1 August 2024

Report to AEMC

Advice regarding congestion modelling for transmission access reform

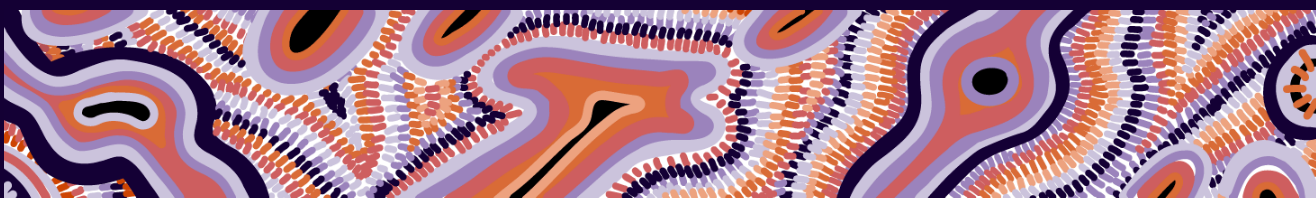
About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

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ACIL Allen thinks that priority access, as currently designed using bid price floors, can be meaningfully modelled by intending participants to support investment cases. In particular, we think that:

- priority access can be included in the usual modelling undertaken for investors in generation
  - a generator could model the cash flow effects of priority access relative to the status quo and its impacts on congestion caused by new entrants
  - a generator could anticipate where its access would be limited/reduced by higher priority generators at certain points on the grid provided that appropriate network information is provided by the Australian Energy Market Operator (AEMO) and transmission network service providers (TNSPs)
- priority access could provide more certainty (relative to the status quo) to intending investors about a project's:
  - access to the regional reference price (RRP) and associated ability to contract and
  - revenue streams that it would earn over its lifetime.
- modelling of priority access and the congestion relief market (CRM) would improve over time.

Introduction 1

1.1 Background

The Australian Energy Market Commission (AEMC) has initiated a review to develop the Energy Security Board's (ESB) work on transmission access reform (TAR) in collaboration with the Australian Energy Regulator (AER) and the Australian Energy Market Operator (AEMO). The review will progress work on TAR and revert to Energy Ministers in 2024 with final recommendations.

The purpose of the TAR is to address four transmission access reform objectives, which have been agreed by Energy Ministers and which were developed by the ESB in consultation with stakeholders:

— Investment efficiency: Better long-term signals for market participants to locate in areas where they can provide the most benefit to consumers, considering the impact on overall congestion.

— Manage access risk: Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to effective competition in the long-term interests of consumers.

— Operational efficiency: Removes incentives for non-cost reflective bidding to promote better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.

— Incentivise congestion relief: Create incentives for demand side and two-way technologies to locate where they are needed most and operate in ways that benefit the broader system.

The ESB has developed a hybrid model for transmission access reform that seeks to achieve the above objectives. This hybrid model comprises the voluntary congestion relief market (CRM) and a queue approach for priority access (PA).

The AEMC is conducting a review to progress the design of the hybrid model for transmission access reform and make final recommendations to the Energy Ministers.

1.2 Scope

The AEMC's primary objective for the scope of work was for ACIL Allen to advise whether the effects of priority access can be meaningfully modelled by intending participants to support investment cases. In the scope of work, the AEMC requested technical advice on the following:

— How congestion modelling is currently completed in the National Electricity Market (NEM) and how it contributes to the investment case of an intending participant. This includes how system security and outage constraints are currently modelled, if at all.

— Could priority access as currently designed be included in the usual modelling undertaken for investors in generation (with reference to our PowerMark market model), and if so, how?

— Whether the inclusion of priority access in the congestion modelling (if possible) would likely have the desired impacts on outcomes for an individual new generator. The desired impacts of priority access would be that:

  – A generator could model the cash flow effects of priority access relative to the status quo due to the priority access queue providing protection against congestion caused by new entrants.

   - A generator could anticipate where its access would be limited/reduced by higher priority generators at certain points on the grid.
- Whether, in your opinion, priority access could provide more certainty (relative to the status quo) to intending investors about the revenues a project would earn over its lifetime.
- Whether modelling of this nature would likely improve over time (e.g. modelling of marginal loss factors (MLFs)).

The model was not intended to be a cost benefit analysis (CBA) on priority access in the NEM or provide NEM specific projections.

1.3 Overview of Approach

The approach ACIL Allen adopted to support the AEMC in determining whether the effects of priority access can be meaningfully modelled by intending participants to support investment cases was as follows:

1. We developed a thorough understanding of the current priority access model based on working papers that the AEMC provided.
2. We provided a brief review of how congestion modelling is currently undertaken.
3. We assessed whether the currently designed hybrid model of priority access and the CRM could be included in the usual modelling processes, using the PowerMark model as an example.
4. We developed a simple prototype model for priority access and investment decisions to enable us to provide an informed opinion on whether priority access could provide more certainty to investors about the revenues a project would earn over its lifetime compared to the status quo. The aim of the model was to compare the outcomes for the status quo and the priority access arrangements for:
   - congestion and network curtailment of existing and new generators, in particular cannibalisation of existing generators by new entrants
   - total renewable and thermal generation given the same capacity incentives for variable renewable energy (VRE) generation
   - impact on variability of annual generation and cash flows.

   We designed the simple prototype model to highlight the differences between the priority access model and the status quo but not to introduce other complexities that muddy or confound the simulation experiment.
5. We participated in a range of workshops with the AEMC, AEMO and TAR technical working group (TWG) and a public forum.
6. We provided the AEMC with our informed opinion on whether the effects of priority access can be meaningfully modelled.

Hybrid priority access and CRM Model

2

2.1 Introduction

The congestion relief market (CRM) model comprises an access dispatch, which is a normal NEM dispatch (previously called the EN dispatch), and a subsequent physical dispatch (CRM dispatch), which aims to improve the economic efficiency of dispatch by better utilising the existing network and lowering congestion costs. Under the CRM, the access dispatch targets are priced at the RRPs, and the deviations from the original access dispatch targets, determined by the physical dispatch, are priced at the local CRM prices (CRMPs[1]).

This CRM model can be considered as an access dispatch to a unit's RRP and a physical dispatch (CRM dispatch) priced at the unit's local CRMP.

The hybrid priority access model aims to favour higher priority units in the access dispatch during periods of congestion, where units are bid at the market floor price (MFP) in the current NEM dispatch. The current proposal for doing this is via units with higher priorities assigned lower bid price floors (BPFs).

2.2 The congestion relief market (CRM)

2.2.1 Introduction

The CRM is a voluntary mechanism whereby market participants can buy and sell congestion relief to revise their physical position (dispatch) after being dispatched under the "status quo" NEM dispatch and pricing arrangements (access dispatch).

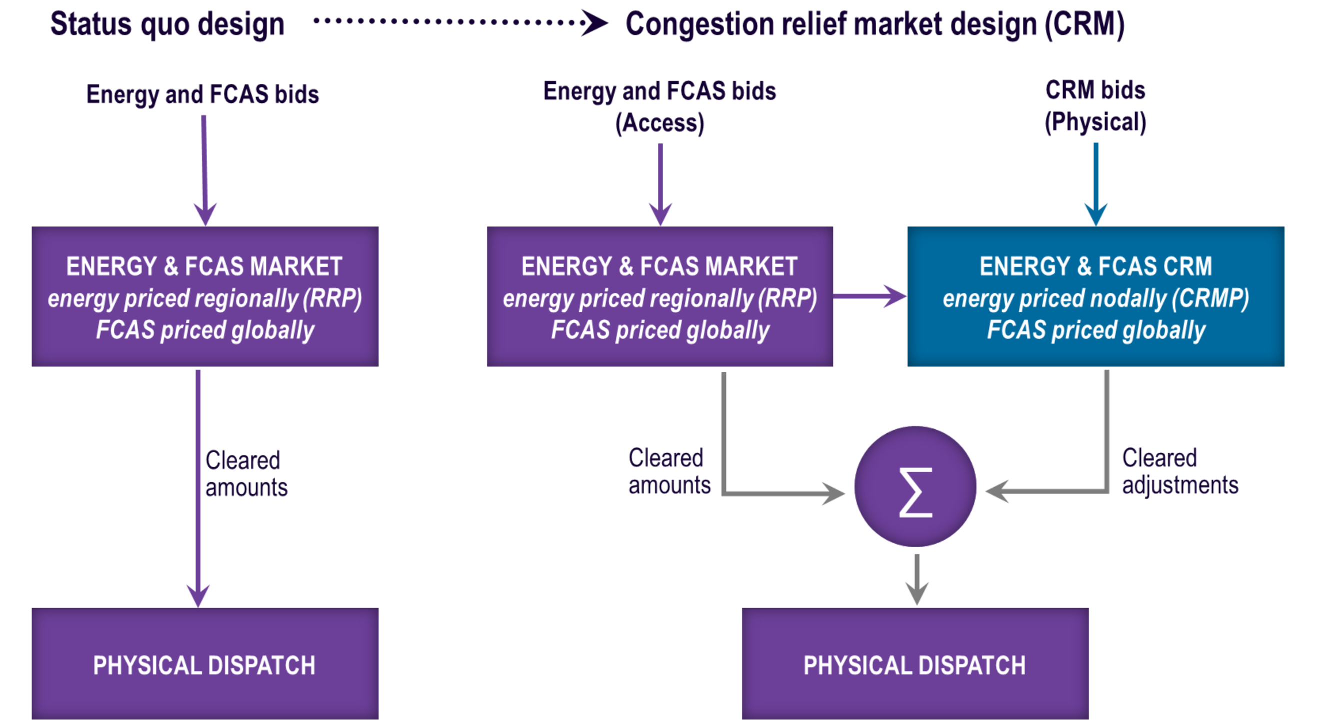
It aims to improve the economic efficiency of the NEM's dispatch outcomes to utilise the existing network better and lower congestion costs.

This mechanism can be summarised as a combination of the current energy market (access) dispatch and a new CRM (physical) adjustments dispatch where generators participating in the CRM receive or pay their CRMP for their increases or decreases (adjustments) to their energy. For units not participating in the CRM nothing would change from current dispatch and settlement arrangements.

The proposed CRM design envisages two optimisation runs: the access dispatch (energy access dispatches paid at RRP) and the physical (CRM) dispatch executed immediately after the access dispatch (energy deviations from the access dispatch paid at CRMP). The proposed design is shown in simplified form in Figure 2.1 below.

[1] The CRMP is the nodal price and represents the marginal value of supply at that location and time, this being determined as the price of meeting an incremental change in load at that location and time.

Figure 2.1 Simplified view of congestion relief market (CRM)



Note: The diagram deliberately simplifies the NEM and CRM dispatch processes. For the CRM, both the access and physical dispatch of energy and FCAS bids must be co-optimised. The primary distinction is that CRM physical energy adjustments will be priced at their CRMPs and the FCAS adjustments at the CRM global FCAS prices.
Source: ACIL Allen (The diagram is an updated version of the diagram that appeared in the ESB's Transmission Access Reform Directions Paper, November 2022)

2.2.2 Key features of CRM

The key features of the currently proposed CRM are as follows.

— Participation in the CRM is optional for NEM participants. At its core the CRM is a voluntary market.

— The access and physical (dispatches are done as two sequential optimisations, and both are full security-constrained dispatches that include all network constraints, FCAS, and any other essential service constraints. The physical dispatch uses the same constraint equations as the access dispatch and is executed immediately after the access dispatch.

