Energy Security Board webinar, 9 September 2021

Forecast congestion in the National Electricity Market

Questions and answers

This document summarises and answers the key questions raised during the ESB's webinar on forecast congestion in the National Electricity Market, held 9 September 2021. The questions can be categorised as follows:

1. **Questions relating to the FTI modelling**
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1. Questions relating to the FTI modelling

1.1 Constraint set underpinning the analysis

Which constraints you have used in the analysis?

The thermal and stability constraint assumptions are provided by AEMO and is publicly available. These assumptions are a set of constraint equations which define the limits of the power system.

With the rapid roll-off of solar generation, to what extent do ramp rate constraints exacerbate price spikes (see slide 19)?

Our model is calculated on an hourly step basis and considers the ramp rates. Ramp rates do not have such a constraint effect on the system.

Re slide 10: How much of the constraint costs being presented are associated with power system security constraints which will be removed by other changes in the market?

Consistent with the ISP, the FTI modelling assumes that technical and regulatory solutions are in place to resolve system strength by 2030. Hence the forecast does not include any system-strength related congestion.

Please confirm whether the 2030 step change case study (constraint library set) includes the 2020 ISP recommended transmission project roadmap to that point in time i.e MarinusLink in 2028/29.

Yes. The modelling adopts the transmission augmentations associated with the ISP Step Change scenario (DP4). The following network augmentations are included: QNI Minor, VNI Minor, Central West Orana, EnergyConnect, Humelink and Marinus (cable 1).

Did AEMO's 2030 constraint library actually have any stability limits? Is this library available to industry? Is the FTI model identical to the ESOO 2021 version?

Yes, AEMO's constraint assumptions are publicly available. It includes stability limits. However, AEMO’s stability limits do not include synchronous plant constraints for inertia/system strength beyond 2025 as these issues are assumed to be resolved by other means.

The AEMO network constraint set only includes committed and anticipated inter- and intra-regional transmission projects which only go out to 2024/25. How would large coal retirements during 2025-30 and prospective network investment impact these results?

The network constraint set goes up to 2032. FTI’s modelling already accounts for the expected coal retirements and prospective network investments during 2025-2030 in line with AEMO's assumptions. FTI has not modelled any deviations to these assumptions apart from the three sensitivity scenarios outlined in the report.

1.2 Treatment of marginal loss factors

Was the marginal loss factor taken into account on your baseline modelling, where the MLF is a single number that measures the electrical losses from the point of generation to the regional reference node?

Yes, this has been taken into account. FTI's model considers marginal loss factors based on AEMO's ISP assumptions.

How do loss factors affect locational decisions?

Marginal loss factors are taken into account in FTI's long term optimisation, which seeks to identify the least cost combination of resources to meet forecast demand. .

1.3 Use of short run marginal cost approach to modelling

The least cost approach is likely to result in oversupply and spilling of solar which is a very different outcome to a market driven approach based on the profit of individual projects or portfolios. For example, the model installs solar even when unprofitable (due to very low daytime prices) just to reduce the amount of coal/gas dispatch and reduce the total cost of dispatch.

However, a developer is unlikely to build a solar project if unprofitable. A market based approach typically forecasts primarily wind projects instead of solar as they achieve a higher dispatch weighted price due to being available during evening peak periods. This would result in less congestion than your forecast

This issue relates to the way that the ISP modelling is undertaken. The ISP, consistent with the transmission investment framework, is based on least cost rather than market driven decision making. That said, the least cost model will fully recognise the value of diversity, both between wind and solar and between different locations. The modelling includes future technology cost reductions and a considerable amount of storage by 2030, so the preferred technology mix can change over time The FTI modelling simply attempts to replicate the ISP modelling (as updated for latest inputs and assumptions that were available at the time). Ideally, the market design would align the profitability of individual projects with the least cost solution..

Is it not appropriate to determine policy questions entirely from total resource cost impacts, rather than prices, which represents a transfer?

Our analysis focusses on total resource cost impacts, however, we wanted stakeholders to understand that actual price impacts are likely to be different from the outcomes of a SRMC modelling exercise.

Why have FTI used a "least cost" approach to determine the new capacity mix similar to the AEMO ISP? This is likely to result in oversupply and spilling of solar which is a very different outcome to a market driven approach based on the profit of individual projects or portfolios.

