REVIEW

Australian Energy Market Commission

INTERIM REPORT

TRANSMISSION ACCESS REFORM: UPDATED TECHNICAL SPECIFICATIONS AND COST-BENEFIT ANALYSIS

7 SEPTEMBER 2020

INQUIRIES

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Reference: EPR0073

CITATION

AEMC, Transmission access reform: Updated technical specifications and cost-benefit analysis, 7 September 2020

ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

EXECUTIVE SUMMARY

1 The Coordination of Generation and Transmission Investment (COGATI) review is focused on examining when the transmission access framework will need to change, and, if so, what it will need to change to.[1]

2 In March 2020 the ministerial forum of Energy Ministers (formerly COAG Energy Council) asked us to continue designing the access reforms as part of the Energy Security Board's (ESB) post 2025 market design process. We are taking the lead on this particular work stream of the ESB's 2025 project, and are designing the access model as part of this process. We anticipate providing core elements of a rule change package by the end of the year, coordinating with the ESB's 2025 project.

3 The proposed transmission access reform involves the introduction of locational marginal pricing (LMP) and financial transmission rights (FTRs). An overview of these core elements and how they work is presented in part two of this executive summary. Part two also sets out a summary of all of the preferred design specifications and the reasons for them. Part one sets out the process to date, how it forms part of the ESB's 2025 work, the decisions and information in this paper, and next steps in the transmission access reform process.

4 PART 1

5 The process to date

6 The inaugural review (final report published in December 2018), concluded that transmission frameworks need to change so that our regulatory frameworks can keep pace with the transition currently under way in the national electricity market (NEM), moving from a system that suits large, centrally located generator, to one that has many relatively small and geographically dispersed generators. The second review – the subject of this Report – outlines the path forward to reformed a transmission access regime that integrates new generation and storage into the national grid in a way that is reliable, secure and works in consumers' best interests.

7 In March 2020, the Commission published a detailed technical specifications or blueprint for the proposed access model. The blueprint set out a cohesive model that implements LMPs and FTRs in the NEM. It incorporated stakeholder feedback, the latest thinking and analysis, as well as the learnings from the accompanying NERA Economic Consulting report that assessed the costs, benefits and learnings from implementing LMPs and FTRs in a number of overseas jurisdictions.

8 A Transmission Access Reform update paper was published alongside the blueprint. That paper set out the need for reform given the transition under way, the role the reform plays to repurpose and set up the transmission frameworks for the future, and the benefits of reform to market participants and consumers.

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1 It is in response to terms of reference received in 2016 from the ministerial forum of Energy Ministers (formerly COAG Energy Council). The Forum asked the Australian Energy Market Commission (the Commission or AEMC) to implement a biennial reporting regime on these matters.

9 *What's in this paper?*

10 The ESB's 2025 consultation paper, and this report, along with the accompanying consultant reports builds on the March papers. Together these papers provide:

- further context on the need for the reform, and how it relates to the ESB's 2025 market design work
- further updates and decisions on the preferred design specification
- a summary of NERA's NEM-specific bottom up economic modelling of the benefits of implementing the reform in the NEM, and
- initial indications of the implementation costs of the reform.

11 *Updated design specifications*

12 The updates in this paper include the preferred design specifications for major elements of the transmission access reform, including:

- the formulation of the regional price at which non-scheduled participants (ie, the majority of load) will be settled
- how losses should be reflected in the wholesale electricity price
- whether FTRs will be used to manage risks associated with losses
- how long in advance FTRs are available for
- FTRs will be available for purchase at a reduced number of nodes
- the length and nature of transitional FTRs.

13 In addition to transitional FTRs being provided to market participants once the reforms commence, the implementation time is proposed to be coordinated with other reforms arising from the ESB's post-2025 market reforms, which would be in the order of four years from the time the final rule is made.

14 In developing the model that we have set out in this paper, we have considered significant stakeholder feedback that has been provided to us through:

- 151 written submissions on four papers since June 2019 (consultation paper in March 2019; directions paper in June 2019; discussion paper in October 2019; update paper in March 2020)
- 12 technical working group meetings
- three public forums
- more than 200 bilateral meetings and workshops with a wide range of stakeholders.

15 This feedback has made a significant impact on the design presented in this report. In particular, it has shaped the preferred design specifications regarding decisions around firmness of FTRs, to make FTRs available up to ten years in advance, simplify the model in the early years by only offering option FTRs, only making FTRs available along a reduced number of possible routes, and decisions around the timing and process for implementation and transitional arrangements.

16 *Cost Benefit Analysis of Access Reform: Modelling Report*

17 A report titled *Cost Benefit Analysis of Access Reform: Modelling Report* by NERA Economic Consulting is published in tandem with this paper. The report provides a comprehensive assessment of the costs and benefits of locational marginal pricing and financial transmission rights in the NEM through bottom-up electricity market modelling. The methodology for the modelling was discussed with the technical working group and is fully explained with the published report. There are a number of key points that are important to be drawn from the analysis.

18 First, the benefits (excluding implementation costs) of introducing the reform are substantial. The total consumer benefit estimated by NERA is between **$6.2 and $8.2 billion** over 15 years operation of the NEM from 2026 to 2040, in net present value terms.

19 Second, the benefits are not restricted to one particular effect of transmission access reform in the NEM. They derive from changes in how power is dispatched in real time, how investments are located over the medium to longer term, how prices are likely to settle with the move to LMP and competition benefits to the extent that FTRs allow for increased competition across different regions in the NEM. There are also additional benefits from the adoption of dynamic loss factors.

20 Third, the rate of accrual is correlated with the rate of change in the NEM. The more retirement of existing plant expected, the earlier this occurs, and the greater the rate of investment in new generation and storage assets, the greater the benefit from locational signals that better indicate where investment would best be located on the network. This suggests we need to implement the transmission access reforms in a timely manner, in coordination with the other reforms being considered through the ESB's post-2025 market design work. To that end, details of the reforms should be completed as soon as practicable, so that the industry has time to prepare for the changes.

21 Finally, NERA's latest and previous quantitative analysis is consistent with both long-lasting, practical international experience of LMPs and FTRs. The analysis concludes that the total consumer benefits of the reform are likely to be in the range $414 - 662m per annum. NERA's previous review of analysis of similar reforms overseas implied a range of $739 - 1,127m per annum in total consumer benefits (inclusive of social benefits or reductions in system costs and wealth transfers or reductions in prices and estimated ex ante). It reinforces the view that there are significant benefits from pricing based on marginal costs and consumers are clear beneficiaries of transmission access reform. As such, the reform is likely to contribute to the achievement of the National Electricity Objective (NEO).

22 Implementation cost estimates

23 With this paper and the March paper outlining the core design specifications for transmission access reform, we can engage with industry to obtain detailed assessments of the direct implementation costs associated with the reform. This will involve engaging a consultant to conduct extensive discussions with AEMO and with market participants during Q3-Q4 2020.

24 In the meantime, we have obtained preliminary cost estimates for both AEMO and market participants through engaging Hard Software to provide preliminary figures on the costs of different reform options being considered. A report titled *A preliminary indication of the*

Information Technology costs of Locational Marginal Pricing by Hard Software, completed for the Commission, is published in tandem with this paper. The preliminary figures provide a benchmark to compare with NERA's assessments of the benefits of the reform and help to inform decisions in respect of specific design elements within the reform.

25 The initial, preliminary high-level benchmarking figures provided by Hard Software, suggests that a well-planned implementation in the NEM could cost in the order of $60-$70 million for AEMO's costs alone. This is supported by similar figures being estimated in the introduction of similar reforms in Ontario.

26 The Commission considers that these figures are on the lower side of what a more detailed assessment of the cost of implementation is likely to reveal. However, they are an order of magnitude below the estimated benefits of the reforms. In order to further substantiate this assessment the AEMC would welcome stakeholder views on the costs that they anticipate would be involved in the reform.

27 How does this fit in with the ESBs 2025 reform plan?

28 The proposed transmission access reforms are designed to form part of the ESB's roadmap to provide a complete set of congestion management arrangements in the long term interests of consumers. The changes that have already been actioned or that are underway include:

1. The completion of the **actioning the ISP** work that was recently implemented by the ESB, and which will improve the previous transmission planning and investment arrangements so that we get the right amount of transmission in the right place at the right time, balancing the cost of congestion with the cost of transmission infrastructure to alleviate it.
2. The ESB is consulting on arrangements that augment the ISP work to focus on planning of Renewable Energy Zones (REZs), reflecting the importance of co-ordination with generation developers and the potential for local community impacts.
3. Longer term, the implementation of **locational marginal pricing** and **financial transmission rights** (ie, the subject of this report), will provide signals and better information and incentives to improve siting decisions of generators within the transmission network so it is better utilised, and also give generators the ability to manage the risks relating to transmission congestion.

29 The changes are also well suited for the potential changes being developed through the ESB's NEM 2025 project. Notably, changing transmission access arrangements – by implementing LMP and FTRs – is a key pillar of any future market design for the rapidly transitioning power system. It is foundational to deliver lower prices for customers. LMP and FTRs will complement and in some cases enhance and enable options being considered by the ESB in its market design work program, as detailed in the ESB's 2025 paper.

30 Evidence from overseas markets where similar reforms have already been implemented, or will shortly be implemented, demonstrate the arrangements are flexible and can accommodate a variety of different market structures and designs. For example, LMP/FTR regimes exist in markets that have centralised capacity mechanisms and centralised ahead markets, and those that do not.

31 Next steps

32 We anticipate providing core elements of a rule change package by the end of the year, coordinating with the ESB's 2025 project. To help develop this package, the Commission welcomes feedback from stakeholders on the matters discussed in this paper. We also encourage stakeholders to contact the project team to continue to engage bilaterally. Of course,given that the changes would be progressed through a rule change process during 2021, stakeholders will have plenty of opportunities to continue to engage and provide input on these matters.

33 We will be holding two public forums with stakeholders in September 2020 regarding:

1. NERA cost-benefit modelling. NERA will present the results of its market modelling and allow stakeholders to provide feedback and ask questions about the methodology and results.
2. Simplified model of access reform. NERA will present a simplified model of the proposed reform that allows stakeholders to see and test how the access reform works under different conditions.

34 Details regarding dates and how to register for the public forums will be available shortly through our website and stakeholder emails.

35 The Commission will also be progressing stage two of its implementation cost analysis. This will build on the initial estimates provided by Hard Software by providing more detailed analysis. This will involve engagement between the Commission's consultants, AEMO and participants.

36 PART 2

37 This section briefly outlines each of the core design features for LMPs and FTRs.

38 Prices faced by market participants

39 Scheduled and non-scheduled market participants would no longer be settled for their energy at a region wide price multiplied by a static marginal loss factor. Instead, they would be settled at the LMP at their location. LMPs are the incremental change in the cost of dispatch of meeting an incremental change in load at that location. These LMPs differ to one another as a result of losses and congestion, which impact different locations differently across the transmission network. The marginal effect of losses would be dynamically included in the LMPs, replacing the static marginal loss factor regime. This will send better locational signals and information to participants, enabling them to make better investment and operational decisions, using the transmission network more effectively.

40 Non-scheduled market participants would continue to face a region-wide price, but that price would now be calculated as the volume weighted average price (VWAP) of the LMPs of non-scheduled market participants. This will minimise impacts on the financial contract market and promote liquidity.

41 Settlement residues

42 The above pricing arrangements would result in settlement residues as a result of congestion

and losses - the difference between what load pays and what generators are paid for energy.

43 The settlement residues relating specifically to losses would be calculated and returned directly to consumers through an offset to their transmission use of system (TUOS) charges - just as intra-regional settlement residues (which relate to losses) are currently returned to consumers.

44 The remaining settlement residue relating to congestion would be used to back financial transmission rights. This will provide market participants with a way to manage congestion, and result in direct benefits to consumers by offsetting their TUOS charges, as well as indirect benefits to consumers due to generators having more certainty over their revenue.

45 Financial transmission rights

46 FTRs would initially be introduced related only to the cost of congestion, that is they would not cover losses. To facilitate this, prices exclusive of losses would also be calculated for each node where FTRs are available for purchase.

47 FTRs would:

- pay out to the holder the congestion related differences in the two LMPs (or VWAPs) defined in the FTRs in each trading interval covered by the FTR
- be three months long and be available up to 10 years in advance
- be available to payout in all trading intervals of a 24-hour day, or at predefined time periods during a 24-hour day
- pay out only on positive price differences
- only be available between a pre-defined list of combinations of LMPs/VWAPs.

48 AEMO would sell these FTRs by auction through a series of tranches, with a limited number of FTRs being made available well in advance, and more being released progressively. The design of the FTRs seeks to balance what participants have said they ideally want, but also make the products relatively simple to start with. Products could be refined and added to over time as participants become more familiar with the regime.

49 The FTR auction would maximise the revenue generated through the sale of FTRs, subject to the FTRs that are being sold being 'simultaneously feasible'. That is, the total FTRs sold across all tranches would be consistent with an estimate of physical transmission capacity. There would be no reserve price for the sale of FTRs.

50 AEMO would maintain a register of FTRs bought and sold in the auctions and secondary market and the associated prices. Anybody, including participants who are not generators, retailers, or other physical participants in the energy market, would be able to purchase FTRs through the auction providing they meet registration criteria. There would be no restrictions on trading FTRs on the secondary market. This would promote transparency and liquidity in the FTR market.

51 FTRs would replace the current inter-regional settlement residue auction products (colloquially known as SRA units). The FTRs are firmer than the existing SRA units and so inter-regional financial contracting would be promoted.

52 If the actual transmission capacity within a dispatch interval is consistent with the capacity assumed when the FTRs were sold, then it is mathematically guaranteed that the settlement residue relating to congestion in that dispatch interval is greater than or equal to the FTR payouts.

53 Because the settlement residue in a dispatch interval is *at least greater than or equal to* the FTR payouts when the transmission capacity is as expected when the FTRs are sold, on average there will be some settlement residue left over, even having made the FTR payouts. This leftover settlement residue, plus the revenue from the auction of the FTRs, is used to back FTRs if the capacity of the network is less than that assumed at the time the FTRs were sold and so the settlement residue arising in the dispatch interval is insufficient to do so.

54 TNSPs could be provided improved incentives, via better focussing the existing service target performance incentive scheme (STPIS), to maintain transmission capacity so that FTRs are more frequently backed without having to use the auction revenue or leftover settlement residue. This will mean that it is more likely that the transmission capacity will be available at times when the market needs it, with the incentives on TNSPs being sharper.

55 At the end of a predefined period, any remaining settlement residue and auction revenue not used to back the FTRs is returned to consumers, via an offset to their transmission use of system (TUOS) charges. In the unlikely event that the settlement residue relating to congestion over the period, plus the auction revenue from the sale of the FTRs, is insufficient to cover the FTR payments, payments would be scaled back accordingly, and consumers would not receive any offset for that particular period. Quantitative analysis has suggested this is unlikely.[2]

56 Changing the existing regional pricing model represents a significant change to the NEM design. But, LMP and FTR markets of broadly the design outlined above are common and well-established for decades overseas in a variety of different settings. These changes have been progressively implemented overseas where it was also necessary to improve market efficiency. The experience from other market allowed them to be implemented with confidence that the challenges could be met, and the benefits delivered, as is the case here.

57 Comparison to the current arrangements

58 While the introduction of LMPs and FTRs is a substantial change to the current arrangements, many of the concepts, such as settlement residue and FTRs have direct analogies.

59 Prices already locationally vary across the NEM as a result of varying marginal loss factors applied to the regional prices for generators and load connected within each region, and different regional prices between regions. This results in settlement residues.

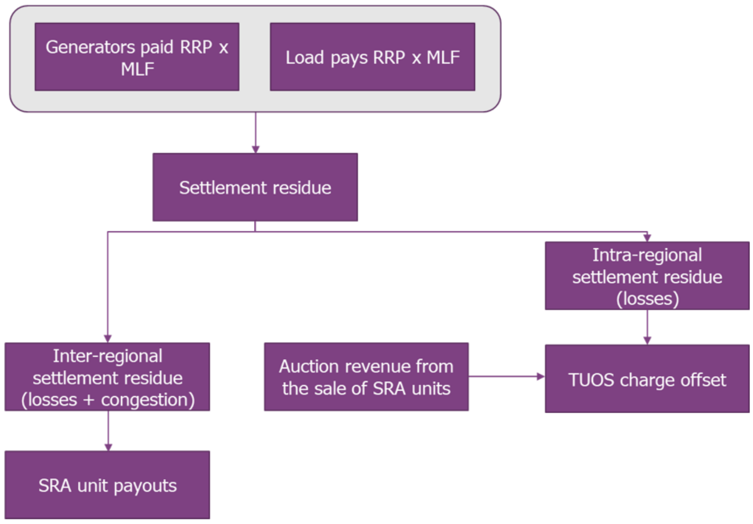
60 Intra-regional settlement residue is already used to offset TUOS charges. Inter-regional settlement residue is currently used to back a form of financial transmission rights - SRA units - with the revenue from the sale of these rights being used to offset TUOS charges.

2 NERA, *Cost Benefit Analysis of Access Reform*, Appendix A, August 2020.

61 The introduction of LMPs results in more efficient price signals for locating new investment compared to the existing regional pricing and static marginal loss factor regime. LMPs also enable the use of more sophisticated FTRs than the existing SRA units, allowing market participants to better manage congestion risk. Finally, the sale of FTRs, which payout on more granular price differences, allows a greater overall amount of TUOS charges to be offset compared to that arising from the existing intra-regional settlement residue and sale of SRA units.

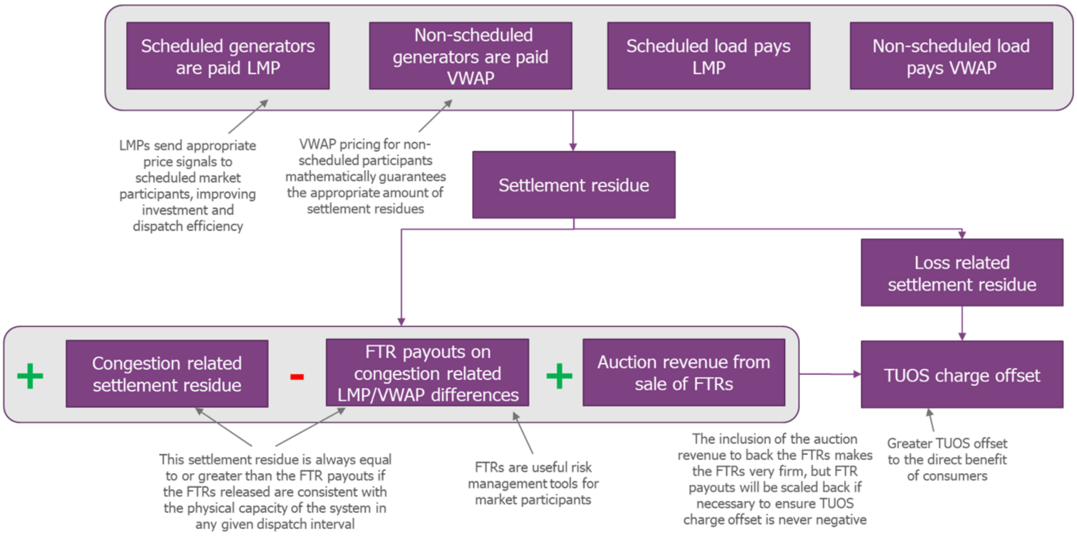
62 The current regime, in comparison to the transmission access reforms, are provided in the figures below.

Figure 1: Current arrangements



Source: AEMC.

Figure 2: Arrangements with transmission access reforms



Source: AEMC.

63 Implementation and initial arrangements

64 These arrangements would be introduced in coordination with other reforms being considered by the ESB, approximately four years after the final rule is made.

65 At the commencement of the reforms, FTRs consistent with almost all of the transmission capacity would be provided to existing and committed generators for free, with only a very small proportion of the available FTRs sold in the auctions. Over the initial period of five years, the FTRs provided for free would be incrementally reduced, and the amount auctioned increased.

66 The combination of the time to make rule changes, the implementation period and the initial period (when transitional FTRs would be allocated) mean existing participants will have approximately ten years before they are fully exposed to the new access framework.

Figure 3: Transmission reform - indicative initiation timeline

Source: AEMC.