— For participants that do not participate in the CRM, it is intended that dispatch outcomes from the access dispatch would be 'locked' for the physical dispatch. Thus, their overall dispatch targets would be identical to the access dispatch.

— CRM participants indicate the lower and upper limits for their physical deviations from their access energy dispatch targets for each of their resources. These limits can be set to zero for any trading interval, so the physical deviations from the resource's access energy dispatch target are zero for that trading interval.

— For each resource participating in the CRM, the physical dispatch requires bids and offers for all of the capacity offered into the access dispatch.

— The CRM model's physical dispatch uses the same FCAS offers as for the access dispatch.

— The CRM's physical dispatch co-optimises energy and FCAS, similar to the current NEM dispatch.

— The CRM's physical dispatch considers all network constraints simultaneously, as is the case for the current NEM dispatch and the access dispatch, not just a selected few.

— The combined access dispatch and physical deviations result in a secure dispatch; that is, the dispatch satisfies all the NEM's security constraints and the technical limits of market participants used in the existing NEM dispatch and the access dispatch.

- The difference between the two dispatch outcomes arises because of different bids from opt-in generators (CRM bids).
- The CRM determines CRMPs for each resource based on the outputs of the physical dispatch optimisation.
- All the physical energy deviations are settled at each resource's CRMP.
- All the physical (CRM) FCAS deviations are settled at each resource's global or regional CRM FCAS price.
- The settlement arrangements for the deviations resulting from the physical dispatch can be viewed as either buying and selling congestion relief or the normal NEM dispatch settlements (access dispatch settlements) combined with a physical deviations settlement.

In summary, the physical dispatch optimisation which is used to determine the dispatches and prices is almost the same as the normal NEM dispatch optimisation (access dispatch optimisation) in that it uses the same system security constraints, regional loads and FCAS requirements. The only difference is that the physical (CRM) dispatch uses different energy bids (CRM energy bids), and it has a set of constraints that can limit how far away from a resource's access dispatch the CRM physical dispatch can move. Like the access dispatch (normal NEM dispatch), the CRM optimisation can provide marginal prices for all locations, including the regional reference node (RRN).

2.2.3 Settlements of access and physical (CRM) markets

Loads and resources dispatched in the access dispatch are settled at the RRPs derived from the access dispatch. However, it is worth noting that both the access and physical dispatch optimisations can be used to determine regional RRPs. These prices conform to the NER clause 3.9.2 (d) definition of the *spot price* at a *regional reference node* being the marginal value of *supply* at that location and time, this being determined as the price of meeting an incremental change in *load* at that location and time under NER clause 3.8.1 (b). Thus, there are two prices for each RRN: the one derived from the access dispatch RRP_{Acc} and the one derived from the physical dispatch RRP_{Phy}

The currently proposed arrangements are to use the RRP_{Acc} for the access dispatch for settlement as this should reduce the potential for problems with existing contracts, and if no one opted into the CRM, nothing would change in the NEM apart from priority access.

The CRM trades for a resource i, $\Delta \mathrm{G_i} = \mathrm{G}_{Phy}(\mathrm{i}) - \mathrm{G}_{Acc}(\mathrm{i})$, are settled at the local CRM price $CRMP_i$.

CRM energy settlement uses the price and quantity information determined by the two dispatch processes, as well as the metering of actual output. Based on stakeholder feedback, the ESB has determined the preferred option is to use the "option 1" settlements formulation from the directions paper where energy CRM physical dispatch variations are settled at CRMP, and everything else is settled at RRP_{Acc} as is currently the case in the NEM:

Energy Revenue = $G_{MET} \times RRP_{Acc} + (G_{Phy} - G_{Acc}) \times (CRMP - RRP_{Acc})$:

Where:

G_{Acc} = access dispatch target

G_{Phy} = physical (CRM) dispatch target

G_{MET} = metered output or load

The above formula is composed of three parts:

1. the access dispatch, which is settled at the RRP_{Acc}
2. the difference between the physical and access dispatch targets, which is settled at the resource's CRMP
3. the difference between metered output and the physical dispatch target settled at the RRP_{Acc}.

In the case of FCAS, the FCAS deviation dispatches ($FCAS_{Phy} - FCAS_{Acc}$) are settled at the FCAS CRM prices.

2.2.4 Bidding behaviour and the CRM

Because generators will generally not know whether their outputs will be increased or decreased in the physical CRM dispatch relative to their access dispatch, they will have incentives to make offers in the CRM's physical dispatch about the price at which they are indifferent to whether their output is increased or decreased. Their prices of indifference should be their opportunity costs/short-run marginal costs (SRMCs).

2.3 Priority access and the CRM

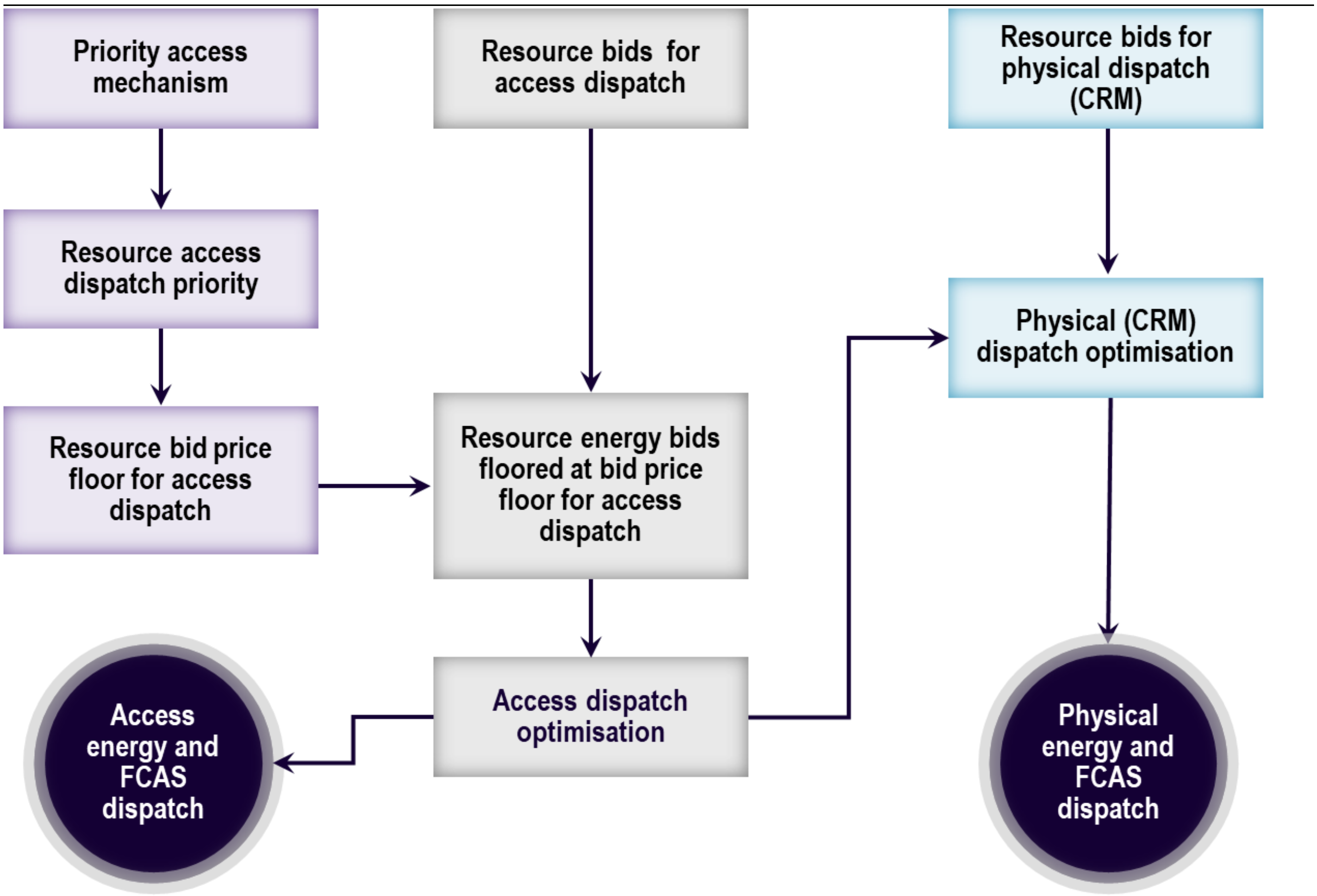
2.3.1 Introduction

The hybrid model comprises priority access and the CRM. Both components aim to collectively achieve the reform objectives of more efficient operations and investment decisions and are designed to work together.

The currently proposed arrangements for priority access are that market participant resources would be assigned a level of priority that can provide an advantage or disadvantage in the access dispatch run when they are subject to network constraints. This aims to provide locational signals for investment decisions to discourage inefficient investment in congested areas.

If implemented in isolation, priority access could lead to inefficient dispatch outcomes. However, when combined with the CRM, which incentivises generators to bid more cost reflectively and consequently enables any inefficiencies in the priority access dispatch to be largely unwound, the hybrid model would result in improved investment and operational efficiency when compared to current NEM dispatch. An outline of the priority access approach using bid price floors and the CRM physical dispatch is presented in Figure 2.2 below.

Figure 2.2 Outline of priority access approach



Source: ACIL Allen

The preferred method to implement priority access is to use separate bid price floors (BPFs). This is because it would give effect to priority access and is relatively easy to integrate into the NEM dispatch engine (NEMDE). Participants with the highest level of priority access would have the lowest BPF at, say, -$1000MWh. Participants with lower levels of priority access would have higher BPFs (e.g., -$400MWh). Lower BPFs provide an advantage to prioritised generators as their offers at their BPF are more likely to be dispatched in NEMDE than lower priority generators with higher BPFs, subject to the binding constraint coefficient.

Priority access reduces the ability for new entrants to cannibalise existing generation in congested areas. Consequentially, the potential revenue is reduced for new entrants in these areas, and investors will be incentivised to locate in less congested areas.

The thinking is that investors who build or have built within congested areas would be protected from later new entrants, therefore reducing their congestion risks. The protection is two-fold:

— new entrants may locate elsewhere to seek higher potential revenue
— new entrants who decide to locate nearby are de-prioritised.

2.3.2 Priority access design

The AEMC is still considering a variety of priority access designs. For the purpose our analysis of priority access we based our modelling on the material that AEMC has provided on the currently most developed model for priority access. This design for priority access is a queue-based annual batching model. In this model, participants would receive priority access based on a predictable chronological queue – this queue is only for priority access and does not affect participants' capabilities to proceed through the connections process. How this is envisaged to work is that:

— Generators (and storage) are assigned a queue number based on the chronological order in which they (or the renewable energy zone (REZ) where they hold an access right) reach a defined event in the connection process (or REZ development process).
— The queue model prioritises generators against generators that connect at a later date. Assigning queue numbers would be mechanical, with rules laying out the process and no discretion required by a central agency.
— There could be 10 dispatch priority positions representing 10 annual periods for which priority access for participants is grouped. Each year, participants would 'roll' to the next dispatch priority level, eventually pooling in the highest level of priority access. Thus, existing investors would be given dispatch priority over the most recent 9 years of new investments.
— The more significant the difference in BPFs between queue positions, the "harder" priority access is.

The current design allocates priority access for an asset's assumed economic life. Once an asset reaches the top priority level, it remains there for its assumed economic life. Beyond its assumed economic life, it moves permanently into queue position 10 (lowest priority). Incumbent generators will be allocated to the top priority level for their remaining technical life.