We asked FTI to use AEMO's published inputs and assumptions to replicate the outcomes of the ISP step change scenario, and then do a deep dive into the congestion outcomes associated with that scenario in the year 2030. We didn't attempt as part of this exercise to extend FTI's modelling beyond those matters already considered by AEMO. The ISP results are highly relevant because, under the actionable ISP framework, they are used to drive transmission investment. We acknowledge that price modelling would give a different result, it is not clear that the balance of resources would be the primary change. The optimization does take into account the value of different technologies to the system and hence their role based on cost-benefit.

1.4 Reasoning for modelling an unconstrained scenario

Why has the model determined the optimal capacity mix without any constraints implemented? Constraints need to be factored in as developers would not develop a project which is curtailed significantly as this would not be economical. With constraints implemented less solar capacity would be installed as congestion is more likely. Why would you build so much solar to be constrained off?

We asked FTI to model to identify the extent and calculate the costs of congestion in 2030 under the step change scenario. To do this, FTI modelled the unconstrained case and then the constrained scenario – the difference is then the impact of network congestion. Importantly this approach differentiates between generation that is not dispatched because it is not needed (i.e., spill) and generation that it is not dispatched due to congestion. Both scenarios used the same mix of generation projects and the same level of customer demand. FTI then measured the difference in outcomes relates to the different operating patterns between the unconstrained and constrained case.

The amount of large-scale solar build in FTI's model is based on the outcomes of the ISP. The ISP assumes that the market provides price signals to incentivise the least cost combination of resources to meet customers' reliability and security needs.

Can you explain how the model results differ from a measure of the benefits of entirely unconstrained transmission, something that at the beginning of the presentation you said (and I agree) was inefficient?

In a high VRE power system, there need to be an optimal mix of generation and storage to meet the customer demand profile. That will mean that there are some occasions on which there is spillage of generation as there is not the customer demand or storage capacity to use it. That spillage is not congestion so by modelling first with no constraints and then looking at the difference with constraints, the modelling isolates the costs of constraints. You are correct that the modelling shows the difference between the (inefficient) unconstrained case and the (efficient) congested case. This suggests that the costs of congestion are less than the costs of building them out, or else the ISP modelling would have recommended further transmission augmentation.

1.5 Treatment of different technology types in the modelling

Is the solar being constrained off large-scale or rooftop solar?

Large scale solar. The demand used in the step change scenario is the customer demand net of rooftop solar.

How will modelling change if storage in congested REZs is Pumped Hydro rather than batteries?

The long-term expansion model determines the optimal mix of pumped storage and batteries. If pumped storage is preferred to batteries in the same REZ, then the new pumped storage capacity will be under the same constraint equations.

How does FTI represent changes in demand behaviour between constrained and unconstrained case?

Demand is based on AEMO's assumptions and is fixed. However, FTI considered the behaviour of storage capacities (pumped storage and batteries) and demand-side participation in their hourly dispatch modelling.

1.6 Assumptions with respect to the location of new generation

How did FTI determine the specific locations of new entrant generators? Was a feedback loop based on congestion in the short-term model applied to optimise these decisions?

The expansion model determines the specific locations of new generators considering the capacity factors of the location and connection costs. Inside a REZ, we split new renewable units according to the allocation key given by AEMO.

How did FTI handle generation locations which do not have a shadow connection point available in the ESOO constraints set?

The capacity expansion model only considers building new generators in locations that have a shadow connection point in accordance with AEMO's inputs and assumptions. The number of locations the model chooses where to build are limited and already included in the ESOO constraints.

The results of modelling of this nature are highly dependent on the choice of location for new entrant generation at a substation level. Could FTI please clarify how this was addressed?

See above.

1.7 Transmission projects included in the modelling

Does the $1 billion include the cost to build additional transmission?

No, the $1bn estimate only includes the impact on cost to load.

Did you estimate the cost of new network infrastructure to avoid the $1bn constraint cost?

No, FTI's modelling relies on AEMO's ISP assumptions which already considers the optimal development path. Additionally, the constraint set provided by AEMO already includes the reinforcement to the intra-regional network.

Wouldn't $1 billion in congestion costs be more than sufficient to pass the RIT-T?