67 This will allow participants time to learn and to adapt to the significant changes.

68 The table below sets out a summary of the updated technical specifications.[3]

3 References throughout the table to the March Technical Specifications Report can be reviewed via this link: https://www.aemc.gov.au/sites/default/files/documents/technical_specifications_report_-_transmission_access_reform_-_march_update.pdf

Table 1: **Design decisions**

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
Who faces the locational marginal price?	Scheduled and semi-scheduled participants (generation, load and storage) would be settled at their locational marginal price.	Parties that are responsive to changes in wholesale prices are currently generally those that are also scheduled. Therefore, large efficiencies can be realised from exposing these parties to their locational marginal price. Load would also have the option of becoming scheduled if load wished to face the local price.	No change. See the March paper section 4.2.	This is consistent with US markets where only the equivalent of scheduled participants face LMPs. In New Zealand, all generation and consumption is settled at the LMP.
Who faces the regional price?	Non-scheduled loads and non-scheduled generation would continue to face a common regional price.	A regional price is retained in order to better support contract market liquidity. Load would also have the option of becoming scheduled if load wished to face the local price.	No change. See the March paper section 4.2.	This is consistent with US markets where only the equivalent of scheduled participants face LMPs. In New Zealand, all generation and consumption is settled at the LMP.
What is the regional price? Should the current regional reference price be retained or should the VWAP be used?	The regional price should be the VWAP. If in the fullness of time, related system changes are not required and more detailed cost estimates	FTRs are more effective in managing basis risk using the VWAP than the regional reference price. Avoids the risk of revenue shortfalls, and makes negative settlement residue impossible.	Yes – Both options were outlined in March, but no recommendation was made at that time.	No international market uses the LMP at a single pre-defined node to collectively settle load (or non-scheduled market participants). Instead:

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
	imply the cost of VWAP is greater than the expected benefit, then this design feature could be reconsidered.		See section 2.2.	US markets use a volume weighted average price. NZ employs full nodal pricing, meaning load is settled at its LMP, and not a regional price.
How are losses reflected in the wholesale electricity prices?	Locational marginal prices should reflect dynamic marginal losses. If in the fullness of time, related system changes are not required and more detailed cost estimates imply the cost of dynamic marginal losses is greater than the expected benefit, then this design feature could be reconsidered.	Replacing static intra-regional marginal loss factors with dynamic marginal losses could result in potentially significant dispatch cost savings. NERA's estimates confirm this analysis. Dynamic losses are a standard feature of state of the art dispatch engines, and hence a redevelopment of the NEM dispatch engine should provide this benefit at no additional cost.	Yes – Option to move to dynamic losses was outlined in March but no recommendation given at that time. See section 2.3.	Internationally LMPs dynamically reflect losses except for ERCOT (Texas)
Are inefficiently high prices an issue with LMPs? If yes, how do we manage this issue?	Further analysis is necessary to determine the extent to which pricing mitigation for high price conditions is necessary under LMP. This empirical analysis will occur over the rest of the year, as well as any resulting later rule change process.	Analysis will focus on the likely frequency and impact of inefficiently high price conditions and the appropriate balance between long term investment signals and short term consumer protection from high prices.	Yes - No recommendation was given in March, pending further analysis and consultation. See section 2.4.	ERCOT and PJM both have an ex ante pricing mitigation approach, generally consisting of a pivotal supplier test. New Zealand uses an ex post approach to mitigate pricing behaviour by assessing bidding

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
	Where mitigation is required, an ex ante pricing mitigation measure should be introduced to apply an offer cap on LMPs in certain conditions.	If required, an ex ante mitigation is preferred as it results in clearly defined and predictable outcomes for market participants.		behaviours of pivotal suppliers or if an "undesirable trading situation" occurs.
What type of rights can participants acquire in the FTR auction? Do these include continuous rights that payout at all times of a 24-hour day or time of use rights that pay out in specific periods of a 24-hour day?	Market participants would be able to acquire financial transmission rights which pay out: • At all times of the day ("continuous rights"). These rights are "fixed volume" i.e. they pay out a fixed quantity multiplied by the price difference defined in the FTR (subject to scaling, discussed on the next row). • At specific pre-defined times of the day ("time of use" rights). These will pay out a fixed volume but only when they are "active" i.e. during the specified times of the 24-hour day.	Fixed volume continuous rights can be sold consistent with the simultaneous feasibility test, ensuring sufficient revenue adequacy to back the FTRs from settlement residue in normal transmission operating conditions. For market participants, continuous rights may be simpler to use and more generic and therefore easier to trade between different parties, increasing the prospective pool of buyers and sellers. Time of use rights may be particularly useful for some forms of variable renewable generators to manage their basis risk. For example, there may be a high correlation between a solar	No change. See the March paper section 5.4	This flexibility in how the acquired rights pay out over time is consistent with the approach taken in US markets. For example, ERCOT has time-of-use blocks that pay out in peak and off-peak periods. Likewise, PJM has peak and off-peak products. New Zealand does not have specific rights set up to pay out at set times of day. This has been noted as an area for future exploration.

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
		generator's preferred output and the time of day when it needs to mitigate against transmission congestion. More bespoke products may emerge through the secondary market.		
What revenues or cashflows are used to back FTR payouts?	FTRs are backed by settlement residue and auction revenue. Any remaining revenue after a defined period of time would be used to offset TUOS charges for consumers. Any shortfalls should be accounted for by reducing FTR payouts.	The use of auction revenue in addition to settlement residues helps to ensure that FTRs are unlikely to be scaled back. In making FTRs firmer, this will increase their value, which will increase the revenue from the sale of FTRs in the auction. This additional revenue is ultimately returned to consumers if not used to back the FTRs. Further backing the FTRs will again increase their firmness and so on. This supports the use of FTRs as a risk management tool, putting downward pressure on the cost of capital.	No change. See the March paper section 5.5.	This is generally consistent with the approach taken internationally. For example, in ERCOT, the settlement residue is primarily used to back FTRs. Revenue from FTR auctions is collected in a balancing account and is used to firm FTR payouts. The residual revenue from the auctioning of FTRs is redistributed to consumers on a zonal basis (zones are equivalent to regions in the NEM).

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICA-TION
		Scaling back FTRs when the funds are exhausted ensures settlement balances, and is preferred to exposing consumers to an uplift charge or exposing TNSPs to a penalty above and beyond that provided through the STPIS. The progressive release of tranches of FTRs over time also helps to manage the revenue sufficiency of FTRs and the likely need for scaling at any point in time.		
Who operates and manages the FTR auction process?	FTRs would be sold through a series of simultaneous feasibility auctions run by AEMO, with input from TNSPs being used to set the parameters of how many financial transmission rights could be sold. There would be a schedule of tranches ahead of real time.	This approach ensures that if the transmission network is consistent with expectations when the FTRs were sold, settlement residue is at least sufficient for FTR payouts The revenue from the sale of the FTRs does not need to be used to back the FTRs (with this being returned to consumers), nor the FTRs being scaled back, during normal transmission network conditions.	No change. See the March paper section 5.7.	

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
		The progressive release of tranches of FTRs over time can also be used to tailor FTR sales to available transmission capacity.		
What degree of transparency will there be around who owns FTRs, the amount sold and clearing prices?	AEMO should maintain a register of the amount of financial transmission rights sold at auction, the purchaser and the associated clearing price. This register may also need to capture the sale of FTRs into the secondary market and maintain an ongoing record of the legal interest in an FTR.	Transparency is an important component of a well-functioning market. A register maintained by AEMO will be a useful tool that is transparent to the market which should promote competitive and efficient market outcomes. A register of legal interest in FTR products, allowing for any on sale, may be required to provide security over FTR rights.	No change. See the March paper section 5.10.	
Are competition concerns regarding FTRs an issue? How should it be addressed?	No specific market design measures are required for the FTR market to address competition concerns. The proposed design addresses competition concerns by allowing non-physical participants to participate in the FTR auction.	The FTR market does not appear to have features such as high barriers to entry that would suggest a particular competition concern. General competition law prohibitions would extend to anti-competitive conduct in the market that would be created for FTRs.	Yes - No recommendation was given in March, pending further analysis and consultation. See section 3.2.	This is consistent with the approaches taken with FTR auctions in overseas markets.
Should FTRs be option instruments,	FTRs would be option instruments only, at least initially.	Stakeholders have indicated that option instruments alone meet	No change. See the March paper	Internationally, both option and obligation instruments are

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
obligation instruments, or should both be available?		their requirements and there is little demand for obligations. This is reinforced by data from international experience.	section 5.2.	commonly sold together and most markets started with obligations.
How long in advance should financial transmission rights (FTRs) be available?	FTRs would start being available in small quantities up to 10 years in advance, sold in three month tranches	A balance between enabling market participants to manage basis risk into the future and the ability to provide FTRs that are as firm as they can be and provide the opportunity for future entrants to purchase FTRs.	Yes - Extra information on detailed policy positions. See section 3.3.	Generally, a longer timeframe than is provided overseas is proposed. NZ offers FTRs up to 26 months in advance, ERCOT up to 24 months in advance, PJM up to 36 months in advance. Some markets, CAISO (California) for example, have limited FTRs available on longer timeframes i.e. up to 10 years for the long term FTR equivalent products.
Who should be allowed to participate in the FTR auction? Physical only, or also non-physical participants?	Physical and non-physical participants would be able to buy FTRs.	Allowing greater participation in the auction will likely increase revenue from the sale of FTRs, increase the TUOS offset, decrease FTR competition issues and increase FTR firmness. It will also improve FTR secondary market liquidity.	Yes - Non-physical market participants were excluded from the FTR auction in the March paper. See section 3.4.	Internationally, financial participants are included in FTR auctions.
Is there a reserve	There should not be a reserve	Competition in the FTR market	Yes - No	This is consistent with

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
price for the FTR auction? What is it?	price for FTRs.	should drive FTR prices towards fair value. There are a number of difficulties in defining an appropriate reserve price.	recommendation was given in March, pending further analysis and consultation. See section 3.5.	approaches overseas where there are no reserve prices.
Between which combination of prices should FTRs be available? All combinations? Any node from/to the regional price? Or between a smaller number of predefined nodes?	Reduce the combination of FTRs available to between a relatively small number of pre-defined nodes in the early phase of access reform. Nodes to be defined by the prevalence of congestion on the transmission network, thereby providing FTRs to cover the majority of participant risk and the majority of capacity across key transmission lines on the network.	Provide simplicity to participants in the early phase of access reform. Scaleable over time. Consistent with international experience such as New Zealand which started with two pre-defined trading locations between which FTRs could be purchased and then increased over time.	Yes – this decision moves away from FTRs available between regional prices and any local price, which was the decision in March. See section 3.6.	This is consistent with NZ where a reduced number of pre-defined nodes are identified. It is inconsistent with the US markets.
How should the STPIS be adjusted to accommodate LMPs and FTRs?	Recommendation that AER adjusts STPIS to be based on the cost of congestion, not instances of material congestion.	Cost of congestion metric likely to incentivise more efficient TNSP behaviour than a count of material congestion.	No change in policy but extra detail provided on implementation. See section 3.7.	It is not clear how transmission performance incentives internationally are impacted by the sale of FTRs.

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
Should FTRs hedge losses? If so, how?	At least initially, FTRs would not hedge price differences that arise due to marginal losses.	FTRs could in principle hedge marginal losses. However, such FTRs are complex to design effectively and may reduce the scope for market participants to hedge congestion. FTRs that hedge losses have been introduced only in NZ, where the FTR market has specific features that support this.	Yes – no firm decision in March, but indicated desire to hedge losses within FTRs. See section 3.8.	Our proposal is consistent with the US approach. Only NZ offers FTRs that hedge marginal losses.
When will transmission access reform be implemented?	The implementation date should be coordinated with other reforms underway, and be in the order of approximately four years after the time the relevant access reform rules are made.	The implementation timeframe would be coordinated with other reforms being progressed under the ESB's post 2025 market design work, and would be in the order of four years after the final rule was made. The implementation period would be the first stage of the Access Reform 'soft start'. It will be the period between the rules being completed and the 'go live' date. The second stage being provided by gradual allocation arrangements outlined below.	No change. Extra detail provided. See section 5.1.	The New Zealand market did not have an implementation period between when the relevant rules were made and the initiation of their LMP regime. PJM had an implementation timeframe of approximately eight months. ERCOT had an implementation period of around four years from when the rule to adopt a nodal market design was made.

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
		The time between the rule being made and the regime going live would balance obtaining the benefits of transmission access reform as soon as possible with providing time for AEMO and market participants to adjust to the reforms.		
What should the approach to initial arrangements be?	The initial arrangements would involve the creation of 'transitional FTRs' provided for free. The transitional FTRs would be granted for five years with one year of near-full transmission capacity, followed by a four year sculpting period. Transitional FTRs allocated for 'free' would be backed by settlement residue. However, auction revenue would not back transitional FTRs. Secondary trading of transitional FTRs would be allowed. The Commission is currently	These allocation arrangements would provide incumbents and committed projects with a learning period and a smoother transition while also giving new entrants the opportunity to adjust to the new framework. Sculpted transitional FTR allocations also help to reduce foregone wealth transfer to consumers from transitional FTRs. Using auction revenue to back transitional FTRs would result in a transfer from buyers of FTRs to transitional FTR holders, and hence this is avoided.	Yes - No recommendation was given in March, pending further analysis and consultation. See section 5.2.	To our knowledge many overseas markets either did not offer initial arrangements or grandfathered in ways that reflected different contexts to the NEM.

DESIGN ELEMENT	PROPOSAL	RATIONALE	CHANGE SINCE MARCH REPORT	INTERNATIONAL APPLICATION
	considering the ideal method for allocating transitional FTRs between participants.	Secondary trading will provide increased liquidity and more opportunities for participants to obtain the number of FTRs they need during the transitional FTRs period.		

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1 INTRODUCTION

The *Coordination of Generation and Transmission Investment* (COGATI) review is focused on examining when the transmission access framework will need to change, and, if so, what it will need to change to.

In March 2020, the ministerial forum of Energy Ministers (formerly COAG Energy Council)[4] asked us to continue designing the access reforms as part of the Energy Security Board's post 2025 market design process. We anticipate providing core elements of a rule change package by the end of the year, coordinating with the ESB's 2025 project.

This review is in response to terms of reference received in 2016 from the former Council of Australian Governments (COAG) Energy Council. The Council asked the Australian Energy Market Commission (the Commission or AEMC) to implement a biennial reporting regime on these matters.[5]

The inaugural review (final report published in December 2018), concluded that transmission frameworks need to change so that our regulatory frameworks can keep pace with the transition currently underway in the National Electricity Market. The second review - the subject of this update - outlines the path forward to a transmission access regime that integrates new technologies into the national grid in way that is reliable, secure and works in consumers' best interests.

In March 2020 we set out technical specifications for transmission access reform - namely the introduction of locational marginal pricing (LMP) and financial transmission rights (FTR).

This paper sets out updated technical specifications for transmission access reform - we are seeking stakeholder feedback on this proposed model, in particular whether the design choices we have made will lower costs for consumers and help generators manage congestion risk.

In developing the draft model that we have set out in this paper, we have considered a number of inputs, including:

- significant stakeholder feedback that has been provided to us through the following:
    - 151 written submissions on four papers since June 2019 (consultation paper in March 2019; directions paper in June 2019; discussion paper in October 2019; update paper in March 2020)
    - 12 technical working group meetings
    - three public forums
    - over 200 bilateral meetings and workshops

4 On 29 May 2020, the Prime Minister announced the establishment of the National Federation Reform Council and the disbanding of COAG. New arrangements for the former COAG Energy Council will be finalised following the National Cabinet Review of COAG Councils and Ministerial Forums which is due to provide recommendations to National Cabinet by September 2020. The Prime Minister has advised that, while this change is being implemented, former Councils may continue meeting as a Ministerial Forum to progress critical and/or well developed work.

5 The terms of reference were provided under section 41 of the National Electricity Law (NEL) and can be found here: https://www.aemc.gov.au/sites/default/files/content/97164a7bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Termsof-Reference.PDF

- independent modelling by NERA Economic Consulting, which estimated the net benefits of the reform in the NEM, as well as inputs that fed into which key design decision choice we should make – this follows a request from stakeholders who told us they wanted to see detailed market modelling
- independent analysis by Hard Software on the various cost implications of making various design decisions
- analysis and input from AEMC staff on how the reform will work, and key drivers in the system
- international experience and learnings, drawing on the experience of the reform in numerous jurisdictions around the world – some of which have been in operation for a long time
- work underway in the ESB's post 2025 market design.

Submissions to this paper are due on **Monday 19 October.** Feedback to the proposed design can also be provided in response to the ESB's consultation paper on post 2025 market design, of which transmission access reform forms an integral part.

Stakeholders are also invited to attend public forums that are planned in September, specifically:

- results of quantitative modelling conducted by NERA Economic Consulting on the impacts of the reforms in the NEM
- a simplified model of the proposed reforms in action - this forum will help explain to stakeholders how the model will work and what its benefits are

Stakeholders can register for both of the forums on the AEMC website.

If stakeholders want to discuss anything arising, please contact Ben Davis at 02 8296 7851 or ben.davis@aemc.gov.au, or Russell Pendlebury at 02 8296 0620 or russell.pendlebury@aemc.gov.au.

During the remainder of the 2020, the AEMC will do the following to progress the reform:

- engaging further with stakeholders on the updated technical specification of the model, including holding more technical working group meetings
- focusing on developing cost estimates of implementing the reforms, including working closely with participants and AEMO on this
- undertaking empirical analysis to support particular design decisions, such as:
  - the number and location of nodes FTRs will be available to be purchased from
  - the ability for generators to raise local prices above efficient levels
- working closely as part of the ESB to consider how the design decisions in other MDIs impact on, and interact with the design decisions set out in this document.

2 LOCATIONAL MARGINAL PRICING DESIGN

2.1 Unchanged design elements

The position on several design elements related to LMPs has not changed from the March paper. The design elements that have remained unchanged are:

- who faces the locational marginal price (scheduled and semi-scheduled market participants)
- who faces the regional price (non-scheduled market participants).

Given that these design elements have not changed from the March paper, they are not addressed in depth in the following section of the report. A summary of these decisions can be found in Table 1, and more detail can be found in section 4 of the March paper.[6]

2.2 The regional price should be the Volume Weighted Average Price

2.2.1 Background

In the March paper, it was stated that a common regional price would be maintained for non-scheduled participants. We did not specify a preference for how that price would be determined. The two options outlined were:

1. retain the existing regional reference price (RRP) approach, which is the LMP at the regional reference node (RRN)
2. the volume weighted average price of non-scheduled participants (VWAP). The VWAP methodology would involve calculating a LMP for all transmission connection points in the system that related to non-scheduled market participants. These prices would then be weighted according to the net load of non-scheduled participants within the region.

2.2.2 Revenue adequacy

It is important for the FTRs that are sold to be regularly backed by the settlement residue that arises, to avoid regularly utilising the auction revenue to back them, or, if this is exhausted, reducing the FTR payouts. This is known as "revenue adequacy".

The simultaneous feasibility auction used for the sale of fixed volume FTRs mathematically guarantees that the settlement residue that arises in a dispatch interval equals or exceeds FTR payouts for that dispatch interval (i.e. is revenue adequate), providing the following two conditions are met:

1. the physical capacity of the network in a given dispatch interval is consistent with the capacity of the network assumed for the purpose of determining the set of FTRs sold through the FTR auction
2. all market participants face their LMP (or equivalently, those market participants that do not face their LMP face the volume weighted average LMP of those market participants that face this averaged price).

6 See: https://www.aemc.gov.au/sites/default/files/documents/technical_specifications_report_-_transmission_access_reform_-_march_update.pdf

As well as being mathematically proven, this has been evidenced by international experience, which has shown that FTRs are highly firm i.e. the FTR pays out (see Appendix C for further detail).

Consequently, if non-scheduled market participants face the volume weighted average LMP of non-scheduled participants (ie, the VWAP) and scheduled and semi-scheduled market participants face their LMP, then condition 2 above is satisfied. Further, if non-scheduled participants face the VWAP, it is mathematically guaranteed that there will be zero or positive settlement residues, because the dispatch engine will never dispatch a combination of scheduled market participants which results in negative settlement residue.[7]

2.2.3 Issues relating to the existing regional pricing methodology

These outcomes are not guaranteed if non-scheduled market participants face the LMP at the RRN (i.e. the existing regional reference price), with a variety of negative results.

