or below in order to be dispatched. Overall, with sufficient storage, prices between time periods will become equalized as price differences are arbitraged away. In this context, energy storage will no longer be able to make money by buying electricity at low-cost time periods and selling at high-cost time periods.

Instead, energy storage will derive value from providing infrastructure services:

- Time-shifting for generators: For example, the cost of shifting a kWh between periods through a battery is fixed and is equal to the LCOE of the battery. Hence, it is likely that as growth in battery storage itself eliminates price arbitrage, batteries would tend to be remunerated through a flat fee for each kWh shifted between periods

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[8] We note that for thermal generators contract positions with respect to both fuel and off-take as well as plant cycling costs can push SRMC down—and even negative—during 5-minute bidding and settlement intervals. Thermal generators may have take or pay contracts for their fuel, meaning that whether or not they burn the fuel generating electricity they still have to pay for it. In these instances, thermal generators may effectively consider their marginal fuel costs as zero because they have to pay for the fuel regardless. This can drive down the SRMC of thermal generation.

The SRMC of VRE can also be negative due to Large-scale Renewable Energy Certificates (LGC). A VRE generator may be incentivized to bid negative by LGC as long as the value of the LGC is greater than the negative bid. So, for example, if LGCs are trading at $45 a VRE with an SRMC of zero can bid up to negative $44.99 and still receive a small profit from because the value of the LGC offsets the negative bid.

[9] For storage, SRMC is the opportunity cost of the price that can be received on discharge. However, as more storage becomes available on the system, price differences between time periods will be arbitraged away, so that energy prices during charging and discharging periods will trend towards a common number. Hence, the cost of a discharge will be the fixed cost of a single battery cycle.

- Providing a substitute for local transmission capacity: While a VRE and energy storage system requires an optimal mix of generation and storage to achieve 24-hour system security, the location of the storage will influence the transmission capacity required at each node.

Coordinating transmission and storage investment at each location is a different challenge to the one that ESB proposes to address through CMM and as such will require a different payment mechanism. Efficient investment in storage will not depend on refining price arbitrage opportunities, but rather on providing appropriate incentives for trading off future transmission and storage investments.

Box 2.1: Defining “Disorderly Bidding” In the Context of Energy Transition

A key goal of achieving efficient dispatch has been to eliminate “disorderly bidding”. Over the life of the NEM, “disorderly bidding” has been used to describe a number of different types of bidding behavior that prevents the NEM from achieving its goals of dispatching generation with the lowest possible underlying costs. Disorderly bidding has been defined as:

- Bidding by generators located electrically closer to regional boundaries than to the regional reference node. In this type of disorderly bidding, generators bid lower than costs to receive the Regional Reference Price(RRP) in their zone while their electricity flows to another zone. This was the original problem that was the basis for attempts early in NEM history to move to multiple non-state-based regions and eventually LMPs
- Bidding opportunistically to take advantage of the incentives offered by the split 5/30 minute dispatch and settlement—this type of disorderly bidding was eliminated when the settlement period for the spot price was changed from 30 minutes to 5 minutes to align the timeframes for dispatch and settlement prices in October 2021
- Any bidding that appears to be influenced by transient market power or “opportunistic” rebidding
- “Race to the floor” bidding by generators when local constraints bind within a region—“race to the floor” bidding occurs when, in the absence of constrained-off payments, generators have an incentive to adjust their offers into the market in order to maximize the amount of output they are dispatched for (and hence their access to the RRP). Generally, this means that generators will make offers at levels lower than their costs. This behavior can ultimately see all generators behind a transmission constraint making offers at the market floor price (currently -$1,000/MWh) with the result being that access is “shared” amongst them. Generators engage in this bidding behavior knowing that there is little risk that such a generator will receive a payment lower than its costs because the constraints on the network usually mean that the RRP (at which all generators are settled) will be set by a higher price generator – remembering that all generators are settled at the same price within a region.

Combined, all four types of disorderly bidding have generally been regarded as a small inefficiency in generation dispatch that unlocks the wider competition and efficiency benefits of a zonal market. However, there is a fear that “race to the floor” bidding may increase in the energy transition as thermal generators engage in “race to the floor” bidding more frequently to be dispatched alongside dominant near zero SRMC VRE. As such, only the “race to the floor” appears to be the focus of the CMM proposal.

However, “race to the floor” bidding could only grow as a problem in the future if VRE generators locate in areas close to thermal generators and where there is inadequate transmission capacity. This is because there is no efficiency loss if one near zero SRMC VRE constrains another. This seems unlikely as VRE locational decisions are driven by factors such as resource availability, cheap land, and access to unconstrainted transmission and VRE are expected to mostly locate in REZs where there are not adjacent thermal generators. This is evidenced by the clear trends in NSW and Victoria for VRE to be in the western regions of the state, while thermal generators are located largely in the east. In SA and Tasmania there are few thermal generators. As such, we do not expect “race to the floor” bidding to lead to a large increase in the cost of disorderly bidding in the energy transition in these states.

2.2.2 Efficient location in the context of energy transition

Since the electricity market reforms that led to the creation of the NEM, but prior to the commencement and acceleration of energy transition, the power grid tended to evolve relatively slowly in response to load and generation decisions. The ESB’s ISP, created in response to the unprecedented challenges of energy transition, largely reverses the process. REZs are planned with the view not just of responding to generators’ location decisions, but also to guiding those decisions.

In this context, the purpose of transmission access reform should be to ensure that the investor response to this guidance is efficient. That is, that the transmission capacity which will be made available is utilized efficiently and leads to least cost roll out of generation, energy storage, and transmission, which will in turn lower the volume of capital required to achieve the energy transition.

Given commitments to the development of REZs, any locational signals to generation and storage investors must be forward-looking and anticipate planned transmission capacity. Locational signals must give investors confidence that they will continue to be able to access that transmission capacity throughout the life of their asset rather than to fight for it during each dispatch period with other generators who have exactly the same marginal cost and who will have to generate at exactly the same time due to sun shining or wind blowing. In other words, efficient locational signals must move away from the current “open access” regime and provide an access right to the transmission grid and the “firmness” of that access right must not vary over time.

2.2.3 Investor confidence after the energy transition

Due to the capital-intensive nature of RE and energy storage, a key driver of the cost of electricity will become the cost of capital instead of competition for dispatch. To illustrate this point, the Clean Energy Investors Group (CEIG) estimated that the current 100-250bps premium on the cost of equity caused by significant uncertainty and risk in the market will cost an additional $7bn. This is close to 10% of the estimated A$70bn NPV in wind and solar investment CEIG estimates is required to achieve the energy transition[10].

Under the current market structure, investors can compare SRMCs to assess where their generation investment would sit in the generation stack and assess the likelihood that it will be dispatched and the amount the generator will be paid for each kWh based on the RRP. Based on these calculations, investors can reasonably assess the riskiness of an investment.

[10] Clean Energy Investor Principles August 2021 Unlocking low-cost capital for clean energy investment

However, as short-term energy prices provide increasingly less useful information about optimal infrastructure investment, what will inform investors is assurances that their investments will not be constrained off by future investments. Thus, curtailment risk will become a key driver of investor perceptions of risk. As a result, any intervention that decreases uncertainty about the amount that a generation investment will be constrained off—decreasing curtailment risk—will increase investor confidence. Interventions which do not resolve curtailment risk will not reduce risk and may decrease investor confidence by sending noisy and confusing signals to investors. As above, improving investor confidence requires providing a firmer access right that will be consistent over time.

Box 2.2: Central-West Orana REZ Scheme for Providing Firmer Grid Access

The NSW Government has recognized that the current open access regime creates challenges for coordination of investment in generation and new network infrastructure and investor confidence due to:

- Connection delays and output curtailment
- Increase in revenue uncertainty due to the higher congestion and MLF risk
- Lack of incentives for generation proponents to fund shared network improvements due to the possible 'free rider' competitors benefiting from the improvements while increasing network congestion.

In response to the issues listed, the NSW Government is planning to pilot a scheme designed to provide firmer access to the transmission grid for generators located in the Central-West Orana REZ. The scheme will tender REZ Access Rights and Long-Term Energy Services Agreement (LTESA).[11] The LTESA provides protection against low wholesale prices and REZ access rights will firm up grid access and reduce curtailment risk.

REZ access rights[12]

In response to the issues created by the 'open access' regime, the NSW Government introduced the access rights scheme that will be applied to REZ Network Infrastructure.

The access right intended to:

- limit capacity connected to the REZ Network Infrastructure based on a targeted level of transmission curtailment
- provide generators with a better ability to forecast NEM locational price signals such as MLF and curtailment
- provide greater certainty around connection standards, processes, and the timing of connections.

Overview of access rights

- Initially awarded up to an Aggregate Maximum Capacity Cap – Allocation 1
- Will permit proponents to enter into a Connection Agreement for the REZ Scheme Network up to their Project Maximum Capacity for each of 4 periods throughout the day. All projects in a REZ will be equal to or less than the Maximum Aggregate Capacity Cap in each of the four time periods
- The Maximum Aggregate Capacity Cap can only be revised (i.e., additional access rights issued) if:
  - Allocation 2: if Headroom exists in one of the four periods of the Aggregate Maximum Capacity Profile
  - Allocation 3: if the market proposes network augmentation, which expands the REZ intended network capacity

11 Long-Term Energy Service Agreement Design

12 REZ access rights and scheme design: Central-West Orana

- It is proposed to run for 15 years from the commissioning of the first substation on the REZ Scheme Network. This means that projects built and energized earlier will benefit from access rights for a longer period.

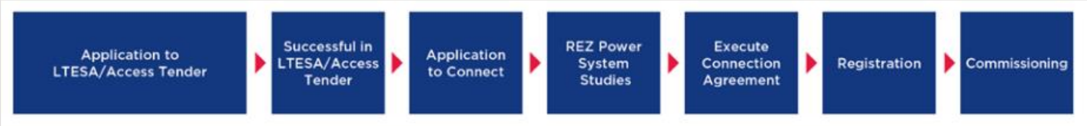
Allocation of access rights

Allocation 1: Series of competitive tenders offering both LTESAs and access rights

Milestones:

- The Project Delivery Agreement sets bonding and collateral arrangements to mitigate the risk of a proponent not utilizing those access rights, construction stage risks and credit risks
- Connection Agreement between the proponent, Primary TNSP and REZ Network Operator
- Project Deed and Transmission Lease is a concession for the REZ Network Operator to design, build, own and finance the New REZ Infrastructure.
- Access fees to the Scheme Financial Vehicle for participating in an access scheme to obtain and maintain an access right.

Streamlined connection process is illustrated below:



To minimize the effort required by proponents applying for access rights the streamlined network connection process will be integrated with the combined tender process.

Source: REZ access rights and scheme design: Central-West Orana

3 Alternative Proposal for Grid Access Reform

We propose a two-part approach to achieving the ESB's Transmission Access Reform:

- Modifying open access by creating a queueing system for generators to access transmission capacity that will protect incumbency
- Introducing a rule change that requires that thermal generators must be dispatched after RE and energy storage when they both have bid the same price and transmission capacity is constrained.

We believe that ESB's objectives of efficient locational signals for generation and energy storage; and increasing investor confidence can be achieved by the introduction of a queue for access to transmission capacity. Further, the ESB's objective of achieving efficient dispatch by eliminating "race to the floor" bidding can be achieved through introducing a change to the dispatch algorithm.

Our alternative proposal effectively meets each of the six criteria laid out by ESB in its project initiation paper. The table below shows how each of the two components of our proposal corresponds to each of the ESB's criteria:

Table 3.1: Comparison of Alternative Proposal Against ESB Assessment Criteria

ESB Assessment Criteria	Proposal Component	Assessment
Efficient market outcomes – investment	Transmission Access Queue	Provides long-term signals to locate where there is transmission capacity by protecting access to that capacity with incumbency rights.
Efficient market outcomes - dispatch	Rule Change	Prevents thermal generation from constraining off cheaper RE, removing the "race to the bottom" component of disorderly bidding.
Appropriate allocation of risk	Transmission Access Queue	Curtailment risk arising from congestion is allocated to new entrants that cause congestion.
Appropriate allocation of cost of transmission investment	Transmission Access Queue	Shifts some of the cost to generators through auctions for planned transmission upgrades and transmission charges for generator led transmission development.
Implementation considerations	Both Components	Straightforward to implement, without requiring complex and difficult to predict mechanisms that raise uncertainty and, as a result, the cost of capital. Proven internationally.
Flexibility to enable jurisdictional differences	Both components	Rule change supplants existing NEM rule; transmission access queue functions in and out of REZs.