It is true that persistent congestion can justify network investment in the RIT-T. As the congestion is spread across the whole NEM, and given the cost of large-scale transmission, it appears that the optimisation model did not identify any additional network investment to be on the optimal development path. A RIT-T analysis should broadly align with a least cost optimisation.

The 2020 ISP whilst setting out the major transmission projects, the ISP does not set out the additional projects that would deliver the new energy flows to the load centres. In the modelling, how was the new transmission that will be needed to deliver energy to the load centres determined. Lack of these feeder networks would tend to increase congestion.

Our modelling relies on AEMO's ISP inputs and assumptions which sets out an optimal development path for the step change scenario (and other scenarios). The constraint set provided by AEMO already includes the reinforcement to the intra-regional network.

What are your intra- and inter-regional network augmentation assumptions during 2030?

Intra-regional assumptions are based entirely on AEMO's constraint assumptions which are publicly available. These assumptions reflect the intra-regional network investments.

FTI's inter-regional assumptions follows the ISP Step Change scenario (DP4). The following network augmentations are included: QNI Minor, VNI Minor, Central West Orana, EnergyConnect, Humelink and Marinus (cable 1).

How has intra-regional transmission been addressed as the ISP only looks at inter-regional transmission. Would expect intra-regional transmission would be added to minimise congestion.

AEMO's constraint set from the ESOO reflects intra-regional transmission investments through the associated constraint equations.

No additional transmission upgrades apart from ISP inter-region upgrades are assumed. As proposed by AEMO (as actionable projects) and the TNSPs, additional transmission upgrades are necessary to build the AEMO step change capacity. The AEMO ESOO 2020 constraints only includes constraints for existing lines and these would change when new transmission upgrades are built to accommodate the step change. The AEMO ISP constraint set only includes the major RIT-T inter-regional upgrades.

The FTI modelling included all actionable ISP projects scheduled between now and 2030 including intra-regional ones (e.g. Central West Orana). The key takeaway is the trend - even if AEMO had perfect foresight and we end up with both the generation and transmission associated with the least cost development path under the step change scenario, we would still see a lot more congestion than at present. Hence, we need to be good at managing congestion.

What other transmission network upgrades were included to complement the augmentations in the ISP?

We rely on AEMO's constraint set. These equations consider the additional intra-regional network investments above the ISP.

1.8 Questions about modelling results

Why do prices in Tasmania rise the most of all States in a constrained scenario?

In the unconstrained case, Tasmanian prices are more correlated with its own hydro and wind units, but in the constrained case, Tasmanian prices are predominantly correlated with thermal generators.

Are the differences in generator output in the constrained and unconstrained cases due to disorderly bidding, or the locational choices of the solar plant that gets constrained off (see slide 18)?

The modelling shows the change in output profiles that arises because there is insufficient transmission network capacity to transport the least cost combination of resources at a given point. I.e. it's neither disorderly bidding nor locational choices as the model assumes economically efficient bidding practices and location decisions. The level of congestion shown in the modelling is the forecast efficient level (apart from the sensitivities) given the cost of building new transmission.

Re slide 19 - Is the reduction in wind output totally due to the lack of network capability and independent of thermal generation output, ie no impact of disorderly bidding, just lack of transmission.

Yes. The model assumes short run marginal cost bidding, which means that it doesn't show the impact of disorderly bidding. Under the current market design, the actual costs of congestion are likely to be significantly higher than the best-case scenario assumed in the modelling (and in the ISP). The key take away is that since congestion is going to become a lot more common in the future, we need to get better at managing it.

If the modelling bids plant at SRMC, why do the results show high price spikes?

The high price spikes may be caused by (1) the offers of thermal power plants which may have high start costs if these units had a cold start; and (2) demand side participation which has a high offer price.

Is the percent of hours constraint each month the wrong / misleading metric by which to measure constraint? Should this not be reflected on a percent of generation holistic basis?

There are a number of ways to present the analysis and we tried to come up with a metric that would be easy to understand. The percent of generation measure also has the potential to cause confusion as there is a difference between spilled generation (which is surplus to requirements) versus congestion. Given the volatile market outcomes that can arise in the presence of congestion (which are very difficult to model) we think the key question is "how often does it happen?"

How does the headline number of $1.05b in congestion costs for FY30 in NEM compare to FY20? Is it 5x higher?