Consider the following possibilities:

1. If the LMP at the RRN exceeds the VWAP then there will be more settlement residue than would otherwise be the case.
2. If the LMP at the RRN is less than the VWAP then there will be a shortfall in settlement residue, which may not be sufficient to cover FTR payouts in the dispatch interval. Furthermore, the money collectively being paid to generators could exceed the money collectively being paid by load, resulting in negative settlement residue.

These results can be considered to be intuitive: a certain segment of the market is settling at prices that are different to prices which guarantee zero or positive settlement and FTR revenue adequacy. These outcomes under the existing regional pricing methodology have a number of negative consequences that are not observed were VWAP to be used.

First, the quantity, firmness and usefulness of the FTRs sold could be negatively impacted, and hence their collective ability to help market participants to manage basis risk:

- If the LMP at the RRN exceeds the VWAP, then FTRs that are sold via the simultaneous feasibility auction would collectively payout at most only a proportion of the settlement residue that arises. This in turn would diminish the collective ability of the FTRs to manage congestion risk. This is because the simultaneous feasibility test is set to sell FTRs based on the two conditions in section 2.2.2. If the case is that market participants do not face their LMP, or VWAP, and the LMP at the RRN exceeds the VWAP then additional settlement residue arises that is not available to the market through the purchase of FTRs in the FTR auction.
- If the LMP at the RRN is less than the VWAP, then FTRs that are sold via the simultaneous feasibility auction would collectively payout in some circumstances more than the settlement residue that arises (even when condition 1 above holds). In turn, the FTRs would be less firm than they would otherwise have been (because of the shortfall in

7 Providing market participants face the VWAP. If the VWAP is not applied (for example, it is capped at the market price cap) then negative settlement residues could arise).

settlement residue), although this may be offset by more revenue from the sale of the FTRs in the first place.

Second, in order to account for the possibility of (sustained) negative settlement residues, there would have to be a process by which either the payments made to generators are scaled back or an uplift charge is placed on consumers.

BOX 1: QUANTIFYING THE IMPACT OF VWAP VS EXISTING REGIONAL PRICING

Modelling undertaken by NERA illustrates these concerns. The NERA modelling estimates that the LMP at the RRN will on average be approximately 2% **less** than the load weighted average LMP price.[1]

A 2% difference in prices results in an estimated approximate $140m less revenue being paid by consumers in 2021. Once generators have been paid for their energy, this leaves an approximately 28% settlement residue deficit compared to the settlement residue that would have arisen under VWAP pricing.

This means that settlement residue will be greater than or equal to only approximately 72% on average of the FTR payouts in any given dispatch interval i.e. FTRs will be less firm than they would otherwise be. The other 28% on average of FTR payouts would not be mathematically guaranteed to be funded by settlement residue within a given dispatch interval, even if condition 1 above is satisfied, and would need to be funded by/scaled back through a combination of:

- excess settlement residue arising because the simultaneous feasibility test means that settlement residue will *on average over time exceed* 72% of the FTR payouts (because in any given dispatch interval the settlement residue will be *greater than* or equal to 72% of the FTR payouts).
- the auction revenue from the sale of the FTRs
- reducing the number of FTRs sold, although this begs the question: by how much?
- failing these, the FTRs would be scaled back.

Note: 1) While the *load* weighted average LMP represents something of an approximation of the weighted average LMP of *non-scheduled* participants, it nevertheless illustrates the magnitude of the problem.

2.2.4 Concerns with changing to the VWAP pricing

There are two potential downsides from moving to VWAP:

1. More changes will be required than retaining the existing LMP at the RRN because existing systems are set up referring to the LMP at the RRN. In particular, this would involve changes to the existing NEM dispatch engine (NEMDE), and existing AEMO and participant IT systems.
2. In order to forecast the VWAP, market participants would need to estimate the LMP and its weighting at every location with a non-scheduled participant.

In addition, some stakeholders have raised concerns about whether moving to VWAP would result in the need to reopen a greater number of contracts than otherwise, and if this was the case, imposing higher costs. Based on our understanding, it is not clear that this is the case given that some contracts may need to be reopened regardless of the move to VWAP as a consequence of the reforms. We are interested in stakeholder views on this point.

2.2.5 Stakeholder views

Stakeholder feedback reflected the advantages and disadvantages of moving to VWAP.

CS Energy, TasNetworks and Energy Networks Australia agreed with the rationale for adopting volume weighted average pricing, including that it will help to ensure FTR revenue adequacy.[8]

The AER, AEC and Energy Queensland are supportive, in principle, of introducing VWAP but have requested that further quantification of the costs and benefits be completed.[9]

Other stakeholders have expressed concerns about the implementation costs of moving to VWAP, including the implications for existing forward contracts and power purchase agreements that have been struck against the regional reference price. For example, Brickworks and Origin note that it is unclear upon which price existing power-purchase agreements and other agreements would settle.[10] Several stakeholders have also noted that the introduction of VWAP would require major changes to market and trading systems.[11]

In addition, some stakeholders consider that it is unclear what impact the move to a VWAP approach would have on regional prices.[12] While acknowledging the potential benefits of a VWAP approach, AFMA have highlighted that a change to the regional pricing methodology could impact the contracting behaviour of all market participants, which presents potential risks to contract market liquidity. [13]

2.2.6 Analysis

The Commission agrees that the cost of implementation for the revised IT systems necessary to support WVAP needs careful review to ensure that it is justified.

In order to provide further quantification of the IT costs of the reform for both AEMO and market participants, Hard Software was engaged to assist in this understanding. Hard Software analysed three reform options and developed upfront and annual IT cost estimates associated with introducing the reform with and without VWAP. Their estimates indicated that

8 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: CS Energy p. 4; TasNetworks, p. 3; Energy Networks Australia, p. 15.

9 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submissions: AER, p. 11; Australian Energy Council, p. 7; Energy Queensland, p. 12.

10 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Brickworks, p. 2; Origin, p. 7.

11 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Aurora Energy, p. 2; AEC, p. 7; Origin, p. 9.

12 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Energy Users Association of Australia, p. 7; Infigen Energy, p. 10.

13 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: AFMA, p. 4.

the total up front cost for participants and AEMO of the required changes to implement a new dispatch engine[14] to facilitate VWAP (and dynamic losses) would be approximately $20m more than the changes needed to solely upgrade NEMDE to support LMPs for generators.[15] The ongoing costs would also be approximately $1.5m higher annually. Further information on these costs is set out in chapter 4. We are interested in stakeholder views on whether these numbers are consistent with participants' understanding.

Changes required to the IT systems to implement VWAP would be similar changes to those required to implement dynamic losses. Given that the preferred technical specification is a move to dynamic losses (see section 2.3) the costs are likely to be split between the two design choices. There may also be synergies from other changes to the NEM dispatch engine that may be required to introduce other reforms being pursued under the ESB's 2025 work program. The IT changes to facilitate VWAP (e.g. upgrade to NEMDE) have the advantage that AEMO's systems will be more flexible to future changes as the electricity system transforms, including the transition to more active market participation in distribution networks and a two-sided market.

Existing contracts that would still be in place upon commencement of reforms (most likely, longer-term PPAs) may also need to be renegotiated. Feedback from participants indicates that a move to VWAP may require re-opening a larger proportion of these contracts, than would otherwise be the case, which could result in costs and disruption. However, based on our analysis we understand that retaining the RRP for unscheduled market participants would also require contract reopenings. Therefore, there may be little contract reopening cost difference based on the regional price choice. More details on these costs are set out in section 4.3.

As noted in Box 1, the VWAP is forecast by NERA to be slightly higher than the RRP. It is important to note that we cannot consider the impact on consumers bills solely from looking at the difference between the VWAP and the RRP. A consumer's *overall* bill includes:

- the wholesale price they pay (the VWAP, in the case of non-scheduled load) less
- an offset to TUOS charges, resulting from the excess settlement residue, being difference between the revenue received from consumers (ie, based on the VWAP price they pay) and the revenue paid to generators.

Therefore, this means that the choice of VWAP versus RRP (or indeed, any other arbitrarily determined price) has no direct or immediate impact on consumers' bills. For example, if the RRP was used instead of the VWAP, while the RRP would be lower, it would also lower the TUOS charge offset by exactly the same amount. This would mean that the *overall* consumer bill would be unchanged.[16]

14 This would likely require changes to other market management system components. Further discussion of these costs is in chapter 4.

15 'A preliminary indication of the Information Technology costs of Locational Marginal Pricing', August 2020. This report can be found here: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

16 The only time this would not be true is if there is no (or only a very low) TUOS charge offset, because the FTR payouts exhaust the auction revenue and settlement residue required to back them. Appendix A of NERA report (Cost benefit analysis of access reform, August 2020) provides empirical analysis which suggests that this is very unlikely: the settlement residue plus the auction revenue used to back FTRs is likely to be sufficient to cover FTR payouts.

However, in the long-run, the VWAP methodology will result in lower prices for consumers compared to the RRP (or any other price), because it:

- improves the quantity, firmness and usefulness of FTRs, enabling market participants to better manage their risk than were the existing regional pricing methodology used. In turn this should result in a lower cost of capital for generators, which will ultimately flow through to lower prices for consumers
- guarantees that there is no negative settlement residue.[17]

2.2.7 International experience

To our knowledge, no international market uses the LMP at a single pre-defined node to collectively settle load (or non-scheduled market participants). Instead:

- US markets use a volume weighted average price
- NZ employs full nodal pricing, meaning load is settled at its LMP, and not a regional price (which also satisfied condition 2 above and guarantees zero or positive settlement residue).

2.2.8 Conclusion

The existing regional pricing method compromises on a key requirement that generators have emphasised, which is the need for plentiful, firm FTRs in order to manage congestion risk. In contrast, VWAP pricing guarantees that there is always sufficient settlement residue to back the FTRs in a given dispatch interval, providing the physical capacity of the network in a given dispatch interval is consistent with the capacity of the network assumed for the purpose of determining the set of FTRs sold through the FTR auction.

Empirical analysis suggests that retaining the existing regional pricing method would risk using the auction revenue to back FTRs, even in normal transmission operating conditions, diminishing the firmness of the FTRs (Box 1). The existing region pricing method also risks negative settlement residues arising, something that is impossible under VWAP pricing.[18]

While the change to VWAP comes with costs, the initial estimate of costs by Hard Software estimates these to be in the order of tens of millions of dollars. These costs will be shared with the move to dynamic losses and it is likely that these costs would need to be incurred over time to facilitate other changes arising from the transition of the sector, for example through the other ESB 2025 reforms.

On the basis of this analysis, the **preferred design is that the regional price should be set to be the VWAP of non-scheduled participants.** While this is the preferred design, this design feature could be reconsidered through the rule change process if certain conditions do not occur in the fullness of time.[19] These conditions include:

17 Providing market participants face the VWAP. If the VWAP is not applied (for example, it is capped at the market price cap) then settlement residues could arise).

18 Providing market participants face the VWAP. If the VWAP is not applied (for example, it is capped at the market price cap) then settlement residues could arise).

19 If, in the fullness of time, it is determined that the existing regional pricing should be retained, the introduction of LMP and FTRs would still be of considerable benefit to consumers. Other changes to the technical specifications would nevertheless be required to accommodate this approach.

- further cost analysis indicating significantly higher costs estimates of a move to VWAP and dynamic losses
- the detailed costs estimates outweighing the expected benefits
- there being no other market design reforms (e.g. the other ESB 2025 reforms) requiring changes to NEMDE.

2.3 LMPs should reflect dynamic marginal losses

2.3.1 Background

Transmission losses are currently reflected in dispatch and settlement on a marginal basis[20]

- **Losses that occur within a region ('intra-regional losses') are modelled as static and are set each year.** AEMO calculates intra-regional marginal loss factors using the weighted average of the forecast actual marginal loss factors that would arise in dispatch over the year.
- **Losses that occur between regions ('inter-regional losses') are calculated quasi-dynamically in dispatch.** The calculation of inter-regional losses might be described as quasi-dynamic. This is because the inter-regional losses calculated in dispatch vary dynamically with flows on the system. However, the linear loss function is itself static and set on an annual basis by AEMO.

As noted in the March paper, the use of static MLFs may result in dispatch inefficiencies. Because MLFs are currently fixed for a year, in practice there will be differences between the actual MLF in any dispatch interval and the static MLF that is set by AEMO. Therefore, the dispatch engine may not see an accurate reflection of different generators' marginal loss-adjusted cost of supply. This could lead to generators with higher loss-adjusted costs being dispatched ahead of lower-cost generators. The March paper noted that, if this dispatch inefficiency is found to be material, static intra-regional MLFs could instead be replaced with marginal losses that are calculated dynamically in dispatch.

2.3.2 Benefits of dynamic marginal losses

As described in section 4.1, NERA has estimated that potential efficiency gains that could accrue if static MLFs were replaced with dynamic marginal losses. NERA's modelling methodology has captured two potential inefficiencies associated with static MLFs:[21]

- A **price effect**, whereby higher cost plant could be dispatched ahead of lower cost plant.
- A **volume effect**, whereby static loss factors result in a less accurate estimate of the level of generation that is required to meet demand and losses.

We understand that AEMO already account for the volume effect in their demand forecasting. Therefore, NERA's estimate of the potential efficiency benefits associated with dynamic marginal losses is necessarily higher than the actual benefit that would arise in practice.

20 See Section 4.5 of the March paper for a more detailed description of how intra-regional MLFs are currently used in dispatch and settlement.

21 NERA, *Cost benefit Analysis of Access Reform: Modelling Report*, August 2020. This report can be found here: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

NERA has estimated that, in 2025/26, the efficiency gain associated with implementing dynamic marginal losses would be up to $102m, for *both* the price and volume effects. Therefore, the price effect alone must be less than this. It is not possible to separate the two effects in the Plexos modelling framework. Nonetheless, this indicates that the efficiency gain associated with the introduction of dynamic marginal losses may be substantial.

2.3.3 Costs associated with dynamic marginal losses

Currently, NEMDE does not explicitly model transmission losses that occur within a region. Therefore, implementing dynamic marginal losses would require a replacement of NEMDE. The future development of existing market systems, including NEMDE, is being considered as part of the ESB's post-2025 review, of which transmission access reform is a key component. Accordingly, the incremental system cost of introducing dynamic marginal losses should be considered in this broader context.

As outlined in section 4.3, the AEMC has engaged Hard Software to provide an initial analysis of the system costs associated with introducing both dynamic marginal losses and volume weighted average pricing (VWAP, see section 2.2). AEMC staff have also developed internal indicative cost estimates. These estimates suggest that the upfront system costs for AEMO to implement dynamic marginal losses and VWAP could be around $15m more than implementing transmission access reform with static marginal losses and regional reference prices.

In addition, the initial analysis undertaken by Hard Software indicates that, if NEMDE were redeveloped as a consequence of other reforms being considered through the broader ESB's post-2025 review:

- In this context, there may be no additional market system costs from implementing dynamic marginal losses.
- Off-the-shelf dispatch systems include dynamic marginal losses as a standard feature. There would be no obvious benefit from 'downgrading' this feature to retain static MLFs.
- AEMO may be able to achieve costs savings, as the current process to estimated MLFs would no longer be required. Hard Software's initial, indicative estimate suggests potential savings in the vicinity of $200,000 per annum.

In addition to AEMO's upfront costs of system changes, there will be additional costs to AEMO associated with developing the appropriate solution. There will also be costs associated with necessary changes to the IT systems of market participants. These costs will be considered throughout the remainder of the year, in conjunction with AEMO, as discussed in section 4.3.

2.3.4 Stakeholder views

In submissions to the October 2019 discussion paper, stakeholders expressed mixed views in relation to the introduction of dynamic marginal losses. Some stakeholders supported the introduction of dynamic marginal losses, as this would more accurately reflect losses on the network.[22] Other stakeholders were concerned that dynamic marginal losses would create additional complexity and risk for market participants, as the impacts of marginal losses would be more volatile relative to the current static MLF framework.[23] While some linked the decision to the availability of an appropriate hedging instrument[24], others noted considered that dynamic marginal losses should be introduced irrespective of whether FTRs hedge marginal losses or not.[25] Other stakeholders noted aspects that should be further considered, including how dynamic marginal losses would be calculated on a trading interval basis[26] and potential complications in relation to the interaction of negative price offers and the nodal dispatch of losses.[27]

2.3.5 Conclusion

The analysis indicates that replacing static intra-regional MLFs with dynamic marginal losses could potentially result in significant benefits while noting that the estimates developed by NERA will exceed the actual benefits that could be achieved in practice.

Further, if NEMDE is to be redeveloped to accommodate other changes to the market design, the system cost impact of adopting dynamic marginal losses may not be significant, as this appears to be a standard feature of current off-the-shelf dispatch systems.

On this basis, the preferred design is that dynamic marginal losses are introduced. As the design work progresses, this proposal may be re-evaluated as new information becomes available. In particular, it would be appropriate to revisit this proposal if, in the fullness of time:

- System changes are not otherwise required as a consequence of other reforms, or such changes are delayed.
- The additional cost analysis being prepared by the AEMC provides significantly higher costs estimates.

The introduction of dynamic marginal losses is not required to implement the other core aspects of the proposed access model. However, if the proposed approach to marginal losses changes, adjustments may be required to other elements of the reform package.

The introduction of dynamic marginal losses has implications for the design of FTRs, which are discussed in section 3.8.

22 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion paper submissions: AER, p. 17; Energy Networks Australia, p. 23; AusNet Services, p. 2; TasNetworks, p. 4; TransGrid, p. 3; Goldwind, p. 4; Tesla, p. 3.

23 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submissions: Meridian Energy Powershop, p. 4; Clean Energy Council, p. 10; SIMEC Energy Australia, p. 3; Infigen Energy, p. 9; Snowy Hydro, p. 2; Origin, p. 9; Lighthouse Infrastructure Management, p. 2; Total Eren, p. 4; ESCO Pacific, p. 4; John Laing, p. 4; BayWare Projects Australia, p. 4; Powering Australia Renewables Fund, p. 3; Windlab, p. 4; Canadian Solar, p. 5; Palisade Investment Partners, p. 3.

24 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submissions: AGL, p. 9.

25 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submissions: Energy Networks Australia, p. 23.

26 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submissions: AGL, p. 9.

27 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submissions: Tilt Renewables, p. 2.

2.4 If required, an ex ante pricing mitigation measure should be introduced to apply an offer cap on LMPs in certain conditions

2.4.1 Background

The introduction of LMP raises the possibility of a situation where generators are able and have an incentive to exploit their position in the market when there are constraints which create "sub-markets". Under these circumstances, generators may have the ability to raise their LMP to a level that would be higher than efficient.

In the March paper, it was noted that these issues could be mitigated through the introduction of an ex ante offer cap, set at a value that is related to conditions in the wholesale market at the time that the cap is applied. By an ex ante mechanism, we mean a mechanism that would be built into the dispatch engine to occur automatically alongside each dispatch interval, identifying potentially harmful situations in real-time. The test would identify situations based on a set of pre-defined conditions in which it is determined that offer mitigation may need to occur. These conditions could be based on structural market characteristics, therefore allowing the mechanism to operate independent of market prices.

Emerging findings on this issue were recently discussed with our technical working group, noting that the introduction of transmission access reform would remove certain pricing mitigation measures that are in the current market design (i.e. prices capped at the RRP/90th percentile price).[28] In effect, the current arrangements automatically and implicitly *regulate* prices at all locations and in all circumstances to equal the locational marginal price at the regional reference node. These features limit the ability of generators to influence the price that they receive in settlement, but appear to be very blunt mechanisms and are a strong limitation on effective price signals. Nevertheless, the removal of these mechanisms could enable inefficiently high prices, absent of alternative price mitigation measures being introduced.

Some stakeholder views at the recent technical working group meeting included:

- Several generators suggested that high price impacts following the introduction of LMP would be trivial in terms of occurrence and impact and have suggested that no mitigation would be preferable.
- Generators also considered that as storage and renewable costs continue to decline, and economies of scale in generation technologies also decline, barriers to new entry are reducing and therefore localised high prices will be able to be quickly mitigated by new entry.
- Those with consumer interests have suggested that mitigation mechanisms may be warranted and were interested in further analysis of the likely magnitude and impact of instances where price mitigation may be required.