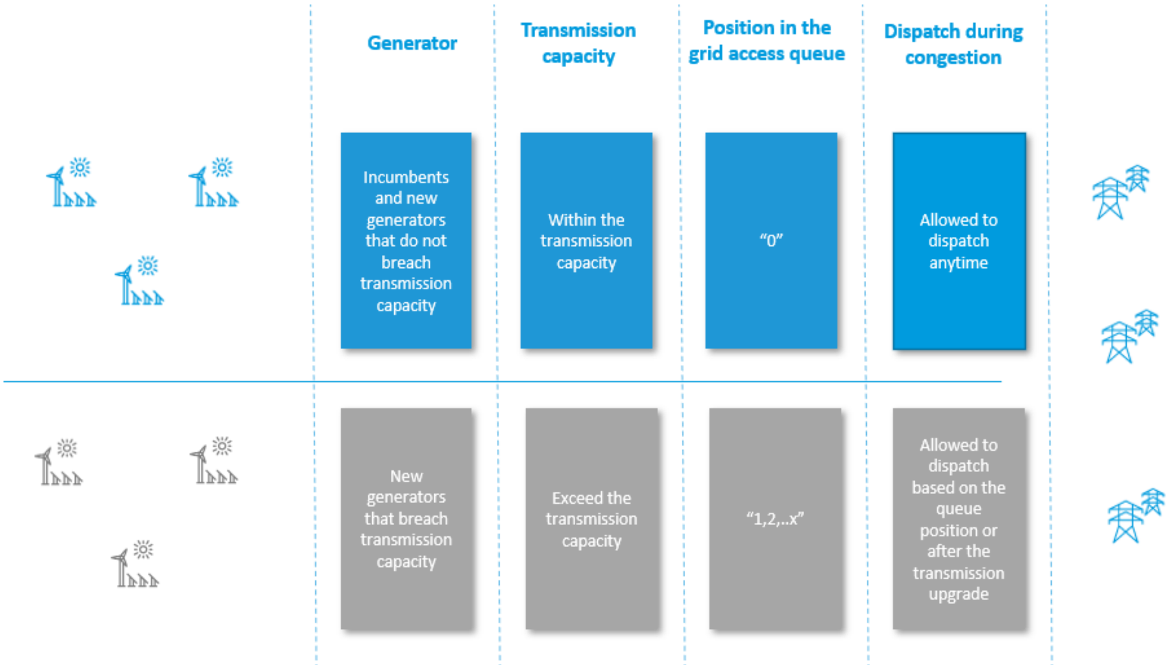
In addition, our proposed approach will achieve the ESB's objectives both during and after the energy transition. Allowing for normal competition to occur between thermal generators and between thermal generators and renewable generators will not disrupt the functioning of the energy market in the near term. However, protecting incumbent RE from being constrained off by new entrant RE will prepare the NEM for the post-energy transition world where all RE generators are likely to bid zero in line with their SRMC and the key determinant in dispatch will be the transmission queue. As such, we believe that our proposal can be implemented now and does not require intermediary steps or a lengthy transition period.

3.1 Sending Efficient Locational Signals and Improving Investor Confidence

We propose introducing a transmission queue that will result in moving away from Australia's extreme version of open access to protect incumbency rights of generators by creating a dispatch queue in times of transmission constraints that will provide a firm and stable access right to local transmission capacity. The queue will protect incumbents' dispatch rights by curtailing new entrants that locate in areas that do not have spare transmission capacity before curtailing incumbents. Thus, the queue will encourage investors to build generation capacity in locations that either a) will not have a negative impact on congestion or b) where they are willing to accept that their higher number in the queue means that they will be constrained off during periods of high generation by generators with a lower number in the transmission queue. The queue is designed to function in all areas of the NEM—including REZ zones where it will be particularly impactful.

Places in the queue will be assigned based on existing incumbency, first-come first serve when there is spare transmission capacity, and through auctions when multiple investors are interested in the same existing or planned transmission capacity. Figure 3.1 illustrates the alternative approach for grid access.

Figure 3.1: Overview of the Transmission Queue



Transmission queues are already in use internationally. In particular, the approach is widely used in the United States with the PJM, MISO, NYISO, CAISO, ISO-NE and SPP Regional Transmission Operators (RTOs)[13]. In all of these examples, the generator interconnection queue is a process that guarantees that valid Interconnections requests are administered in the order they are received.[14]

The transmission access queue will provide strong locational signals and benefit generators by providing certainty of dispatch

The transmission access queue will provide strong locational signals to generators to locate where there is spare transmission capacity by rewarding generators for locating in areas that have spare transmission capacity with a better spot in the transmission queue for local transmission capacity. Importantly, the queue will not prohibit investors from building generation capacity where they will have a high number in the transmission queue. Instead, it will allow them to make informed decisions about their likelihood of being curtailed now and in the future.

This will represent a significant benefit for generators as it will provide them certainty that their ability to dispatch will not be degraded over time. While investors have a clear preference for a firm physical access right, consultations with ESB made clear that the complexity of a meshed transmission grid means that a 100 percent firm access right is not possible because overlapping physical access rights will threaten grid stability. As such, the queuing system is not designed to

13 ISO/RTO Council Whitepaper on Interconnection Queue Management Process

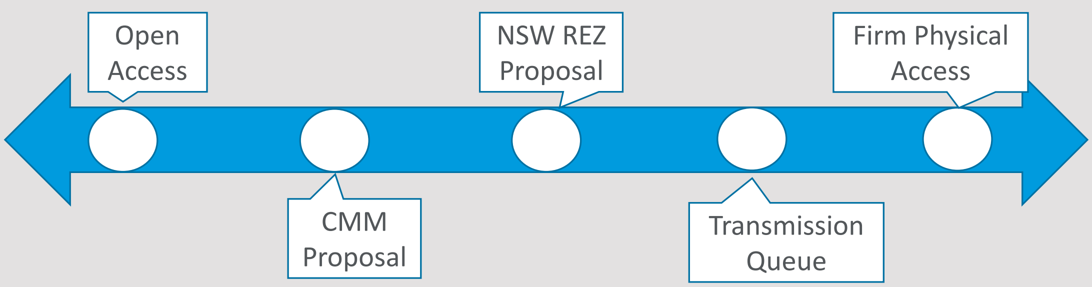
14 Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions

provide a firm physical transmission right to the whole of the meshed transmission grid. Instead, it will provide a much firmer access right to local transmission capacity that, importantly, will not degrade over time. While congestion on the overall NEM prevents guaranteeing that a firm access right to local transmission capacity can be translated into a firm right to the NEM overall, the transmission access queue will resolve local transmission constraints. This will be a significant improvement over the open access system—which provides no access rights at all—and the proposed CMM model which also does not protect against curtailment. We believe that the transmission access queue will "firm-up" transmission rights to a sufficient degree to improve investor confidence by providing greater clarity about the likelihood of a generator being curtailed. Thus, the transmission access queue will lower the cost of capital.

Box 3.1: Spectrum of "Firmness" for Access Rights

The firmness of access rights in the context of the various proposals put forward for reforming transmission access can be conceptualized as existing on a spectrum ranging from the current open access regime which, by design, does not provide any guarantee of transmission access. On the other end of the spectrum a firm physical access right would guarantee that you have access to the transmission grid at any time up to your full capacity.

As discussed in Section 2.2, as the energy transition advances the open access regimes will no longer deliver benefits as competition for dispatch becomes effectively meaningless. On the other hand, as ESB notes "physical access rights do not work well on meshed alternating-current networks" such as the NEM.[15] Given that fully firm physical access rights are not possible on meshed grids, proposals to reform transmission access to provide incumbency protection and firm up the rights of generators fall on a spectrum between the two extremes.



In the spectrum above we assess that the CMM proposal provides some incumbency protection and a very weak improvement in access firmness, the NSW REZ proposal improves firmness by introducing REZ access rights, and our transmission queue proposal goes further, by extending incumbency protection beyond the REZ.

The CMM proposal aims to provide some protection for incumbents by introducing rebates against congestion charges for incumbents. This proposal hopes to provide firmer access to incumbents by encouraging new entrants to locate away from congested areas where they will not face congestion charges. This should

[15] "Renewable Energy Zones: Consultation Paper." Energy Security Board. January 2021

improve the access rights of existing generators somewhat; however, it is an indirect and weak signal for creating a firmer access right as it does not guarantee that a generators access will not degrade over time.

NSW proposes offering very firm access rights to local transmission capacity through its "REZ access rights and scheme design: Central-West Orana". This scheme would offer participants firm access rights to the REZ's transmission infrastructure with a targeted transmission curtailment within the REZ of only 0.3%. However, the proposal is limited to the REZ and all participants are subject to transmission curtailment that may occur as a result of constraints that arise outside the REZ. In fact, they expect that generators that locate within the REZ will face up to 10-15% curtailment in total each year. Thus, the significance of limiting the scheme to REZ zones is that congestion caused by new entrants outside the REZ zone can lead to curtailment of incumbent generators within the REZ.[16]

Our transmission queue proposal would provide firmer access by introducing incumbency protections for local transmission infrastructure throughout the NEM—including within and outside of REZs. Protecting incumbents throughout the NEM will result in a reduction in congestion throughout the meshed grid. Because, as the ESB points out, "the output of every generator and electricity drawn by every electrical appliance at every location affects the flows on each and every line in the meshed network" introducing the transmission queue that will reduce congestion throughout the NEM will improve the access rights of all generators.

Allowing efficient overbuild of generation capacity will ensure efficient use of transmission capacity

Our proposal allows that all major transmission investments would continue to be made through the RIT-T process guided by the ISP to ensure that all major investments are cost benefit justified and aimed at ensuring that consumers pay the lowest cost possible for transmission services. As such, our proposal will not force consumers to pay more to ensure firmer access rights for generators.

To ensure that transmission investments made through the RIT-T process are utilized efficiently, our proposal allows for the efficient overbuild of generation capacity. The queue will lead to an efficient utilization of transmission capacity because it is likely that VRE generators will be willing to build capacity that will be constrained off during peak generation periods, but which is able to utilize unused transmission capacity during periods of lower generation—commonly referred to as economic curtailment.

One key feature of renewable generators located in a specific area is that they are likely to dispatch at the same time as the wind blows or the sun shines. As a result, capping generation capacity on a transmission to the maximum capacity of the transmission line would result in long periods of time when transmission capacity is unused. Thus, to lower the overall volume of capital required for the energy transition by efficiently using transmission capacity, the transmission access queue will allow for efficient overbuild of generation capacity by new entrants willing to be constrained off during periods of peak generation. For example:

[16] "REZ access rights and scheme design: Central-West Orana." NSW Department of Planning, Industry and Environment. December 2021

- A new entrant wind farm willing to accept the risk that it will be constrained off during the middle of the day when incumbent solar PV is generating in order to access transmission capacity at night
- A new entrant solar PV farm which is willing to be constrained off during peak production in the middle of the day because the value of utilizing transmission capacity during shoulder periods or charging energy storage and disbursing it off-peak means the project is still viable. This logic would also apply to an existing VRE installation that realizes that adding a bit of extra capacity that may be constrained off during peak periods is still viable.

These examples show how efficient overbuild of generation capacity allows for greater usage of transmission capacity by VRE, noting that in both examples the ability of incumbents to dispatch is not degraded and the new entrants are willing to accept the risk of curtailment during peak periods in order to utilize transmission capacity in off-peak periods.

The desire to allow for efficient overbuild is mirrored in NSW Central-West Orana REZ proposal which includes a target of 0.3% transmission curtailment. However, a key difference between the transmission access queue and the NSW proposal is that rather than setting a target for curtailment, the transmission access queue would allow for investors to determine if the curtailment they will face based on their spot in the queue is prohibitive.[17] Thus, the market will determine whether there is a viable case for using available transmission capacity rather than a central planner. This will allow for innovative projects to come forward and utilize transmission capacity in ways that central planners may not have anticipated or appreciated.

3.1.1 How the transmission queue will impact the dispatch order

The transmission queue will protect incumbency and encourage new entrants to locate where there is spare transmission capacity by changing the way that the dispatch engine addresses time periods where a transmission node has reached its capacity and where two or more generators with the same MLF are vying to evacuate their electricity have bid the same price for the given time-period. This change will impact the dispatch order throughout the NEM and be particularly impactful in REZ zones where we propose that all generators should be given the same MLF.

Figure 3.2: Order of Decision Making in Dispatch Order

[17] "REZ access rights and scheme design: Central-West Orana." NSW Department of Planning, Industry and Environment. December 2021

As the figure above shows, the bid price will still be the first determinant of the dispatch order followed by MLF. This is important to ensure that during the energy transition competition between thermal generators and between thermal generators and RE continues. However, where multiple generators have bid the same price(which is likely to be zero in areas where there are several VRE generators)and have the same MLF(which is likely in REZs)the dispatch algorithm will rank them in the merit order based on their order in the transmission queue.

We understand that, particularly in a loop, this will not mean that the transmission queue provides the final dispatch order or the capacity for which each plant is dispatched. After receiving the merit order ranked by the queue, the dispatch engine must still consider the impact of each plant's constraint coefficient whenever there is a binding constraint before ultimately dispatching each plant in the merit order. Our transmission access queue proposal would not interfere with this process. Instead, the queue would provide additional information to the dispatch engine when it is making its dispatch calculations on which generators should be given priority where it is physically possible. Thus, the transmission access queue would instruct the dispatch engine to curtail in the order established by the queue, recognizing that where this is not possible the dispatch engine will override the queue to maintain grid stability.

We do not propose removing MLF from the dispatch algorithm and the transmission queue can work in tandem with the MLF in determining the dispatch order. However, we have two concerns about continuing to use MLFs in the dispatch order:

- We are concerned about how they will disadvantage generators located in REZs that are far from load. As a result, MLFs will continue to send locational signals that discourage generators from locating in REZs.
- We are also concerned that the level of granularity in calculating MLFs is unwarranted and differentiates generation plants when there is extremely limited or no real differentiation. As such, we propose that the level of granularity of MLFs be reconsidered to allow for generating plants which have a near identical impact on congestions to tie and allow the transmission queue to serve as the tiebreaker.