Table 2.1 below illustrates the proposed annual batching process and associated dispatch priorities based on AEMC's Overview of priority access slides.

Table 2.1 Proposed annual batching process and associated dispatch priorities

	Dispatch priority number												
	Annual batch												
Year	1	2	3	4	5	6	7	8	9	10	11	12	13
0	1												
1	1	2											
2	1	2	3										
3	1	2	3	4									
4	1	2	3	4	5								
5	1	2	3	4	5	6							
6	1	2	3	4	5	6	7						
7	1	2	3	4	5	6	7	8					
8	1	2	3	4	5	6	7	8	9				
9	1	2	3	4	5	6	7	8	9	10			
10	1	1	2	3	4	5	6	7	8	9	10		
11	1	1	1	2	3	4	5	6	7	8	9	10	
12	1	1	1	1	2	3	4	5	6	7	8	9	10

Source ACIL Allen

Table 2.2 below illustrates how the dispatch priorities could translate into bid price floors over time. However, it should be noted that the AEMC has not finalised what the BPFs would be, and that these are indicative only.

Table 2.2 Illustration of how the dispatch priorities could translate into bid price floors over time

	Bid Price Floors (BPFs)									
	Priority									
Year	1	2	3	4	5	6	7	8	9	10
1	-1,000	-200								
2	-1,000	-600	-200							
3	-1,000	-733	-467	-200						
4	-1,000	-800	-600	-400	-200					
5	-1,000	-840	-680	-520	-360	-200				
6	-1,000	-867	-733	-600	-467	-333	-200			
7	-1,000	-886	-771	-657	-543	-429	-314	-200		
8	-1,000	-900	-800	-700	-600	-500	-400	-300	-200	
9	-1,000	-911	-822	-733	-644	-556	-467	-378	-289	-200

Source ACIL Allen

Congestion modelling and generation investments in the NEM

3

3.1 Generation investment – congestion considerations

Undertaking a generation investment is complex as it requires drawing together a range of uncertainties into a coherent package, which is then used to convince debt and equity providers to invest. For variable renewable energy (VRE) projects, the most significant risks are:

1. volume risk – driven by uncertainty around the variable renewable energy source supplying the generator
2. price risk – exposure to volatile spot prices and demand for VRE power purchase agreements (PPAs)
3. economic curtailment – insufficient demand to use available renewable generation
4. network congestion.

The first three risks can be modelled deterministically, and the effects can be predicted with some degree of certainty based on assumptions or modelled stochastically to develop a robust distribution of outcomes. In addition, the first three risks can, to some extent, be managed or mitigated by entering part or whole of meter-based PPAs and employing bidding strategies to avoid generating when prices are below a project's price of indifference/SRMC.

Under current arrangements, network congestion is difficult to forecast because of the uncertainty associated with the location of future investment and the potential for future investment to alter the priority of dispatch when congestion occurs, with later entry potentially crowding out earlier entry.

Investors in generation do not expect certainty about future outcomes. Still, they need to be confident when assessing risks that the results are consistent and repeatable (i.e., they can rely on the assessment). The current network congestion arrangements are not designed to give generation investors the confidence required. This deficiency will become a more significant problem for generation investors as the penetration of VRE investment expands under various government programs. Many government programs underwrite minimum revenues for projects to support development and financing. The current congestion arrangements do not send appropriate signals to drive investors to locate efficiently. If the locational signals are not improved, governments (taxpayers) will likely bear much of the cost of the resulting inefficient investment.

3.2 The current approach to congestion modelling in the NEM

There has been a significant increase in renewable capacity investment over recent years, resulting in moderate network congestion levels for wind and solar generators in North-West Victoria, Central New South Wales, South-West New South Wales, and Queensland. This is because as more renewable capacity enters the market and line flows increase, spare network hosting capacity decreases, and the frequency of constraints binding increases to avoid line overloads. Major government renewable energy programs include:

— the Commonwealth Capacity Investment Scheme (CIS)

— the New South Wales Electricity Infrastructure Roadmap

— the Queensland Energy and Jobs Plan

— the Tasmanian Renewable Energy Target

— the Victorian renewable energy and storage targets.

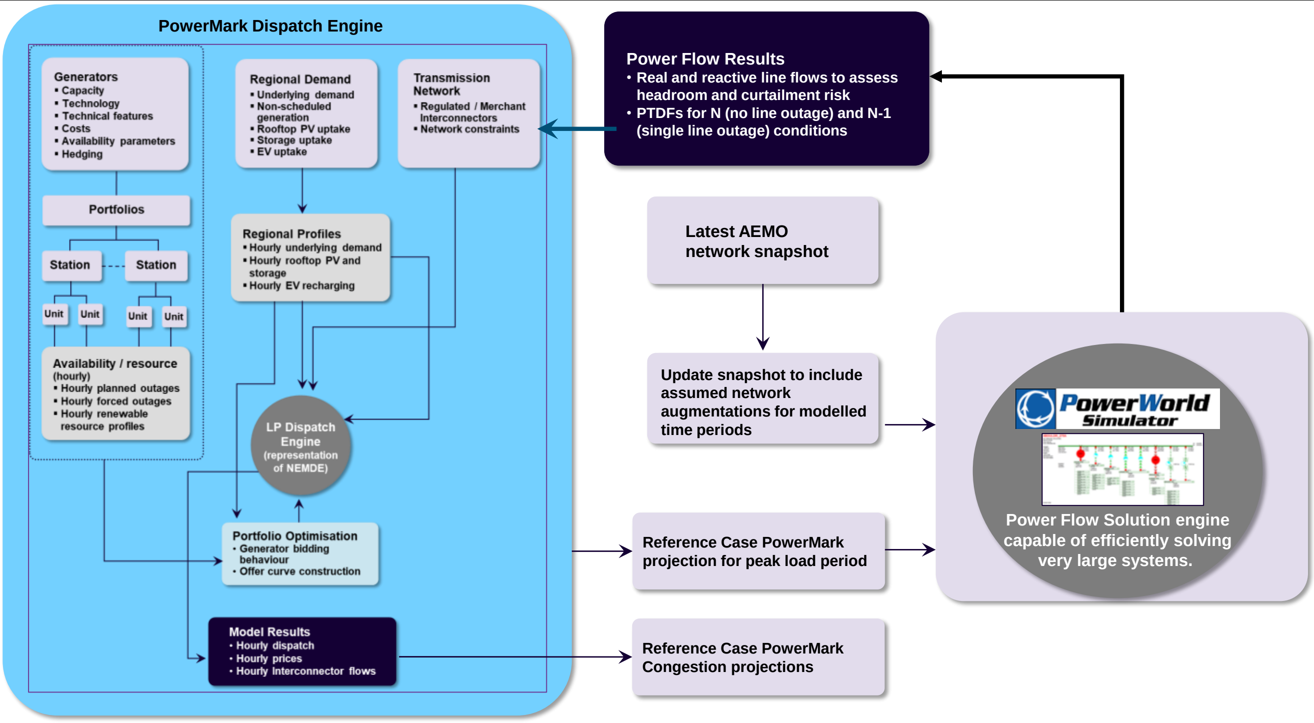
These programs create the potential for significant increases in network congestion if they are not accompanied with corresponding network upgrades.

It is now standard practice for project developers and financiers to conduct congestion assessments as part of their due diligence. ACIL Allen regularly conducts these assessments for renewable and storage project proponents for their internal planning and financial evaluation. To do this, we utilise the following software and inputs:

1. The latest set of AEMO Standard Snapshot Packages and the latest publicly available information on transmission line ratings to generate network constraint equations. Note that the AEMO currently restricts market participants' access to standard snapshot data. Market participants can share the snapshot data with their advisors.
2. A commercial load flow solver is used to load the network snapshot and formulate network constraint equations, which are then included in ACIL Allen's proprietary market simulation model, PowerMark.
3. PowerMark produces generation and load projections at an hourly resolution taking into consideration network constraints. Congestion modellers typically rely on similar software, such as an in-house market simulator or a commercially available engine such as Plexos. However, some power engineering consultants only use load flow modelling to assess congestion and do not use a dispatch engine. This can produce incorrect results because congestion is impacted simultaneously by both bids (economic dispatch) and physical line limitations in the form of network constraint equations, which can only be modelled correctly using a linear optimisation dispatch solver.
4. Half-hourly demand projections at a substation level, which we currently need to produce internally as they are not made publicly available by AEMO. Regional minimum and maximum demand projections are available from the ESOO and ISP, but there is no breakdown of demand at different nodes or in terms of the shape of demand. It is, therefore, difficult to determine the time of day variation of substation load, which is typically dynamic due to rooftop PV and is critical to consider in developing constraint equations.

Figure 3.1 below shows how these components are integrated at a high level in order to model congestion.

Figure 3.1 Network Study Software and Inputs



Source: ACIL Allen network modelling software

A typical congestion analysis study involves the following steps:

1. Analyse the impact of existing AEMO constraints in the area and TNSP annual reports to identify potential transmission bottlenecks and understand how these could impact future generation projections.
2. Run a power flow study to determine the available headroom on potential transmission bottlenecks relevant to the project to give an indicative assessment of project sizing under N and N-1 conditions (zero and single line outages).
3. Formulate the N and N-1 constraint equations for all the lines in the area using power flow software and model them in a dispatch engine such as PowerMark under a reference case scenario, which contains plausible projections of generation and load. This is like the previous stage but is more comprehensive as it considers all N and N-1 transmission limits simultaneously and the dispatch of existing and future generation projections under an economic market model, consistent with how AEMO dispatches generators.

Note that some power engineering houses only conduct the power flow study step because they do not have the capability to do the market simulation and economic dispatch modelling.

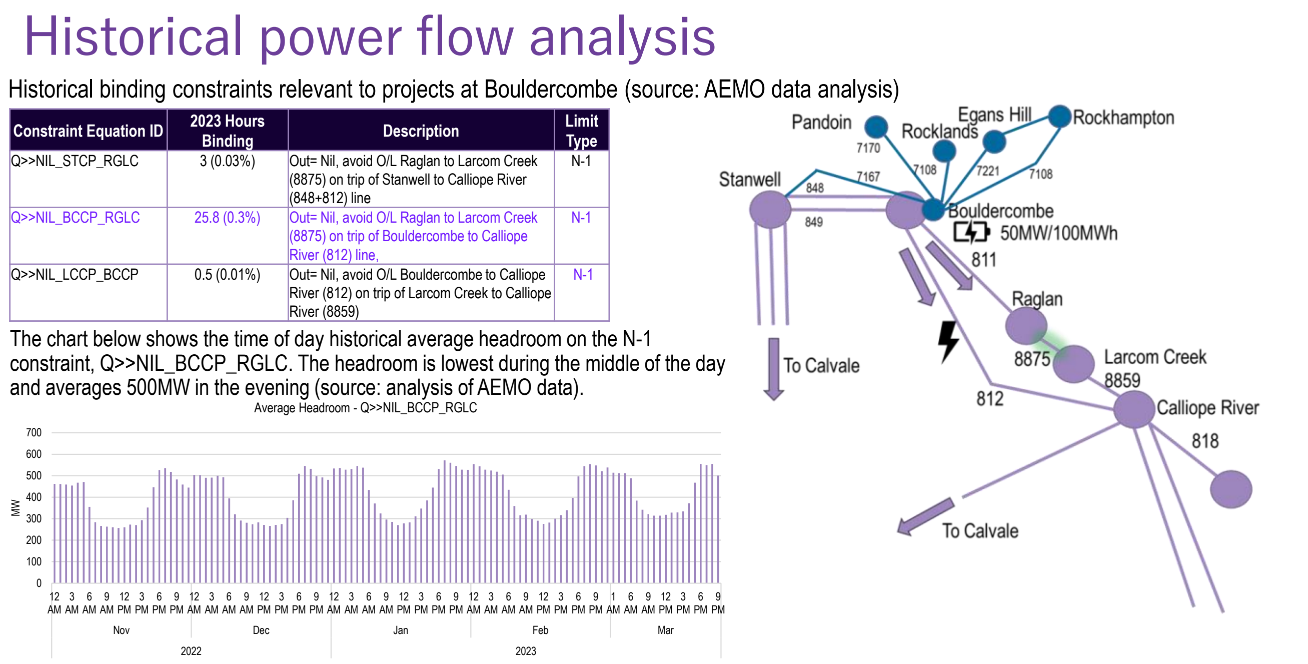
3.3 Example of a congestion assessment at Bouldercombe substation in Queensland

Further details on the steps typically undertaken in a congestion assessment are shown in an example of network congestion at Bouldercombe substation in Queensland.