28 For more information, see: https://www.aemc.gov.au/sites/default/files/2020-08/TWG%2311%20Market%20Power.pdf

2.4.2 Analysis and conclusion

The decision to mitigate high LMPs under specific conditions, and the choice of mitigation mechanism, must balance the risk of inhibiting participants from recovering the efficiently incurred costs of their investments and dampening efficient investment signals, against protecting consumers from periods of high or volatile prices.

When considering these risks, there are a number of trade-offs that inform the approach that should be taken. These include:

- The scale, duration and frequency of these local high price events.
  - If the events are not large, not enduring, or are infrequent, less mitigation will be necessary compared to if events are large, enduring or frequent.
- The time-frame within which new generation can respond.
  - If new plant can be built in a reasonable time-frame to counter high prices, this may be the most appropriate approach.
- The size of generation investment relative to the size of the market.
  - If small generators are needed to relieve high prices, these will require small investments and therefore limit the appropriateness of mitigation.
- The dampening impact of mitigation on investment signals.
  - If planned mitigation is expected to have a large impact on investment signals, it may have a net negative impact.

Based on stakeholder feedback and the above analysis, **further analysis is needed to quantify the scale of the problem before we reach a preferred design decision.** This analysis involves analysing historical dispatch information to quantify the number of potentially inefficient pricing outcomes that occur. This analysis will occur over the rest of 2020. As the reforms are not changing the physical structure of the system, this analysis will provide a reference of how often such outcomes occur, and whether the scale of the problem is large.

The reform can be progressed and designed, and rules written that are complete and functional without a decision on a market design mechanism aimed at mitigating inefficiently high price events under the specified conditions. Therefore, given the relatively separate nature of this aspect to the main body of the reform, the preferred design for this element is that:

- An ex ante mechanism is still preferred, pending empirical analysis on the need for such a mechanism.
- A decision on the specific design of ex ante mechanism be taken through the remainder of 2020, consistent with the detailed design of other aspects of the reforms.

To the extent that an ex ante offer cap mechanism is introduced, it is likely to represent a significant improvement on the current arrangements, which currently regulate prices to equal regional prices in all circumstances, regardless of the prevailing market conditions. Any ex ante mechanism would seek to take account of real time market conditions in order to determine whether the offer cap would apply. As a result, an ex ante mechanism would be a more sophisticated tool for mitigating against inefficiently high prices while avoiding bluntly disrupting efficient price signals.

3 FINANCIAL TRANSMISSION RIGHTS DESIGN

3.1 Unchanged design elements

The position on several design elements related to FTRs has not changed from the March paper. The design elements that have remained unchanged are:

- Participants will be able to acquire FTRs that pay out continuously or at specific times of a 24-hour day i.e. time of use products will be available.
- FTRs are backed by settlement residue and auction revenue, making the FTRs very firm.
- FTRs would be sold in auctions run by AEMO which would reflect TNSP data and inputs, and there would be a schedule of FTRs released in tranches over time, with more FTRs available the closer to real-time you get.
- AEMO would maintain a publicly available register of the amount of financial transmission rights sold at auction and the clearing price, as well as the purchaser. This register may also need to capture the sale of FTRs into the secondary market and maintain an ongoing record of the legal interest in an FTR.

Given that these design elements have not changed from the March paper, they are not addressed in depth in the following section of the report. A summary of these decisions can be found in Table 1, and more detail can be found in section 5 of the March paper.

3.2 No specific measures are required for a lack of competition in the FTR market

3.2.1 Background

The introduction of FTRs will result in a new market being created i.e. a market for the sale and purchase of FTRs. Any time a new market is created, there needs to be consideration about whether the market will be sufficiently competitive, and if not, the extent to which issues associated with a lack of competition within that market may arise.

This has been raised by some stakeholders in regard to the FTR market, with the market being run by AEMO selling FTRs to participants in an auction. For example, Snowy Hydro have raised concerns that market participants, including non-physical market participants if they are allowed to purchase FTRs (see section 3.4), may "hoard" FTRs. That is, these participants may seek to acquire FTRs in order to gain a competitive advantage in an upstream or downstream market, such as the wholesale market for energy or the accompanying contract market.[29]

No specific measures to address perceived competition concerns in the FTR market were included in the March paper, beyond the inclusion of a transparency measure: a register of FTR holders. This would provide transparency to the market, and enable analysis of the competitiveness of the market (discussed in section 5.10 of the March paper) by the AER, Australian Competition and Consumer Commission and other interested parties.

29 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submission: Snowy Hydro, p.8. https://www.aemc.gov.au/sites/default/files/2019-11/Snowy%20Hydro.pdf

The Commission also noted that competition law prohibitions in the Competition and Consumer Act 2010 (Cth), as well as the AER's market monitoring functions, are of general application, and so would apply to conduct in the market that would be created for FTRs, if anti-competitive behaviour or other conduct was an issue.

The Commission recently discussed this issue with the technical working group.[30]

3.2.2 Analysis and conclusion

A lack of competition in the FTR market could lead to FTRs being consistently sold for less than their fair value (which should approximate the cost of congestion that exists between the nodes that the FTR is covering). This would likely provide windfall gains to FTR market participants at the expense of consumers.

A lack of competition in the FTR market could also preclude market participants from being able to purchase the FTRs they might otherwise have acquired if the market was more competitive, with this in turn limiting their ability to manage risks associated with congestion and so potentially increasing their cost of capital. These outcomes in turn may negatively impact consumers.

However, the view that concerns relating to a lack of competition in the FTR market, including any 'hoarding' of FTRs, seem to be unfounded, particularly if non-physical participants are allowed to participate in the FTR auction (see section 3.4). This is because:

- the FTR market does not appear to have features such as high barriers to entry that would suggest this would be a particular concern.
  - Each FTR route is not its own market: the simultaneous feasibility auction for FTR allocation means that the allocation of FTRs along a particular route reduces the allocated FTRs on another route. This means that buyers of FTRs compete with one another despite bidding for different routes.
- we are not aware of this being a particular concern in international FTR markets, nor there being any specific FTR mitigation measures for hoarding.
- even were hoarding to occur, this does not directly impact the physical dispatch of the system, since FTRs are financial rights - therefore, the energy market would still dispatch based on a least cost optimisation, although generators would potentially not be able to get access to congestion management tools that they otherwise would have been able to purchase.

The previous design proposal to exclude non-physical participants from the FTR auction would exacerbate competition issues as restricting participation would potentially lead to decreased competition in the FTR market. Consequently, and for the other reasons discussed in section 3.4, non-physical participants should be allowed to participate in the FTR auction in order to increase competition and decrease the ability of participants to "hoard" FTRs. Participants supported this change at the technical working group.

30 See: https://www.aemc.gov.au/sites/default/files/2020-08/COGATI%20TWG%2311%2C%20minutes%202020_08_03v1%20%281%29.PDF.

In light of this change, and the register of the amount of FTRs sold at auction and the clearing price (section 5.10 of the March paper), the Commission continues to consider that no specific mitigation mechanism be implemented for the FTR market. The issue of the potential for participants to manipulate locational marginal prices is discussed further in section 3.4.

3.3 FTRs would be available up to 10 years in advance

3.3.1 Background

In the March paper, it was proposed that the FTR auction would offer FTRs that would be available for purchase up to ten years in advance, with this change being made in response to stakeholder feedback. Previous to the March paper, the tenure proposed for FTRs had been somewhat shorter, three to four years into the future, consistent with trade in ASX derivative instruments, international examples of LMP and FTRs, and the existing settlement residue auction (SRA) process.

However, stakeholder feedback suggested that a longer tenure was needed in the NEM, given the contract market in Australia, and the dominance of longer term PPAs. For example, Neoen noted that the horizon for FTR purchasing is too short for the financing of a new generator.[31] This was also reinforced by feedback from participants noting a strong desire for a greater degree of investment certainty, which would be increased with longer-term FTRs. Several generators have proposed being able to buy FTRs ten years in advance, with some proposing that FTRs should be available for an asset's design life, generally longer than twenty years. Therefore, the decision to offer products up to 10 years in the future was driven by the view that products further into the future would be better for market participants to manage the risk of congestion, better enabling them to make investment decisions.

A ten-year timeframe for FTRs was also noted to be consistent with the main planning horizon of the ISP. The ISP will inform expected augmentation of the transmission system, working out the 'right' amount of transmission to be built, balancing the costs of the transmission build itself with the costs of congestion. The level of transmission capacity will determine the quantity of FTRs that can be made available in future periods.

In international jurisdictions that have implemented LMP and FTRs, FTRs are rarely available longer than three years in advance, although they have been made available over longer timeframes in CAISO for example (see Appendix A). It should be noted however that in California, the ability to acquire FTRs for the longer duration is driven by contracting obligations for load serving entities (LSE's, largely vertically integrated retailers) under California's resource adequacy construct. Not all market participants have access to FTRs with the longer tenure. Non-LSEs (or non-retailers) can only obtain shorter term FTRs in the auction.

Not all stakeholders have supported the provision of longer tenure products. The ENA suggested that tenures of FTRs are not expected to align with the tenures of generation

31 NEOEN, submission to the October discussion paper.

projects in other markets with FTRs.[32] Canadian Solar have suggested that longer term FTRs would make it more difficult for intending generators to buy FTRs.[33]

Some stakeholders have also acknowledged the difficulties associated with making a longer tenure FTR available:

- the increased uncertainty in relation to available transmission capacity
- the difficulty in valuing a longer term product, given the challenges associated with forecasting price differences further into the future.

3.3.2 Analysis and conclusion

The Commission's analysis suggests there are benefits and drawbacks with offering ten-year tenure FTRs in the FTR auction.

In relation to benefits, longer term FTRs are likely to better enable market participants to manage congestion related risk in the operation of an asset and in the process better enable the participant to manage investment uncertainty and risk. A number of stakeholders have considered this would be beneficial, suggesting that the benefit may accrue across the market more broadly and as a consequence have some value to consumers, albeit this is difficult to quantify. Having longer term FTRs also better aligns with long-term PPAs which are more widely used in the NEM than other markets, potentially driving greater investment certainty.

However, there are drawbacks associated with offering longer tenure FTRs. For example, as the transmission system changes over time as new network is planned and operational decisions are made, this may make determining the appropriate quantity of FTRs harder to define and value. This may therefore limit the investment certainty that participants consider they may achieve.

A key consideration is how to design the offering of long-term FTRs such that:

- fungibility and liquidity is promoted – this suggests that ten-year products should not be available, but rather participants would purchase FTRs in smaller chunks that could be strung together to form a ten-year FTR
- future entrants will still have the opportunity to purchase FTRs – this suggests that not all of the network capacity that is projected to be available in 10 years time would be auctioned at the start, so that only a proportion of the capacity would be auctioned off 10 years in advance
- the FTRs are as firm as they can be – this suggests that given network conditions change over time, and further reinforces that the FTRs available in 10 years time would be a subset of the network capacity.

32 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submission: ENA, p.24. https://www.aemc.gov.au/sites/default/files/2019-11/Energy%20Networks%20Australia_0.pdf

33 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submission: Canadian Solar, p.3.https://www.aemc.gov.au/sites/default/files/2019-11/Canadian%20Solar%20%20-%20received%2013%20November%202019.pdf

These considerations, both the stated benefit to market participants, and the potential drawbacks to providing FTR products so far into the future, suggest both that longer tenure FTRs, of up to ten years, should be provided, but that the amount that avaliable for purchase 10 years in the future will not reflect the full network capacity. The **preferred design** is therefore that:

- FTRs can be purchased up to ten years in advance
- the quantity of FTRs sold well in advance form a small portion of the total quantity of FTRs provided in the auction
- FTRs sold in advance will be released progressively in a series of tranches. While the proportion available ten years in advance will form a small portion of available network capacity, this proportion will increase as we move closer to real-time.

The proportion to be provided ten years in advance will be determined through any rule change process to implement this reform, in tandem with the development of the FTR auction process itself. We are interested in feedback on how the length of FTRs available will influence stakeholder investment and operational decisions.

We are also interested in stakeholder feedback on whether longer-term FTRs might emerge on the secondary market for FTRs. Were this not to be the case, it would suggest that counterparties are not willing to agree a price given the risks associated with defining the appropriate FTRs to be provided. This calls into question whether consumers, who effectively back FTRs with settlement residues, should be willing to sell these residues so far into the future in these circumstances.

3.4 Physical and non-physical participants would be able to buy FTRs

3.4.1 Background

In the March paper it was proposed that:

- The purchase of financial transmission rights between an LMP and a regional price would be limited to only physical market participants. Additionally, their ability to use these FTRs should be capped at some measure of their physical capacity in the market as a whole. The rationale for this was to promote the ability of physical market participants to manage basis risk - by allowing physical market participants not to purchase more than they would need for their capacity, and making sure that only physical participants can purchase them.
- Other registered participants (who do not participate in the wholesale market) would be able to purchase FTRs between two regional prices (based on the existing inclusion of non-physical participants, i.e. traders, in the existing inter-regional settlement residue auctions). This decision was made in order to maintain consistency in transitioning from the current arrangements.
- Anybody would be able to trade FTRs on any secondary market for FTRs that may emerge.

The March paper also stated that, if the purchase of FTRs was to be limited to physical market participants, a methodology for establishing a cap (mentioned above) on the quantity of FTRs that could be purchased would be needed, and that any design decision on participants would need to be consistent with other elements of the FTR design (e.g. product tenure and auction reserve price).

3.4.2 Analysis and conclusions

Analysis, as well as stakeholder feedback, has indicated that there are drawbacks associated with excluding non-physical participants from the FTR auction.

It is also not consistent with what is undertaken in international markets. Internationally, financial participants are included in FTR auctions. One study performed by PJM, on the impact of not including financial participants in their FTR[34] auctions, showed that added competition from financial participants benefits load by increasing the overall revenue generated by the sale of FTRs. Their paper also states, "financial trader participation in the FTR markets benefits load through increased liquidity and competition that ultimately provides value to physical participants through increased revenues and additional congestion hedging opportunities"[35].

Excluding non-physical participants from participating in the FTR auction could have the effect of potentially:

- decreasing competition in the FTR market given there would be less parties competing than there could be
- reducing the revenue generated from the sale of FTRs (due to lower competition), which may reduce the amount by which consumer TUOS charges are offset
- decreasing the firmness of FTRs, since the market will be less competitive and therefore there will be less auction revenue to back the FTRs
- decreasing FTR secondary market liquidity.

Additionally, excluding participants from auctions would likely necessitate the following to be developed and included in the design of the FTR/LMP regime:

- the development of a reserve price, and quantity caps for physical participants which may also decrease the number of FTRs sold, as well as the price those FTRs are sold at
- a careful delineation between who can and cannot participate (e.g. would intending participants be allowed?). This is likely to be difficult
- further consideration of price mitigation measures (as discussed in section 3.2).

All of these would be additional components for participants to learn and understand - and we've heard from stakeholders that ideally the model would be as simple as possible.

Arguments in favour of excluding non-physical participants appear to be largely driven by:

34 PJM has both FTRs and auction revenue rights (ARRs). FTRs give their holders a share of congestion residue while ARRs give their holders a share of FTR auction revenue. ARRs can be converted into FTRs.

35 See: https://pjm.com/-/media/library/reports-notices/special-reports/2020/ftr-market-review-whitepaper.ashx?la=en

- concerns that non-physical participants would hoard FTRs (i.e. pay more than fair value in an attempt to gain an advantage in an upstream or downstream market - discussed further in section 3.2), and
- concerns that physical participants will not be able to purchase as many FTRs, given the increased competition from other parties, often accompanied by the incorrect inference that this will directly impact their physical dispatch. As explained in section 3.2, FTRs provide a financial hedge - the least cost optimisation of the NEM dispatch engine and dispatch of generators will happen as normal.

In response, the we note that non-physical players are unable to gain an advantage in the energy market because they do not participate in this market, and so hoarding would expose themselves to financial loss in the FTR market. Competition law prohibitions in the Competition and Consumer Act 2010 (Cth), as well as the AER's market monitoring functions, are of general applications, and so would apply to conduct in the market that would be created for FTRs, if anticompetitive behaviour or other conduct was an issue.

Transitional FTRs provided to existing physical participants should also allay concerns of some existing physical participants that they will be unable to acquire FTRs. At the commencement of the regime, all existing participants would have some transitional FTRs, which they will have been granted for free - this is discussed further in section 5.2.

Under the preferred design FTRs will be sold through a blind simultaneous feasibility auction with the express function of maximising total value of FTRs sold. Physical and non-physical participants will have equal opportunity to bid at a price they value the FTRs at. If physical participants do not bid sufficiently high then they will not receive the FTRs in that period – instead, a non-physical participant will buy the rights at a higher price. This is a good outcome for consumers, as it increases the amount by which TUOS charges are offset, and, as noted by PJM above, provides positive outcomes for market participants through increased liquidity in the FTR market.

For these reasons the preferred design specification is that all physical and non-physical participants who are appropriately registered (e.g. traders) are able to buy any available FTR products in the auction. This will promote competition in the FTR market, enabling generators with more options to manage congestion but also promoting the benefits from the regime for consumers. The design decision in the March paper that secondary trading should be allowed by anybody (including non-physical participants) also remains appropriate.

3.5 There should not be a reserve price for FTRs

3.5.1 Background

The auction revenue, which is the money resulting from the sale of the FTRs, is used to back the FTRs (i.e. added to the FTR funding pool along with the settlement residue) with any excess funds within the pool returned to consumers after apre-defined period (perhaps the three-month length of the FTRs) through offsetting TUOS charges. This raises the question of should a reserve price be set to make sure that the clearing price of the auction is at a sufficient level to promote consumers receiving a larger TUOS offset or whether competition in the FTR auction alone will be sufficient to have adequate auction results?

The March paper discuss the FTR auction reserve price. It was noted that:

- as the FTRs are option only instruments which only ever have a positive payout, negative bids would not be allowed
- there may need to be a positive reserve price, particularly for FTRs sold further in advance of real-time, as the degree of competition may be lower for FTRs.

3.5.2 Analysis and conclusions

Any excess settlement funds (i.e. both the settlement residue and the FTR auction revenue not used to back FTRs) is returned to consumers. Simplistically, consumer's TUOS charges offset is therefore:

TUOS offset = Settlement residue + auction revenue - FTR payouts

If the auction revenue from the sale of an FTR is less than the payout for that FTR, then consumers' TUOS charges would be offset by a greater amount had the FTR not been sold.

The rationale for a reserve price is that if the price at which FTRs is sold is low due to a lack of competition in the FTR market, it would be better for consumers' TUOS charge offset for the FTRs to not be sold at that price. A reserve price attempts to increase the auction revenue (by forcing the market to pay at least a minimum price to secure an FTR) or reduce the FTR payout (by not selling the FTR if the market is not willing to pay the minimum price), or a combination of the two, such that the TUOS charge offset is greater than it would otherwise have been had the reserve price not been in place.

On the other hand, the rationale for having FTRs is to enable market participants to manage their risk (which is ultimately in consumers' interest since it should lower market participants' cost of capital), and so restricting the overall supply of FTRs through the use of a reserve price would appear contrary to this objective.

There would also likely be practical challenges with setting an appropriate reserve price - and indeed this price could potentially change over time. It would presumably require a central agency acting on behalf of consumers, such as the AER or AEMO, to estimate the expected FTR payouts and set the reserve price accordingly. Alternatively, the quantity of FTRs sold could be reduced, although determining the appropriate reduction would be similarly challenging. Setting the reserve price too high (or the quantity sold too low) risks unnecessarily restricting market participants from being able to manage their risk, to the ultimate detriment of consumers.

Internationally, reserve prices in FTR auctions are not used. Instead, the auctions rely on competition to drive good outcomes for consumers. The appropriateness of this approach appears to be promoted via other aspects of the overall design:

- Allowing non-physical participants to buy FTRs in the auction, which in turn increases the competition for FTRs compared to if they were excluded (section 3.4).

- Limiting to a low number the proportion of FTRs sold well in advance (section 3.3). By constraining supply well in advance, this is likely to result in the FTRs being sold closer to "fair value". Furthermore, to the extent that FTRs are sold at an uncompetitive price well in advance, the negative impact of this for consumers would be limited because of the relatively low quantity sold at that time.
- Having an initial period with transitional FTR allocations such that the quantity of FTRs sold starts low and increases over time (section 5.2) - for the same rationale as above.
- Reducing the number of FTR routes available, promoting liquidity and competition in those routes (section 3.6), including in secondary markets where market participants may trade FTRs among themselves.

Further, and as noted in section 3.2, the FTR market does not appear to have features such as high barriers to entry that would suggest the level of competition in the FTR market would be a particular concern.