At present, MLFs are calculated down to the fourth decimal point. This degree of specificity is unwarranted given that MLFs are based on theoretical constraints on the system, rather than calculated in real time. As such, using such specific MLFs does not represent a real benefit to the NEM; however, they can unfairly influence the dispatch order by—for example—allowing for a new entrant wind farm built slightly closer to the regional reference node than an incumbent wind farm to be dispatched ahead of the incumbent windfarm. This type of gamesmanship provides no value to the NEM as a whole but can lead to considerable harm to an incumbent generator. At the least, the degree of specificity in MLFs should be reduced such that all generators located within a REZ zone are given the same MLF.

The transmission queue will eliminate uncertainty about curtailment risk by clarifying the order in which generators are dispatched during congested periods. Incumbents will be allowed to dispatch their maximum capacity up to the point that the transmission capacity constraint is reached. As a result, the transmission queue will eliminate pro-rata curtailment when maximum capacity is breached and there are multiple bids to provide electricity at that same price. Instead, curtailment will be based on the transmission queue wherein generators with higher numbers in the queue will be curtailed until generation does not exceed the transmission grid's ability to absorb electricity generated in a given time period.

In practice, this will mean that after the energy transition VRE generators in a transmission node will be dispatched in order of their incumbency because, as explained above, the SRMC of all VRE plants and energy storage is zero and, as a result, they are all likely to bid zero. In addition, the MLFs of VRE in REZs will also be the same. As a result, the only point of differentiation between VRE in a transmission node—particularly in a REZ where the majority of the VRE will be located—will be the number in the queue. As a result, incumbent VRE will be dispatched first followed by more recent VRE generators. This means that while the transmission access queue will play a key role in the dispatch algorithm throughout the NEM. It will be particularly impactful in REZ areas where the ISP envisions the majority of generation investment will take place.

3.1.2 Addressing Concerns about the physical management of the grid

Initial feedback on our proposed queueing system raised concerns about how the transmission queue would affect the physical management of the grid due to the impact of overlapping transmission access rights in a meshed transmission network.

Importantly, the queue is not intended as a firm physical access right to the whole of the NEM. It will provide stable access to local transmission capacity, acknowledging that congestion conditions in the NEM as a whole may still lead to some curtailment. Instead, it is designed as a clear signal to generation investors about the order in which they will be curtailed, should curtailment become necessary. This will provide the certainty and clarity that investors require without compromising the ability of the grid to curtail generation to maintain grid stability.

In addition, while meshed networks are complex, with loop flows and thousands of complex constraint equations, the ISP makes clear that most new generation is expected to be VRE constructed in REZs. REZs are often in remote areas served by a radial line connecting them to the rest of the meshed transmission grid. As such, many of the concerns that apply over firm physical access rights in meshed networks, will not apply to new generation constructed in REZs. Regardless, any complexity introduced to grid management by a transmission queue will be in line with complexity introduced by other systems for addressing curtailment risk. For example, LMP based solutions encounter problems in meshed networks due to the "spring washer effect".[18]

3.1.3 How the transmission queue will be ordered

The locational signals of the transmission access queue can only work if incumbent generators can maintain their access to the local transmission capacity as new generators enter a location. This means that places in the queue must be assigned without degrading incumbents' access to local transmission capacity over the life of the incumbent generator.

[18] Feiyu, Lu. "Spring Washer Effect A Market Clearing Engine Study of the NEMS". Energy Markey Company. Accessed at: https://www.emcsg.com/f261,6430/Spring_Washer_Effect.pdf

When the transmission queue in implemented all incumbents will receive a queue number of zero. New entrants vying for transmission capacity on RIT-T approved transmission investments will be assigned places in the transmission queue either through:

- Auctions—when there is available transmission capacity or planned new transmission capacity and proposed generation exceeds that capacity, an auction can be held to determine the order of the queue
- First-come, first serve—in instances where there is available transmission capacity and proposed generation does not exceed the available capacity, places in the queue will be assigned on a first come, first served basis.

Assigning places in the queue through incumbency

At the time that the transmission queue is put into place all incumbent generators will be given the lowest possible spot in the queue of 0. This indicates that the incumbent generator will have priority of dispatch when transmission is constrained and the incumbent generators has bid the same price as new entrant generators. This will essentially freeze in place the status quo for existing generators. This means that the transmission access queue can be introduced in its entirety in one step without the need for a gradual phase-in process.

In instances where the existing capacity of incumbent generators breaches transmission capacity, pro-rata curtailment will continue for generators with a queue number of 0 when they have bid the same price. However, as generators retire and transmission upgrades improve the capacity of the transmission grid, these instances will become increasingly rare.

Further, expansion of existing plants shall be treated as new entrants for the purposes of assigning places in the queue. For example, if an incumbent generator located in a congested transmission node with a capacity of 100MW and a place in the transmission queue of “0” proposes a 50MW extension, that extension would be treated as a new entrant. This means that the additional 50MW of capacity will be given a place in the queue via auction and dispatched after the existing 100MW of generation.

Assigning places in the queue through auction and first come, first serve

A comparison of the first come, first served approach and the auction approach to assigning places in the transmission queue is illustrated in the figure below.

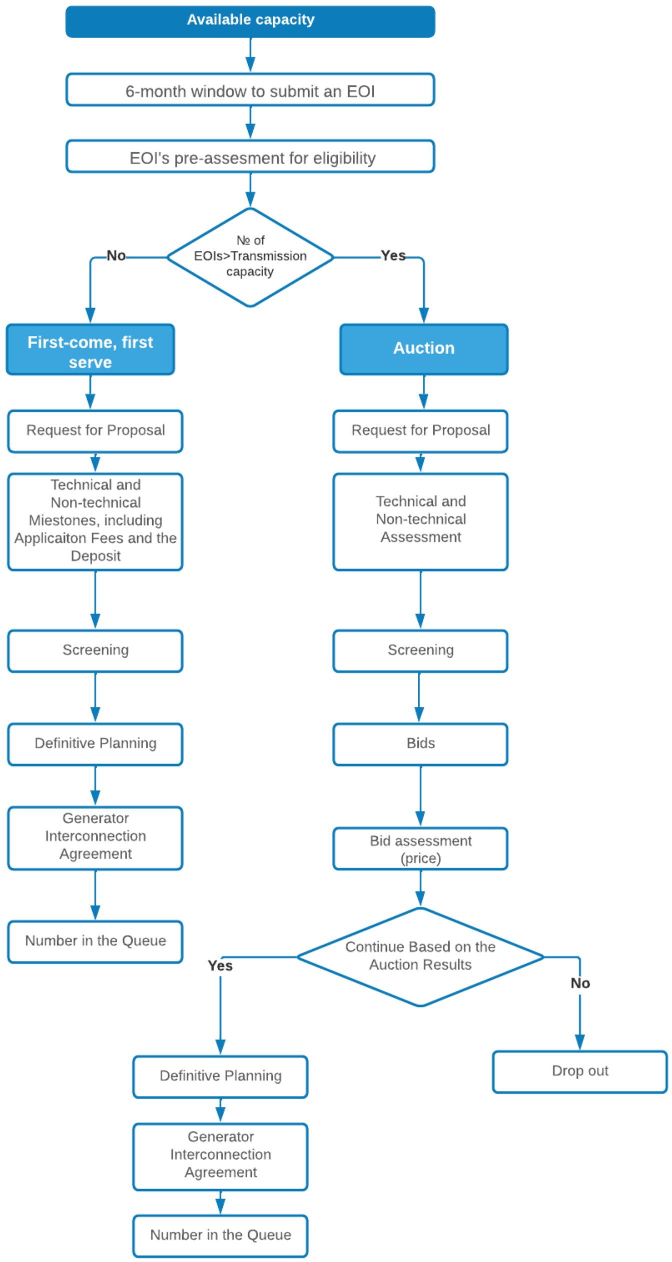
In the figure below the first step is to assess if there is available transmission capacity and, if so, how much and when. AEMO should undertake this analysis annually.

To assess the amount of transmission capacity available AEMO should rely on historical data of transmission usage. Further, in areas where new generation is expected to come primarily from VRE, AEMO should use historical data on sun and wind resources to calculate how much spare capacity will be available and when it would be available based on likely generation pattern of VRE as well as target an optimal mix of solar and wind power to fill the generation capacity.

In calculating spare transmission capacity, AEMO should also consider voltage and stability requirements. Further, we recommend that AEMO consider adopting NSW’s proposed REZ access standards for inverter-based generators which specify the technical limits that each plant must meet—including minimum short circuit ratio, voltage phase shift withstand capability, and rate of change of frequency requirements. These requirements will limit the adverse system strength impact of inverter-based generation.

After having conducted this analysis, and in advance of the EOI stage AEMO should make public all of the data used to calculate spare capacity and its ideal mix of VRE technology. We do not propose that AEMO take steps to ensure that its target mix of wind and solar, is met. Rather, we propose that investors use the information provided to assess their interest in the spare capacity that is made available and, if an auction takes place, the value they place on having a low number in the transmission access queue.

Figure 3.3: Generator Interconnection Queueing Process



Where this is transmission capacity available—either already existing or as the result of a RIT-T approved transmission upgrade—AEMO would announce that projects interested in connecting can submit an EOI. The window for the EOI submission would be open for 6 months. Once the submission window closes, AEMO would pre-assess all EOI's received and evaluate the level of interest. As a result of the evaluation:

- If the generation capacity of the EOIs submitted is less than the available transmission capacity, AEMO would apply a first come, first-serve (FCFS) approach, where all eligible projects submit a request for proposal (RFP) that would be evaluated in order of its submission date. AEMO would assess each application for technical and non-technical milestones, including proof of paid application fees and the deposit. Once the application is approved, the proponent would proceed to definitive planning and sign the Generator Interconnection Agreements. The allocation of the position in the queue is the last step in the FCFS process. All generators will receive a queue number of zero reflecting the fact that there is still available local transmission capacity after all successful applicants are approved.
- If the generation capacity of submitted EOIs is greater than the available transmission capacity, AEMO would perform a batch study of all RFPs and filter out applications that are not eligible to proceed to the next round of the tender process based on technical and non-technical criteria. The successful applicants will be invited to participate in the tender and submit their price proposals.

  Next, AEMO would rank bidders based on their bid price and bidders would be able to assess, based on the results of the auction where they might sit in the transmission access queue. At this point, some bidders may choose not to go forward with their proposed projects due to the likelihood of receiving a high queue number. If a bidder drops out, remaining bidders will move up in the ranking order accordingly.

  Finally, the remaining projects will proceed to definitive planning and sign the Generator Interconnection Agreement and will then be assigned their finalized position in the queue. Up to the point where the capacity of local transmission is reached, bidders will be assigned a number of zero. Bidders higher in the ranking order will then receive a queue number in sequential order according to their ranking.

In essence, receiving a queue number of zero—whether through first come, first served or through auction—will provide a renewable generator with near guaranteed physical right to specific local transmission capacity. In addition to grid-wide terms on quality of service, interconnection agreements signed with TNSP will include Service Level Agreements (SLAs) that require TNSPs to maintain local transmission capacity to the amount auctioned or achieved. This will ensure that a generator’s ability to evacuate its electricity will not degrade over time.

The EOI phase will be designed to eliminate bidders who do not have the technical or financial backing to deliver a project. Requirements for project proponents should be calibrated to be tight enough to prevent unserious bidders from being considered, but not so onerous that they deter interest or prevent smaller or innovative applicants from being considered.

Further, to maintain the place in the queue assigned by AEMO, the project proponent must commence construction within two years of receiving their place in the queue. If the generator has not commenced operations within that time-period, then the project proponent will lose their spot in the queue and all deposits and fees paid will be lost.

Fees required by proponents should be sufficient to mitigate the risk of successful bidders not meeting the terms of their bid or legally binding obligations. Further, places in the queue are nontransferrable. This is intended to avoid a scenario where project proponents hold up transmission capacity—thus causing subsequent projects to receive higher places in the queue—without any real intention or ability to deliver the generation project or attempt to secure spots in the queue only to sell them later. Finally, if at the time that a project that received a queue number of zero through the first come, first served process loses is queue number due to inactivity the proposed generation capacity is above the existing or proposed transmission capacity, then the project proponent must enter into an auction.

Proceeds of the auction process

The auction is not designed to cover the cost of transmission investment; the cost of RIT-T approved transmission upgrades will still largely be socialized across all customers of the NEM. Rather, the purpose of the auction is to ensure that the most efficient generators have access to the available transmission capacity. The underlying logic is that project proponents that can afford the highest bid for transmission capacity will be understood to be the generators that have the most efficient cost structure—including CAPEX, cost of capital, and OPEX—for constructing, operating, and maintaining the generation plant.

However, the proceeds of the auction will be used to defray the cost of transmission for customers through reducing network charges or pay for programs that will increase the social license of the proposed transmission investment. The ESB has proposed that if the tender process for REZ generates surplus revenue, then that surplus revenue should be returned to customers in the form of a reduction in network charges.[19] "Surplus" revenue means tender revenue in excess of the efficient costs of the REZ coordinator in conducting the tender. Meanwhile in the Central-West Orana consultation paper proposes that access fees be used for local community and employment purposes. The consultation paper also seeks stakeholder feedback on whether the fees should recover a component of REZ network infrastructure.[20]

Examples in practice of transmission queue

In the international examples provided by the RTOs of the United States, the overall interconnection process includes the following steps:

- The interconnection applicant submits interconnection request
- The applicant is given a queue position and goes though the technical review
- Joint signing of Interconnection Agreement.