Yes that is correct (in real terms - all our figures are in real 2020 terms).

What happens to the $1.05b figure if the top six NSW solar farms impacted are relocated to another REZ? (i.e those six impacted by >40% of their potential). How robust is the $1.05b figure to locational signals in the NEM and in this study?

We can't provide a quantitative answer to this question as it would require a substantial additional modelling exercise.

However, the highly congested NSW solar farms are existing and/or committed projects, not modelled projects. The $1.05b figure is a best case scenario. The model places generation in the locations that deliver lowest overall cost given the relevant inputs and assumptions– it is able to have perfect foresight within the confines of the model. Reality is more messy and real life congestion costs are likely to be higher, particularly given the inaccurate locational signals under the current market design.*How much of the cost of congestion is from those few NSW solar plant?*

We would need to undertake further analysis by running the model with and without those specific plants to answer the question.

Slide 6. If we end up in a worst case scenario rather than a best case one, does that mean the benefits for reducing congestion will be higher?

Yes, that is correct. The key takeaway from the FTI modelling is the trend - the cost of congestion is likely increase over time, so we should design a market that can manage it efficiently.

The cost of congestion does not go up linearly as shown in the report. At some point, you would build infrastructure to accommodate new capacity and the cost of congestion would go down.

The underlying logic of this point is correct. However, the UK example, and the first few years of the Australian chart, use historic data. This suggests that at the aggregated level, there is a correlation between VRE output and congestion. The FTI modelling for 2030 incorporates the planned network expansion for the step-change scenario. In a high VRE system a higher level of congestion will be efficient.

Which software are you using to perform the modelling?

Plexos

1.9 Application of step change scenario and ESOO inputs and assumptions

Where you indicate the actual outcomes are above the "step change" scenario, could you be specific as to what features of the scenario are being exceeded. Grid delivered demand is well below the levels in the "step change" scenario and this would have a significant impact on the level of forecast congestion in the future.

Actual outcomes are above the step change scenario in terms of the projected investment in renewable generation. However we recognise that projected investment is an output, not an input to the ISP modelling, so it is more accurate to say that the actual outcomes are 27% above the least cost development path associated with step change scenario. The 2020 ISP did not include the NSW Roadmap and some other government policy decisions which means there will be considerably more renewable generation investment than included.

Network congestion is a function of both generation injection and one end and consumer demand at the other end. Lower consumer demand = lower network congestion.

The FTI modelling reflects the inputs and assumptions from the ISP's step change scenario together with the least cost development path (generation, storage and transmission) associated with the ISP's step change scenario. If demand is lower than forecast, the energy will be spilled rather than curtailed.

Contrary to the statements from the ESB, the ESOO does not set out a future transmission expansion model. The ESOO only includes in its modelling, network upgrades, including those set out in the ISP as priority projects, those network projects that have passed a RIT-T, have an approved AER funding application and have a notified TNSP Board committed project letter sent to AEMO. Projects that do not meet this criteria are not included in the ESOO modelling. As an example, HumeLink is not included in the ESOO reliability assessment calculation as a committed project. It is however included in the ESOO assessment as a sensitivity case.

To clarify – the FTI modelling adopted the most recent set of AEMO inputs, assumptions and scenarios that were available at the time. These were the inputs and assumptions that were applied to the 2020 ESOO (which were newer than the forecasts used in the 2020 ISP). FTI applied these inputs and assumptions in their version of AEMO's ISP model.

AEMO has a regular process to maintain and publish up to date forecasts for relevant inputs and assumptions such as generator costs, forecast demand and uptake of rooftop solar. These inputs and assumptions are used for multiple purposes, including the ESOO and the ISP.

2. Questions relating to the ESB's proposal for transmission access reform

2.1 Role of storage in alleviating congestion

What impact is considered by the location of storage - particularly ""virtual transmission"" where batteries at each end of TX can buffer/optimise the use of TX? It follows what is the value of "forward provisioning" putting batteries deep in the distribution to absorb VRE at times of low demand but high generation?

Can we do the sensitivity analysis with battery storage system that can show reduction in congestion too?