For these reasons, **the preferred design specification is for there to be no reserve price in the FTR auction**.[36] Instead, competition in the FTR market, promoted by various design features, would be relied upon to drive good pricing outcomes for consumers. This approach maximises the FTRs sold, promoting the ability for FTRs to help market participants manage congestion, in turn reducing costs for consumers. It is also simpler than attempting to determine an appropriate reserve price, enabling market participants to better manage their risk, which is ultimately in consumers' interests.

3.6 FTRs would be available between a limited number of pre-defined nodes

3.6.1 Background

In the March paper, the preferred design was for FTRs to be available in the auction which paid out on the price differences between:

- any local price and any regional price, and
- any two regional prices.

That is, FTRs would *not* be available in the auction that paid out between *any* two locational prices.

The AER, Energy Queensland, CS Energy and Mondo Energy supported enabling FTRs between an LMP and any regional price (local to regional rights).[37]

This approach represented a middle-ground between alternative approaches considered:

- FTRs available in the primary auction that paid out between *any* two locational prices - an approach taken in some markets in the US

36 In practice, no reserve price is identical to a reserve price of zero. It is mathematically impossible (with option only instruments) for the FTR to clear negative bids, given its objective function is to maximise the revenue generated through the auction.

37 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submissions: AER, p. 14; Energy Queensland, p. 13; CS Energy, p. 4; Mondo Energy, p. 4.

- FTRs only available in the primary auction that paid out on the price differences of a limited number of pre-defined locations - the approach taken in New Zealand.

Some stakeholders suggested that further consideration could be given to these alternative approaches. Energy Networks Australia considered it is too early to conclude that certain FTR configurations should be excluded from the access model.[38] AusNet Services suggested that the number of price pairs could be based on what is computationally possible.[39] TasNetworks stated that if the computational complexity can be reduced, hedging between any two LMPs should also be adopted.[40] EnergyAustralia proposed to simplify the reform by identifying a subset of connection points that are likely to be congested and introducing trading around these connection points only.[41]

In response to the above feedback, as well as that provided through bilateral meetings and the technical working group the Commission has recognised that limiting the sale of FTRs to a limited set of nodes may be simpler for participants to manage. As a consequence, the technical specifications hsa been updated to be simpler for participants, and so instead will now allow FTRs to only be available in the auction that paid out on the price differences of a limited number of pre-defined locations, at least initially. The rationale for this is laid out below.

3.6.2 Analysis and conclusion

Stakeholders have in general raised concerns regarding the apparent complexity of the proposed transmission access reforms.[42] In response to this stakeholder feedback, we have sought to consider ways in which the model could be made simpler for market participants, yet still deliver the significant consumer benefits of the reforms.

A key design decision that was relevant to these considerations is that the very large number of possible FTRs that could be purchased if any combination of nodes was allowed through the auction may impose complexity for market participants. The approach recommended in March would allow stakeholders to consider purchasing FTRs across a large number of possible FTR routes (in the order of a few thousand).[43] While this is a far smaller number than the number of routes available in some US markets (such as Midcontinent Independent System Operator which has 4.8 million conceivable FTR paths; and the Pennsylvania, Jersey, Maryland Powerpool (PJM) which has 3.5 million), this large number of routes may be too complicated, at least initially.

38 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submission: Energy Networks Australia, p. 19.

39 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submission: AusNet Services, p. 3.

40 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submission: TasNetworks, p. 5.

41 Australian Energy Market Commission, Coordination of generation and transmission investment implementation - access and charging, discussion papers submission: EnergyAustralia, p. 9.

42 For example, Neoen noted that this was a 'complicated dispatch system'. See: Neoen, submission to the discussion paper, p. 1.

43 In the NERA report on the Cost Benefit Analysis of Access Reform published with this paper, NERA reflected that there would be 1,060 nodes in the NEM, based on the creation of a node for each scheduled participant on the transmission network.

Therefore, the design decision has changed to only have a smaller number of pre-defined nodes that FTRs can be purchased between being in place at the start of the regime.

Constraining the number of FTRs available to between a pre-defined number of locations has a number of benefits for participants, and most importantly, for consumers:

- decreases complexity for market participants, potentially reducing costs associated with developing and managing strategies for FTRs with more routes available
- allows for a learning period while participants become familiar with the arrangements
- does not preclude the addition of FTRs between more locations over time, as familiarity with the LMP/FTR arrangements increases
- may increase liquidity in the FTR instruments that are sold, because of a concentration of trading into a limited number of instruments
- does not preclude the development on the secondary market of FTRs between other locations, to the extent they are valued by market participants
- potentially increases competition in FTR market, raising the FTR auction revenue and hence increasing the FTR firmness and the money returned to consumers through an offset to TUOS charges.[44]

Additionally, this approach balances some of the other design choices that are changes from the current arrangements elsewhere in the model, allowing for participants to become familiar with the new arrangements over time. For example, the introduction of dynamical losses (section 2.3) and volume weighted average pricing for non-scheduled market participants (section 2.2).

There are some potential drawbacks of the approach, which are that:

- Generators which are not located at the pre-defined locations are not able to manage all their basis risk. It therefore leaves market participants with the risk of any remaining price difference between their connection point and the pre-defined node(s), and limited means to manage this. We are undertaking empirical analysis to determine how significant this is.
- It may be unlikely to reduce the complexity of the FTR auction design process for AEMO. Further considerations would need to be made as to the best way to design the model, but it would likely make more sense for the simultaneous feasibility auction to be built to accommodate any possible locational combinations for FTRs - even if they weren't all used from day one of the regime (i.e.the combinations available to be bid on by market participants would be constrained). This would allow the regime to increase the number of nodes between which FTRs would be available over time.

We have heard from stakeholders that simplicity for participants in the initial stages of the reform is going to be of greatest importance for this design element. Therefore, given the

44 It should be noted that each FTR route is not its own market: the simultaneous feasibility auction for FTR allocation means that the allocation of FTRs along a particular route reduces the allocated FTRs on another route. This means that buyers of FTRs all compete with one another despite bidding for different routes, with that level of competition between greater between locations which "share" much of the same route across the network. In practice, just because thousands or millions of FTRs are available in the US, it does not mean that thousands or millions of different types of FTRs are actually sold.

benefits set out above, the preferred design is to only have FTRs made available in the auction between a relatively small number of pre-defined locations initially.

Of key importance in this decision is the ability to add more FTR routes over time, in a step-wise fashion, up to or beyond the number proposed in March. In this respect, we have been guided by the approach taken in New Zealand, which started with just two locations, and now has eight locations, between which FTRs can be bought at auction.

Given this, an approach needs to be develop to select the pre-defined nodes to start with, as well as a process for how extra locations can be added over time. The process by which the available routes are determined will be developed over the remainder of 2020. The key trade off to be considered in this process is balancing:

- having sufficient locations such that most or all market participants are not substantially precluded from managing their basis risk in a manner which they would if more routes were available, with
- the complexity for market participants of numerous possible FTR routes.

An intended outcome of any process to determine the locations between which FTRs would be available would be to define the locations based on the prevalence of congestion on the transmission network, thereby providing FTRs to cover the majority of participant risk and the majority of capacity across key transmission lines on the network, especially those subject to material and/or frequent constraints.

Empirical analysis will be taken over the rest of the year to provide initial indications of how many nodes would be available for the purchase of FTRs in the first instance. This will consider such matters as:

- the likely differences in LMPs caused by congestion
- the quantity of generation and load at different locations across the network.

We are also interested in stakeholder views on what else we should take into account.

As noted in the March paper (section 5.3.2), the routes available between regions would replace, and be an improvement on, the existing inter-regional settlement residue auction products (colloquially known as SRA units). One of the key benefits of introducing financial transmission rights is that it promotes competition in other markets in the electricity sector. For example, it should promote retail competition between regions because participants will be able to purchase contracts sold in one region, with an FTR to another region. This has been observed in other markets e.g. New Zealand has seen an increase in retail competition as a result of introducing financial transmission rights.

BOX 2: A NOTE ON LANGUAGE

'Hubs'

In the March paper, the term 'hubs' was to describe the pre-defined locations between which the FTR routes can be purchased. This is the language used in New Zealand to describe this approach.

However, this term appears easily misinterpreted to mean a *collection* of locations which somehow share a common locational marginal price. To be clear, under the proposed approach, market participants would only be able to purchase FTRs between specific, pre-defined, individual connection point on the transmission network, not a collection of connection points.

'Routes'

Throughout this section, reference is made to FTR "routes". To be clear, FTRs are financial, not physical, transmission rights, which pay out on the price difference between two locations defined in the FTR. The concept of an FTR route is a useful *analogy*, but should not be taken to imply any physical outcome.

3.7 STPIS adjusted to be based on cost of congestion, not instances of material congestion

3.7.1 Background

In the March paper, the preferred design was for the AER to adjust the market impact component of the current STPIS to better align with the transmission access reforms.[45] The granular information from locational marginal pricing would be used to inform the market impact component, rather than having the incentive based on all relevant outage events with a market impact of over $10/MWh.

This would provide TNSPs with a small financial reward as an incentive to manage the physical capacity of the system. Symmetrically, TNSPs would also be penalised a small amount for poor performance. Penalties and rewards under the scheme will flow to and from TUOS charges.

These adjustments would enhance the existing market impact component of the STPIS. As such, the expected that the 'strength' (i.e. the revenue at risk) of the incentive scheme would be the same which would avoid significantly altering the TNSPs' risk profile.

3.7.2 Analysis and conclusion

The policy position outlined in the March paper has not changed. However, we note that the details of the STPIS, including the metric for the market impact component, are contained within the AER's STPIS decision document rather than the NER.[46] Therefore, to implement the suggested changes, the AER will need to update the market impact component of the

45 Clause 6A.7.4 of the NER sets out a requirement for the AER to develop a STPIS. The AER's current STPIS has a market impact component. The market impact component uses financial incentives to encourage TNSPs to minimise the effect of transmission outages on the wholesale price of electricity.

46 AER, FINAL, Electricity transmission network service provider service target performance incentive scheme, Version 5 (corrected) October 2015.

STPIS for TNSPs to reflect the Commission's considerations above, with this occurring alongside any development of rules.

3.8 FTRs would not hedge price differences that arise due to marginal losses.

As described in section 2.3, differences between LMPs will arise because of both marginal transmission losses and congestion. As losses are always present, there will be price differences between locations on the transmission network even when there are no binding transmission constraints.

In the March paper, the potential benefits from allowing market participants to purchase FTRs that manage the risk arising from both congestion and loss-related price differences were recognised. At the same time, we observed that FTRs that hedge loss-related price differences are relatively unusual in market designs overseas, compared to FTRs that hedge against congestion risks. The March paper also identified that there are significant challenges associated with ensuring adequate funding of FTRs that hedge marginal losses.

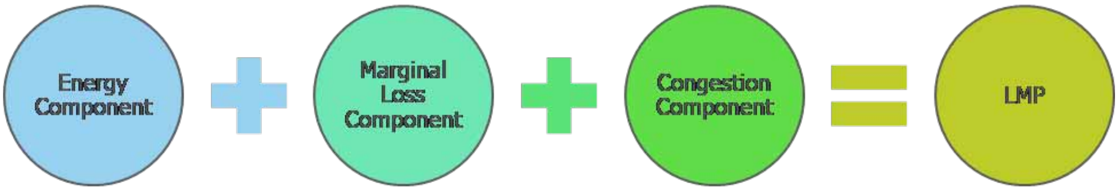
Following publication of the March paper, we have undertaken further research into international approaches to reflecting losses within the FTR design. This research has identified several options that could be adopted in the NEM. The analysis of these options, combined with the feedback received from stakeholders, suggests that at least initially, FTRs should only hedge congestion-related price differences. This would not preclude the introduction of FTRs that also hedge marginal losses at a later date, should this be in the interest of consumers. The remainder of this section sets out the rationale for this proposal.

3.8.1 What do we mean by FTRs that hedge marginal losses?

The LMP at a connection point reflects the change in system costs that would arise from supplying an additional increment of demand at that connection point. Conceptually, the LMP at a connection point can be represented by the sum of three components:

- The **energy component** can be thought of as the marginal cost of supply in the absence of congestion or losses. Accordingly, the energy component of the LMP is the same across all connection points in the network.
- The **marginal loss component** of the LMP at a connection point reflects the increase in system losses that arises from supplying an additional increment of demand at that connection point.
- Similarly, the **congestion component** reflects how the system-wide costs of congestion would change as a result of supplying incremental demand at that connection point.

Figure 3.1: Composition of LMPs



Source: AEMC

An FTR that hedges marginal losses would pay out the full LMP difference between two connection points, including all three components: energy (which as noted above would not differ between locations), marginal losses and congestion.

New Zealand is the only LMP/FTR market that allows participants to purchase FTRs that hedge the price impact of marginal losses. In New Zealand's FTR market, the FTR payout is calculated as the FTR quantity multiplied by the full differences between two LMPs (i.e. reflecting both the marginal losses and congestion components of LMPs). In contrast, in the LMP/FTR markets that have been implemented in the US, the FTR payout is based only on congestion-related LMP differences. (i.e. only the congestion component of LMPs).

3.8.2 Why is it challenging to hedge marginal losses

As described in the March paper, the most common FTR design uses a simultaneous feasibility auction to ensure that the congestion rent arising from wholesale market settlement will be at least enough to fund the FTRs that are issued.[47] This property of FTR design and issuance is known as 'simultaneous feasibility ensures revenue adequacy'.[48]

This characteristic of the simultaneous feasibility auction can be demonstrated in the case of FTRs that only hedge congestion-related LMP differences. However, if FTRs were to pay out based on the full LMP price difference - including the marginal loss component - simultaneous feasibility would not ensure revenue adequacy. This is because the loss-related settlement residue that arises from wholesale market settlement is only enough to fund part of the LMP difference that occurs due to marginal losses. This is illustrated in Figure 3.2 below.

47 At least, this will be the case when actual transmission system capacity is consistent with that assumed in the simultaneous feasibility auction model.

48 For further details, refer to Hogan, W., 1992. "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics 4, pp. 211 – 242.

BOX 3: MARGINAL LOSSES AND FTR FUNDING

The stylised example below assumes a simple two node network, with a load at one end.In this example, the flow on the line is P (equal to demand D, if measured at the load node). Losses between the generator and the load are proportional to the square of the flow on the line (i.e. $L = kP^2$).

If demand at the load node increases by 1MW, the total change in system costs will be the additional output of the generator multiplied by its offer price (λ). Due to the effect of losses, to supply the increment of load the generator's output will need to change by ($1 + 2kP$) MW. From this, the energy and marginal loss components of the LMP can be derived, as indicated in Figure 3.1.

The maximum transfer capacity of the line (i.e. its maximum flow) is P^{Max}. P is currently less than P^{Max}, and the line is unconstrained. Therefore, the congestion component of the LMP (θ) is zero.

In wholesale market settlement:

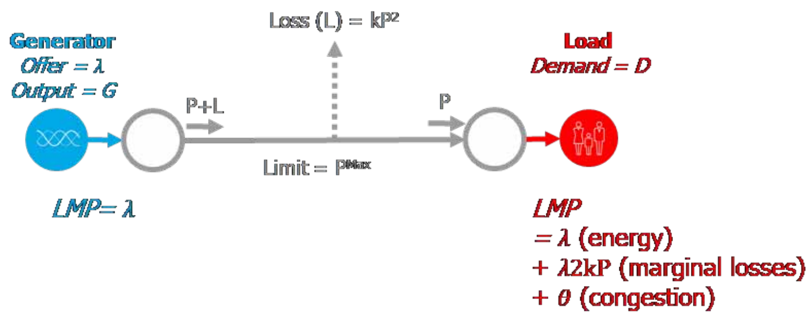
- The load will pay: $P \times (\lambda + \lambda 2kP)$
- The generator will be paid: $(P+L) \times \lambda$

Subtracting these equations from one another (because the load is *paying* and the generator is *being paid*), we can see that there will be a loss-related settlement residue equal to λL.

Suppose the generator had purchased an FTR with a quantity equal to P, and that FTR paid out on the full LMP difference between its node and the local node. In FTR settlement, the generator will be paid: $P \times [(\lambda + \lambda 2kP) - \lambda]$, which simplifies to $2\lambda L$.

Consequently, there will be an FTR settlement shortfall of λL. In effect, this is due to the actual cost of losses. That is, actual losses in this example are L, and their cost is equal to the generator's offer price (λ)

Figure 3.2: Example of losses on a radial network



Source: AEMC

Note: Note that the 2:1 ratio of the loss-related settlement residue to the FTR payout in this simple example does not hold in general across a meshed network.

The properties outlined in Box 3 above mean that there are two broad options for the FTR design if dynamic marginal losses are introduced:

- **Option 1:** FTRs hedge the full difference between LMPs (i.e. both marginal losses and congestion). This would, however, require an adjustment to the 'standard' FTR design to ensure that the FTRs can be funded, given the cost of actual losses as outlined in Box 3.
- **Option 2:** FTRs only hedge congestion-related price differences. This would require a methodology to separately identify the different components of LMPs. That is, so that the marginal cost of losses outlined in Box 3 can be removed form the FTR settlement.

Analysis of these options is summarised in the following sections.

3.8.3 Option 1 - FTRs hedge marginal losses

Since publication of the March paper, research has focused on four sub-options for FTRs that hedge the full price difference between LMPs. These sub-options are:

- **Option 1a - Adjustment to the FTR auction.** The capacity of the network that is reflected in the simultaneous feasibility auction would be adjusted downwards to reflect the impact of actual losses.
- **Option 1b - Unbalanced FTRs.** FTRs would have different MW quantities at the injection/withdrawal connection points, reflecting actual losses.
- **Option 1c - Scaled FTR payouts.** FRT payouts would be scaled to match the available loss and congestion rent in each dispatch interval.
- **Option 1d - Fund cost of actual losses.** Another source of funding, in addition to the loss and congestion rent, is used to back FTRs. In New Zealand, the FTR auction revenue is used for this purpose.

At the recent technical working group meeting, we discussed these options in more detail and noted that Option 1a appeared to be the most feasible option.[49] Informed by the technical working group's feedback, research then focussed on developing a better understanding of Option 1a. The main findings of this research are summarised in Box 4.

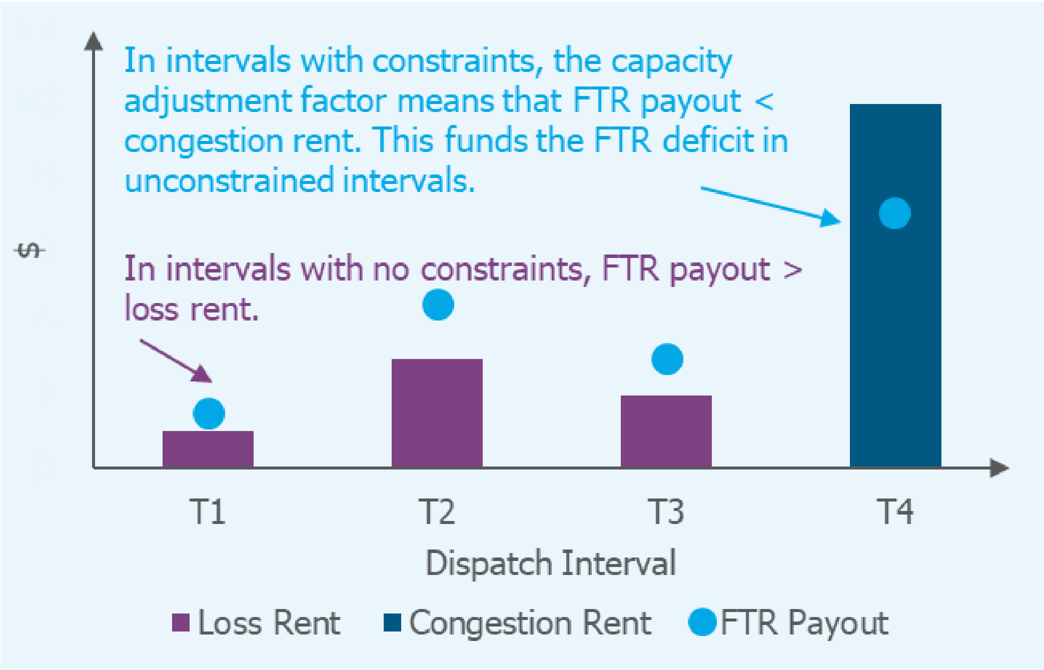
BOX 4: FTR AUCTION ADJUSTMENT

What would an adjustment to the FTR auction capacity do?