Box 3.2below provides more information on the transmission queueing process in PJM, an RTO in the United States. Further, Box 3.3 provides an example of a successful transmission capacity auction that has already occurred in Australia and Box 3.4 describes the NSW governments upcoming transmission capacity auction. Finally, Box 3.5 provides an example of first come, first serve transmission access queueing in the USA.

[19] "ENERGY SECURITY BOARD INTERIM FRAMEWORK FOR RENEWABLE ENERGY ZONES." ESB. June 2021

[20] "REZ access rights and scheme design: Central-West Orana." NSW Department of Planning, Industry and Environment. December 2021

Box 3.2: Pennsylvania, New Jersey, and Maryland (PJM) Interconnection Process (USA)

The PJM Regional Transmission Organization (RTO) is responsible for planning the expansion and enhancement of the PJM Transmission System on a regional basis. PJM coordinates the planning process, performs reliability studies, and oversees the construction of the required Interconnection Facilities, Merchant Transmission facilities, and any associated network upgrades.

PJM's interconnection process requires a potential new generation to submit an interconnection request.

- Requests are entered into a queue and treated on a first in, first out basis
- Queue windows are 6 months long and all requests entered are studied collectively
- PJM provides the costs to physically connect the generator to the transmission system and upgrade the transmission system to ensure the generator is deliverable to all PJM load.

Following are the steps in the PJM's Interconnection process:

New request
- New service queue request
- Deficiency review
- Project manager is assigend
- PJM Membership

Study Overview
- Feasibility Study
- System Impact Study
- Interconnecti on Facilities Study

Agreements
- Interconnecti on Service Agreement
- Construction Service Agreement
- Wholesale Market Participation Agreement
- Upgrade Construction Service Agreement

Implementati on
- Interconnecti on Service Agreement
- Construction Service Agreement
- Wholesale Market Participation Agreement
- Upgrade Construction Service Agreement

Commercial Operation
- Commercial Operation

- **New service queue request**

  The application window opens twice per year and lasts around 6 months. A New Service Request will not be assigned a queue position until all Tariff requisite information, data, agreements, and deposits are submitted. A deficiency review determines the validity of the application. Next, PJM assigns the project manager and the client manager to guide each customer through the process.

- **Study Overview**

  Each Study imposes its financial obligations and establishes milestone responsibilities.

  – The Feasibility Study evaluates the practicality and cost of incorporating the generating unit increased generating or transmission capacity into the PJM system and is generally completed within 90 days

  – System Impact Study analyses the impact of adding the new generation and/or transmission facility to the system and evaluates their impact on deliverability to PJM load. This Study identifies the system constraints relating to the project and the necessary Attachment Facilities, Local Upgrades, and Network Upgrades

  – Facilities Study includes a stability analysis. The System Impact Study results are retooled as required to reflect changes in the New Services Queue, such as withdrawing from the queue, reducing the size of their projects, choosing different types of equipment, and providing updated equipment parameters.

Agreements

After the Studies Phase, the PJM will provide an Interconnection Service Agreement (ISA) that defines the obligation of the generation or transmission Developer regarding cost responsibility for any required system upgrades. The Construction Service Agreement identifies the scope of work, construction and payment schedule.

Implementation

The Implementation Phase includes construction milestone and cost tracking, outage and Test Energy Injection coordination.

Commercial Operation

Generation Resources is required to comply with all relevant operational terms and conditions set forth in PJM's Operating Agreement and Open Access Transmission Tariff.

Source: PJM Manual 14A; PJM Interconnection Process, May 25, 2021; An Introduction to Interconnection Policy in the United States

Box 3.3: New England Connection Capacity Auction (Australia)

To support the energy transition in Australia towards RE generation and simplify challenges associated with a hampered and slow regulatory process, Lumea* proposed developing the New England Transmission Infrastructure (NETI) through the New England Connection Capacity Auction (NECCA) model.

The NETI involves the upgrade of an existing 66 kV easement to a 330 kV line and provides firm access rights under a new transmission investment model – creating the upgraded line as the backbone for a new energy zone which will host ~1400 MW of connected capacity.

Lumea offered participants the ability to secure firm capacity on NECCA in return for an annual services payment. Project NECCA was a two-staged process comprising:

1. Expression of Interest ("EOI")
2. Request for Capacity ("RFC") phase.

EOI Phase

Lumea received a solid market response during the EOI Phase, including 23 submissions totaling 6,900MW of capacity. Ten participants were shortlisted, representing 15 proposed projects to take through to the RFC stage. Depending on final configurations, the requested capacity from the shortlisted participants is 3200 – 3600MW, which materially exceeds the NETI capacity.

RFC Phase

During the RFC Phase, the 10 shortlisted participants from EOI Phase were invited to participate and to bid:

– an all-inclusive Connection Fee ($/MWAC), and

– comments to the proposed contractual arrangements, which will govern connection to the NETI.

During the RFC Phase, Lumea has received 7 bids.

Shortlisted Participants and next stage

Lumea shortlisted 4 participants out of 7 bids received during the RFC Phase. The aggregate maximum project capacity of the recommended shortlisted proponents exceeded the design capacity of 1400MWAC.

Selected participants will secure access to the NETI and related rights for their projects via the pre-development phase of the project. Binding bids will be provided by each of the four shortlisted participants to bid a Connection Fee assuming 24-hour access to the NETI.

*Lumea is formally known as TransGrid Services.

Source: Project: NECCA Lumea – Final Report

Box 3.4: New South Wales (NSW) Competitive Tender for LTESAs (Long-term energy service agreement) and REZ (Renewable Energy Zone) access rights. (Australia)

In August 2021, the NSW government received a level of interest from the potential RE projects for its New England REZ that is more than four times that needed to develop the 8GW REZ.

To determine participation in the REZ, the Government will conduct a competitive tender process. The first auction for RE projects across NSW is expected in the second quarter of 2022. As the NSW Consumer Trustee, AEMO Services will conduct the competitive tender. The tendering would be conducted for LTESAs (Long-term energy service agreement) and REZ access rights.

The tender process and assessment will include eight stages:

- Pre-accreditation
- Announcing a competitive tender
- Request for proposal (non-price)
- Non-price assessment
- Request for proposal (price)
- Price assessment
- Due diligence
- Portfolio assessment
- AEMO Services Board considers and recommends projects to the Scheme Financial Vehicle (SFV)
- SFV awards contract

The non-price assessment includes eligibility and merit criteria to determine which projects are shortlisted to progress to the price proposal and assessment stage. After the price submissions are received, AEMO Service will conduct the assessment, including a merit criteria assessment. The portfolios assessment analyzes the cumulative impacts of a shortlisted set of proposals to mitigate any aggregated adverse effects that arise from the shortlisted proposals. Next, the AEMO Services Board will consider and recommend a final selection of proposals to the Scheme Financial Vehicle.

To ensure the integrity of the tender process, proponents will be required to make substantial contractual commitments that would need to be collateralized by financial bonding. The bonding protects against losses if a project does not meet a legal commitment under a binding tender bid, LTESA or REZ access right. The size of the bonding will indicate the commitments of the parties and the characteristics of the rights granted. The bonding will be provided at the price proposal stage and the development and construction period.

Source: AEMO, Competitive Tender Discussion Guide

Box 3.5: The Generator Interconnection Process (GI) in the Midcontinent Independent System Operator (MISO) (USA)

The Generator Interconnection Process (GI) in the Midcontinent Independent System Operator (MISO) is divided into three parts:

- Pre-Queue
- Application Review
- Definitive Planning

Pre-Queue Phase

The goal of the Pre-Queue Phase is to provide various channels for communication, workshops to become familiar with the interconnection process and/or ask questions.

Application Review Phase

To join the next Definitive Planning Phase (DPP) an Interconnection Customer (IC) or an MHVDC Connection Customer needs to submit their Interconnection Request (IR) to the Transmission Provider. However, before IRs can enter the DPP they all need to go through a set of screenings. This screening includes verifying that the application submitted has the required technical information and meets the necessary Milestones:

- *Application Milestones (M1):* Non-Technical Requirements and Technical Requirements, which also includes the (D1) Application Fee and the (D2) DPP Study Funding
- *Definitive Planning Phase Entry Milestones (M2):* in the form of a cash deposit or an irrevocable Letter of Credit.

MISO also may perform a power flow analysis and use in-house post processing tools to determine project grouping, where all projects contributing to any common constraint will be grouped together for study.

The Initial Queue Position for the DPP is based on the date and time that the IC satisfies all of the requirements to enter the DPP cycle. MISO records the dates Milestones are received for each project. Within a study group, the queue positions for projects are determined based on the date they met the last Milestone in the process. The queue position is used to determine the cost responsibility of Network Upgrades for a project, except if the project was part of a Group Study.

Definitive Planning Phase

After IC satisfies all required milestones, the project will enter into the DPP. MISO conducts two DPP cycles every year. Each DPP cycle consists of three DPP Phases:

- Phase I of the DPP is designed to provide the IC with a preliminary detailed analysis of their IR’s impact on the reliability of the Transmission System
- Phase II of the DPP is designed to provide the IC a revised and detailed analysis of their Interconnection Project’s impact on the reliability of the Transmission System after incorporating updated generation assumptions resulting from the withdrawal of IRs during DPP I
- Phase III is designed to provide ICs a final, detailed analysis of their Interconnection Project’s impact on the reliability of the Transmission System after incorporating updated generation assumptions due to potential withdrawal of IRs during DPP II. MISO completes the Interconnection Facilities Study and issues a draft Generator Interconnection Agreement appendix and, as applicable, associated draft appendices for the related Facility Construction Agreement (FCA(s)) and/or Multi Party Facility Construction Agreement(s) (MPFCA(s)), along with supporting documentation.

Source: MISO Business Practices Manual Generator Interconnection

Reordering the queue in response to a transmission grid upgrade or generator retirement

If the transmission grid is upgraded by a RIT-T approved transmission investment then the queue would be reordered for each generator. Similarly, if a generator retires this will also spur a reordering of the queue for generators that continue to operate in recognition that the retiring generator has freed up spare transmission capacity. In the recalculation process, a generators place in the queue can only improve, they cannot deteriorate.

We propose that reordering would consider the place in the queue of existing generators. Thus, the spare capacity freed up by the retirement or new transmission investment would be distributed to those who failed to secure a position of zero in the queue and remaining capacity would then be offered to new entrants. If positions in the queue are allocated through auctions, instead of holding a new auction it may be more appropriate to first offer additional capacity to parties that lost the auction but were next in line in terms of their willingness to pay for a spot.

Through this process, AEMO will work up the queue allocating new capacity to existing generators until the transmission capacity is again reached. Generators whose capacity is still beyond the transmission capacity of the transmission grid will then receive a sequential number in the queue in their order of incumbency. For example, if a transmission line which currently has a capacity of 300MW and serves generators with a capacity of 500MW were upgraded to have a 1,000MW capacity:

- 200MW of the upgrade would be allocated to existing generators giving them a queue positions of zero to the incumbent
- the remaining 500MW would then be offered to new entrants on a first come, first serve basis or through auction depending on the level of interest garnered in a six-month window during which the capacity is advertised.

3.1.4 Generator-paid transmission investment and energy storage to improve position in transmission queue

Where there is no available position in the queue for local transmission capacity being implemented through the regulated transmission investment process (and particularly, through ISP projects), a renewable generation investor may be willing to pay to create additional capacity for themselves either through paying a Transmission Charge (TC) to augment local transmission capacity or by installing storage and seeking the right to dispatch during periods when there is no shortage of transmission capacity. Note that TC are different than Deep Transmission Charges (DTC) because TC requires a level of investment to provide firm access to local transmission capacity without increasing congestion; whereas DTC requires sufficient investment throughout the transmission network to avoid creating congestion anywhere in the network. In a meshed network this is notoriously difficult to achieve and estimate.

In theory, the option to pay for transmission capacity or to invest in storage already exists; however, at present it is done on an ad-hoc, bilateral basis between the generator and the TNSP. This option is largely unworkable:

- First, generation investors face considerable uncertainty about what transmission capacity may become available to them through planned investment and private investment in additional capacity does not eliminate the risk of being crowded out by others in the future
- Second, commercially negotiated transmission upgrades are not regulated, and hence there is no guarantee that the pricing will be appropriate
- Third, each such commercial arrangement requires a bespoke negotiation with TNSP.

Thus, we propose formalizing and regulating the process by integrating the option to pay a TC into the transmission queueing framework. A generator that is willing to pay TC or invest in storage such that they will not cause congestion on the grid would be given a queue number of "zero", giving the generator the same local transmission access rights as other incumbents. Generators that pay TC would not have additional privileges over incumbents with a queue number of zero.

This process would standardize generator-paid transmission upgrades and allow for regulatory oversight.

A structured and regulated option in the context of a well-defined queue and protection of incumbency rights will provide an efficient locational signal as it requires investors to evaluate the benefits of locating a generator in a particular area with an abundance of wind and sun but where there is also risk of being constrained off due to limited transmission capacity against the cost of the TC or energy storage as a substitute for that enhancement. As such, the option to pay TC or invest in energy storage will operate as a “safety-valve” when investors believe that the value of a transmission upgrade is great enough that they are willing to pay it, even if it has not been included in the ISP or approved through the RIT-T process.