The ISP and FTI modelling already includes storage based on optimising the overall cost of supply including transmission, generation and storage capital and operating costs. In addition, FTI undertook a battery sensitivity which is described in their report (see https://esb-post2025-market-design.aemc.gov.au/32572/1629773972-fti-esb-forecast-congestion-in-the-nem-final-5-august-2021.pdf).

The ESB asked FTI to look at the impact on congestion if batteries decided to locate near the regional reference node (RRN) rather than in the REZs. Currently many batteries prefer to locate near load to make sure that they are not curtailed during peak price events, whereas the ISP assumes that batteries locate in the REZs where they can help to alleviate congestion. The results were quite nuanced and suggest that in the future we will need batteries both near load (where they can act as peakers) and near REZs (where they can help to firm renewable supply).

Consistent with the ISP, the uptake of distributed battery storage is an exogenous assumption in the FTI model. The behaviour of distributed storage is assumed to be optimised according to the constraints, load peak and RES peak generation.

The NEM has had a major utility battery operating under zonal pricing for 4 years and it seems to be doing well. How does this relate to your comment on disorderly bidding being a big deal for batteries?

Batteries are very versatile and have a range of potential functions, some of which are supported by the current market design and some which are not. To date the most successful batteries in the NEM have derived a lot of their income from FCAS markets, however that market is relatively small. Batteries have the potential to provide a valuable firming role to renewable generators, but at present they are incentivised to compete with generators to receive high prices (thus exacerbating congestion) rather than charging during periods of congestion (and soaking up the surplus VRE).

Won't requiring batteries to pay TUOS as per integrating storage proposal disincentivise storage which could reduce congestion?

The question of whether batteries should pay TUOS is not being considered as part of this process. Under regional pricing, storage is not remunerated for alleviating transmission congestion - instead it is rewarded for behaving like a generator.

Wouldn't constrained generators build more storage to adjust? Similarly is there more storage constructed to respond to high prices due to congestion?

The ISP and FTI modelling already include an optimal mix of generation, storage and transmission. There is scope for constrained generators to build their own battery behind the meter, however it is challenging to get the business case to add up. Under the CMM, merchant storage providers would be able to take advantage of the higher diurnal spread that you would get in a REZ under a local pricing model. In this case batteries would be rewarded for providing firming services and alleviating transmission congestion. In future we expect to see both "firming" storage located behind constraints and "peaking" storage in uncongested locations.

Can you please explain what work has been done on analysing the value of storage and particularly electric vehicles in soaking excess demand during the day and back feeding into the grid during the evening peaks? Particularly if this is embedded in the community where the power is being generated and used. This may require a suitable tariff structure to incentivise but could provide a valuable resource.

The ISP includes quite a lot of storage, battery storage and pumped hydro, as required to deliver the optimal outcome. FTI examined the issue of the location of storage and the answer was - it depends. Storage located out with the renewable generation can reduce congestion but storage close to load does not get congested itself. Both types of storage have value.

2.2 Discussion of locational marginal pricing

How can you state that zonal pricing always involves rent transfer from consumer to generators? If there is congestion at a major load centre that is not the RRN then those customers will pay a 'lower' zonal price than their nodal price?

All settlements with a region are based on the Regional Reference Price adjusted for losses. If a generator is constrained on, they typically bid unavailable in to avoid being dispatched at a price that is beneath their cost to supply. Instead they are directed on by AEMO, which means that they are eligible to receive fair compensation in accordance with NER 3.15.7, which is based on the 90th percentile price in the relevant region over the preceding 12 month period for the service or services that were provided in compliance with the direction. If that directed participant considers that it is still out of pocket after receiving compensation under clause 3.15.7, they can make an additional claim for compensation under clause 3.15.7B in relation to lost revenue and additional net direct costs.

Isn't your analysis actually just proving we don't need nodal pricing? You have shown exactly what's done today, which is to determine the potential volume of curtailment which is then incorporated into business cases. There is nothing here to show that there would be any difference under nodal pricing.

The objective of this modelling exercise is to highlight that congestion is likely to be an ongoing feature of the NEM and hence we need to learn to live with congestion. It does not make a case for any particular solution. The ESB is not proposing to introduce nodal pricing, except in rare circumstances where a party wishes to connect in a part of the network that is already congested.

Interconnector counter-flow problem is due to unsatisfactory network region boundaries. However the regional boundaries reflect Jurisdictional government decisions - they don't want large price differences within their jurisdictions. Given that political sensitivity, is it likely that the Jurisdiction governments will want nodal pricing?