Under this option, the capacity of the network that is reflected in the simultaneous feasibility auction would be adjusted downwards to reflect the impact of actual losses. This option would reserve a portion of the congestion rent to fund the inclusion of losses in FTRs. As illustrated below, reducing the network capacity effectively 'borrows' some of the congestion rent that arises when the network is constrained, to fund FTR payouts in unconstrained periods.

49 For a more detailed description of these options and the rationale for focussing on Option 1a, please refer to https://www.aemc.gov.au/sites/default/files/2020-06/TWG%20%237%20Working%20Paper%20-%20Loss%20FTR%20Funding%20and%20Procurement.PDF.

Figure 3.3: Impacts of an adjustment to FTR auction capacity



Source: AEMC

A key point to note is that the capacity adjustment factor reduces the overall quantity of FTRs that can be made available to hedge congestion-related price risk in periods when transmission constraints bind.

How could the adjustment factor be set?

In New Zealand's FTR market, FTRs pay out on the full difference between LMPs (i.e. resulting from congestion and marginal losses).

The cost of actual losses is funded through the use of the FTR auction revenue to back payments to FTR holders. At the start of the FTR market, the New Zealand FTR made an adjustment to the network capacity assumed in the FTR auction, to reflect uncertainty around whether the auction revenue would be sufficient to fund the cost of actual losses. The overall cost of actual losses depends not just on network flows, but also on market prices. Accordingly, if auction participants expect market prices to be lower than they turn out to be in practice, the auction revenue might not be enough to fully fund the FTRs, even though it reflects participants' view of fair value at the time.

We understand that to account for this possibility, the FTR Manager conducted a backwards-looking analysis of FTR revenue adequacy: note: 1

- For each month in the analysis, revenue adequacy was assessed by comparing (a) the assumed FTR payout against (b) the assumed FTR auction revenue plus the actual loss and constraint rental.

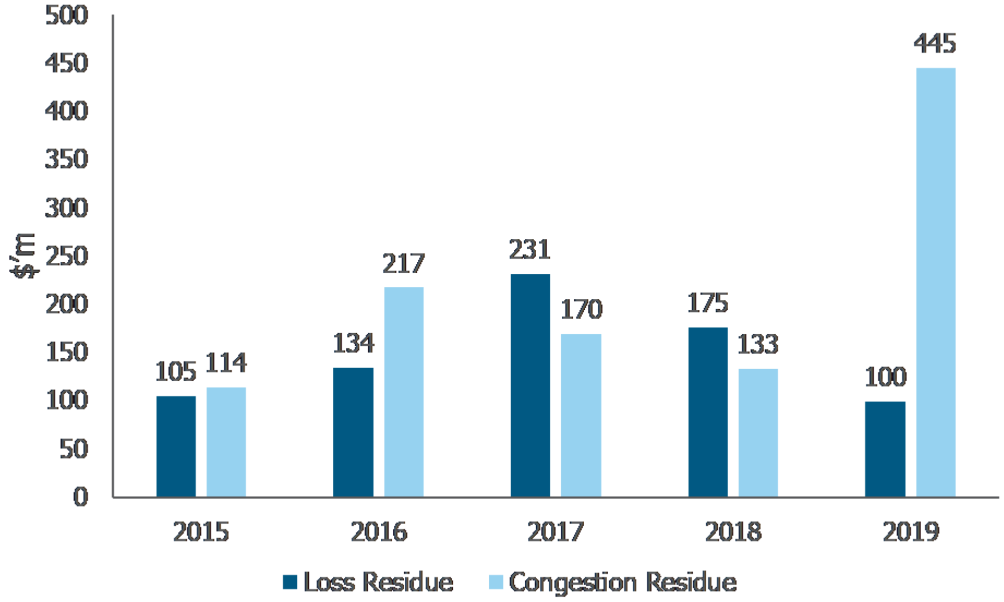
- The assumed FTR payout was based on the actual price differentials between the Benmore and Otahuhu nodes (BEN-OTA) in each month, assuming that FTR options had been sold in both directions for the full BEN-OTA capacity.
- The assumed FTR auction revenue was calculated based on participants valuing the FTRs in line with historical OTA-BEN price differences. Price differences were considered over a range of lookback windows.
- The different lookback windows gave a range of capacity adjustment factors that would have been needed to achieve the 11-in-12 month revenue adequacy target. note: 2 The average of these (84%) was then rounded down to 80% to set the final adjustment factor.

Would this work for the NEM?

In principle, a similar analysis – either backward or forward-looking – could be conducted to set an auction capacity adjustment factor the NEM. note: 3 However, we are concerned that this approach would not be appropriate in the context of the proposed FTR design for the NEM. This is because:

- New Zealand's FTR market was, initially, based on two pre-defined nodes between which FTRs could be purchased (BEN-OTA). The current design for the NEM would involve many more nodes, which would likely reduce the accuracy of the adjustment.
- In the New Zealand market, FTRs are made available up to two years in advance of the settlement period. Confidence in the adjustment factor would be lower for a longer FTR lead-time and tenure, as is being proposed for the NEM.
- The magnitude of the required adjustment factor depends not just on network flows, but also market prices. This suggests that the scope of the analysis, if forward looking, would be relatively complex and potentially subjective.
- The adjustment factor required for the NEM might need to be larger than in New Zealand, as in their FTR market auction revenues are used to fund actual losses. A higher adjustment factor reduces participants' ability to hedge congestion risk.
- A comparison of historical loss and congestion rent in the NEM (see figure below) indicates that the actual cost of losses could potentially be a large, and highly variable, fraction of congestion rent. node: 4 This increases the likelihood that the estimated adjustment factor could be inaccurate, and that inaccuracy could have a material impact on the ability of FTRs to be fully funded.
- At the time the FTR market was being introduced (2014), New Zealand already had substantial experience with LMPs (since 1996). Therefore, historic LMPs in New Zealand might have been a more reliable indicator of future outcomes, relative to the historic settlement residue data for the NEM that is presented in Figure 3.4. For example, this data reflects the current bidding incentives that market participants have due to regional pricing, and the effect of static MLFs, which would both change with the introduction of the proposed access reforms.

Figure 3.4: Intra-regional losses residue compared to intra-regional congestion residue



Source: AEMC

Note: 1. Further details can be found in: FTR Manager, *Note: FTR Grid Policy - Supporting Analysis,* Note: 24 November 2014, available at: Note: https://www.ftr.co.nz/documents/10179/66236/3+1+5A+FTR+Grid+Policy+Supporting+Analysis+-+24112014+-+Final.pdf/fc403d48-ef84-4873-aa03-acbd663b0debNote: .

Note: 2. New Zealand's FTR market rules require the FTR manager to target sales of FTRs such that there will be revenue adequacy in one out of every 12 months.

Note: 3. Noting that the FTR auction revenues would not be included as a source of FTR funding, as is the case in New Zealand.

Note: 4. Figure 3.4 presents *Note: intra-regional* Note: loss and congestion residues only (i.e. inter-regional loss and congestion residues are not included). However, our analysis indicates that including the inter-regional residues would not change the overall conclusion of this analysis, being that historically the loss residue has been both large, and variable, relative to the congestion residue.

3.8.4 Option 2 - FTRs do not hedge marginal losses

If, as outlined in section 3.8.3, FTRs that hedging the full LMP differences is challenging to implement, the alternative option is to have FTRs that hedge only prices differences that are caused by congestion.

This is the approach adopted in all US LMP/FTR markets. In many of these market (with the exception of ERCOT), marginal losses are reflected in LMPs on a dynamic basis. This means that the loss component of LMPs needs to be separately identified for the purpose of FTR settlement.

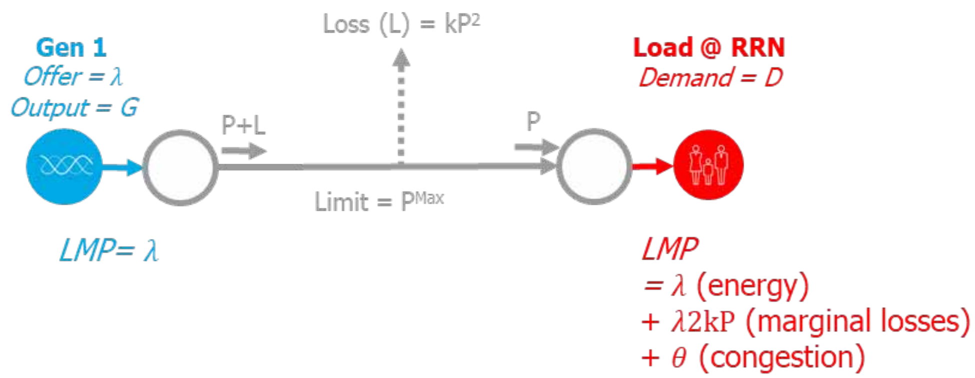
As outlined in section 3.8.1, the LMP at a connection point is defined as the change in system costs from supplying an additional increment of demand at that connection point. This could be represented mathematically as the sum of three components: energy, marginal loss and congestion components. While not explicitly stated in section 3.8.1, disaggregating LMPs into these components requires a 'slack node' to be chosen. The slack node is defined as the location in the system where the additional increment in demand at a connection is assumed to be supplied from. In this way, it provides a point of reference that allows each component of the LMP to be calculated. So more precisely, the different components of an LMP can be defined as:

- **Energy component:** The energy component of all LMPs in the network is defined as the LMP ***at the slack node***. At the slack node, by definition the marginal loss and congestion components of the LMP are zero. Conceptually, this reflects that an increment of demand at the slack node is assumed to be supplied by a generator located at the slack node, and therefore there is no incremental transmission loss or congestion associated with that supply.
- **Marginal loss component:** The incremental change in system losses from supplying an increment of demand at a connection point, assuming that the change in demand is supplied ***from the slack node***.
- **Congestion component**: The incremental change in system congestion costs from supplying an increment of demand at a connection point, again assuming that the change in demand is supplied ***from the slack node***.

So effectively, the LMP at each location represents the change in system costs from supplying an additional increment of demand at a particular connection point (defined as the slack node) plus or minus the incremental cost of congestion and losses from supplying an addition unit of load to another connection point. This is similar to the current arrangements in the NEM, where MLFs are defined relative to the regional reference node, and transmission constraints are oriented towards the regional reference node.

The total LMP at a connection point does not depend on the choice of slack node. However, the split between energy, congestion and losses does depend on this. We can see this by returning to the example from Box 3 above, in which the generator node was implicitly selected as the slack node.

Figure 3.5: LMP components



Source: AEMC

In this example, the LMP at the generator's node was setting the energy component of the LMP at the load node. The marginal costs of losses and congestion were then defined as *additions* to this. However, the load node could alternatively be designated as the slack node, in which case the marginal cost of congestion and losses would be treated as *deductions* from the load node LMP to calculate the LMP at the generator's node.

The US LMP/FTR markets take different approaches to defining the slack node. For example, some markets (such as CAISO) have adopted a 'distributed slack node'. Rather than a single node, this is a collection of nodes across the system, that can be weighted according to the distribution of load or generation. In CAISO's case, the slack node is weighted according to the distribution of load in each dispatch interval. Other jurisdictions (such as NYISO) have adopted a single node as the slack node. The choice of slack node is essentially arbitrary, in the sense that there is no theoretical guiding principle for selecting the appropriate point in the system. However, experience in other markets indicates the choice can be driven by practical considerations, such as the distribution of loss effects between LMPs and the effect of this distribution on market participants.

Regardless of how the slack node is defined, provided that the same LMP split determines both the loss and congestion rent *and* the FTR payouts, the revenue adequacy of the FTRs is theoretically preserved.[50] The research undertaken by AEMC staff to date has not identified that the US markets have encountered particular difficulties with FTR revenue adequacy associated with their approach to selecting a slack node.

However, as the selection of slack node can affect the LMP components, and therefore the value of FTRs, it is important that market participants have visibility with regard to what the slack node is, and how it affects the LMP composition and FTR payments.

3.8.5 Conclusions

Based on an analysis of the issues outlined above, the preferred design option is Option 2 – FTRs that only hedge congestion costs. This is the most appropriate starting point for implementing an LMP/FTR model in the NEM.

Option 1 has certain advantages. In particular, it is relatively simple for participants to understand, as the FTR payout is simply a function of the difference in price between two locations. Unlike Option 2, participants would not need to consider how particular components of LMPs are derived and affect the value of the FTR instruments. In addition, it would provide participants with the option to purchase a financial product that manages the price risk associated with marginal losses, which has recently been of concern to some participants.

However, the research undertaken indicates that there is a high level of complexity involved in ensuring that the type of FTR product that Option 1 would make available could be funded. This complexity would impact the level of confidence that the FTR products issued would have a high degree of firmness, reducing their usefulness as a risk management tool. Feedback received from stakeholders has indicated that firmness is a very important characteristic of FTRs. Further, depending on how Option 1 were to be implemented (for

50 That is, assuming that the capacity of the network that is assumed in the FTR is an accurate representation of the network at the time the FTRs are active. In this example, this would require that FTR sales do not exceed P^{Max} and that actual network capacity is not less than P^{Max} when the FTRs are settled.

example, as Option 1a), it could potentially restrict the ability of participants to manage price risks associated with congestion (relative to the issuance of congestion-only FTRs). The ability to manage congestion risks effectively may be a more important consideration for participants than the option to hedge marginal losses.

In contrast, Option 2 has the advantage of providing much greater certainty that the FTR products issued through the auction will have a high degree of firmness, and that the quantity made available to manage congestion-related risk can be maximised (within the limitations of the transmission system).

The main disadvantage of Option 2 is that, at least initially, participants would not have access to a product that manage the risk of fluctuating marginal losses. This may be of concern to participants if dynamic marginal losses are introduced. However, the option to introduce FTRs that hedge marginal losses at a later date (or indeed for such products to arise on the secondary market, outside of the FTR auction administered by AEMO) would not be closed off by this starting point. Therefore, there would be scope to reconsider this aspect of the FTR design as experience with managing dynamic marginal losses grows.

Accordingly, the current design proposal is that, similarly to the LMP/FTR designs implemented in the US:

- FTRs would not hedge LMP differences caused by marginal losses.
- Accordingly, the energy, loss and congestion related components of LMPs would be identified separately. This would be achieved through the selection of an appropriate slack node.

Further analysis and discussion with stakeholders would be needed to confirm what the appropriate choice of slack node would be for the NEM. This will likely depend on both other components of the access model design (for example, the specific details of how dynamic marginal losses could implemented in the dispatch engine, and the design of the simultaneous feasibility auction) and the fundamental characteristics of the NEM (e.g. the distribution of load and generation).

4 QUANTITATIVE IMPACT ASSESSMENT

This chapter provides an overview of the Commission's updated quantitative assessment of the costs and benefits of the access reform. It covers:

- plans in the coming months for a detailed implementation cost impact assessment, including working with AEMO and participants to gain a better understanding of their potential costs
- NERA's benefit analysis
- implementation cost assessments to date.

NERA has estimated that the net benefit of transmission access reform in the NEM (excluding implementation costs) to be substantial, in the order of **$6.2 - $8.2 billion** in total consumer benefit over fifteen years operation of the NEM from 2026 to 2040.

These benefits are expected to accrue immediately on implementation of the reform and to persist and grow over time as changes in the NEM gather pace with the replacement of existing thermal generation with new renewable and dispatchable sources of power.

The expected benefits are not dissimilar in magnitude to those forecast and observed in markets overseas where similar reforms have already been implemented, or are in the process of being implemented. They also relate to a range of factors, including:

- improved efficiency of dispatch,
- improved efficiency of investment in new generation, storage and transmission,
- benefits from the implementation of dynamic loss factors and
- above all lower prices for consumers, compared to a world in which access arrangements are left unchanged.

While implementation of such a major change in the NEM will have costs for the market, the expected costs of this change are likely to be an order of magnitude below the estimated benefits of the reform. The preliminary, initial, high-lvel costs provided by Hard Software, suggests that a well-planned implementation in the NEM could cost in the order of $60-$70 million for AEMO's total costs alone. This magnitude of figures is supported by the reform experience in Ontario market. We recognise that these figures are on the lower side of what a more detailed assessment of the cost of implementation is likely to reveal.

Further work is now under way to test this figure in detail with stakeholders, in particular through engagement with AEMO and market participants on the full range of changes and costs that are required to implement the reform. While this cost figure is only preliminary, prior to more detailed implementation cost analysis being completed, it is an order of magnitude lower than the estimated benefits.

Preparation of detailed cost estimates for the implementation of the reform will provide an opportunity to maximise any implementation cost efficiencies for AEMO and market participants from other reforms being considered, such as those in the ESB's post 2025 review by potentially coordinating the timing and staging of transmission access reform with other system changes and reforms that may be required.

4.1 Overview of NERA cost benefit analysis

4.1.1 Background

In January 2020, NERA Economic Consulting (NERA) was tasked with providing a detailed cost benefit analysis of implementing transmission access reform in the NEM. This analysis was divided into two stages.

The first stage from January 2020 to March 2020 comprised a benchmarking study of cost benefit analyses conducted for similar reforms implemented in overseas jurisdictions. This was published alongside the March paper.[51]

The first stage report found that the potential net benefits from the introduction of LMP and FTRs in the NEM would be significant. While the most recent guide to implementation costs was provided by the example of the Ontario market (which is currently going through the process of implementing similar but larger reforms, and so the costs are considered to be most relevant) at $149m based on an ex ante 2015 study, this initial cost would be more than offset by the ongoing benefits to the improved efficiency of dispatch alone, in the order of $30-$137m per annum. The capital cost savings from better siting of generation investment were seen to be in the order of hundreds of millions per annum. Overall benefits to consumers reflecting expected reductions in wholesale prices paid by consumers were also expected to be in the order of hundreds of millions per annum.

This analysis was conducted across a number of different markets that have implemented LMP and FTRs and was careful to cast the benefits analysed in the light of the particular characteristics of the NEM, and the differences between the NEM and these markets.

The second stage ran from April 2020 to August 2020, and assessed the impact of the reform with specific reference to the NEM. This was conducted through the construction of a nodal model of the NEM, and a comparison of forecast outcomes under this model with the proposed reform in place, compared to forecast outcomes if the current regional pricing arrangements were retained. Implementation costs were not considered.

The methodology employed in analysing the net benefits in the NEM was the subject of a technical working group conducted in June.[52] Generally stakeholders considered that this was an appropriate approach.

4.1.2 Analysis

The scope of the net benefits of reform covered a number of tranches of benefit. These are as follows:

Social benefits: the improvement in economic efficiency, which is quantified as the net reduction in system costs, with this benefit accruing to society as a whole:

51 See: https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-_aemc_transmission_access_reform_-_march_update.pdf

52 See: https://www.aemc.gov.au/news-centre/media-releases/grid-access-reform-technical-working-group-modelling-meeting-summary

- capital and fuel cost savings over time from more efficient locational decisions by generators.
- dispatch efficiency improved through elimination of race to the floor bidding. Under the current arrangements, generators have a financial incentive to bid to the floor price in the event they would otherwise be "constrained off": not dispatched despite offering at a price below the regional reference price, as a consequence of constraints. These generators share output rather than allocate it to the lowest cost generator, which increases system costs.
- more efficient dispatch through the incorporation of dynamic loss factors.
- competition benefit. Efficiency benefits related to increased competition.

Wealth transfers - reductions in prices can occur that do not result in any change in the underlying volume of electricity generated/consumed or the costs of producing that volume of electricity. This occurs where the reduction in bills for consumers are as a direct result of a reduction in revenues for generators (including hypothetical, yet to be built generators), with no *overall* benefit to consumers and generators collectively:

- Wealth transfers. The degree to which transmission access reform leads to changes in market price outcomes resulting in a transfer of wealth from those receiving payment from the wholesale market, generators, to those making payments to the market, consumers.
- Competition related wealth transfers from generators/retailers to consumers.

Consumer benefits are the sum of the social benefit and the wealth transfer, assuming that changes in system costs ultimately accrue to consumers.

NERA created a nodal model of the NEM using the PLEXOS software modelling program, and then applied two different pricing outcomes:

- the existing pricing mechanism of the NEM, with regional reference prices,
- locational marginal pricing for generators.