3.3.1 Example of Historical Line Flow Analysis

The first stage involves a preliminary assessment of historical binding constraints around Bouldercombe to understand the existing level of spare network capacity. Under the priority access scheme, an incumbent would have a higher degree of certainty that it would get access to this capacity, in the access dispatch, relative to local new entrants than is currently the case. The example shows that the level of spare capacity at Bouldercombe varies by time of day and is lowest during the middle of the day when power typically flows south from solar farms in northern and central Queensland.

Figure 3.2 Historical Line Flow Analysis



Constraint Equation ID	2023 Hours Binding	Description	Limit Type
Q>>NIL_STCP_RGLC	3 (0.03%)	Out= Nil, avoid O/L Raglan to Larcom Creek (8875) on trip of Stanwell to Calliope River (848+812) line	N-1
Q>>NIL_BCCP_RGLC	25.8 (0.3%)	Out= Nil, avoid O/L Raglan to Larcom Creek (8875) on trip of Bouldercombe to Calliope River (812) line,	N-1
Q>>NIL_LCCP_BCCP	0.5 (0.01%)	Out= Nil, avoid O/L Bouldercombe to Calliope River (812) on trip of Larcom Creek to Calliope River (8859)	N-1

Source: ACIL Allen analysis of publicly available AEMO data

3.3.2 Example of line utilisation projections using load flow simulator

The next step involves analysing the utilisation of the lines around the Bouldercombe substation under N (zero line outages) and N-1 (a credible contingency of a single line) conditions, as shown below.

Figure 3.3 Example of line utilisation projections using load flow simulator

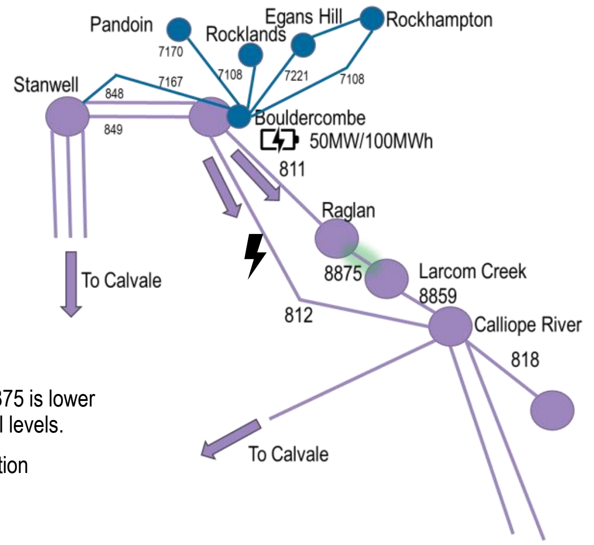
N and N-1 power flow analysis

- This figure shows power flow projections for April 2024. We typically run the study over a projection horizon of 10-15 years to consider future network and generator assumptions. A sample month is shown for demonstration purposes and indicates existing line utilization.
- The table below shows summary statistics for lines relevant to Projects near Bouldercombe.
- The average line headroom on the lines from Bouldercombe to Calliope River under N conditions is around 520MW.

Line No	Avg Dynamic Rating (Summer)	Avg Flow (N)	Avg Headroom (N)
812	688	175	514
811	750	204	546
8875	698	198	500

- As expected, upon outage of line 812 (N-1 conditions) the headroom on 8875 is lower by around 100MW and averages 408MW which is consistent with historical levels.
- This suggests that there is around 408MW of spare capacity at this substation

Line No	Avg Dynamic Rating (Summer)	Avg Flow (N-1)	Avg Headroom (N-1)
811	750	339	453
8875	698	262	408



Source: ACIL Allen power flow analysis

3.3.3 Market modelling under network constraints

This section describes a credible approach to modelling congestion. The approach is closely aligned with AEMO's approach of formulating network constraints using a load flow solver and adding them to an economic dispatch model similar to NEMDE.

Running power flow analysis (network modelling only) without a market simulator (bid and offer generator and dispatch engine) may produce unrealistic outcomes because they are unlikely to reflect underlying market conditions and dispatch, especially as the generation and demand profiles and characteristics change over time. Incorporating a market simulator allows likely variations in generator behaviour and dispatch to be accounted for in the assessment.

To perform congestion analysis correctly and consistent with the approach used by AEMO, network constraints that reflect the power flow thermal limits and bids that reflect the generator opportunity cost need to be included in a market dispatch model. It should be noted that we have used the term opportunity cost, not SRMC. The market simulator incorporates profit-maximising behaviour, resulting in some plants occasionally bidding well above SRMC.

By including network constraints and expected bids in our market simulator, we can provide annual projections of generator curtailment caused by network congestion over the next ten to fifteen years.

Project developers and investors will generally undertake scenario modelling to understand the downside risk and range of plausible outcomes. However, one of the critical limitations of congestion modelling under the current arrangements is the high uncertainty of events with a material impact on project congestion. For example, a new project could be located slightly closer to the reference node and gain a lower constraint coefficient, causing the existing project to be curtailed while the new project operates without curtailment. Scenarios are helpful to model when they are equally likely and plausible but not when the range of plausible outcomes is high and uncertain.

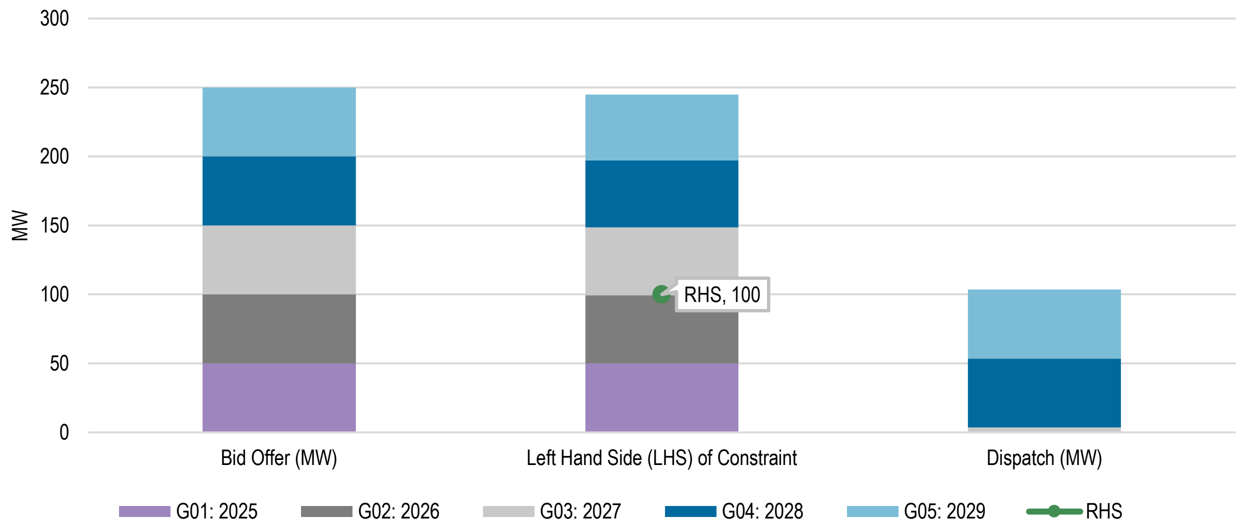
Figure 3.5 shows a hypothetical example of thermal constraint curtailment under an economic market dispatch model with the constraint equation:

$$1 * G01 + 0.99 * G02 + 0.98 * G03 + 0.97 * G04 + 0.96 * G05 \;<=\; 100$$

This constraint equation represents a hypothetical scenario where the output of five generators, located relatively close to each other, is limited to 100 MW due to a thermal line rating limit of 100MW

The figure below shows that each generator offers 50MW of generation. The middle column shows the potential result of the left-hand side (LHS) of the constraint equation (potential dispatch times constraint coefficient) and the right column shows the actual dispatch outcome from the dispatch optimisation. In the dispatch optimisation, when the constraint is binding, the LHS equals the right-hand side (RHS); in this discussion, we are only talking about the potential LHS. Table 3.2 shows the assumed coefficients, bids, dispatch and curtailment due to the constraint. Because the potential LHS equals 250MW and is greater than the RHS of 100MW, some generators are curtailed based on their bids and coefficients in the dispatch optimisation. The dispatch outcome in Figure 3.4 highlights how the slight differences in constraint coefficients result in material differences in curtailment. For example, even though all generators offer energy at the same price, G04 and G05 are dispatched over the other generators because they have lower coefficients. This occurs in the NEM under the status quo when a new generator is located near to an existing generator but has a smaller constraint coefficient and, due to the constraint, cannibalises the existing generator's access to the transmission network and revenue.

Figure 3.4 Winners and losers of thermal curtailment under the status quo



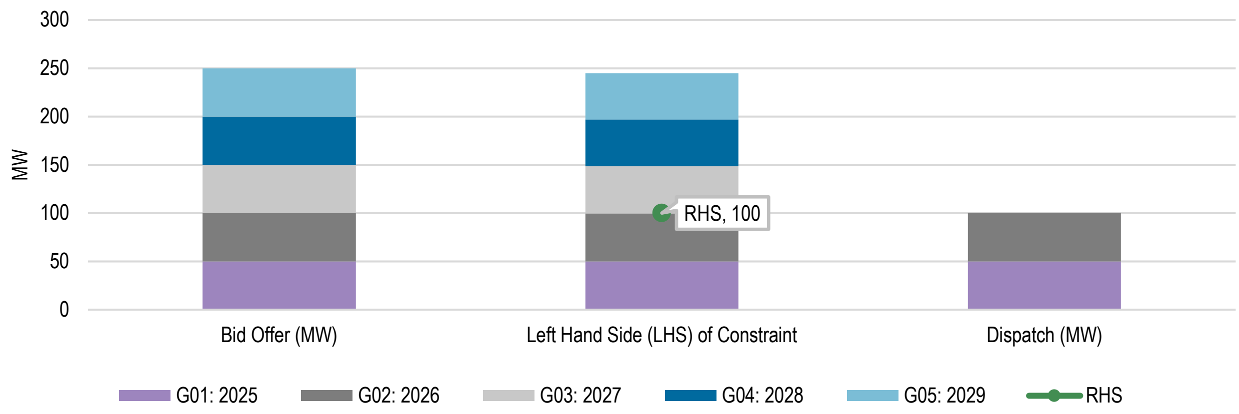
Source: ACIL Allen PowerMark model

Table 3.1 Assumptions and curtailment outcomes under the status quo

DUID	Start Date	LHS Coefficient	Bid Offer (MW)	Bid Price ($/MWh)	Dispatch (MW)	Curtailment
G01	2025	1	50	-1000	0	100%
G02	2026	0.99	50	-1000	0	100%
G03	2027	0.98	50	-1000	3.57	93%
G04	2028	0.97	50	-1000	50	0%
G05	2029	0.96	50	-1000	50	0%

Figure 3.5 and Table 3.2 shows the same example under the proposed priority access scheme where upon congestion, generators receive higher bid price floors than generators installed in previous years. In this scenario, G01 and G02 are able to outbid the newer generators and are subsequently fully dispatched over the newer generators.