Regulatory Considerations for TC

For TC to function properly, the AER will be required to take on regulatory functions to ensure that TNSPs are offering fair TC charges delivered in a reasonable timeframe. The AER must:

- Ensure that TNSPs offer fair TC to generators. In addition, generators must be given the right to appeal the TNSPs offered TC to the regulator
- Ensure that contracts between TNSPs and generators to complete the transmission upgrade include SLAs on par with SLAs offered to incumbent through the queuing system, and the period of the agreement
- Defining the necessary TC will require analysis of what time of day new generation investments will utilize the transmission grid to determine if they are straining the transmission grid at the times they are dispatched
- Ensure that future entrants do not degrade the access right of the generator that has paid the TC.

For projects paid for by TC there would be no need for a RIT-T and AEMO will define incumbents with a position in the transmission queue of zero as the generator(s) that paid the TC. However, should the situation arise where a transmission investment funded by TC becomes RIT-T approved, the generators that paid TC be refunded their TC and retain their incumbency rights.

The transmission queue will send clear locational signals for energy storage

The transmission queue will also incentivize efficient location of battery storage by signaling that investors should build energy storage in locations where the cost of storing energy and disbursing it at a time when the grid is not congested is lower than the cost of TC required to avoid congestion or the penalty of being curtailed due to a high place in the queue. As a result, the transmission access queue will incentivize storage to locate behind transmission constraints and help ease constraints in the transmission system by smoothing out demand for transmission capacity over the day.

One key feature of renewable generators located in a specific area is that they are likely to dispatch at the same time as the wind blows or the sun shines. As a result, a new entrant weighing options to avoid congestion on the transmission grid and avoid a high number in the queue that will result in curtailment will consider that paying a TC required to raise transmission capacity to the maximum outputs of the renewable fleet in that area might not be efficient because some of the capacity may not be utilized over a 24-hour period. As a result, the transmission queue will encourage the investor to consider investing in storage as a substitute for transmission investment in a way that shifts the new entrants dispatch to a different period when the transmission grid will not be congested. This will result in a more efficient utilization of transmission capacity. Further, this means that additional transmission investments could be lower if the overall cost of additional storage is lower than the cost of additional transmission investment or the cost of electricity lost to curtailment.

In our proposal, energy storage would enter the queue on the same terms as any other generation project. In fact, an energy storage project entering the queue and receiving a high number that means that it can only dispatch when other generators are not dispatching will be key to encouraging energy storage to locate in a way that eases congestion. If energy storage providers were exempt from the queue, they could attempt to discharge during congested periods which would worsen congestion rather than relieve it.

Because energy storage can provide ancillary services to the grid, it may seem logical to exempt storage from the queue. However:

- The incentives provided by the recent AEMC rule change would be sufficient to incentivize storage investments
- The ancillary market is separate from the energy market and therefore separate from the queue for generators.

In December 2021, AEMC published a final rule determination for Integrating Energy Storage Systems into the NEM. The final decision removes barriers to storage and hybrid systems participating in the market. This will primarily be achieved by introducing a new technology-neutral participant category, the Integrated Resource Provider (IRP), to accommodate participants with bi-directional energy flows. This new category allows aggregators to classify small storage units and provide energy and ancillary services. AEMC believes that this would provide a strong market signal to investors to accommodate and promote innovation[21]. Therefore, we believe that the new rule would create sufficient investment signals and there is no need to create any preferences for energy storage in the transmission access queue for providing ancillary services.

In the US, the LMP market co-optimizes energy and ancillary services procurement. For example, in the CAISO market, all ancillary service bids may be accompanied by an energy bid in the Day-Ahead Market and must be accompanied by an energy bid in the Real-Time Market. In Australia, however, the ancillary market is separated from the energy market. For example, to provide Frequency Control Ancillary Services (FCAS), the participant must register with AEMO and submit the bid for the service via AEMO's Market Management System[22]. In this context, we believe it is reasonable to separate the energy and ancillary market incentives. This means that encouraging

[21] AEMC, Rule Determination National Electricity Amendment (Integrating Energy Storage Systems Into The NEM) Rule 2021, December 2021

[22] Report on the benchmarked costs of ancillary services in different jurisdictions, February 2020

storage participation in the ancillary market should be addressed under the ancillary market regulations, not through the transmission access queue.

3.1.5 Addressing concerns raised by long interconnection queues in the US

We understand in recent years that there has been a concern raised about long interconnection queues in jurisdictions in the USA where the RTO uses a transmission queue. However, we believe that our proposal is substantially different, in that it will not result in long interconnection queues. There are two key drivers of the long backlogs in interconnection queues:

- A requirement for individual generators to build and fund a large share of needed transmission upgrades—this means that RTOs must study all proposed projects and assign them charges for transmission upgrades, which leads to lengthy workloads and inevitable delays
- Gamesmanship in the queues which leads project proponents to place many appliations in the hope of receiving a low transmission upgrade charge. This leads to an increase in the amount of interconnection applications that RTOs must study.

In jurisdictions in the US where these concerns have been raised, each project is responsible for bearing upgrade costs from its interconnection to the grid. These costs can be substantially different depending on the project's position in the queue. Often one project would be assigned a high cost to upgrade the network, but then subsequent projects can utilize the capacity that the first project created and, as a result, will be assigned a lower interconnection cost. As a result, some projects with a high upgrade cost would drop out of the queue, shifting the upgrade cost onto others, causing cascading cancellations. Also, knowing there was a chance of getting a "free ride", some projects have had an incentive to enter multiple project proposals and multiple locations. Thus, many projects would join queues, and many would cancel, leading to a cycle of continuous churn. As a whole, these strategies increase the number of applications for RTOs to assess and lead to long lines in the transmission access queue.[23]

In our proposal, transmission upgrade costs are socialized and transmission charges act only as a "safety valve". As a result, AEMO will not be required to calculate transmission charges for each proposed generation project, significantly simplifying and shortening the queue process. Further, generators would not have an incentive to submit multiple applications in the hopes of receiving a lower transmission charge. This is a key difference between our proposal and the queue approach in the US, and as a result, we do not expect that our proposal will result in similarly long queues.

3.1.6 Increasing investor confidence by moving from MLFs to ALFs for settlement purposes

We propose retaining MLFs for the dispatch order; however, to increase investor confidence we propose replacing the MLF with an ALF when determining settlement price on the spot market. Investors chief complaint about MLFs is that they create revenue uncertainty,[24] whereas ALFs are

[23] Americans for a Clean Energy Grid, Disconnected: The Need for a New Generator Interconnection Policy, January 2021

[24] Rule Determination National Electricity Amendment (Transmission Loss Factors) Rule 2020 (February 2020)

more predictable and, as a result, will provide certainty that will increase investor confidence and lower cost of capital.

Box 3.6: Average Loss Factor (ALF) calculation method

The ALF is calculated every year "by dividing the average loss by the load at the operating point and adding 1."[25]For instance, if the average loss factor over a period of time is 3MW and the average load is 100MW:

ALF=1+(Average loss over period)/(average load over a period)= 1+ 3.0/100=1.03

From the perspective of a generator, if 100MW is injected by generator and 3MW is lost due to the flows in the transmission line it means that the average losses are 0.03[26] and ALF=1-0.03=0.97

Source: Treatment Of Loss Factors in The National Electricity Market ; Draft Rule Determination National Electricity Amendment (Transmission Loss Factors) Rule 2020

MLFs are relatively short-term signals (that is, they are based on anticipated annual average marginal losses without taking into account medium-term transmission investments). Using short-term based signals to offset market direction based on long-term system efficiency is directly contrary to the National Electricity Objective.

The volatility caused by MLFs also increases the risk of investment that must be priced through a risk premium which increases the cost of capital. This issue is especially relevant in regional areas that are located further from regional reference nodes[27], which includes most REZ's where the ISP would like generators to locate. Our analysis provided in Section 3.2.4 shows that, given the 125GW increase in VRE by 2050 projected by the ISP , a 50-basis point increase in the cost of capital alone could increase the cost of capital by $497m p.a. On the contrary, moving from MLF to ALF would benefit consumers through lower retail prices. Modelling conducted by Baringa suggests a 2 percent reduction in total annual consumer payments for wholesale electricity. For example, the wholesale part of an average residential bill in Queensland is approximately $600. As a result, a 2 percent reduction would mean around $12 p.a. saving[28].

Further, the method for calculating MLFs means that they do not increase dispatch efficiency. MLFs at each node are calculated as a volume-weighted average of forecast marginal losses throughout the year. As a result, during any given trading interval, actual marginal losses at a node will differ from its fixed MLF. In other words, there is no reason to expect that generator bidding behavior under MLF is responding to actual marginal loss during any bidding period. In addition, the methodology for calculating MLFs, means that they are frequently overstating losses and unfairly penalizing generators during periods of low losses.

[25] Treatment Of Loss Factors in The National Electricity Market

[26] Draft Rule Determination National Electricity Amendment (Transmission Loss Factors) Rule 2020

[27] CEIG Response to draft rule determination on Connection to dedicated connection assets (ERC0294)

[28] Clean Energy Council, Supplementary Submission to Transmission Loss Factors Rule Change Proposal (ERC0251): Consultation Paper

MLFs also cause complications with the Inter-Regional Settlement Surplus (IRSS). Because MLFs overstate the value of losses, the use of MLFs typically results in an over-recovery of funds or positive intra-regional settlement residues (IRSR). In this case, the IRSRs are paid to, or recovered from TNSP and used to decrease or increase TUOS charges. However, AEMO suggest that while the use of MLFs tends to result in a positive accrued IRSR, under certain conditions the IRSR can be negative and then TNSPs are liable to reimburse that to AEMO. This may lead to higher electrical losses in the system than the forecast annual MLFs accounted for, resulting in AEMO collecting less than what it must pay generators. A move to ALFs instead of MLFs would allow losses to be calculated more precisely and would result in zero IRSRs.

Overall, using ALFs would provide an annual average number which is similarly unrelated to the actual marginal loss factor during each dispatch period. However, ALFs which are based on observable historical data have the benefit of predictability and would not unfairly transfer wealth from generators to customers because they are based on actual system losses. Predictability and a fair allotment of the cost of losses will increase investor confidence and lower the overall cost of capital.

3.1.7 Comparison with CMM Approach to Locational Signals and Investor Confidence

Investors are most concerned about long-term transmission constraints affected by the locational decisions of future generation investors and future transmission investments. However, CMM does not provide adequate locational signals to deter investors from locating in congested areas and, as a result, will not improve investor confidence.

Further, the CMM proposal is very similar to the approach rejected under the COGATI process. The ESB has made clear they do not want to relitigate previously rejected approaches. Similarly, to CMM (REZ), the COGATI approach suggested implementing dynamic regional pricing or LMP[29]. However, LMP pricing under the COGATI reform was previously rejected because, while it may provide optimal generation dispatch, it was found not to provide the overall optimum for the market in terms of:

- Generator and retail competition—in New Zealand we observed that nodal pricing can result in generators exercising market power in nodes where there is significant load through increased concentration. Further retail competition will reduce unless all nodal price risk is eliminated.[30]
- Zonal pricing allows deep and liquid hedge markets, whereas nodal pricing does not allow for a large enough market for hedges unless you can establish an inter-nodal hedge market which requires financial transmission rights
- Nodal pricing doesn't provide locational signals, particularly ex-ante—much as we have argued in this proposal, short term signals provided by nodal pricing were found not to

[29] Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis, 7 September 2020

[30] "Improving Electricity Market Performance: A preliminary report to the Ministerial Review of Electricity Market Performance by the Electricity Technical Advisory Group and the Ministry of Economic Development." Electrical Technical Advisory Group. August 2009

provide adequate locational signals to encourage generators to locate where there is transmission capacity. Similarly nodal pricing was not found to provide signals to TNSP to relieve congestion through constructing additional transmission. As such, congestion still occurs and isn't managed better. Instead, the same money gets allocated differently amongst generators

- Ministers were concerned about non-uniform pricing across their states where the basis for differentiation were random factors such as generation location and the layout of the transmission system. Due to the sparsely populated nature of Australia, state governments –in particular, Queensland and South Australia—were opposed to the possibility that rural customers would need to pay noticeably higher prices for electricity whereas urban customers would receive nearly imperceptible reductions in price.

CMM Impact on Locational Signals

Overall, our view is that there is no relationship between transmission elements of energy pricing—whether it is MLFs, LMPs or the proposed congestion charges and rebates—and the locational decisions of future generation investors and future transmission investments. CMM charges are based on current congestion conditions and do not reflect forward-looking effects of transmission and generation investment at that location. The hope of CMM is that CMM charges will deter new entrants from entering areas where there is congestion and that rebates will protect incumbents from the costs of CMM charges. However:

- Because CMM charges are short-term they do not send signals to generation investors to invest in areas where there is sufficient transmission capacity by providing them confidence that they will have access to transmission capacity in the future
- CMM charges are irrelevant for transmission service providers and do not provide any signals about where future transmission investments should or will be made
- As a result, generators may still choose to locate in an area where there is congestion because they:
  - believe that future transmission investment will alleviate congestion
  - that it will still be profitable to invest in these areas, even with the risk of curtailment and CMM charges.

Thus, incumbent generators will still face the risk of being curtailed due to locational decisions made by future entrants. CMM only protects incumbent generators from CMM charges through rebates when generators are dispatched. However, this only solves a problem that the CMM itself created and does not protect incumbents' ability to dispatch. Hence, they will not be compensated for electricity that they could not dispatch due to pro-rata curtailment under current market rules.