The CMM-REZ model is not nodal pricing, even though it incorporates the operational benefits of nodal prices. Customers would continue to pay the RRP (unless they choose to be scheduled load in order to take advantage of cheaper local prices). Nearly all generators would receive a congestion rebate that is designed to deliver a financial outcome that is broadly reflective of the status quo, and more stable than at present where generators can suffer substantial curtailment due to subsequent entry.

The CMM only applies nodal prices to market participants that wish to connect in places that are already congested. Incumbent generators and generators that connect in places where there is transmission hosting capacity available receive a rebate.

2.3 Impact of five minute settlement

How will this modelling change with 5MS?

The modelling won't change as it emulates the ISP step change scenario, which is focussed on costs rather than prices.

Won’t disorderly bidding be much reduced once five minute settlements starts?

There are several different types of disorderly bidding. The five minute settlement reforms are expected to resolve 5/30 bidding, where market participants bid in a way that spikes the price in the last dispatch interval of a trading period. 5MS will not resolve the "race to the floor" bidding that sometimes occurs in the presence of congestion.

2.4 Interaction with contract markets

Do Power Purchase Agreements for renewables have any impact on disorderly bidding?

PPAs can make disorderly bidding worse. Poorly designed PPAs (for instance, those that do not take account of negative prices) can incentivise generators to maximise their output at all times irrespective of market signals. When prices are negative, counterparties end up paying the difference between the negative RRP and the agreed contractual price, when they should be getting paid to consume.

Will the analysis quantify the cost of reduced wholesale contract market liquidity under a nodal pricing model?

The objective of the modelling was to explore future congestion outcomes in the NEM - i.e. to identify the problem that needs to be addressed. It did not attempt to propose or assess any particular solution. However, the ESB would observe that the CMM-REZ is not the same as nodal pricing. Unless they choose to locate in already congested locations, generators will receive congestion rebates, which results in a financial outcome that reflects the RRP. As the CMM-REZ retains the RRP and reduces curtailment risk, it is likely that wholesale contract market liquidity will increase relative to the status quo, where liquidity is being undermined due to curtailment risk.

2.5 Interconnectors and counter price flows

Another way to reduce counter price flow would be to invest in network stability at interconnectors to prevent constraints at an interconnector from causing a price separation between regional reference nodes and hence remove the opportunity for negative residues to accrue in the first place. Wouldn't such a solution more directly resolve the issue of counter price flows?

Counter-price flows do not arise due to congestion on interconnectors – they arise due to congestion between the generators and the regional reference node.

Further, we note that investing in transmission infrastructure is an expensive way to solve a problem that is caused by flaws in the regulatory framework.

The problem arises because our market design is not granular enough to reflect what is actually happening on the power system - with the result that from time to time the amount paid by customers is less than the amount owed to generators. To stop the associated costs from growing too large, we switch off the interconnectors - with the result that the exporting generator gets curtailed, and customers in the importing region have to pay more expensive local generators to meet their supply.

Would a change in the formulation of constraint equation remove the frequency of counter-price flows?

A change in the constraint equation would change the overall dynamics and point of equilibrium of the model. The frequency of counter-price flows would be expected to change. Constraint formulation was subject to detailed analysis, consultation and ministerial decision early in the operation of the NEM. Alternative formulations raised security concerns.

We note that this change would represent a further distortion of physical network outcomes to address a mispricing issue. Accordingly, it's unclear that it would provide a better solution than clamping.

2.6 Impact of congestion on profitability

How is it possible for generators to be profitable in a congested area? Any examples?

The slide on incremental solar or wind investment demonstrates the "tragedy of the commons".[1] A potential investor could look at an additional solar investment in that case and accept they will be constrained (on top of any curtailment due to spillage) by only 5% of their total output. However other generators in the NEM would also experience higher congestion such that overall 55% of the additional generation is lost to additional congestion.

More for ESB than FTI. All this study has done has shown the step change ISP scenario is flawed. Those investments suffering significant curtailment won't actually be built because investors will use the exact

[1] Wikipedia describes the tragedy of the commons as "a situation where individual users, acting independently according to their own self-interest, behave contrary to the common good of all users, by depleting or spoiling that resource through their collective action."

analysis here. Justifying introducing a CMM because of a congestion scenario that will never arise makes little sense.