Figure 3.5 Winners and losers of thermal curtailment under priority access



Source:

Table 3.2 Assumptions and curtailment outcomes under priority access

DUID	Start Date	LHS Coefficient	Bid Offer (MW)	Bid Price ($/MWh)	Dispatch (MW)	Curtailment
G01	2025	1	50	-1000	50	0%
G02	2026	0.99	50	-800	50	0%
G03	2027	0.98	50	-600	0.51	99%
G04	2028	0.97	50	-400	0	100%
G05	2029	0.96	50	-200	0	100%

Incorporating priority access into investment modelling 4

4.1 Introduction

This section outlines how ACIL Allen would model the hybrid market arrangements of priority access and the CRM. We expect that other consultants and market participants would go about modelling the hybrid model and the potential cash flows of new investments similarly.

4.2 Dispatch and pricing

To model priority access and the CRM dispatch and pricing, the following need to be done:

- Implement a two-pass dispatch process: access dispatch immediately followed by a CRM physical dispatch where:
  - the access dispatch and pricing is the same as the current NEM dispatch and pricing
  - the CRM physical dispatch uses a new set of CRM energy bids for those participating in the CRM, and it includes a new set of CRM deviation constraints which can be used to limit the deviation of a market participant resource's CRM physical dispatch from its access dispatch
  - the CRM dispatch targets are assumed to be the actual metered dispatches for the dispatch interval and consequently become the starting states for the next access and CRM physical dispatches
- Calculate the CRMPs for each market participant resource from the CRM physical dispatch optimisation as the local marginal prices. This could be done directly from the nodal prices of a DC load flow model that explicitly models the transmission network or could be calculated based on the shadow prices of the binding network constraints as is currently done with NEMDE.

  The calculation of CRMPs for the current situation in the NEM where there are no inter-regional loop flows is as follows.

  For node n (bus n), which has market participant resources at its location, its nodal price is

$$CRMP_n = RRP + \sum_{k \text{ in network constraints}} \lambda_k \times c_{k,n}$$

  Where λ_k is the shadow price of the kth network constraint, and $c_{k,n}$ is the coefficient of the market participant resource at node n (bus n) in constraint k. Note that λ_k will be negative for a '<=' constraint as an increase in the RHS by one unit will reduce the objective function (total of dispatch costs) whereas λ_k will be positive for a '>=' constraint as an increase in the RHS will increase the objective function.

  With the addition of an inter-regional loop flow constraint, the formula above no longer correctly calculates CRMPs. The shadow price of the loop flow constraint and the coefficients of the lines involved now need to be included. In effect, the loop flow constraint adds to the shadow prices of the network constraints.

  If the shadow price of the inter-regional loop flow constraint is μ and the coefficient of line k in this constraint is d_k then modelling only simple thermal steady state constraints, the CRMP of bus n is

$$CRMP_n = RRP + \sum_{k \text{ in network constraints}} (\lambda_k + d_k \times \mu) \times c_{k,n}$$

4.3 Market participant bidding

As a first approximation, we would assume that market participants bid into the access dispatch in much the same way they currently bid into the NEM. If they are in an unconstrained sub-region, they will bid to maximise profit, considering any impact their dispatch might have on the RRPs. For market participant resources in constrained sub-regions, we would assume that market participants would bid at the MFP or their BPF if the RRP was greater than their opportunity costs of generating/not generating. Otherwise, if the RRP was less than their opportunity costs, they would bid at their opportunity cost.

The incorporation of BPFs into market modelling requires that, for each year, each resource has to have its annual BPF determined along the lines of Table 2.2 and then this BPF has to be incorporated into its bidding.

In any current market simulation software, the incorporation of each market participant's BPFs into its bidding could be done in two ways:

- The easier way is to just have the software generate the bids for each market participant's resource as is currently done with participant's able to offer prices at the MFP and then floor these offers at each participant's BPF at the time, that is bid price = max(normal NEM bid price, BPF) or
- The harder way, is to directly construct the bids using each market participant resource's bids and offers such that the lowest price is greater than or equal to the participant's BPF.

There is not much benefit in taking the second harder option because when a resource is bid at the MFP in the normal NEM dispatch it would probably bid at the BPF in the priority dispatch and similarly if a resource bids at its BPF in the priority dispatch it is likely to bid at the MFP in the normal NEM dispatch provided its BPF is well below its opportunity cost, that is its bid at its BPF is not a reflection of its actual opportunity cost.

In the case of the CRM, as a first approximation, because generators will generally not know whether their outputs will be increased or decreased in the CRM physical dispatch relative to their access dispatch, they will have incentives to make offers in the CRM about the price at which they are indifferent to whether their output is increased or decreased; the indifference prices would be their opportunity costs/SRMCs.

For the priority access dispatch, the bids could be constructed using the normal modelling approach used for the NEM, and then the floor could be applied to each resource's BPF before they are used in the access dispatch.

4.4 Management of short-term storage

The issue of modelling batteries and long-duration storage is difficult to deal with well in market simulation software. Some software uses perfect foresight or deterministic central planning approaches, but neither is especially realistic. For this difficult area, we plan to explore the use of storage value functions that result in sensible behaviour over a day or two rather than trying to optimise storage with a price look ahead directly. The storage valuation functions better reflect what can be done using batteries when future energy prices are stochastic and material parts of their incomes will come from FCAS and other essential system services. The storage valuation functions would have to reflect the location in the network. For instance, storage in a heavily constrained solar PV area would have a storage valuation function that encouraged charging at low prices in the middle of the day and discharging at higher prices around the evening peak. The storage valuation functions would vary from location to location and would vary by time of day and season. This approach would also speed up the simulations and the market-based investment selection computations.

4.5 Market and network information

Congestion modelling requires the latest AEMO network snapshot which is currently only available to market participants. This is a significant barrier to entry for consultants who are still building their client base and modelling capability and are unable to obtain the snapshot through their existing client base. To remove this barrier, this data should be publicly available so that more consultancies and research agencies can conduct congestion assessments which will increase competition, reduce the price of this service for participants and increase the quality of the modelling.

Another requirement which is currently not available is historical transmission substation demand at half hourly resolution. The network snapshots only contain the demand for eight periods in the year. With increasing levels of rooftop PV this information is necessary to model power flows during the middle of the day when there are large variations in behind the meter PV generation.

4.6 Network constraints and security constrained dispatch

ACIL Allen would model the network and security constraints required for priority access and the CRM along very similar lines to what we currently do, outlined in section 3. This is because the physical network and security constraints are precisely the same for a normal NEM dispatch, a CRM physical dispatch and an access dispatch with priority access.

4.7 Market based new generation investments

The most challenging part of modelling priority access will likely be determining market-driven new entry investments. We would likely use a similar approach to what we currently do, where we use small generic investments to indicate the business opportunities of investing in different technologies in a region at a particular time. For the priority access model, we would extend this to all major network locations at which a variety of generation investments could be made. This would not be a centrally planned least-cost set of generation investments but market-driven investments.

Once prospective locations have been determined using the small generic investments, modelling of realistically sized investments would be undertaken.

Long-term equilibrium prices will tend to be capped at the long-run marginal cost of new build capacity (often referred to as levelised cost of electricity (LCOE) in the case of renewables), adjusted for MLF and taking into account any curtailment. As there is a different LCOE for each project development due to its individual characteristics, ACIL Allen uses a measure of annualised costs and fixed operating and maintenance (FOM) costs as the investment hurdle rate within its modelling. In this way, the expected net revenue (taking into account the MLF, curtailment, negative pricing and any other project specific factors) for each candidate project can be compared against this cost measure for each year to indicate whether an investment is likely to be profitable.

We expect that under priority access new entrant investments will be installed in areas with a lower risk of curtailment from existing investments and, also, priority access will in turn will reduce the risks of new investments being cannibalised by subsequent investments. Consequently, priority access should result in new investments earning more certain revenues over the lifetime of the project than under the status quo. Under the status quo there is a risk that a new entrant project cannibalises the revenue of a project installed earlier.

4.8 Changes to our-house PowerMark model required for priority access

The main changes that we would have to make are the incorporation of the access and physical (CRM) dispatch runs as outlined in section 4.2, updating settlements as outlined in section 2.2.3, using two different bidding strategies for access and CRM as outlined in section 4.3 and incorporation of each participant's BPF.

4.9 Modelling priority access with other software such as PLEXOS

Most off-the-shelf market modelling software such as Plexos and Prophet use sequential market simulations where the dispatch targets from the previous time period are the starting values for the next time period unless a resource suffers a forced outage. To model the access and physical dispatches would require that the previous dispatch targets from the physical dispatch are passed to the access dispatch as the starting values for the next access dispatch rather than the access targets from the previous dispatch. The access and physical dispatches are coupled. Thus, due to the coupling of the access and physical dispatches, it could be difficult to effectively and easily model priority access plus the CRM using off-the-shelf market modelling software which is available today.

It would not be viable just to run the access and CRM physical dispatch as two independent dispatches. It might be possible to run a CRM physical market simulation first and then use the physical dispatch results and availabilities as inputs into the access dispatch. Updating off-the-shelf market modelling software to be able to model the CRM is not conceptually difficult. It is just a matter of running two sequential dispatches. How much effort this would require will probably vary by software vendor. However, if the hybrid model of priority access and the CRM are implemented, over time, we expect commercial developers will modify their software offerings to include priority access and CRM dispatch.

4.10 Intuitive thoughts regarding priority access and investment decisions

A priori ACIL Allen expected that introducing a hybrid priority access and CRM regime would make the NEM operations and investment decisions more efficient. We expected the hybrid regime would reduce the risks of incumbents and new-generation investments' access being cannibalised by later investments wanting to locate in similar electrical locations. We expected to see this reflected in modelling outcomes. For further discussion see section 7.

In theory, priority access combined with CRM should provide more certainty for future investors, but this hypothesis needed to be tested to see whether it was a reasonable assumption. To do this, we developed a simple prototype that compared the operations and generation development plans based on generators making profit-maximising investments over a 15-year horizon with (a) status quo arrangements and (b) priority access arrangements.

The aim of the model was to compare the outcomes for the status quo and the priority access arrangements for:

— congestion and network curtailment of existing and new generators, in particular cannibalisation of generators by later new entrants
— total renewable and thermal generation given the same capacity incentives for VRE generation
— impact on variability of annual generation and cash flows.

We designed the simple prototype model to highlight the differences between the priority access model and the status quo but not to introduce other complexities that muddy or confound the simulation experiment.