Ironically, CMM could have the perverse effect of discouraging renewable investment in REZs where AEMO makes clear through the ISP that they would like them to locate. Because REZs are located in remote areas often connected by a single radial transmission line, they are particularly prone to congestion. Since CMM does not provide incumbents with certainty of dispatch, investors will see REZ's as particularly risky places to invest. They may also choose to wait to invest in REZ's in anticipation of the already approved or signaled transmission enhancement projects, as the cost and risk of investing in generation ahead of the transmission upgrade would increase.

In New Zealand, we believe that nodal pricing has failed to produce adequate locational signals to encourage generators to locate in areas that are not congested. Our assessment is that by creating base risk that is difficult to hedge, nodal pricing led gen-tailers to make locational decisions for new generation based on where they have a retail base to avoid nodal pricing risk instead of locating where there was unused transmission capacity. Further, locational pricing did not have an impact on VRE as wind farms chose to locate based on quality of wind resource rather than unpredictable nodal pricing.

CMM Impact on Investor Confidence

In summary, CMM does not create the incumbency right required to improve investor confidence and lower the cost of capital.

The key risk that investors are worries about is curtailment risk; however, CMM does not protect incumbents from curtailment. Instead, the CMM proposal introduces a complicated system of charges and rebates which are short-term, and investors cannot rely on them to predict revenues over the life of a generation asset. Unpredictability is the key determinant in increasing risk.

As a result, the additional pricing volatility introduced by CMM intended to provide locational signals reduces the overall incentive to invest in generation anywhere and raises the costs of capital through increased uncertainty, rather than providing efficient locational signals. CEIG's members have already made this clear through their reaction to the proposed CMM proposal.[31]

3.2 Proposal to Achieve Efficient Dispatch

We propose a simple rule change to the dispatch algorithm that requires that RE and energy storage are dispatched before thermal generators when both have bid the same price and transmission capacity is constrained. The only exception being when grid stability requires continuing to dispatch positive SRMC generators.

We believe that a simple rule change will achieve the effect of eliminating "race to the floor" bidding, which is the disorderly bidding that the ESB is most concerned about. Further, we show that the rule change can achieve this effect without the cost and complexity introduced by the CMM proposal. Finally, while this would create a clear distinction between thermal generation and RE, it would be technology neutral for RE—for example, hydropower and wind would be treated the same.

3.2.1 Disorderly bidding results from pro-rata curtailment (Rule 3.8.16)

Under the current system disorderly bidding occurs during periods of high demand and corresponding high RRPs when all generators are highly incentivized to pursue a "race to the floor"

[31] CEIG Response to Interim Report on Transmission access reform: Updated technical specifications and cost-benefit analysis

bidding strategy that will ensure they are dispatched. During these periods all market participants in a constrained market node may bid the market floor of -1000AUD per MW to ensure they are dispatched.

They are able to pursue this strategy, because Rule 3.8.16 of the National Electricity Rules stipulates that:

> *If there are scheduled generating units, wholesale demand response units, semi-scheduled generating units or scheduled loads, in the same region, for which the prices submitted in dispatch bids or dispatch offers for a particular trading interval result in identical prices at their regional reference node, then the MW quantities specified in the relevant price bands of those dispatch bids or dispatch offers must be dispatched on a pro-rata basis, where this can be achieved without imposing undue costs on any party, or violating other constraints.*

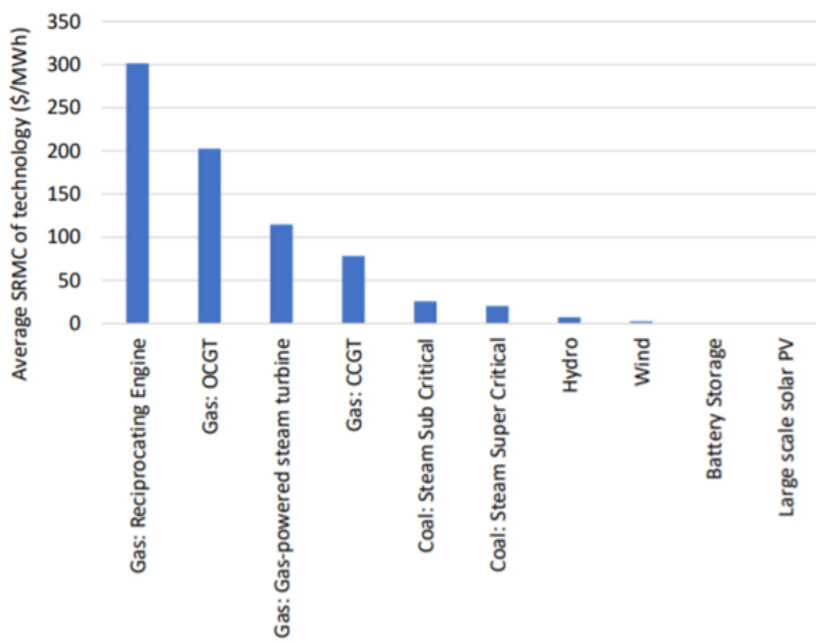
As a result, thermal generators with higher underlying costs may be dispatched alongside RE which have near zero SRMC.

3.2.2 Rule change would require RE to be dispatched before thermal generators

We propose changing Rule 3.8.16 to require that RE generators and energy storage are dispatched before thermal generators in a scenario where generators have made identical bids and transmission capacity is constrained. This would prevent generators with higher underlying costs from being dispatched and remove the incentive to bid in a disorderly manner, regardless of their place in our proposed transmission queue. In a scenario where there is more RE capacity than the transmission constraint, they will be dispatched according to their place in the transmission queue. Where the amount of generation capacity with a queue number of zero exceeds the transmission capacity, then the generators with a queue number of zero will be constrained on a pro-rata basis.

There is no economic reason to dispatch a thermal generator over RE or energy storage. As the figure below makes clear, RE or energy storage will always have a lower SRMC. Thus, this rule change is in line with the overall objective of reducing the underlying cost of electricity generation.

Figure 3.4: Average SRMC of Each Technology in the NEM



Source: AEMO. 2019 Input and Assumptions workbook. 5 July 2020. Tab: Generator Summary -Existing, Committed and Anticipated Generators.

We believe that this fix will solve "race to the floor" bidding without incurring extra costs or introducing complexity that will increase risk and lower investor confidence into the electricity market. Further, this simple fix will allow RE to continue to compete against thermal generators and for thermal generators to compete against each other without allowing for disorderly bidding. In doing so, the rule change will protect RE from curtailment risk imposed by thermal generators as a result of disorderly bidding which will further reduce the cost RE.

The proposed rule is in line with international experience wherein we find many examples of curtailment not based on pro-rata curtailment. For example:

- Various US RTOs have curtailment rules based on the effectiveness of generators in alleviating constraints. For example, in CAISO, generators that are most effective in relieving congestion will be curtailed to their scheduled output first. In MISO, the curtailment order is based on the impact on congestion. In SPP, wind generators are curtailed if they contribute 5% or more to a constraint. If more than one generator creates this impact, the curtailment is divided equally.
- In Hawaii, curtailment is generally applied in reverse installation order. They provide preference to projects based on the order that they were installed, meaning that the most

recently installed resources are curtailed first, which limits the financial impacts and risks of curtailment for existing renewable energy facilities. [32]

- In EU markets, there are various forms of priority curtailment. For example, in Italy, Lithuania, Bulgaria and Malta, renewable energy sources (RES) installations are curtailed as a last option. There is no specific order defined for different RES technologies. In Romania RES are also curtailed as the last option, considering the merit order. In Ireland, under the EU Renewable Energy Directive, the TSOs are required to prioritize RE over conventional sources[33].

3.2.3 Dispatch algorithm already incorporates "physical" aspects, such as ramp rates to ensure supply in future periods.

We acknowledge that there are technical reasons for wanting to dispatch a thermal generator in front of RE with a lower SRMC. For example, a thermal coal plant that is needed to serve peak demand within twelve hours and which requires several hours to ramp up may be dispatched over a lower cost RE during a period of low demand.

However, the dispatch engine's algorithm already accounts for technical reasons to dispatch a generator through consideration of ramp rates. We propose that the rule that RE and energy storage are dispatched before positive thermal generators will not override the technical considerations for running a thermal generator to allow for physical management of the system.

3.2.4 Comparison with CMM approach to achieving efficient dispatch

We agree that CMM as proposed by ESB would solve the very rare instances of out of order dispatch. However, our analysis shows that CMM would create more collateral costs than benefits by raising the cost of capital. As such, CMM will increase the overall long-run marginal cost of the electricity system. This increase in LRMC would more than offset the very small reduction in SRMC.

AEMC has highlighted the fact that actual examples of disorderly bidding resulting in out of merit dispatch are extremely rare.[34, 35] As such, disorderly bidding has been pragmatically accepted as a small inefficiency that helped facilitate an overall efficient market. For example, a Charles Rivers report concluded that multiple non-State based pricing regions might be slightly more efficient but not sufficient to justify the cost, risks and complexity of implementation. So, the requirement for regular reviews of regional boundaries was removed from the rules in 2005. Hence, costly and complicated refinements to the market rules to avoid a relatively small problem, and one that will arise even less as energy transition advances does not appear to be justified.

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32 Wind and Solar Energy Curtailment: Experience and Practices in the United States

33 Status Review of Renewable Support Schemes in Europe for 2016 and 2017

34 AEMC, FINAL REPORT - VOLUME 1 Optional Firm Access, Design and Testing (9 July 2015) AEMC notes that the short-term inefficiencies do not mean that the market is not operating efficiently. The estimated costs of "race to the floor" bidding behaviour in terms of productive efficiency has not been material and the current economic cost of "disorderly bidding" is actually extremely small.

35 Frontier Economics, OFA design and testing – response to AEMC First Interim Report, March 2015

The cost of increasing the cost of capital compared with the benefit of achieving disorderly dispatch

There are a range of estimates of the cost of disorderly bidding; however, they are all less than the increase in the cost of capital that would result from CMM. The maximum estimate for the cost of disorderly bidding is A$180 million per annum; however, the increased cost of capital due to uncertainty introduced by CMM would easily dwarf that figure.

Estimates of the cost of disorderly bidding include:

- NERA modelling undertaken for the AEMC estimates that the costs arising from disorderly bidding could reach up to NPV $1 bn over the period from 2026 – 2040 ($2020) or $140m-$180m p.a[36]. This finding is backed by international case studies that suggest benefits to consumers from efficient dispatch signals could be up to $137m p.a.
- The COGATI proposal issued two years earlier indicated that removing disorderly bidding could only save $8.8 m (NPV) over the 18 years to 2030[37]
- The 2015 Frontier Economics report suggests that the dispatch costs of disorderly bidding lie between 0.02% and 0.22% ($1m and $14m) p.a of aggregate generation resource costs across the NEM, with a higher probability of the low end of the range being correct. The report also refers to the modelling of disorderly bidding undertaken by ROAM consulting on behalf of AEMC, which indicates that the efficiency benefits of eliminating disorderly bidding to be $4 – 11 million in total from 2012/13 to 2029/30 inclusive[38].

Thus, estimates of the cost of disorderly bidding range from several hundred thousand dollars per year to NERA's estimate of A$180 million per annum. However, the NERA analysis indicates that the primary increase from disorderly bidding in total system costs comes from increased out of order production by higher-cost coal plants. This seems unlikely given that AEMO's ISP makes clear that coal will rapidly disappear from the generation mix over the next decade and increased VRE is likely to be located far from thermal generators in REZs. As a result, the future energy market where near zero SRMC VREs dominate the generation mix will have limited opportunities for disorderly bidding and the cost of disorderly bidding will rapidly fade away.

Further, "race to the floor" bidding happens infrequently and there has been no observed trend of it increasing. In its Reliability Standard and Settings Review conducted in 2018 (the most recent of the quadrennial reviews), AEMC's reliability panel found "that there has not been a sustained increase (i.e., over a number of years) in the number of dispatch intervals with low price events (less than -$900/MWH)." Further, from 2015 to 2017 there were 84 such events and over the study period from 2010 to 2018, there was an average of roughly 62 low price events per year. As such, the frequency of race to the low-price events did not pass AEMC's materiality test that would trigger a review of the price floor.[39]

[36] NERA Economic Consulting, Cost Benefit Analysis of Access Reform: Modelling Report, 7 September 2020

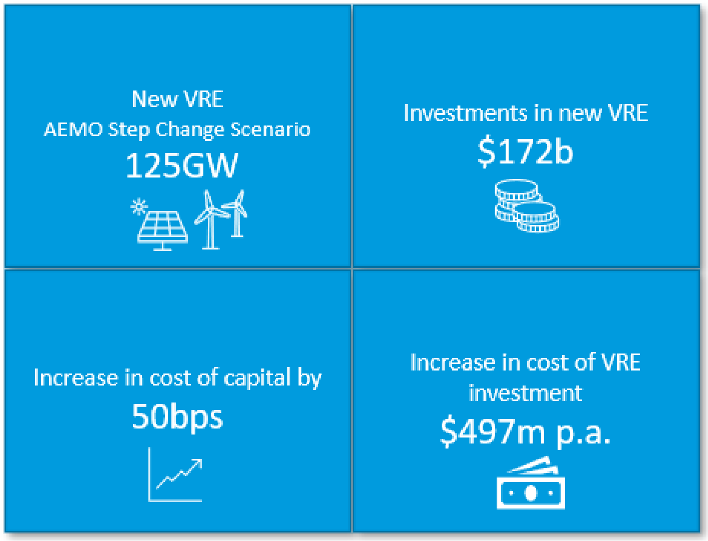
[37] AEMC, Directions Paper, Coordination of Generation and Transmission Investment–Access Reform, 27 June 2019

[38] Frontier Economics | March 2015

[39] "Final Report: Reliability standard and settings review 2018." AEMC. 30 April 2018 Accessed at: https://www.aemc.gov.au/sites/default/files/2018-04/Reliability%20Panel%20Final%20Report.pdf

For comparison, we calculated that that a 50-basis point increase in the cost of capital on the investment required to build the 125GW of VRE by 2050 that the ISP calls for would have a cost of $A497 million per annum.

