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ENERGY MARKET Newsletter

ACIL ALLEN

Longford outage – risks for the east coast gas market

An outage at the Longford gas processing plant has once again highlighted how susceptible the east coast market is to unplanned supply outages.

In early July, an unexpected outage at ExxonMobil's Longford processing plant occurred, disrupting supply for a short period. Supply was reduced by about 25% from the plant, which was enough to cause gas prices to increase noticeably given the importance of Longford's supply to the southern states, particularly Victoria.

Unplanned outages at Longford are increasingly important to avoid in the coming years given how reliant the market is on Longford to supply the market. This is especially the case in the winter period when demand spikes due to the extra demand from gas heating. The market has some ability to cover outages like in this case where supply is partially affected. However, an outage that causes a much larger reduction in supply from Longford would be difficult to manage, and this remains a large risk to the east coast gas market and Victorian gas consumers in particular.

Our analysis in recent months supports this. To meet seasonal and peak day demand in the next few years, the maximum contribution from Longford is needed. The market has always been highly reliant on Longford and this will continue to be the case. Other processing plants, such as the Iona gas storage facility, can cover off on reduced supply from Longford if the reduction is not too large, or extends for too long. In the case that outages are large, or extend for too long, Victoria is likely to face a physical shortfall in gas. Events like this are likely to accelerate the pace in finding other supply solutions to avoid instances like this in the future.

Draft community benefits guidelines for renewable energy projects

Industry and Government have long promised regional and community benefits will flow from the transition to renewable energy.

The most promising areas for large scale renewable generation projects – wind turbines, solar panels, pumped hydro – are often outside of established cities and industrial zones. Building new infrastructure necessitates disturbance and disruption, in areas which are generally valued for their peace and tranquillity.

This is seen as a particularly significant issue in Western Australia, where many projects are honing in on tree change regions within a few hundred kilometres of Perth.

There's often a (no pun intended) power imbalance at play. Project owners seeking social licence will generally know more about the value of a particular region than land owners, land stewards, or the community at large.

Recognising this, the Western Australian Government's PoweringWA team within the newly-established Department of Energy and Economic Development (DEED) released a *Draft Guideline on Community Benefits for Renewable Energy Projects* in May 2025. Industry, interest groups and the general public are invited to make submissions to the draft Guideline until August 2025.

Central to these guidelines is a recognition by Government that the scale of direct benefits an impacted community can expect to enjoy are not like those typical of minerals and energy, agriculture or manufacturing projects which are the sorts of activities the regions are used to hosting:

> *The larger benefits of renewable energy infrastructure are often strategic and shared across the State, including major industries and export sectors. Unlike other projects which have high levels of employment and economic activity created throughout the life of the project, renewable energy projects are characterised by large assets with much lower ongoing activity in the surrounding regions.*

The Guidelines put forward a broad characterisation of what may constitute a regional benefit, often centring this on local investments and supports funded by payments made by a project owner. The Guidelines include a guide "price" of between $500 and $1,500 per MW per annum for wind turbines and $150 and $850 per MW per annum for solar farms.

These are relatively modest values. ACIL Allen calculates accounting for these payments in a feasibility model may add between 0.1% and 0.7% to the upfront capital expenditure required for a new solar or wind generation project of typical size.

Recognition of these impacts, and a policy to help set the rules of engagement, is an important step towards unlocking some of the pragmatic challenges in developing new renewable energy projects.

You can read more about Community Benefit Guidelines here.

Read more

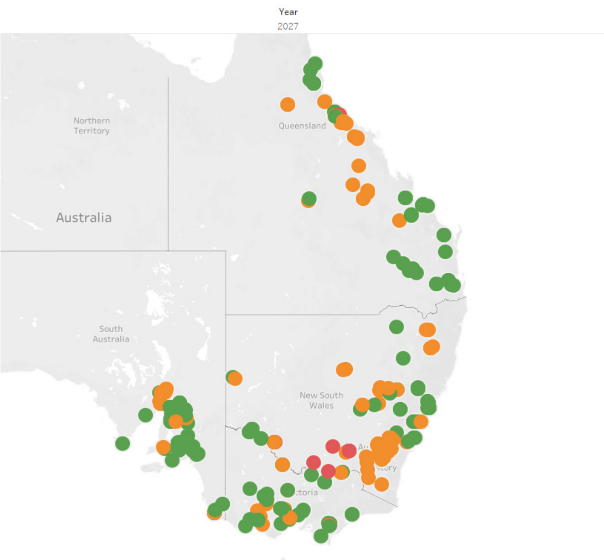
What's ahead: MLF and congestion risk over the short to medium term

As the energy transition accelerates, the grid is set to undergo significant structural change. Over the next 10–15 years, key questions are emerging for generators, developers, investors, and government bodies.