Prototype model 5

5.1 Introduction

ACIL Allen's aim for developing a simple prototype model was to test whether priority access combined with the CRM is likely to provide more certainty for future investors. The model was not intended to be a cost benefit analysis (CBA) on priority access in the NEM or provide NEM specific projections. We designed the model to highlight the differences between the priority access model and the status quo but not to introduce other complexities that muddy or confound the simulation experiment.

The model compares the generation development plans based on generators making profit-maximising investments over a 15-year horizon with (a) status quo arrangements and (b) priority access.

We developed a model that is as simple as possible to understand the dynamics of the hybrid model compared to the status quo but complex enough to capture the important issues of multiple constraints binding with a range of coefficients, multiple loop flows and a loop flow involving a regional reference node.

In a full NEM model, it is too hard to understand what is going on when comparing two regimes like the status quo and priority access. There are potentially too many complexities and confounding factors to clearly see what is the impact of the different regimes.

To simplify the model, we made the following assumptions:

— all generators participate in the CRM (if generator is bid optimally it can always increase profitability or do no worse by participating in the CRM)
— a single region using a network of three sub-regions with the option to model two regions by moving existing nodes to a second region
— ignored the Commonwealth Government's CIS and other State Government schemes/targets but had annual new renewable generation capacity targets which are the same for the status quo and hybrid options
— no REZs or other potential zones of priority access, priority access would be applied to individual resources but these could represent a REZ
— only allowed market-based entry of wind, solar and gas (sufficient to maintain equivalent reliability between status quo and priority access) and meet the renewable capacity targets
— started with a relatively unconstrained generation fleet
— gradually decommissioned thermal generation
— no storage included in the modelling to keep the model simple for easier comparison of results.

We extracted the following results at hourly resolution and annual summary:

- regional data: demand, RRPs, frequency of negative prices
- generation data: dispatch, availability, bid price, economic and network curtailment, net revenue (profit), net revenue per MW
- constraints data: marginal value of binding constraints and summary statistics such as binding frequency.

5.2 Macro-economic assumptions

5.2.1 Short-run marginal costs of thermal generators

The three main inputs into the short run marginal cost (SRMC) of a thermal generator are its variable operations and maintenance (O&M) costs, thermal efficiency and fuel costs.

Variable and fixed O&M costs

ACIL Allen incorporates assumptions about variable and fixed O&M costs for each generator. O&M costs are assumed to remain constant in real terms.

We assume the fixed O&M of coal fired stations are doubled at the assumed end of technical life to reflect the increase in capital spend to extend the life of the station. This is used in the modelling to assess the viability of the station after the end of its technical life.

The variable and fixed O&M costs for new entrant plant types are shown in Table 5.2.

Short-run marginal costs (real 2024)

The SRMC of coal generator is assumed to be $70/MWh at the SRMC of the gas-fired generator is assumed to be $150/MWh.

5.2.2 New investment costs and technical parameters

The table below summarises the capital costs assumed in the model for new investment.

Table 5.1 Assumed capital costs for new investment ($/kW, real 2024)

Technology	2024	2025	2030	2035	2040	2045	2050
Wind (onshore)	$2,926	$2,875	$2,632	$2,410	$2,234	$2,125	$2,072
Solar PV SAT Oversized	$1,777	$1,670	$1,239	$979	$840	$769	$724

Source: ACIL Allen

Table 5.2 summarises the assumed operating costs and technical parameters for new investment in the model.

Table 5.2 Assumed operating costs and technical parameters for new investment (real 2024)

Technology	Fixed O&M ($/MW)	Variable O&M ($/MWh, sent-out)	Auxiliary	Thermal Efficiency	Round trip loss	Economic life (Years)
Wind	$61,896	$0	1.00%			25
Solar PV - SAT Oversized	$40,317	$0	1.00%			25

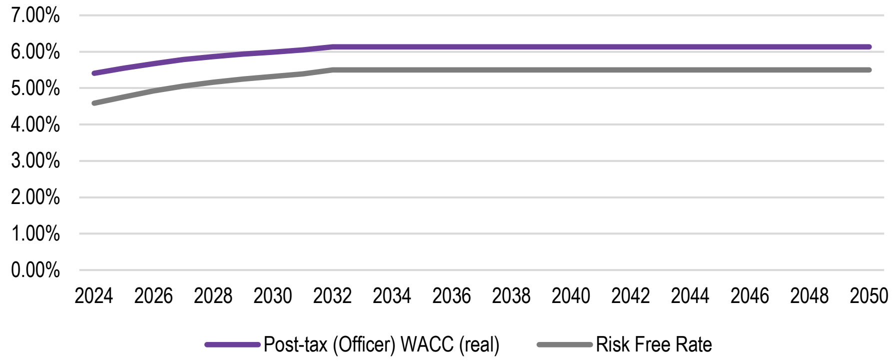
Source: ACIL Allen

Weighted Average Cost of Capital (WACC)

The required returns for new entrant power generation projects are derived using a discounted cash flow model with a discount factor set at the investment's assumed WACC. We use a standard post-tax real officer WACC formulation.

Our estimate of the current post-tax real WACC for power generation projects is 4.20% based on current interest rates. The Reference case assumes interest rates normalise by the early-2030s (rising to around 6.00% in nominal terms), and the WACC increases to a long-term assumption of 6.13%.

Figure 5.1 Assumed WACC and the risk-free rate (%)



Source: ACIL Allen

Resulting Levelised Cost of Electricity (LCOEs)

ACIL Allen takes the assumed new entrant costs inputs and calculates the **annualised capital costs** of new entrant generation projects in the NEM using a discounted cash flow (DCF). The values are expressed in $ per kW of installed capacity per year

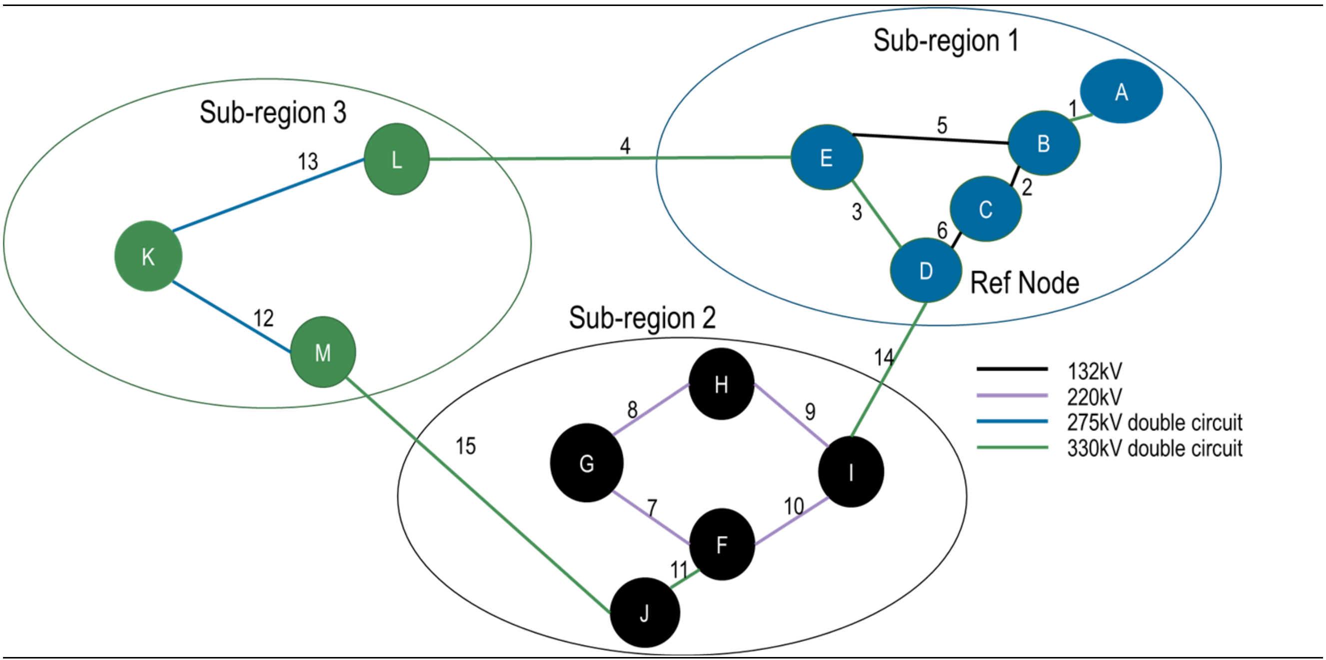
5.3 Model assumptions

Overview

The model's network topology is shown in Figure 5.2 and resembles sub-regions of the NEM to allow a wide range of constraint coefficients from 0.1 to 1. We assumed similar branch ratings and resistances (Rs), reactances (Xs) to those in areas of the NEM to formulate the N and N-1 constraints. Based on this topology we developed a prototype dispatch engine in C#. The key features of the model were:

- The network topology consisted of 13 nodes (substations) from A to M with D being the regional reference node.
- The projection period was for 15 years, from 2025 to 2039 at hourly simulation resolution (8760 periods per year)
- To encourage new investment: demand was increased steadily from 2025 to 2039 and a 200MW thermal generator at node D reduced capacity to 100MW on 1/1/2027 and fully retired from 1/1/2031 onwards.
- 25MW increments of new entrant wind/solar projects were installed in nodes B to M when financially viable in the year. In nodes A and J, it was assumed that no new capacity can be installed, forcing capacity into more areas subject to network constraints.
- Each sub-region has a different wind and solar profile to simulate the geographical variance in wind and solar resources in the NEM. Under the status quo, we expect more capacity to be installed in the locations with the best solar and wind resources even if these areas are congestion because they can cannibalise existing generators and be profitable.

Figure 5.2 Prototype model network topology



Generators

The model starting point consisted of an existing 200MW wind farm at node F, a 200MW solar farm at node C, a coal 200MW coal generator at node D and a 2GW gas generator at node D. The gas generator was chosen to be sufficiently large to ensure there is no unserved energy. The generator input data consist of:

— node/bus connection point
— type of generating unit
— maximum power output (Pmax)
— hourly generation profile for wind and solar based on location
— bid price offer for energy
— fixed O&M.

New entrant generators

The projected annual net revenue projections for generic new entrants in each node informed the capacity and location of new investments for both the status quo and priority access scenarios.

The dispatch optimisation formulation

The formulation of the optimisation is:

Minimise the total energy and violation penalty costs subject to generator bid offers

Subject to the following constraints:

— dispatch of energy price bands >= 0
— dispatch of energy price bands <= offered capacity
— dispatch of energy >= operational Pmin
— dispatch of energy <= operational Pmax
— regional energy violations >= 0
— network thermal constraints using the AEMO methodology to ensure energy power flows are within N and N-1 line limits
— regional energy balance.

Generators, Bids and Offers

As discussed in section 4.3 above, we modelled the status quo and the PA dispatches and their RRPs using our current opportunistic bid curves.

For the prototype model assumed that market participants bid into the access dispatch in much the same way they currently bid into the NEM. We assumed that:

— If they are in an unconstrained sub-region, they will bid to maximise profit, considering any impact their dispatch might have on the RRPs.
— If they are in a constrained sub-region, they will bid at the MFP or their BPF if their RRP is greater than their opportunity costs of generating/not generating. Otherwise, if the RRP is less than their opportunity costs, they will bid at their opportunity cost.

For the priority access dispatch, the bids were constructed using the normal modelling approach used for the NEM, and then each resource’s bid price floor was applied to each resource's bids in the access dispatch.