Differences in modelled outcomes between these two pricing mechanisms were compared to estimate the net benefits (i.e. the benefits and costs) of the proposed transmission access reform.

The key input assumptions for the model are consistent with AEMO's Electricity Statement of Opportunities (ESOO) and with the Integrated System Plan (ISP).[53] The modelling assumes that priority one and two transmission projects, including relevant transmission infrastructure for renewable energy zones, and the Marinus Link from the ISP go ahead in both the reform and no reform modelling runs.

NERA assumes new construction of renewable plant to meet published renewables targets:

53 NERA used data and assumptions from the Draft 2020 Integrated System Plan database published in December 2019. Draft ISP: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/Draft-2020-Integrated-System-Plan.pdf, Assumptions workbook: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-input-and-assumptions-workbook-v1-3-dec-19.xlsx?la=en

- LRET: Nationwide generation target requiring 33,000 GWh of renewable generation in 2020
- QRET: Queensland generation target requiring 50% of total capacity to come from renewables by 2030
- VRET: Victoria generation target requiring 40% of generation to come from renewables by 2025 and 50% by 2030.

Direct costs associated with the reforms - such as implementation costs - were not in NERA's scope of work. These are discussed in section 4.3.

Table 4.1 presents a summary of the results of NERA's analysis.

Table 4.1: **Summary results of NERA Cost Benefit Analysis of Access Reform**

	DESCRIPTION	BENEFIT IN 2026 ($2026)M	NPV 2026-2035 ($2020M)	NPV 2036-2040 ($2020M)	NPV 2026-2040 ($2020M)
1	Capital and fuel cost savings from more efficient locational decisions	66	454	1,285	1,738
2	Dispatch efficiency improved through elimination of race to the floor bidding	141 - 181	700 - 898	95 - 122	795 - 1,020
3	Dynamic losses	102	510	151	661
4	Competition benefit	0 - 9	0 - 140	0 - 68	0 - 209
	Total social benefit	**308 - 358**	**1,663 - 2,002**	**1,531 - 1,626**	**3,194 - 3,629**
5	Wealth transfer	105	1,176	1,785	2,961
6	Competition related wealth transfer from generators/retailers to consumers	0 - 200	0 - 1,119	0 - 536	0 - 1,655
	Total Consumer Benefit	**414 - 662**	**2,839 - 4,297**	**3,316 - 3,948**	**6,155 - 8,245**

Source: NERA Cost Benefit Analysis of Access Reform: Modelling Report, August 2020

The total consumer benefit estimated by NERA is significant: between $6.2 and $8.2 billion over 15 years operation of the NEM from 2026 to 2040 in net present value terms.[54]

54 Net present value: the present value of a security or an investment project, found by discounting all present and future receipts and outgoings at an appropriate rate of discount - assumed to be 7 per cent by NERA.

Approximately half of this is benefit (the total social benefit) arises due to improved economic efficiency, while half is as a result of a wealth transfer from generators (including from hypothetical, yet to be built generators) to consumers.

Approximately half of the social benefits in NPV terms occur from 2036 to 2040. The accrual of benefit in this period is largely prompted by retirement of coal plant at this time, consistent with assumptions made in the ISP. Were coal plant to retire earlier, the benefits of reform would be brought forward and therefore be larger in net present value. Prior to coal retirement, the benefits are still substantial and commence in the first year of operation of the reform.

Capital and fuel cost savings

Capital cost savings, and fuel cost savings as a result of more efficient investment, are significant under the proposed reforms.

NERA's modelling suggests that the existing regional reference pricing approach, which sends an inefficient price signal, results in considerable inefficiencies. Under the transmission access reforms, the efficient signal provided by LMPs results in more efficient quantities and patterns of investment.

Generators are also better utilised as a result of the reforms. Renewables plants have higher capacity factors under transmission access reform than under a scenario in which existing transmission access arrangements are maintained, because generators are located making better use of the transmission infrastructure available, avoiding congestion.

Capital and fuel cost savings increase over the forecasting period, particularly as coal plants retire and a greater amount of new investment is required to replace retiring plant. Under transmission access reform, this new investment receives a more accurate price signal on where to invest in the network. As a consequence, less capacity is required to be built, and the capacity that is built is used more effectively, to the long term benefit of consumers.

Dispatch efficiency

Dispatch efficiency benefits relate to the removal of race to the floor bidding under transmission access reform. In the current market, generators behind supply constraints with marginal costs below the RRP but which are constrained off (i.e. not dispatched), have an incentive to "race to the floor" in order to receive the RRP. These generators share output rather than output being allocated it the lowest cost generator, which increases system costs.

NERA estimates the benefit relating to removing incentives for race to the floor bidding is substantial, particularly through the first ten years operation of grid access reform, when non-zero marginal cost generators (coal and gas plant predominantly) still form the majority of dispatchable capacity in the system, and are dispatched more efficiently under grid access reform.

The operational benefits from changing the incentives for generators to 'race to the floor' are forecast to decline over time. This happens as higher cost plant (e.g. coal, gas) exits the market. Once this happens, given the generation mix has similar SRMCs, race to the floor bidding behaviour results in plant with similar cost displacing one another (e.g. renewables) –

with lower resulting inefficiencies. Nevertheless, while these benefits decrease over time, they are substantial (~$120m pa) until 2035/36, and are still in the order of $60m pa over the rest of the forecasting horizon.

The impact on total system costs of racing to the floor depends on the relative costs of the generation technologies on the system. In NERA's analysis, most of the change in system costs as a result of race to the floor bidding arises from higher cost coal plant supplanting cheaper coal plant or other technologies. In a future scenario where all plant on the system had zero marginal cost, the impact of dispatching one or other plant would be minimal, however the increasing role of batteries, with a positive opportunity cost and a cost associated with each dispatch, means that race to the floor bidding would continue to result in increased system costs.

Dynamic losses

The benefit of adopting dynamic MLFs accrues from the cheaper procurement of energy in dispatch as the cost of losses for each generator is more accurately reflected in each five minute dispatch interval.

NERA's calculation of this benefit encompasses both a "volume effect" in that the procurement of volumes to cover losses is more efficient and a "price effect" from the more accurate reflection of generators bids in dispatch.

NERA note that the "volume effect" benefit may be an overstatement, in so far as AEMO accounts for dynamic losses in its demand forecasting methodology. The analysis on the other hand may understate the impact of dynamic losses on the efficiency of investment in the system over time. This benefit is not addressed.

Competition benefits: Efficiency gains and wealth transfers

Introducing FTRs in place of SRAs may provide an improvement in locational price hedging across different regions of the NEM. Where an inability to hedge locational price risk is currently hindering inter-regional competition, and where there are existing competition concerns in certain regions of the NEM, this may result in improved competition in generation and retail markets.

Competition benefits arise both as a function of the impact of increased competition on lowering prices (the wealth transfer benefit) and as a function of the impact of increased competition on the productive efficiency of the market (the action of market participants to operate more efficiently and reduce costs as a result of increased competition). There is a further benefit to the extent that additional demand is served as a consequence of lower prices, referred to as an allocative efficiency benefit in NERA's report.

NERA suggest that some competitive benefit is likely to accrue in some regions of the NEM under grid access reform, where concentration in generation ownership and the lack of an effective risk management tool to manage competition has prevented new entrants from entering the market, or smaller market players from aggressively pursuing greater market share. However, NERA's analysis recognises that this benefit is contingent both on the degree to which there are competition concerns and the extent to which conclusions can be drawn on the improvements to inter regional risk management from the introduction of FTRs. The lower bound of the benefit, estimated by NERA to be zero, is informed by these considerations.

NERA based much of the competition analysis on analysis of the New Zealand market[55] following the introduction of FTRs.

BOX 5: NZ COMPETITION EXPERIENCE IN RELATION TO LMP AND FTRS

FTRs were implemented in the New Zealand electricity market in 2013 across two nodes, and were extended in 2014 to include three new nodes, then again with three further nodes in 2018.

NERA analysed data on the regional share of generation and retail to test what impact the introduction of FTRs had on competition in regional markets.

In particular, NERA considered (as displayed in the figure below) the regional proportion of generation capacity and retail customers in the North Island, for of each of the 6 main gentailers in New Zealand. For each gentailer, the graph shows the proportion of the gentailer's retail customers in the North Island (the remaining proportion will be located in the South Island, not shown on the graph), and the proportion of the gentailer's generation capacity in the North Island (again with the remaining proportion in the South Island). A vertical line is shown at 2013, when FTRs were first implemented at two nodes.

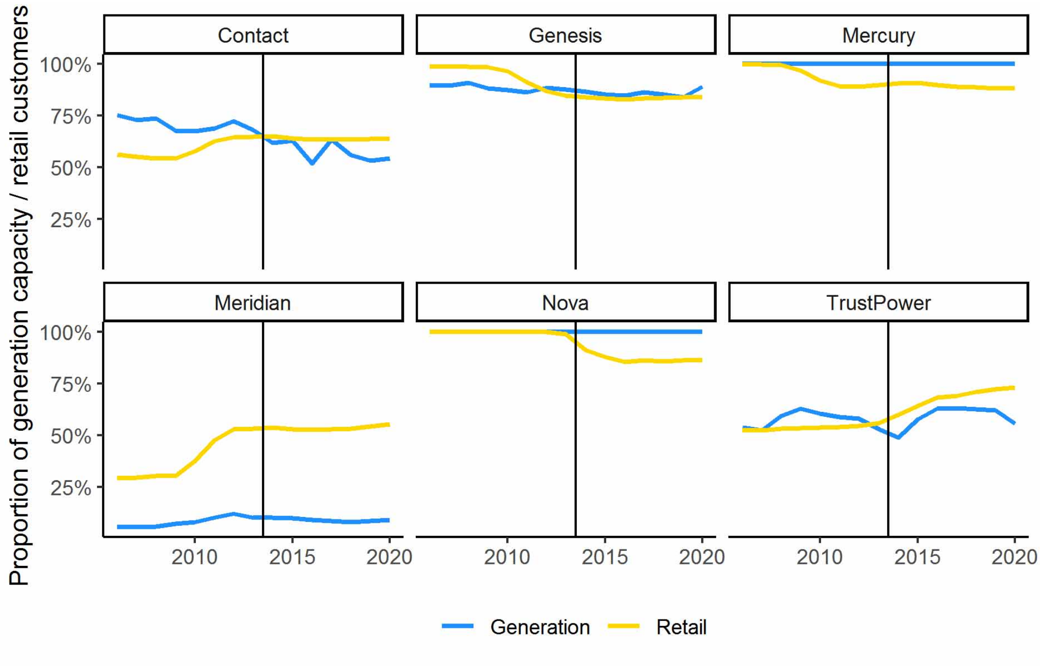
The graphs show some evidence that FTRs may have allowed gentailers to break regional vertical integration, albeit this evidence is limited. Nova is of particular interest, as the figure shows the proportion of Nova's customers in North Island markets dropping shortly after FTRs were first introduced, due to its entry into South Island retail markets, despite it having all of its generation located in the North Island. The graphs for Mercury Energy/Mighty River Power and Genesis Energy also show a slight downward trend in the proportion of retail customers in the North Island, despite these gentailers having all, or the majority of, their generation in the North Island. Contact Energy has decreased the proportion of its generation in the North Island, despite having a relatively large proportion of its retail customer base there. Meridian Energy has increased its North Island customer base, despite most of its generation being located in the South Island.

NERA note, however, that in many cases these trends were evident prior to the introduction of FTRs. Moreover, there were a number of other reforms occurring over the period of NERA's analysis, to enhance competition in both retail and generation markets, therefore making it difficult to isolate the impact of FTRs from other market changes. The New Zealand example should not be relied upon, and treated with caution since it is a different market to the NEM. However, it provides a useful case study demonstrating the potential range of benefits of FTRs to competition across different regions in a connected market. NERA also

55 Terminology used in the explanatory box refers to nodes. In New Zealand the terminology used is hubs, but the term nodes is used here for ease of comparison with the proposed reform design.

note the recent view expressed by the New Zealand Electricity Authority, stating that "we are pleased with the current state of the FTR market, and its impact in supporting retail competition".

Figure 4.1: Proportion of each NZ gentailer's total generation capacity and retail customers located in the North Island



Source: NERA analysis of EA EMI data (Source: https://www.emi.ea.govt.nz/Source:)
Note: The vertical black line is the date when FTRs were introduced in New Zealand.

Source: NERA report

Wealth transfers

NERA estimates that consumers will pay lower prices in the modelling, in part due to the societal benefits described above, but also because of wealth transfers between generators (including yet-to-be built generators) and consumers. This arises because generators are paid the marginal value of energy dispatched at their specific location, or the LMP, versus being paid for the marginal value of energy supplied to the regional reference node, or the RRP. On average, the LMP received by generators under the reforms tends to be a lower price than the locational marginal price at the regional reference node (ie, the regional reference price). This is reflected in NERA's analysis in the extent to which the LMP is seen to deviate from the RRP (Figure 3.5 in the NERA report).

The extent of this difference increases over time depending on the level of congestion on the transmission network. In a world without transmission access reform, this increases substantially following the retirement of significant coal capacity post 2035, and the need to build new capacity in already constrained parts of the network.

Transmission access reform enables these increasing congestion rents, or the difference between the RRP load pays and the effective value of generation as settled at the LMP, to be returned to consumers.

Liquidity in the contract market

The impact on contract market liquidity was also analysed by NERA. NERA suggest that no material impact on contract market liquidity is expected over the long term.

Transmission access reform changes the risks faced by generators. Transmission access reform introduces basis risk in that a generators' locational marginal price may differ to the VWAP or RRP at which forward contracts may be struck. The reform introduces an instrument, in the form of an FTR, that can be used to hedge that basis risk. NERA found that liquidity is unlikely to fall if generators are able to purchase sufficient FTRs to cover their existing forward contracting level, such that their risks remain the same.

The analysis found that the incentive to hedge declines for generators who do not own an FTR. As a consequence, NERA concludes that liquidity could fall in products trading outside the period in which FTR products are available. The Commission notes that a feature of the design is that FTRs will be made available in the auction up to ten years in advance, for a limited portion of the available network capacity but with increasing tranches of the available network capacity released over time. This timeframe covers the period in which ASX and OTC forward contracts are traded.

NERA concluded in addition that inter-regional FTRs may provide liquidity benefits to market participants who may more easily access forward contract products in other regions at lower transactions costs.

4.1.3 Conclusions

Modelling the benefits of transmission access reform in the NEM is a challenging exercise, requiring a nodal representation of the NEM over an extended time period. Representation of participant behaviour under transmission access reform and the existing rules requires some simplifying assumptions, but a number of key conclusions can be drawn from the results of the analysis.

First, the order of magnitude of the benefits is substantial and is supported by previous analysis by NERA of international estimates of the benefits of LMPs/FTRs. The stage two analysis concludes total consumer benefits are likely to be in the range $414 - $662m per annum in benefits. The stage one analysis implied a range of $739 - $1,127m[56] per annum in total consumer benefits, based on overseas implementation of LMP/FTRs.

Second, benefits are not restricted to one particular effect of transmission access reform in the NEM. They derive from changes in how power is dispatched in real time, how investments are located over the medium to longer term, how prices are likely to settle with

56 This range is inclusive of wealth transfer benefit. The figure exclusive of wealth transfer benefit is estimated at $382 - $877m per annum. Table 3, NERA Costs and Benefits of Access Reform, March 2020. https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-_aemc_transmission_access_reform_-_march_update.pdf

the move to locational marginal pricing and competition benefits to the extent that FTRs allow for increased competition across difference regions in the NEM. There are also additional benefits from the adoption of dynamic loss factors.

Third, the rate of accrual of benefits, in particular in relation to the benefits of more efficient investment appears to be correlated with the rate of change in the NEM. The more retirement of existing plant expected, the earlier this occurs, and the greater the rate of investment in new generation and storage assets, the greater the benefit from locational signals that better indicate where investment would best be located on the network. Under the scenarios in the NEM modelled by NERA, the generation mix changes significantly over time, with significant thermal capacity retiring, in particular coal, and significant new build of renewable sources of power. The greater the change in generation mix over time, and the quicker this occurs, the greater the benefits of access reform are likely to be.

NERA's latest and previous quantitative analysis is consistent with both long-lasting, practical international experience of LMPs and FTRs, and the theory of pricing based on marginal costs. It reinforces the Commission's view that consumers are clear beneficiaries of transmission access reform and as such the reform is likely to contribute to the achievement of the National Electricity Objective (NEO). The NEO is:[57]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system

The Commission seeks stakeholder feedback and submissions on NERA's analysis.

4.2 Plan for detailed implementation cost assessment

In addition to the analysis published by NERA in March 2020, we have also sought to obtain a preliminary assessment of the direct costs associated with proceeding with the transmission access reform.

Now that the core preferred design specifications for the overall access model design have been made, we plan to engage a consultant to conduct a detailed implementation cost assessment during Q3-Q4 2020. This will include discussions with AEMO and market participants on the costs of a NEMDE or market management system (MMS) redesign, implementation costs and participant costs.

Previously, cost assessments associated with transmission access reform were sought, but this was difficult to obtain detailed figures because:

- was still finalising the overall transmission access model design
- required additional time to ensure that extensive stakeholder engagement could occur on the costs of the reform across the NEM.

57 Section 7 of the NEL

Recently, we have obtained preliminary costs of transmission access reform for both AEMO and market participants through its own assessments and by engaging Hard Software to provide preliminary figures on the costs of different reform options.

Due to the aforementioned challenges, Hard Software's assessments of the costs of the reform are on the basis of their expertise rather than on engagement with AEMO and market participants on their costs.

The intent of these preliminary assessments was to provide indicative costs to inform decisions on VWAP and dynamic losses and to provide benchmarked cost figures to compare to NERA's analysis.

We recognise that these figures are on the lower side of what a more detailed assessment of the cost of implementation is likely to reveal and are keen to work with stakeholders to obtain more precise estimates.[58] Any further considerations could include considering that while efficiencies are likely to be gained from coordinating the implementation of reform, any costs estimated should only capture those required to implement transmission access reform.

4.3 Overview of preliminary reform cost assessment work

This section includes both the assessments completed to date, and do not include the costs of unrelated upgrades that stakeholders could incur while preparing for the transmission access reforms.

We are interested in stakeholder views on whether the preliminary figures in this section are reflective of AEMO's and market participants' estimated costs due to the reforms.

4.3.1 AEMC obtained preliminary figures for IT and associated costs

We have also undertaken a preliminary high level assessment of both IT costs and other costs. These preliminary figures are provided below.

<u>AEMO's IT-associated costs for a new MMS</u>

A number of leading providers of market management systems provided the AEMC with a range of $5m to $50m as ballpark figures for the vendor costs of a new market management system.[59] This excludes internal costs for AEMO. Various consultants that are familiar with similar IT implementation projects overseas provided high-level cost assessments of around $100m for vendor costs of a new MMS in our scoping conversations.

The Ontario market operator (the Ontario IESO) is implementing similar but broader reforms.[60] In 2015 the IESO assessed the costs for LMP and FTR implementation at a total of $149m.[61] Their 2015 assessment suggested that the system operator costs would be 38% of

58 We are interested in any details from stakeholders about the potential costs, or additional cost elements that should be considered. For example, Neoen has previously commented that the ongoing cost of modelling will become substantial for participants. See: Neoen, submission to October discussion paper.

59 This corresponds with Hard Software's Option 3 in section 4.3.2.

60 The Market Renewal reforms in Ontario include the introduction of LMPs, the introduction of an ahead market, and changes to the process by which generators commit their units.

61 This figure is in $AUD 2019 and refers to one-off implementation costs only. For more information, please see NERA's March 2020 report at: https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-

this total or $57m in one-off implementation costs.[62] In 2019, in analysis of the broader reform package, including ahead markets and generating unit commitment processes, they reported higher total market operator implementation costs of $184m, with ongoing costs for the market operator of approximately $6.5m in addition to this.[63] Hardware and software costs represented $56m of the initial implementation costs.[64] The system operator costs for LMP and FTR reforms of $57m provided in 2015 plus the ongoing costs for the market operator of approximately $6.5m provided in 2019 could suggest total market operator costs of around $64m. This may not be relevant to considering the costs of transmission access reform only, given that Ontario implemented several changes at the same time.