- How will MLFs shift as the generation mix, storage, and transmission evolve?
- Which parts of the network are becoming increasingly congested and why?
- What role will REZ development, storage build-out, and major transmission projects play in reshaping market outcomes?
- Are there early signals of grid risk or revenue volatility?
  See our map teaser on the right showing projected MLF changes across the NEM for 2026–27.
- What should projects be doing now to future-proof investment decisions?
- Are current project locations likely to remain favourable as the system transforms?
- Where are the best locations to build a project – and why?

We've been helping clients explore these questions through detailed modelling and scenario testing, drawing on the latest AEMO network data and project pipeline data and our own internal models.

Curious about how the grid is likely to change and what it could mean for your project? We'd be happy to chat.



Projected MLF reductions 2026–27 Outlook

Legend

Green: <1.5% decrease
Orange: <10% decrease
Red: <25% decrease

Projected MLF reductions across the NEM highlight emerging pressure points as new generation connects and the impact of new transmission, such as PEC Stage 1 and the Victorian minor augmentations.

Colour-coded by indicative magnitude of decrease between 2025–26 and 2026–27. Some regions are holding up better than others, while others are starting to show signs of high degradation. This can have a major impact on revenue certainty and project economics, particularly for merchant-exposed assets.

ACIL Allen undertakes regular RIT-T assessments

ACIL Allen deploys the Plexos modelling platform where least cost planning approaches to modelling are required, such as in Transmission Investment Test for Transmission (RIT-T) assessments.

Plexos is a globally recognised energy market simulation engine providing analytics and decision-support across electric, water, gas and renewable energy markets.

Recently, ACIL Allen has been engaged by clients such as Transgrid, the Australian Energy Regulator (AER), and APA, to undertake RIT-T assessments of network and generation assets in the National Electricity Market (NEM).

ACIL Allen has developed an in-house model for RIT-T assessments, which draws from the Australian Energy Market Operator (AEMO) Integrated System Plan (ISP) model. The AEMO ISP dataset forms the basis for the detailed long-term (DLT) planning component of the ISP and has been used in the past as the basis for RIT-T assessments.

ACIL Allen's modelling framework allows us to model the NEM at three levels, encapsulating long-term investment (typically in 7-year steps), medium-term operational decisions (typically in annual steps), and short-term operational constraints (typically in hourly steps):

The detailed long term (DLT) planning component within Plexos is used to produce the generator and transmission development program, which is consistent with the RIT-T application guidelines. The DLT divides the modelling horizon into multiple steps (4, seven-year blocks) which are optimised sequentially. The shorter optimisation windows allow a chronological optimisation of each day of the modelling horizon that preserves the original chronology of the demand and renewable resource time series, ensuring a more detailed representation of demand and variable renewable energy (VRE) variability. Demand and VRE profiles are represented using a fitted chronology.

The DLT utilises a sub-regional representation of the NEM as shown in the figure to reflect current and emerging intra-regional transmission limitations.

Secondly, the medium term (MT) component is deployed to optimise the operation of hydro storages subject to annual energy limits and storage targets, which are decomposed into a set of equivalent short-term constraints which can be applied in the third component (short term). The MT component models the market at an hourly resolution and divides the modelling horizon into annual steps, which are optimised sequentially. Demand and VRE profiles are represented using a fitted chronology.

Finally, the short term (ST) component is run to chronologically optimise dispatch at an hourly resolution. Generators are assumed to bid in at their short-run marginal cost (SRMC), consistent with the RIT-T guidelines. This component utilises the look-ahead function allowing short-duration storage facilities to optimise their operation across a 24-hour period.