In the case of physical dispatch, as a first approximation, because generators will generally not know whether their outputs will be increased or decreased in the physical dispatch relative to their access dispatch, they will have incentives to make offers at the price at which they are indifferent to whether their output is increased or decreased; the indifference prices would be their opportunity costs/SRMCs.

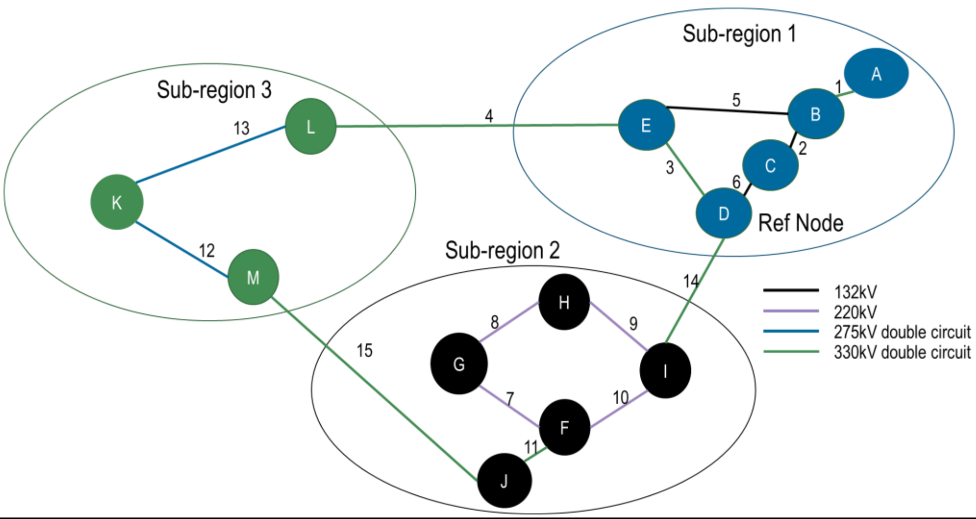
Network Constraints

Using power flow simulation software, we calculated generator power transfer distribution factors (PTDFs) for 17, N and N-1 transmission line limits. To calculate the generator or factors under a single line outage (N-1), the contingent transmission element is switched out of service in the power flow software and the power flow is solved on the new configuration. The PTDF is the contribution, relative to a single node (known as the swing bus), to the monitored line flow that a generator/load makes for a 1 MW increase in the generator output. In the NEM, the swing bus is set to the RRN of the region where the network limitation is located. In our model, the swing bus is at the regional reference node. The calculated generator factors for each line outage configuration then form the LHS constraint coefficients. The coefficients on the LHS of constraint equations are normalised so that the absolute value of the largest factor is 1. Figure 5.3 shows the list of N and N-1 network limitations. 17 network constraints were formulated to capture network limits in our single region model, which represent similar network limits applied by AEMO to enforce network security in the NEM.

Figure 5.3 Network limits included in model

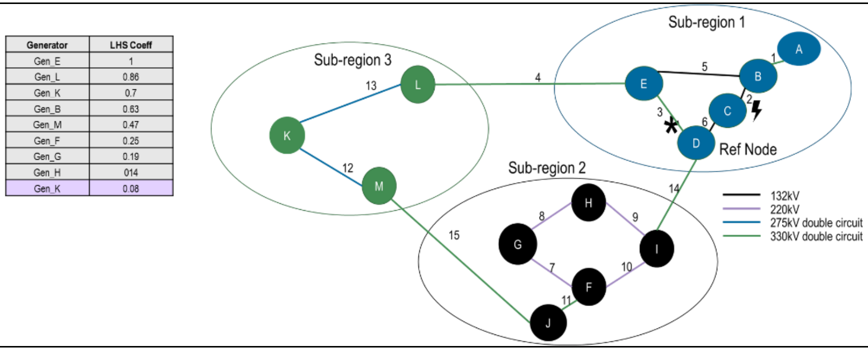
N and N-1 Network Constraints:

Constraint ID	Description	RHS Limit (MW)
1	Out=10, Monitor 7	360
2	Out=12, Monitor 13	325
3	Out=13, Monitor 12	325
4	Out=14, Monitor 4	380
5	Out=2, Monitor 3	359
6	Out=3, Monitor 2	184
7	Out=3, Monitor 6	143
8	Out=4, Monitor 14	340
9	Out=5, Monitor 10	400
10	Out=5, Monitor 3	359
11	Out=5, Monitor 4	420
12	Out=5, Monitor 7	440
13	Out=7, Monitor 10	450
14	Out=8, Monitor 9	292
15	Out=9, Monitor 8	347
16	Out=NIL, Monitor 11	460
17	Out=NIL, Monitor 15	500



The network constraints include constraints with a wide range of coefficients to test the impact of priority access on generation electrically close and far from a congested part of the network. For example, Figure 5.4 shows that the constraint: “Out=2, Monitor 3 (D To E)” has coefficients ranging from 0.08 to 1 on the LHS. The RHS is approximately equal to the line limit of 360MW:

Figure 5.4 Example of a far reaching constraint with wide range of coefficients: Out=2, Monitor 3 (D To E)



Bid Price Floors

Harder initial bid price floors (BPFs)

The bid price floor table shown in Figure 5.5 was the default BPF table used to implement "Harder" Priority Access which had a greater difference in the bid price floors for the higher priority units in the initial years. A "softer" initial bid price floor table was also tested as an additional sensitivity run. The results can be found in section 6.2.

Figure 5.5 Harder Bid Price Floors under priority access

Hard BPF	Priority																	
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1	-1000	-200																
2	-1000	-600	-200															
3	-1000	-733	-467	-200														
4	-1000	-800	-600	-400	-200													
5	-1000	-840	-680	-520	-360	-200												
6	-1000	-867	-733	-600	-467	-333	-200											
7	-1000	-886	-771	-657	-543	-429	-314	-200										
8	-1000	-900	-800	-700	-600	-500	-400	-300	-200									
9	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200								
10	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200							
11	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200						
12	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200					
13	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200				
14	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200			
15	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200		
16	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200	
17	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200

Softer initial bid price floors (BPFs)

The "softer" BPFs are shown in **Figure 5.6.** Under "softer" BPFs, the bid price floors in the first ten years of the priority queue are much closer to each other than under the "harder" BPF table, which means there is a higher risk of cannibalising existing generators from new entrants in earlier years compared to when the "harder" BPFs are used.

Figure 5.6 Softer Bid Price Floors under priority access

Soft BPF	Priority																	
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
1	-1000	-911																
2	-1000	-911	-822															
3	-1000	-911	-822	-733														
4	-1000	-911	-822	-733	-644													
5	-1000	-911	-822	-733	-644	-556												
6	-1000	-911	-822	-733	-644	-556	-467											
7	-1000	-911	-822	-733	-644	-556	-467	-378										
8	-1000	-911	-822	-733	-644	-556	-467	-378	-289									
9	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200								
10	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200							
11	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200						
12	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200					
13	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200				
14	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200			
15	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200		
16	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200	
17	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-1000	-911	-822	-733	-644	-556	-467	-378	-289	-200

Modelling Approach to Market-based new entry

For each node (B to M), the model checks if a dummy 0.1MW generator is financially viable in each forecast year. Next, for each dummy generator, in the order from most viable to least viable, the model.

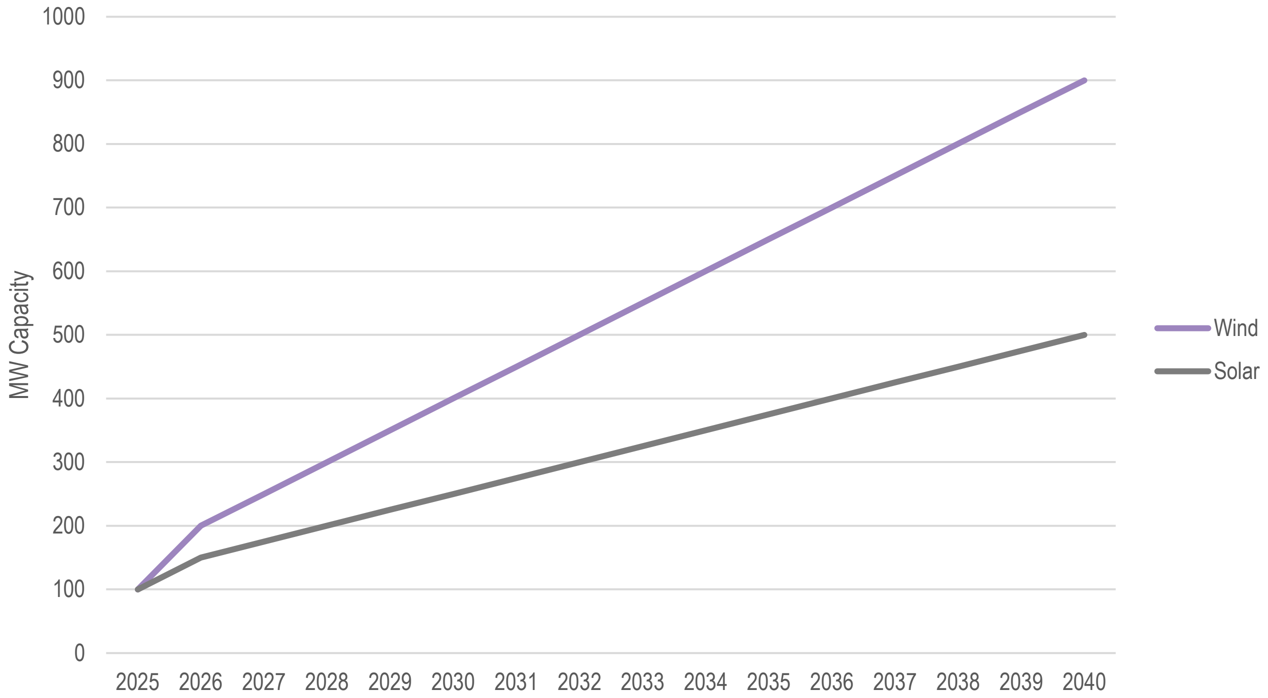
— creates a 25MW new entrant if the dummy generator is financially viable
— checks the new entrant's revenue to see if it is financially viable, if not, it removes the 25MW
— repeats all of the above:
  – if a dummy generator is financially viable where the new entrant has been installed, increase the new entrant capacity by 25MW
  – if the capacity target is met and there are no more financially viable new entrants, then the most viable entrant is installed.

The only difference in this approach to our normal approach to modelling new entrants is that BPFs are used to floor new entrant bids in the priority access simulations

5.4 Capacity modelling

To ensure that we are comparing like with like we ensured that the status quo and priority access development plans had the same new capacity entering the market. This is a rough reflection of the range of jurisdictional schemes which aim to encourage new renewable generation capacity. Figure 5.7 shows the assumed annual capacity targets for wind and solar capacity.

Figure 5.7 Annual targets for wind and solar capacity



Prototype comparison of priority access vs status quo 6

6.1 Modelled Results under "harder" priority access

Table 6.1 shows a summary of the key findings and Table 6.2 compares modelled generation investment projections under the status quo and priority access. Compared to the status quo, under priority access more capacity is installed in locations with lower congestion which results in lower curtailment and less cannibalisation from new entrants. This is likely to result in greater revenue certainty for new investments. There was mildly lower renewable net revenue under priority access driven by lower spot prices because of lower levels of VRE curtailment.