Under the current market design, clever investors can avoid congestion by locating in places where they cause others to be curtailed rather than being curtailed themselves. This is individually profitable but adds cost from a whole of system perspective. It makes investing in the NEM riskier than it should be and causes us to waste low cost renewable energy. The highly congested projects shown in the modelling are committed or existing projects, not modelled projects.

We note the opportunities for stakeholders to be involved in the development of the ISP as that drives network planning.

I don't agree that there is a tragedy of the commons situation in the NEM. Generators conduct MLF and congestion studies to assess the risk of congestion and losses before locating. If this situation were true then more generators would build in Broken Hill as there is excellent wind and solar resource there.

It is obviously true that that a new investor into Broken Hill would assess their congestion, losses and connection costs (which in this particular case, would all be related). However in considering only the congestion and other costs their project would cost in deciding whether to invest or not, they are not considering the overall impact of their investment decision on all parties. Others would also face increased congestion and lower loss factors as a result of that decision. That is the essence of the 'tragedy of the commons'. They also cannot know what other parties might decide to do in the future which would potentially reduce their access to market through more congestion or lower loss factors. One of the FTI's modelled scenarios sought to quantify that effect in 2030 for incremental investment.

2.7 Questions relating to CMM-REZ

Doesn't CMM cement this issue [of congestion caused by one party being felt by another]? It smooths the impact. CMM is not "last in first out".

CMM creates a two tier hierarchy - generators with and without rebates. Generators with rebates would receive an amount that is broadly the same as they do at present with the RRP. If generators still wish to connect after all the rebates are allocated, they would receive the LMP. It will be important to design the regime so that rebates are available for all beneficial projects.

CMM wouldn't change net cashflows to counter price flows.

CMM avoids the need for customers to pay to top up intra-regional settlement residue shortfalls, which means that we don't need to clamp the interconnectors. Under the CMM, generators that are affected by congestion receive (LMP*dispatch) plus a congestion rebate, where the congestion rebate equals (settlement residue*allocation metric e.g. availability). Any settlement shortfall would be absorbed by congested generators in the form of a smaller rebate. This is better for the congested generators than the status quo, where they would not get dispatched at all in the event of clamping. It's also better for customers in the importing state, as they can consume less expensive energy than they would if the interconnector was clamped.

The incentives to bid strategically remain with CMM.

We are not aware of any market design that removes all incentives to bid strategically. Experience in other jurisdictions suggests that the bidding incentives under CMM will be an improvement on the distorted incentives that we have now.

Won't market participants have more opportunity for disorderly bidding under nodal pricing?

No, because the price that they receive is more closely aligned with the price that they bid. At present it is rational for a generator that is subject to congestion to bid to the price floor because they know their bid will not set the price.

2.8 Disorderly bidding

In a high VRE world with all generators having a low marginal costs, wouldn't the negative impacts of disorderly bidding be low?

The efficiency impacts of disorderly bidding are random and it is true that in some cases they will be immaterial. However they can prompt AEMO to clamp flows which will have negative impacts. Even in a high VRE world, there will be a need for firming capacity (e.g. storage), and under the current market model, it would be rational for storage to engage in race to the floor bidding in order to take advantage of the price volatility associated with congestion.

Surely firming services would only be required in-service when VRE output is low, therefore the assumption that disorderly bidding where low cost VRE generation is displaced is questioned.

The current market design does not reward firming services commensurate with the overall benefit that such services offer to the system. The regional reference price acts to smooth the more volatile local prices that arise in congested locations, which means that the spreads available to storage is not as great as they would be under a local pricing model. Rather, storage is rewarded for providing FCAS & peaking services, which means that it is rational for them to try to be dispatched when congestion causes prices to spike.

Can't disorderly bidding be managed in other ways - for example by increasing the market floor, which was primarily set low to manage de-commitment of coal power stations, likely to be less important in future?

Increasing the market floor will simply change the price that market participants race to when racing to the floor. It would not stop high cost plant from being dispatched ahead of low cost plant due to the operation of the tie breaker rule. The flaw in the market design is that the market auction is not discovering cost through participants' bids.