Figure 3.5: Increasing the cost of capital



As shown in the figure above, AEMO anticipates an increase in utility-scale wind and solar generation capacity by 125GW under the Step Change scenario by 2050. The investment in 1GW of VRE would approximately cost $1.37b per GW[40], which means that a 125GW increase in VRE would require around $172b (NPV). A simple calculation of a difference between payments caused by the increase in the cost of capital by 50 basis points would result in an increased cost of VRE investment by approximately $497m p.a. Thus, our conservative estimate of the increased cost of capital is much larger than even the direst estimates of the cost of disorderly bidding.

CMM impact on retail competition

In addition to CMMs impact on the cost of capital, CMM may also reduce retail competition. Evidence of this view can be found in the example of New Zealand where we have observed that the location of a gen-tailers retail customer base is strongly correlated with its generation assets. Thus, unlike in Australia where retailers typically compete for customers across a whole state, retailers in New Zealand focused much more on areas behind a transmission constraint where they already have existing generation capacity to serve potential customers.

[40] Clean Energy Investor Principles August 2021 Unlocking low-cost capital for clean energy investment According to the report, the total investments required for 51GW new VRE require around $70b (NPV) of investments, which means that the cost of 1GW of new VRE is approximately $1.37b.

As a result, this trend also led to increased vertical integration within congested areas and reduced the number of retailers behind a transmission constraint. This means that competition was reduced as gen-tailers withdrew from or chose not to compete in nodes where they did not have generation assets.

3.3 Comparison of Castalia's Alternative Proposal to Other Alternative Proposals

We understand that ESB has received a number of alternative proposals for transmission access reform. We are eager to see more detail on proposals made. However, based on information presented by ESB on the third of February,2022, we believe that our proposal would achieve the same objectives as other alternatives. During the development process of our alternative model, we have considered to several of the alternative models proposed. Further, we believe there is room to incorporate the congestion relief market under our proposal. In the table below, we provide some high-level reactions to alternatives to CMM proposed by other stakeholders with the caveat that we have very limited information on the details of the proposal.

Table 3.2: Our alternative against alternatives proposed by other stakeholders

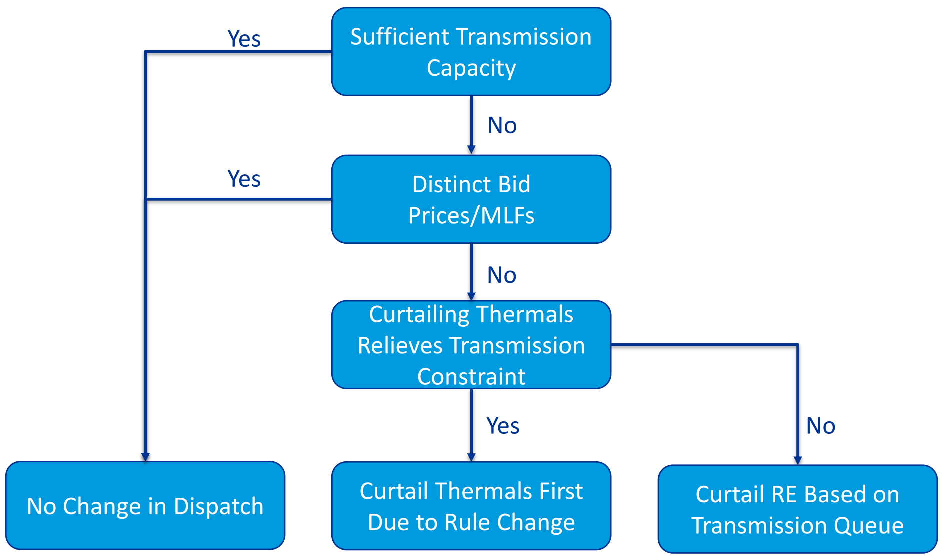
Alternatives to CMM proposed by other stakeholders	Details	Component of our proposal that matches	Comments/Details
Congestion relief market	Dispatch based mechanism which recognises the ability of various assets to alleviate congestion in operational timeframes. Creates a 'side market' that allows for parties to trade congestion relief behind a constraint.	**Transmission Access Queue**	The queue will reduce congestion by encouraging generators to locate where there is spare transmission capacity. We do not believe that this proposal sends equivalent locational signals. However, we expect that the transmission access queue would create an "efficient" level of economic curtailment. As such, we believe that the congestion relief market is compatible with our proposal as an add-on.
Locational connection fees	Connection applicants would work with TNSPs to remedy the impact of their connection on other participants. Potential for run-back schemes and/or commercial compensation agreements as alternatives to physical upgrades.	**Transmission charges (TC)**	The option to pay TC or invest in energy storage included in our proposal will operate as a "safety-valve" that will offer the same benefits as proposed locational connection fees.
State based access schemes	ESB could consider global application of proposed REZ access schemes (i.e., physical access caps).	**Transmission Access Queue**	Physical management of the grid might create a threat of overlapping transmission access rights in a meshed transmission network and will prevent efficient overbuild. The queue will avoid these difficulties.

Dual price floors	Reduces transmission access risk for dispatchable generation by lifting the Market Floor Price for semi-scheduled generation.	**Rule Change allowing RE to be dispatched before Thermal**	We believe that because current price floors reflect cycling cost it should not be changed. The rule change will achieve the same objective without tampering with price floors.
New tie breaker rules	Where constrained generators have tied bids, lower cost generators could get preferential dispatch. If bid-tied generators have the same cost, those with an earlier commissioning date could get preferential dispatch.	**Rule Change allowing RE to be dispatched before Thermal**	We considered a tie-break ruled based on SRMC. However, calculating SRMC is complex and a plants SRMC may vary depending on contract position and cycling costs. As a result, we opted for the much simpler rule change which would dispatch RE generators ahead of thermal generators.
Shaped MLFs	Use fixed-shape time-of-day Marginal Loss Factors (MLFs) to strengthen locational signals	**Transmission Access Queue**	The transmission access queue sends long term locational signals by protecting incumbency rights. Fixed shape time of day MLFs would still leave generators open to curtailment resulting from new entrants and MLFs would change over time if they are recalculated.
Public Interest Advocacy Centre (PIAC) model	Model proposes new approach for developing and funding REZs. Under the PIAC model, the cost and risk of investment in new and existing transmission for REZs could be shared between consumers, generators, transmission network service providers, and other investors	**Transmission Access Queue and Transmission charges (TC)**	We propose shifting some of the cost to generators through auctions and transmission charges. However, it is unclear how much of a shift this proposal advocates for.

4 Worked Examples

In this section, we will demonstrate how the transmission access queue and the rule change would work together to achieve the ESB's goals. The transmission queue and the rule change will interact with each other to protect incumbency of RE generators against other RE generators after the energy transition while still allowing for competition between thermal generation and RE during the energy transition. Figure 4.1 below shows the interaction between the rule change and the transmission queue in the dispatch order.

Figure 4.1: Transmission Queue and Rule Change Interaction



In the figure above, the first decision point is whether there is sufficient transmission capacity. If so, the competition for dispatch occurs normally and no change is made. Next, if there is a transmission constraint then the dispatch algorithm would consider if there are distinct bid prices or MLFs which can order the bids in the bid stack. If so, then dispatch order would be decided as normal.

However, if all generators behind the transmission constraint have bid the same price (as is the case in "race to the floor" bidding, our approach to transmission access would first filter out thermal generation by requiring that RE is dispatched before thermal generation. Thus, the rule change will prevent disorderly bidding and will not allow thermal generators to be dispatched alongside RE when both have bid the same price.

If, after curtailing thermal generators, there is still more generation than transmission capacity, then the transmission queue will come into effect and generators will be curtailed based on their number in the transmission queue. As the order of the transmission queue will be based on incumbency, the transmission queue will protect the incumbency of RE generators against other RE generators.

In the remainder of this section, we provide four worked examples for a radial line with 100MW of transmission capacity constraint and ignore the impact of losses which matches the examples provided by the ESB to show how our proposal would impact dispatch under those same scenarios. These examples show that our approach will protect the incumbency of RE against new entrants. They also effectively demonstrate that overtime with an increased penetration of renewables, disorderly bidding would gradually disappear.

Figure 4.2: Summary of Dispatch Outcomes for Worked Examples

Scenario 1: Current dispatch arrangement with multiple thermal generators

- Disorderly bidding remains
- The total system cost incurred is $700
- System cost associated with disorderly bidding $200

Scenario 2: Dispatch arrangements with multiple thermal and a single near zero SRMC generator

- Disorderly bidding is partially resolved
- The total system cost is $350
- System cost associated with disorderly bidding $100

Scenario 3: Dispatch arrangements with multiple thermal and multiple near zero SRMC generators

- Disordely bidding is fully resolved
- The total system cost $0
- System cost associated with disorderly bidding $0

Scenario 4: Dispatch arrangements with multiple thermal, multiple near zero SRMC generators and energy storage

- Disorderly bidding is fully resolved
- The total system cost $0
- System cost associated with disorderly bidding $0

The four examples above show how our alternative grid access proposal does not solve all problems all at once. The issue of disorderly bidding between competing thermal generators will remain. However, the examples show that our proposal will resolve the most pressing and costly problems facing the NEM by gradually resolve the problem of disorderly bidding by eliminating the ability of thermal generators to bid in a disorderly fashion that would allow them to be dispatched alongside RE and creating the right locational signals for generators and energy storage to locate in areas with available transmission capacity.

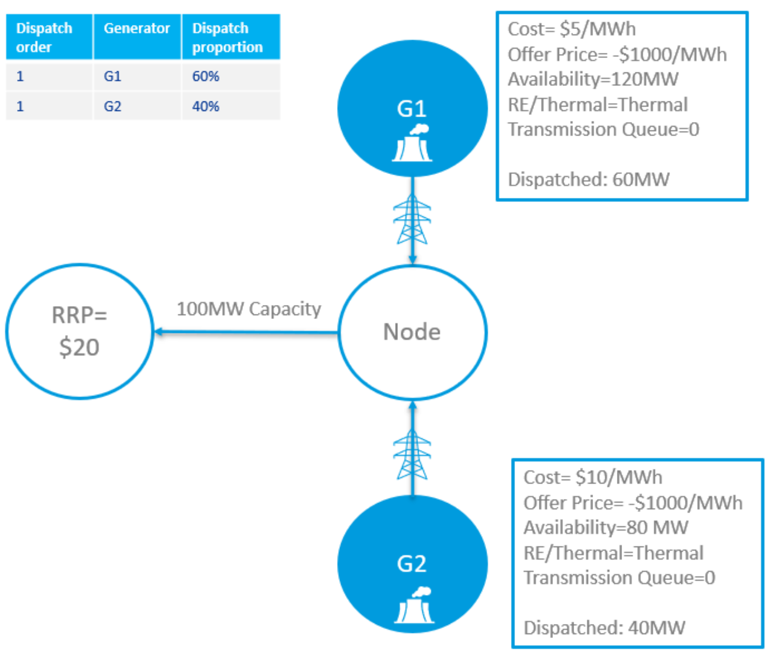
Allowing RE generators to be dispatched ahead of thermal generators effectively reduces the system costs associated with disorderly bidding in the transitional period and eliminates it in the future energy market with high penetration of RE.

In addition, the transmission queue mechanism creates appropriate locational signals for both generators and energy storage. By protecting generators that do not breach the transmission capacity it sends signals to new generators to locate in areas with available transmission capacity. It also provides the correct incentive to build an efficient mix of solar, wind and energy storage. This is achieved by creating an incentive to build different types of technology that would take advantage of periods of low generation from existing generation capacity.

4.1 Scenario 1: Dispatch arrangement with multiple incumbent thermal generators

Under the current arrangements, the dispatch algorithm is unable to distinguish between two thermal generators with different underlying costs when both generators “race to the floor” and bid -$1,000/MWh. Therefore, both generator 1 (G1) and generator 2 (G2) are dispatched in proportion to their availability. Our transmission access proposal would not change this as shows in the figure below.

Figure 4.3: Current dispatch arrangement with multiple thermal generators



We understand that the current arrangement is inefficient and creates costs for the system and indirectly for customers. G1 has a lower underlying cost than G2 and should be dispatched for 100MW. However, due to the dispatch algorithm’s inability to distinguish between two generators with the same price but different underlying costs, G2 is also getting dispatched. As a result, the problem of disorderly bidding remains.

However, as noted in Section 3.2.4 disorderly bidding resulting from out of merit dispatch is extremely rare and accepted as a small inefficiency that helps to facilitate an overall efficient market. Moreover, an enhanced dispatch algorithm as a tiebreaker between prices and increased penetration of VRE generators will gradually eliminate this problem. This is illustrated in more detail in the following scenarios. Hence, while our proposal would not resolve this scenario, we do not consider it to be as important as the following scenarios.

Table 4.1 illustrates that under our proposal arrangement, the total system cost incurred is $700. In the absence of disorderly bidding, only G1 would be dispatched, and the total system cost would be $500. This means that the disorderly bidding increases system cost by $200.