Table 6.1 Key Findings - priority access vs. status quo

Modelling Result	Priority access Compared to Status Quo
Total curtailment	Overall lower curtailment of existing and new entrant investments. Under priority access, new entrants entering the market in the same year may incur some curtailment from cannibalisation. In addition, under the proposed BPF table, some new entrants may incur curtailment after a few years if subsequent new entrants with a lower constraint coefficient in a regularly binding constraint enter the market. This is because when the priority access order is softer, generators with lower coefficients and higher BPFs in binding constraints can cannibalise existing generators with higher coefficients and lower BPFs.
New entrant investment certainty	Better returns for existing and new entrants due to reduced curtailment. There is a lower likelihood of new investments being heavily constrained from later investments causing high levels of curtailment.
New entrant investment decisions	Less investment in congested areas.
Thermal generation and emissions	Lower thermal generation and lower emissions due to more efficient investment given the same new capacity of renewable generation.
Annual average load-weighted RRP	Mildly lower RRP under priority access due to lower levels of curtailment of VRE generation

Table 6.2 Summary Results

Result	Priority access	Status quo	Difference (PA-SQ)
Total Installed Renewable Capacity (GW)	1,725	1,725	0
Total Renewable Generation (GWh)	44,318	43,212	1,106
Total Thermal Generation (GWh)	31,568	32,675	-1,106
Total Renewable Curtailment (GWh)	4,166	5,433	-1,267
Average Existing Solar Network Curtailment	9.8%	18.5%	-8.7%
Average Existing Wind Network Curtailment	0.0%	7.3%	-7.3%

Result	Priority access	Status quo	Difference (PA-SQ)
Average N.E. Solar Network Curtailment	4.9%	7.3%	-2.3%
Average N.E. Wind Network Curtailment	8.5%	8.3%	0.2%
Total New Entrant Renewable Net Revenue ($m)	3,650	4,097	-448
Total Existing Renewable Net Revenue ($m)	1,400	1,063	338
Total Renewable Net Revenue ($m)	5,050	5,160	-110
Total Thermal Net Revenue ($m)	863	935	-72
Total Negative Price Periods	1.5%	0.9%	0.6%
Average RRP $/MWh	134.37	138.95	-4.59

6.2 Modelled results using “softer” BPFs under priority access

An additional model sensitivity was run using “softer” bid price floors to compare against the “harder” bid price floors and the status quo. Under “softer” BPFs, the bid price floors in the first ten years of the priority queue are much closer to each other than under the “harder” BPF table, which means there is a higher risk of cannibalising existing generators from new entrants in earlier years.

Table 6.1 shows a summary of the key findings and Table 6.2 compares modelled generation investment projections under “softer” and “harder” priority access against the status quo. Under “softer” priority access, the modelled outcomes are very similar to “harder” priority access, except there is much higher cannibalisation of existing generators due to the BPFs being much closer to -$1000 in the earlier years.

Table 6.3 Key Findings – Softer priority access vs. status quo

Modelling Result	“Softer” priority access Compared to Status Quo
Total curtailment	Mildly lower curtailment of existing and new entrant investments. Higher cannibalisation of existing generators than under “harder” BPFs due to the BPFs being closer to -$1000.
New entrant investment certainty	Better returns for existing and new entrants due to reduced curtailment. There is a lower likelihood of new investments being heavily constrained from later investments causing high levels of curtailment
New entrant investment decisions	Less investment in congested areas.
Thermal generation and emissions	Lower thermal generation and lower emissions due to more efficient investment given the same new capacity of renewable generation
Annual average load-weighted RRP	Mildly lower RRP under priority access due to lower levels of curtailment of VRE generation but higher RRP than “hard” BPFs due to higher congestion of existing generators.

Table 6.4 Comparison of softer PA and harder PA against status quo

Result	Softer priority access	Harder priority access	Status quo	Difference (PA Soft-SQ)	Difference (PA Hard-SQ)
Total Installed Renewable Capacity (GW)	1,725	1,725	1,725	0	0
Total Renewable Generation (GWh)	44,528	44,318	43,212	1,316	1,106
Total Thermal Generation (GWh)	31,359	31,568	32,675	-1,316	-1,106
Total Renewable Curtailment (GWh)	4,003	4,166	5,433	-1,430	-1,267

Result	Softer priority access	Harder priority access	Status quo	Difference (PA Soft-SQ)	Difference (PA Hard-SQ)
Average Existing Solar Network Curtailment	16.3%	9.8%	18.5%	-2.3%	-8.7%
Average Existing Wind Network Curtailment	0.0%	0.0%	7.3%	-7.3%	-7.3%
Average NE Solar Network Curtailment	5.0%	4.9%	7.3%	-2.2%	-2.3%
Average NE Wind Network Curtailment	8.9%	8.5%	8.3%	0.6%	0.2%
Total New Entrant Renewable Net Revenue ($m)	3,933	3,650	4,097	-164	-448
Total Existing Renewable Net Revenue ($m)	1,359	1,400	1,063	297	338
Total Renewable Net Revenue ($m)	5,293	5,050	5,160	133	-110
Total Thermal Net Revenue ($m)	866	863	935	-69	-72
Total Negative Price Periods	1.4%	1.5%	0.9%	0.5%	0.6%
Average RRP $/MWh	137.44	134.37	138.95	-1.51	-4.59

Opinion about priority access 7

This chapter provides our views on the proposed priority access arrangements.

7.1 Can priority access provide more certainty for investors?

Our thoughts about the hybrid priority access and CRM regime which uses bid price floors and annual batching, as outlined in this report and informed by our prototype model, are that it would provide more certainty for investors. The reasons why we have come to this conclusion are as follows:

— The hybrid priority access and CRM regime using BPFs is readily modellable, with results likely to be consistent and repeatable, and therefore, potential investors can be provided with market modelling and likely cash flows for possible investments that they can rely on.

— Having a range of BPFs means that some of the modelling results would be less arbitrary than modelling the current NEM arrangements where, at times, a large number of generators may bid at the same market floor price of -$1000/MWh and for computational speed, tie-breaking is not used in the modelled dispatch process.

— We agree with the AEMC/ESB's proposition that priority access would provide existing generators and new entrants in uncongested areas of the grid with an advantage in the access dispatch over generators that invest later in areas where the network is congested. This would discourage new generators locating in congested areas of the network as their lower priorities in the access dispatch would mean they have lower access to the RRP and thus would find it more difficult to underwrite projects with contracts. This would reduce new entrants' potential to substantially cannibalise existing generators' access to the RRPs and incentivise new entrants to locate in uncongested areas.

— The CRM side of the hybrid model should unwind any dispatch inefficiencies in the priority access dispatch and facilitate more efficient physical dispatches than is currently the case in the NEM assuming there is sufficient participation in the CRM. This in turn may reduce carbon emissions if some thermal generation in the access dispatch is replaced by renewable generation in the CRM physical dispatch.

— Under the NEM’s status quo arrangement of regional pricing there are no pricing incentives for batteries or storage to locate in regularly constrained areas even though the value (marginal cost) of energy at these locations can be low or negative at times. A battery, under the status quo, could charge at the times when the marginal cost of energy is very low but have to pay for this energy at a much higher RRP. In contrast under the CRM, a battery would see the marginal cost of energy in a constrained area in the CRM physical dispatch and be able to charge at the CRMP rather than the RRP. Thus, in constrained areas, low CRMPs resulting from VRE generation bidding at their opportunity costs could facilitate the introduction of batteries or other storage systems at locations that would not be considered under the NEM's regional pricing regime. Low CRMPs would enable storage to charge in areas where VRE is constrained due to network limits and improve operational efficiency by reducing the potentially wasted energy which would occur due to curtailment of generation due to network congestion. Overall, the CRM can improve the efficiency of storage investments and operations.

— Under the current NEM regional pricing regime, the difference in investment potential for VRE generation at different locations is primarily driven by the quality of the VRE resource and the potential of being constrained. Many areas appear to have very similar investment potentials. It seems to be a relatively flat landscape regarding investment potential and location. However, even though different projects may have similar investment potential, they may cause significant differences in congestion suffered by existing generators. Some investments may contribute very little to meeting the demand and are thus uneconomic from a societal point of view. On the other hand, priority access is likely to create a hillier landscape from the point of view of making new generation investments. It would encourage new investments to be made in areas less likely to substantially cannibalise existing investments, consequently giving investors greater certainty once they have committed to their investment.

— We expect that the hybrid regime would reduce the risks of new generation investments' access being cannibalised by later investments wanting to locate in similar electrical locations. However, this does not mean that all future access constraint risks would be removed from existing generators; it is just that the probability and the likely extent of this would be reduced.

7.2 Will it reduce the chances of an existing generator's dispatch being curtailed by new generation investments?

Our view is that the hybrid priority access and CRM regime would reduce the chances of an existing generator's dispatch being curtailed by new generation investments. We hold this view because the proposed arrangements would force more efficient physical dispatch outcomes and send clearer signals to encourage projects to locate in less congested (more efficient) locations.

7.3 Is modelling of priority access likely to improve over time?

Our view is that the modelling of priority access is likely to improve over time due to several factors:

— Service providers and generation investors would enhance the capability of models as more is learned about the hybrid priority access and CRM regime through undertaking modelling.

— Information to be used in modelling the hybrid priority access and CRM regime should improve over time (participants would press AEMO and TNSPs to improve information, e.g., more frequent and accurate snapshots, more granular demand information, better and more comprehensive network information etc.).

— Computing capacity and optimising engines used in the modelling are expected to run faster and incorporate new features over time.

7.4 Will priority access help to reduce uneconomic congestion and dispatch?

Our view is that the hybrid priority access and CRM regime would help to reduce uneconomic congestion and dispatch. There are several aspects of the proposed arrangements that work towards reducing uneconomic congestion and dispatch:

— Priority access would provide existing generators and new entrants in uncongested areas of the grid with an advantage in the access dispatch over generators that invest later in areas where the network is congested. This, in turn, is expected to discourage new generators in congested network areas as their lower priorities in the access dispatch would mean they have lower access to the RRP and thus would find it more challenging to underwrite projects with contracts. This would reduce the potential of new entrants cannibalising existing generators' access to the RRPs and incentivise new entrants to locate in uncongested areas.

— The CRM side of the hybrid model should unwind any dispatch inefficiencies in the priority access dispatch and facilitate more efficient physical dispatches than is currently the case in the NEM. Furthermore, the CRM should provide incentives for batteries and other energy storage systems to locate in some constrained areas that the NEM’s status quo regional pricing regime does not provide.

— We expect that the hybrid regime would reduce the risks of new generation investments' access being substantially cannibalised by later investments wanting to locate in similar electrical locations.

7.5 Conclusions

ACIL Allen think that priority access, as currently designed using bid price floors, can be meaningfully modelled by intending participants to support investment cases. In particular we think that

- priority access can be included in the usual modelling undertaken for investors in generation
  - a generator could model the cash flow effects of priority access relative to the status quo and its impacts on congestion caused by new entrants
  - a generator could anticipate where its access would be limited/reduced by higher priority generators at certain points on the grid provided that appropriate network information is provided by AEMO and the TNSPs
- priority access could provide more certainty (relative to the status quo) to intending investors about a project's:
  - access to the RRP and associated ability to contract and
  - revenue streams that it would earn over its lifetime.
- modelling of priority access and the CRM would improve over time.

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