Isn't the issue here that disorderly bidding isn't just VRE vs VRE, it is impacting dispatch of battery (or electrolyser, flexible load)?

Yes, that is correct. The list of affected parties would be longer and include hydro generation and storage. .

2.9 Alternative options for managing congestion

Is multiple RRN per region an option? It should be able to resolve inter, intra-regional congestion.

Yes, this is a potential solution. However, this approach would entail low RRPs during periods of high VRE output, and contractual disruption each time we change the regional boundaries, which is why this option has received limited support in the past. The CMM is designed to avoid these problems by retaining the RRP as the price paid by customers, and granting a congestion rebate to eligible generators so that they are kept broadly whole.

Could this not be resolved far more easily, cheaply, and fairly via strategically locating storage assets at the relevant constraint points to enable capture of otherwise constrained / spilled renewable generation, which could then be time / shape shifted to be delivered via the same network without constraint in the lower renewable periods?

First, one of the advantages of CMM relative to COGATI is that it is much cheaper and easier to implement. It is also arguably fairer than the open access regime where prudent investors can have their projects "cannibalised" by subsequent investments which do not deliver whole of system benefits.

Second, at present, the market does not adequately reward storage assets for operating in the suggested manner, which means they would require costly subsidies. An important benefit of CMM is that it will create new opportunities for storage assets to be paid to alleviate transmission congestion since they will be able to selectively target the most congested locations which will have a greater diurnal spread in their LMP.

Has there been any modelling done around what the prices would look like if congestion were avoided through less aggregate generation being constructed, and comparing that with the BAU congested scenario?

The ISP models the least cost combination of resources to deliver a reliable electricity supply based on forecast demand. FTI were not asked to develop alternative options. We note that considerable generation in the ISP is driven by various government policies.

2.10 General comments

All electricity market designs have strengths and weaknesses. Rather than just focus on perceived NEM shortcomings, it would be more balanced to provide a comparison of market design strengths and weaknesses. Do you, or will you, provide such a "fair comparison" of market design choices?

We recognise that all electricity market designs have strengths and weaknesses and that there is no silver bullet. The ESB’s Post 2025 process (as well as many other reviews by the AEMC and its predecessor organisations) has attempted to show why the current access regime is unsustainable and a key underlying cause of the risk and uncertainty faced by NEM investors.

Did you speak to any investors about how they model congestion?

The issue at point is not whether investors do a good job of modelling congestion. FTI’s modelling exercise demonstrates that (a) the system is being planned to have higher levels of congestion “built-in” as this is an efficient characteristic of a high VRE power system and (b) there is a discrepancy between what might be a profitable investment decision from an investor's perspective and what is in the best interests of the broader power system.

Does the UK/EU congestion management model of socialising congestion costs across everyone result in lower costs for consumers (from congestion) than the NZ/US model?

FTI's scope of work did not consider benchmarking the different congestion management approaches globally. However, from FTI's perspective, the NZ/US model would lead to lower costs than the UK/EU model as the value of congestion between two nodes is revealed. A UK/EU approach also requires supplementary policies to drive efficient location.

Was the modelling completed prior to or during the pandemic and the wide-spread adoption of remote working arrangements and commercial shut-downs? If during, what impact did the past 18-20 months have on the modelling?

Our modelling is focussed on future congestion in the NEM and uses the inputs and assumptions from AEMO's 2020 ESOO step change scenario, which were the latest available inputs and assumptions available at the time. AEMO is better placed to comment on the impact of the pandemic.

By reading the 2021 ESOO, underlying load at NEM will be around 30-35GW, and minimum demand will be 4-6GW. Could you please explain the rationale behind on planning the transmission network for 72GW installation capacity? Is it provision for future electrification or Hydrogen load ?

The ISP models the least cost combination of resources to deliver a reliable electricity supply to meet forecast demand. A key feature of a high VRE power system is that a much higher nameplate capacity needs to be connected to the system given the lower capacity factor of wind and solar compared to conventional generators plus the need to connect storage. The high VRE system still delivers a relatively low cost solution because of the very low operating cost of wind and solar.

The demand forecast used is that in the 2020 ISP step-change scenario, details of which are available on AEMO's website. This includes forecasts for growth of electric vehicles and electrification of the economy relevant to the scenario and information available at the that time.