Table 4.1: Financial outcomes under scenario 1

Generator	Price Received (MWh)	Cost ($/MWh)	Quantity Generated (MWh)	Cost Incurred ($)	Profit ($)
Generator 1	20	5	60	300	900
Generator 2	20	10	40	400	400
Total				700	1300

4.2 Scenario 2: Dispatch arrangements with multiple thermal and a single near zero SRMC generator

Figure 4.4 illustrates the impact our proposal will have on dispatch when the two existing thermal generators (G1 and G2) are joined by a new entrant RE generator (G3).

Under this scenario, all three generators still bid -$1000/MWh in an effort to be dispatched knowing that they are behind a transmission constraint. However, because the algorithm can distinguish between thermal and RE generators, it filters some of the expensive thermal generation by requiring the RE generator to be dispatched before thermal. As a result, this approach prevents disorderly bidding between the thermal and RE generators.

Thus, the RE generator (G3) with a near zero SRMC is dispatched to its full availability of 50MW, while thermal generators cover the remaining 50MW of the load on the pro-rata base as before. This translates into a lower total system cost. However, while the algorithm resolves the issue of disorderly bidding between RE and thermal generators, the issue of disorderly bidding between thermal generators remains.

Figure 4.4: Dispatch arrangements with multiple thermal and a single RE generator

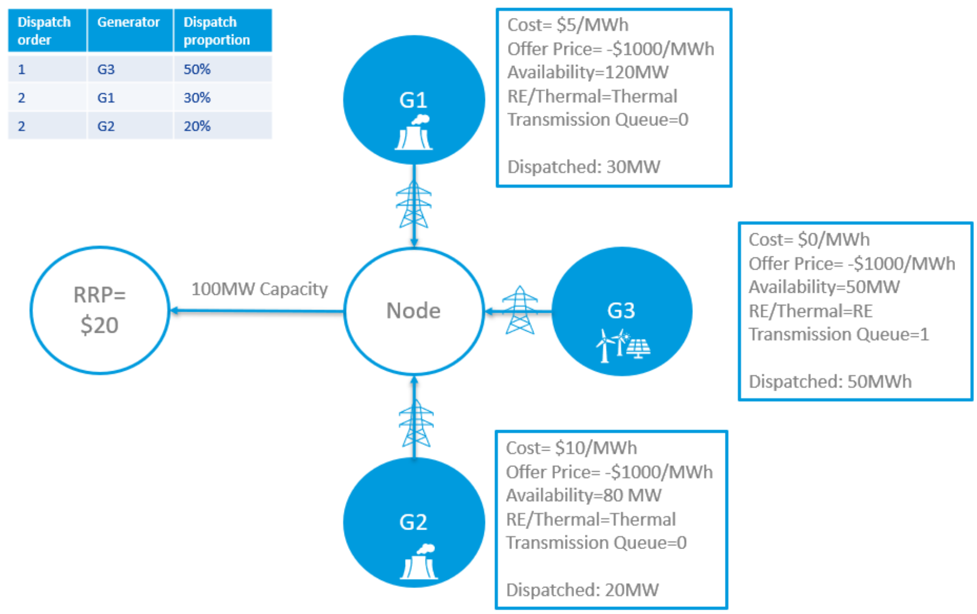


Table 4.2 illustrates that under scenario 2, the total system cost incurred is $350. In the absence of disorderly bidding, only G3 and G1 would have been dispatched, which would incur a system cost of $250. This means that the disorderly bidding between thermal generators increases the total system cost by $100. However, while disorderly bidding between thermal generators still creates additional system cost, the ability of the dispatch algorithm to distinguish between thermal and RE generators reduces the additional system cost by 50% relative to the additional costs incurred under scenario 1.

Table 4.2: Financial outcomes under scenario 2

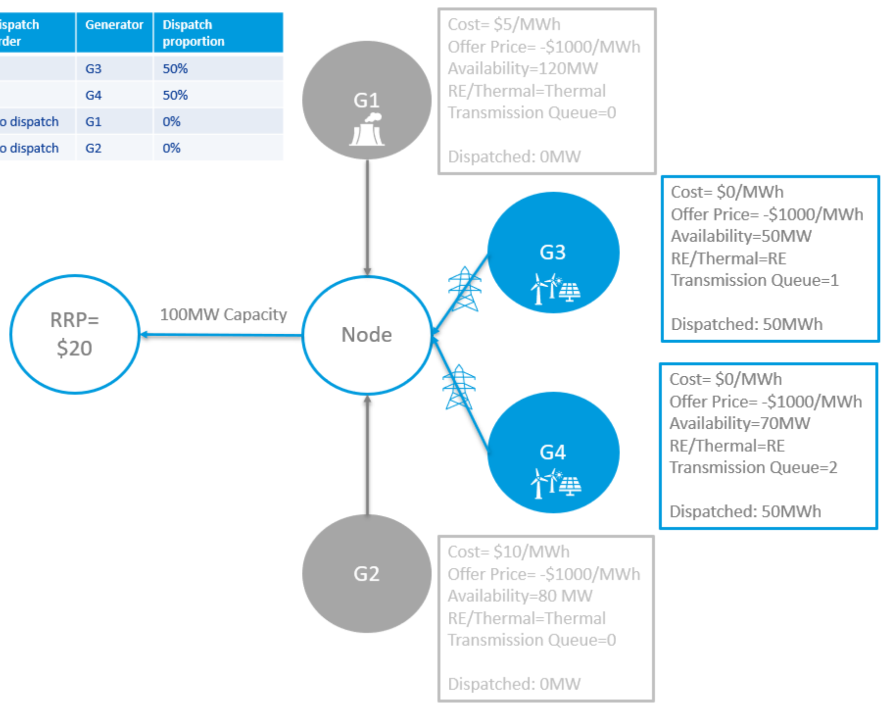
Generator	Price Received (MWh)	Cost ($/MWh)	Quantity Generated (MWh)	Cost Incurred ($)	Profit ($)
Generator 1	20	5	30	150	450
Generator 2	20	10	20	200	200
Generator 3	20	0	50	0	1000
Total				350	1650

4.3 Scenario 3: Dispatch arrangements with multiple thermal and multiple RE generators

Under the following scenario, an additional RE generator with zero SRMC (G4) is added to the node. As in the previous scenario, all generators bid -$1000/MWh; however, the dispatch algorithm distinguishes between thermal and RE generators. The combined generation capacity of G3 and G4 is 120MW, more than the transmission capacity constraint of 100MW. Thus, both thermal generators (G1 and G2) are filtered out and will not be dispatched. G3 and G4 are then dispatched based on the transmission queue number. Figure 4.5 illustrates the outcome for generators under the scenario 3.

Figure 4.5: Dispatch arrangements with multiple thermal and multiple zero SRMC generators

Dispatch order	Generator	Dispatch proportion
1	G3	50%
2	G4	50%
No dispatch	G1	0%
No dispatch	G2	0%



Under scenario 3, the issue of disorderly bidding is fully resolved by filtering out thermal generators with higher underlying cost from the dispatch. The order and the proportion that are RE are dispatched does not affect the system cost, as both RE generators have zero SRMC. However, it remains important for the RE generators as the transmission queue protects incumbent RE generators from being crowded out by newcomers. As a result, G3 gets to dispatch all of its available capacity of 50MW, while G4 only dispatches the remaining 50MW, despite having an available capacity of 70MW. Table 4.3 shows that under scenario 3, there is no additional cost for the system and the total system cost incurred is $0, which means that with an increase of RE generators and the rule that prioritizes the RE over thermal generators when the bid price is the same, disorderly bidding problem will be effectively resolved.

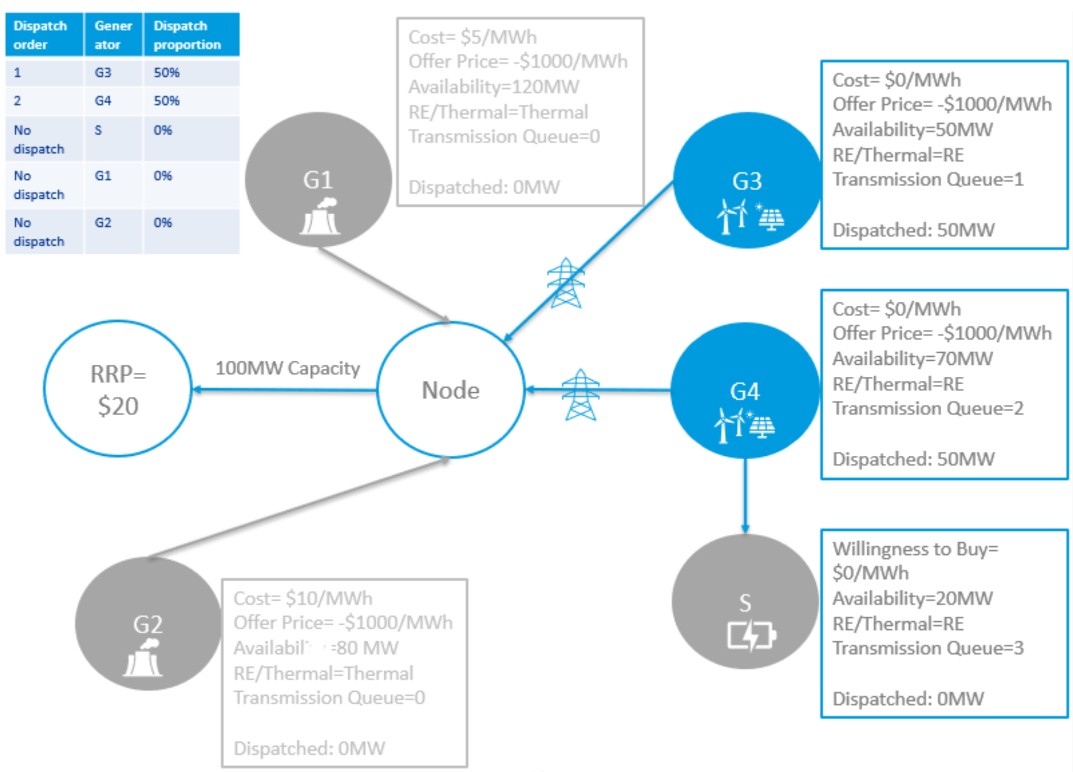
Table 4.3: Financial outcomes under scenario 3

Generator	Price Received (MWh)	Cost ($/MWh)	Quantity Generated (MWh)	Cost Incurred ($)	Profit ($)
Generator 1	20	5	0	0	0
Generator 2	20	10	0	0	0
Generator 3	20	0	50	0	1000
Generator 4	20	0	50	0	1000
Total				0	2000

4.4 Scenario 4: Dispatch arrangements with multiple thermal, multiple zero SRMC generators and energy storage

In this final example, we consider how the presence of energy storage would affect the outcome of dispatch. For ease of explanation, we assume that energy storage is owned by the renewable generator (G4). However, in reality, energy storage can be separated from the generator and be dispatched on an individual basis. Table 4.4 illustrates dispatch outcomes for the generators.

Figure 4.6: Dispatch arrangements with multiple thermal, multiple zero SRMC generators and storage



Under scenario 4, as in previous scenarios, all generators bid -$1000, while the dispatch algorithm prohibits thermal generators from dispatching ahead of RE generators. As a result, G3 and G4 are dispatched first, constraining off G1 and G2. Based on the transmission queue order, G3 is dispatched first to its full availability of 50MW. G4 has 70 MW available for dispatch, but due to the lower transmission queue position, it is allowed to dispatch only 50MW. In this scenario, G4 also owns an energy storage unit that allows it to capture energy spill of 20MW. The energy stored can be dispatched in a different time period. For instance, when G4 does not have enough available capacity due to an unfavorable energy generation environment (e.g., no sun or no wind) it can dispatch from its energy storage unit. Table 4.4 show the financial outcomes for generators and a storage unit.

Table 4.4: Financial outcomes under scenario 4

Generator	Price Received (MWh)	Cost ($/MWh)	Quantity Generated (MWh)	Cost Incurred ($)	Profit
Generator 1	20	5	0	0	0
Generator 2	20	10	0	0	0
Generator 3	20	0	50	0	1000
Generator 4	20	0	50	0	1000
G4-Storage	20	0	-20	0	0
Total					2000

Similar to scenario 3, under scenario 4 the issue of “race to the floor” bidding is resolved and no additional cost is incurred to the system. Generators with zero SRMC are dispatch ahead of generators with higher underlying cost.

In cases where the energy storage unit is not owned by the RE generator, the generator and storage provider would sign long-term bilateral agreements that would specify the transaction terms, including price that an energy storage unit would pay to buy energy from the generator. Our proposal leaves it to the generator and the storage provider to negotiate an arrangement that is commercially suitable for both parties.

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WASHINGTON, DC
1747 Pennsylvania Avenue NW, Suite 1200
Washington, DC 20006
United States of America
+1 (202) 466-6790

SYDNEY
Suite 19.01, Level 19, 227 Elizabeth Street
Sydney NSW 2000
Australia
+61 (2) 9231 6862

AUCKLAND
74D France Street, Newton South
Auckland 1010
New Zealand
+64 (4) 913 2800

WELLINGTON
Level 2, 88 The Terrace
Wellington 6011
New Zealand
+64 (4) 913 2800

PARIS
64-66 Rue des Archives
Paris 75003
France
+33 (0)1 84 60 02 00

Thinking for a better world.

enquiries@castalia-advisors.com
castalia-advisors.com