ERCOT shifted from a zonal regime to a nodal regime in 2010. This involved NPV costs incurred of $971m.[65] However, it is important to note that the scope of ERCOT's reforms was larger than the NEM's transmission access reforms; their reforms also included a shift from portfolio bidding to resource-specific bidding, a move from 15-minute to 5-minute dispatch intervals, the implementation of a day-ahead market, and changes to ERCOT's congestion management practices.[66]

According to the report of a consultant retained by ERCOT and the Texas Public Utilities Commission to "perform an independent assessment and evaluation of the development and implementation of ERCOT's nodal market system", several of the main reasons for the high costs of ERCOT's reform were due to its failure to maintain an effective program management and governance structure, particularly during the early stages of its transition. In particular, ERCOT did not appropriately monitor, manage and mitigate the effects of many of the key risks inherent to a project of its complexity and size. The project also faced a lack of senior management/executive support, business ownership/accountability, over-optimistic planning and unrealistic timescales, technology integration problems and employee turnover issues.[67]

<u>Market participant costs from Optional Firm Access</u>

While completing the Optional Firm Access (OFA) Design and Testing review on transmission access in 2014-2015, the AEMC engaged Market Reform to assess the adoption costs to OFA for generators in the NEM, including both implementation costs and five years of operating

_aemc_transmission_access_reform_-_march_update.pdf

62 ibid.

63 This figure is in $AUD 2019 and refers to one-off implementation costs only. For more information, please see NERA's March 2020 report at: https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-_aemc_transmission_access_reform_-_march_update.pdf. See also: http://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf?la=en, p. 19

64 This figure is in $AUD 2020m. The figure in Ontario's report is $53m CAD. Source: http://www.ieso.ca/-/media/Files/IESO/Document-Library/market-renewal/MRP-Energy-Stream-Business-Case-2019.pdf?la=en, p. 19.

65 This figure is in $2019 AUD. The total costs in USD reported were $660m. Source: https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-_aemc_transmission_access_reform_-_march_update.pdf, p.19

66 Source: https://www.aemc.gov.au/sites/default/files/documents/nera_benchmarking_consultant_report_-_aemc_transmission_access_reform_-_march_update.pdf, p.2

67 More detailed explanations for the reasons behind the high costs of ERCOT's nodal reforms can be found at 'Evaluation of the ERCOT Texas Nodal Market Implementation Project (TNMIP)', Navigant, August 2012. This report can be found by searching for its title at: https://interchange.puc.texas.gov/

costs. Market Reform provided a cost range of approximately $50m to $129m with a best estimate of approximately $79m for all generators across the NEM.[68]

4.3.2 Hard Software preliminary figures

In July 2020, Hard Software was engaged by the AEMC to assess the IT costs of the reform for both AEMO and for market participants on a preliminary basis. While associated professional services were included in these assessments, other costs (such as training, legal and market design costs) were not estimated. Their full report is available on the transmission access reform project page.[69]

The intent of Hard Software's work was to provide indicative costs to inform decisions on the introduction of VWAP (section 2.2) and dynamic losses (section 2.3) and to provide benchmarked cost figures to compare to NERA's benefits analysis.

Hard Software analysed three options and developed upfront and annual costings associated with IT costs for each one:

- Option 1 involves calculating LMPs for generators using the current NEM dispatch engine (NEMDE). This option would facilitate transmission access reforms that would not include VWAP or dynamic losses, but instead would retain the regional reference price for unscheduled market participants and static marginal loss factors.
- Option 2 involves calculating LMPs for generators and for loads using the current NEMDE. This option facilitates a transmission access reforms that would include VWAP, but would exclude dynamic losses.
- Option 3 involves calculating LMPs with a new security constrained dispatch system and associated market management system changes, which would facilitate both VWAP and dynamic losses.

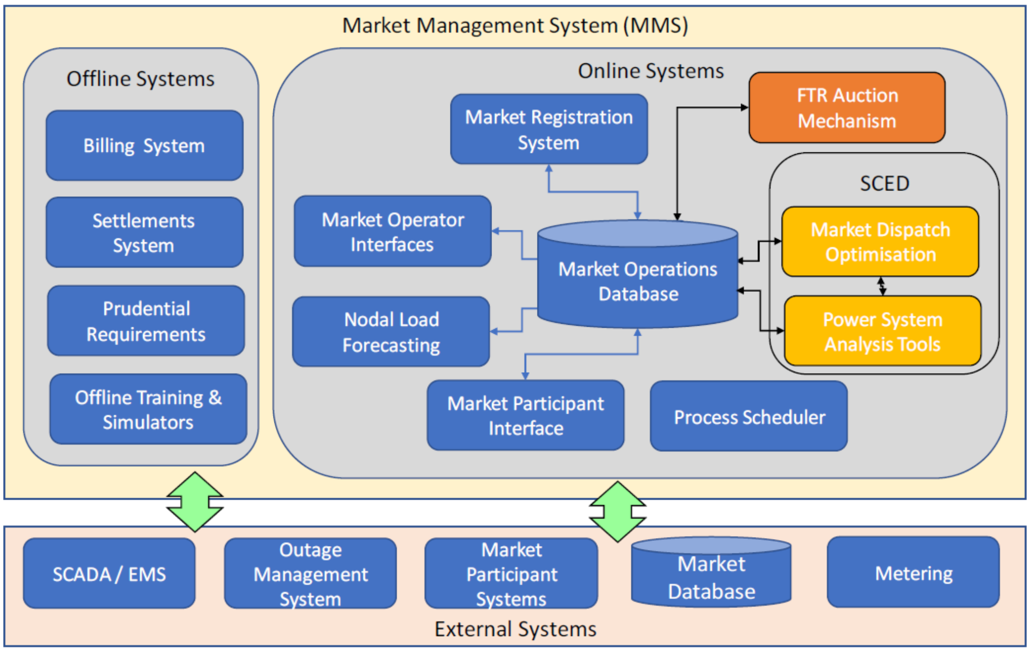
BOX 6: MARKET MANAGEMENT SYSTEMS

A market management system (MMS) is a system that covers a large number of functions for an electricity market system operator, including dispatch systems. NEMDE is one part of AEMO's broader market management system, as is its supervisory control and data acquisition (SCADA) systems and its market settlement and transfer solutions (MSATS) systems. The regular components of a modern market management system are provided in the figure below.

68 All figures are in $2014. Source: https://www.aemc.gov.au/sites/default/files/content/a3f8d13e-b49b-4c4a-9f08-9331883f8393/Market-Reform-Transaction-costs-of-OFA-for-generators-in-the-NEM.pdf

69 See: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

Figure 4.2: Components of a market management system



Source: Hard Software, 'A preliminary indication of the Information Technology costs of Locational Marginal Pricing', September 2020. This report can be found on the Transmission Access Reform project page.

One of the main relevant systems for the purposes of transmission access reform is NEMDE, which is represented here by the Energy Management System or EMS external system and by the Market Dispatch Optimisation online system. Another important system for transmission access reform is an FTR Auction Mechanism.

Hard Software's report provides a more detailed breakdown of the AEMO MMS components that would likely require upgrading, replacements or new versions where a current one does not exist (such as nodal load forecasting).

Other potential reforms may require similar changes to different aspects of AEMO's MMS, including ESB reforms such as ahead markets and two-sided markets, as well as AEMO's ST PASA replacement project. As a result, the costs associated with making changes to AEMO's MMS can likely be shared with some of these other reforms.

Source: Hard Software Report. https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data. Source for the ST PASA replacement project: https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project

Hard Software made several key assumptions when developing their report:

- Any change to LMP would not occur for four years and most existing market contracts would have expired by then.
- Cost estimates are based on assessments of incremental costs from normal operations.
- No allowance will be made for redeployed existing internal resources or the upgrade to legacy systems unrelated to the implementation of the proposed market reform.

- The scope of the analysis is based solely upon external review of the requirements associated with LMP for market operations and participants.
- That some of the IT costs for AEMO's changes could be shared with other similar reforms, which would require similar implementation costs to be incurred.

The table below provides a summary of the preliminary upfront and ongoing costs that Hard Software provided for pursuing each of the three options in its report.

Table 4.2: AEMO and market participant upfront and ongoing IT-associated costs of the transmission access reforms

	OPTION 1		OPTION 2		OPTION 3	
	Upfront costs	**Ongoing annual costs**	**Upfront costs**	**Ongoing annual costs**	**Upfront costs**	**Ongoing annual costs**
AEMO	$8.2m	$2.7m	$15m	$3.1m	$23.6m	$4.5m
Market participant	$31.5m	$0	$37.9m	$0	$37.9m	$0
Total	**$39.7m**	**$2.7m**	**$52.9m**	**$3.1m**	**$61.4m**	**$4.5m**

Source: Hard Software ,'A preliminary indication of the Information Technology costs of Locational Marginal Pricing', September 2020, This report can be found on the Transmission Access Reform project page.

Note: Market participants include generators, retailers, small generation aggregators, non-scheduled load participants and network service providers.

Note: AEMO's upfront costs include hardware and software costs, as well as professional services needed for customisation of the MMS products, factory acceptance testing, onsite interfacing and integration, site acceptance testing and training and handover to staff.

In NPV terms over a period of 20 years, the costs would be:

- $62m for option 1 (including $34m from AEMO costs)
- $80m for option 2 (including $46m from AEMO costs)
- $105m for option 3 (including $71m from AEMO costs).

Hard Software also noted (but did not quantify) IT benefits in their report that were not in the scope of NERA's work assessing the economic impacts of the transmission access reforms. For example, Hard Software noted that the current use of manual constraints can undermine dispatch efficiency compared to constraints being calculated automatically through a new security constrained dispatch system.

The Commission is aware of the importance of obtaining cost estimates to underpin market design decisions, but notes that there is difficulty and uncertainty in achieving this for a variety of reasons. IT system costs are inherently difficult to estimate. Recognising this, the Commission has used a variety of approaches to discern some preliminary, indicative costs and drawn some broad conclusions from these, without relying completely on any one source of evidence. This has provided preliminary, high-level estimate for the cost figures that suggests that the costs are an order of magnitude lower than the estimated benefits, and may be incurred in any event as part of the overall market development program. We recognise that these figures are on the lower side of what a more detailed assessment of the cost of implementation is likely to reveal. We will be working with stakeholders and AEMO over the coming months to provide more precise figures now that more details of the reform are proposed.

4.3.3 Contract reopening costs

While the approximately four-year implementation period should allow all pre-existing ASX and SRA contracts to expire prior to the commencement of the LMP/FTR regime,[70] there are some longer-term contracts (particularly power purchase agreements (PPAs)) that have already been struck and will likely need to be reopened in response to changes of prices that market participants will face due to the transmission access reforms. This is because PPAs use the regional reference price currently faced by both generation and load as the strike price.

We understand that whether a contract reopener will be triggered will depend on a range of factors, including the terms and conditions of the contract and the approach ultimately taken in drafting the changes to the Rules.

A high-level assessment of the contract reopening costs associated with the transmission access reforms has been undertaken. Energetics and the CEFC provided the AEMC with non-confidential information on the number of renewable corporate, state government and wholesale PPAs they are aware of that are currently in effect in the NEM, which is 273. Assuming that none of these PPAs expire prior to implementation and that the transmission access reforms would trigger a reopening of each of these PPAs, and based on an estimated average cost of between $5k and $20k per PPA, this implies legal costs relating to reopening PPAs totalling $1.4m to $5.4m. Other reforms being considered by the ESB may also require the same contract reopenings to occur, suggesting that the incremental contract reopening costs of the transmission access reforms may be lower than these figures indicate.

4.3.4 Conclusion

While the cost figures and the figures developed by Hard Software for stage 1 are only preliminary high-level estimates, and should therefore be treated with caution, they appear to indicate that implementing the proposed transmission access reforms with VWAP and dynamic losses would cost around $110m, of which $70m would be AEMO's costs. This total figure includes both IT costs and contract reopening costs for market participants. The least comprehensive option for transmission access reforms which retains the RRP and static loss factors would cost around $70m, of which around $35m would be AEMO's costs.

Ontario's experience, in addition to the initial indications provided by Hard Software, suggests that a well-planned implementation in the NEM could cost in the order of $60-$70m for AEMO's costs alone.

Notably, the benefits that NERA suggested would accrue as a result of this reform (around $3.3bn in social benefits alone and around $7bn in consumer benefits) would far exceed the costs of the reform, even if AEMO's costs were to increase several fold beyond expected

70 See section 5.1 for more information on this period.

levels to resemble ERCOT's (ie, $970m of AEMO costs plus $46m of market participant costs, resulting in a total cost of $1.016bn).

We recognise that these figures are on the lower side of what a more detailed assessment of the cost of implementation is likely to reveal. We will be working with stakeholders and AEMO over the coming months to obtain more precise figures. This work will take into account the efficiencies that may be gained from undertaking implementation of other reforms at the same time.

We are interested in stakeholders views on this analysis, and would value evidence that stakeholders can share indicating that the costs may be similar or different to the ones obtained through the preliminary reform cost assessment work.

5 IMPLEMENTATION AND TRANSITIONAL FTR ARRANGEMENTS

This chapter covers the two stages of the 'soft start' to the transmission access reforms:

- the **implementation period** (between the date the final rule is made and the date that the reforms commence) - which allows coordination with other market reforms, as well as time for the market bodies and market participants to change systems and contracts in order to prepare for the regime; and
- the **initial period** (during which time a quantity of transitional FTRs would be provided to generators for free) - that would provide for a period of learning and would mitigate the financial impact of sudden changes.

The proposal for the length of the implementation paper is the same as in the March paper for the implementation period to be coordinated with the introduction of other reforms being considered under the ESB's 2025 work, and so would result in the LMP and FTRs regime going 'live' approximately four years after the final rule is made.

More detail has been set out on the initial considerations made in the March paper regarding the starting transitional FTR allocations and how these allocations would reduce over time. This section contains proposed timeframes for the entire allocation period for stakeholder feedback.

Finally, new positions are outlined on which parties would qualify to receive transitional FTRs and has progressed considerations on how transitional FTRs should be allocated between different parties.[71]

5.1 The implementation period

5.1.1 Background

The transmission access reforms are substantial reforms in their own right, and are being developed during a time when a number of other major changes and reforms are occurring across the NEM. As a result, like any other reform, there will be a period where the transmission access rules would not commence after being made, in effect temporarily retaining the current framework. This would allow market participants and the market bodies to make the necessary preparations for the changes, including system changes, contractual changes and training. It also enables the work required to implement the transmission access reforms to be better coordinated with other reforms being implemented in the sector, such as those being considered under the rest of the ESB's 2025 work.

Following extensive stakeholder feedback to have a longer implementation period,[72] the March paper proposed an approximately four-year implementation period prior to the implementation date of LMPs and FTRs (when the regime would go 'live').

71 Details on the Commission's current considerations and possible allocation methods are provided in Appendix B.

72 Submissions to the October 2019 access model discussion paper: Australian Energy Council, p. 1; Clean Energy Council, p. 4; CS Energy, p. 9; Energy Queensland, p. 19; EnergyAustralia, p. 1; ESCO Pacific, p. 1; Innology, p. 1; Meridian Powershop, p. 2; Origin Energy, p. 10; Snowy Hydro, p. 9; TasNetworks, p. 4; Windlab, p. 3

5.1.2 The timelines and process of the implementation period

The preferred design specification is to coordinate the implementation with other reforms such as those being considered in the ESB's 2025 work, and so would be in the order of a four-year implementation period.

This implementation period would have two major benefits:

- It would allow the reforms to be effectively coordinated with the other post-2025 reforms being developed by the ESB. While work on developing the transmission access reform commenced before the other ESB projects that are currently underway, it now forms part of the ESB's 2025 work, with the AEMC taking the lead on this workstream. As can be seen from the ESB's 2025 consultation paper, released at the same time as this paper, there is the need to coordinate the implementation of transmission access reform with the relevant periods for other major reforms, which requires consideration of which reforms should be implemented together.
- It would provide the first stage of the 'soft-start' that would help market participants to adapt to the changes that transmission access reform entails. A period in the order of four year provides a balance between obtaining the benefits from the reforms as soon as possible with providing time for AEMO and market participants to adjust to the reforms. Notably, four years will provide for ASX contracts, and existing SRA units, to come to an end and for market participants to analyse LMPs and prepare for the changed pricing arrangements.[73]

5.2 The initial period

To provide certainty to participants, this section sets out the preferred design choices regarding the nature and magnitude of the transitional FTRs allocated during the initial period, the length of the period, sculpting within the period and which participants would qualify for transitional FTRs. However, it does not set out design preferences on the methodology for allocating transitional FTRs between parties. Some options for the allocation are explained in Appendix B.

5.2.1 Background

During this initial period, the LMP and FTR system will be live, meaning scheduled and semi-scheduled market participants will be settled at their LMP and non-scheduled market participants be settled at their VWAP.

While the prior implementation period will help market participants to prepare for the new transmission access framework, the Commission considers that there are benefits in

73 LMPs available to registered market participants in the form of 'mis-pricing data' via its market management system (MMS) data model. For more information, see page 7 of https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Dispatch/Guide-to-Mis-Pricing-Information.pdf and (https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data). AEMO also makes this information publicly available at http://nemweb.com.au/. An interested party can select the 'Dispatch' tab followed by the 'Dispatch Summary - Public' tab and then download the CSV. The relevant prices are referred to as 'local prices'. Notably, these 'mis-priced' local prices do not account for the impacts of marginal loss factors, and AEMO does not have prices available for loads or non-scheduled generators. Additionally, since some system strength constraints or stability constraints are specific to certain units, the local prices affected by these constraints may not fully reflect the nodal price.

supporting market participants as they begin to interact with LMPs and FTRs on a daily basis. This initial period will provide the second stage and conclusion of the 'soft start' by allocating transitional FTRs for free to some market participants to help them adjust to these changes.

Stakeholders have indicated mixed views on the need for allocating transitional FTRs (the transitional FTRs have at times been referred to as 'grandfathered FTRs') in responses to previous AEMC papers and at the technical working group:

- The AEC and the Clean Energy Council expressed support for the allocation of transitional FTRs in their submissions to the October 2019 access model discussion paper.[74] The AEC suggested that not granting access rights to existing participants would risk introducing a financial shock to existing investments without providing any efficiency benefit.
- UPC Renewables and Canadian Solar both opposed the allocation of transitional FTRs in their submissions. Canadian Solar stated that if 90% or more of FTRs in most areas would be grandfathered for at least 5 years, then very few, if any, new development projects will be built because project finance will become unavailable.[75]

No firm recommendations were given on transitional FTRs in March, aside from the fact that there would be some. The March paper set out that:

- incumbent generators would need to be granted some level of financial transmission rights for free to assist the successful implementation of these reforms and give stakeholders the time needed to adjust to them
- the new arrangements should start somewhere close to most of the transmission network being 'covered' by transitional FTRs
- transitional FTRs should approximate the implicit access that generators currently enjoy, based on how they use the network
- recognising the fact that generators' implicit access is currently at risk of being degraded over time (for example by the location of new generators nearby), transitional FTR allocations would be reduced over time.

5.2.2 What are the objectives for the initial period?

The initial period and all associated transitional FTR allocations should be guided by three main objectives:

1. to provide a learning period to help market participants adapt to the reforms so they can develop their internal capabilities to operate new or changed processes under the access reforms without incurring undue operational or financial risks
2. to mitigate any sudden changes to wholesale electricity prices or margins for market participants on commencement of the reform
3. to balance the interests of incumbent generators against those of incoming generators and consumers.

74 Submissions to the October 2019 access model discussion paper: Australian Energy Council, p. 5; Clean Energy Council, p. 11

75 Submissions to the October 2019 access model discussion paper: UPC Renewables, p. 2; Canadian Solar, p. 3

5.2.3 What are transitional FTRs?

The transitional FTRs that would be available during the initial period (the first few years after the regime has commenced) are similar to the regular/enduring FTRs that can be purchased at the FTR auction, as they would provide a hedge between two LMPs (or VWAPs).[76] However, unlike regular FTRs, these transitional FTRs would be allocated to generators for free during this period to mitigate against sudden changes and provide a learning period for engaging with an LMP/FTR regime.

Secondary trading of transitional FTRs should be allowed (as would be the case with the enduring regime). This is because it should:

- provide for greater liquidity in the secondary market
- provide new entrants and non-physical participants with greater access to FTRs during the initial period
- provide incumbents with the opportunity to optimise their FTR allocation, post the granting of transitional rights
- appear to leave consumers broadly unaffected, as the capacity allocated to the transitional FTRs and settlement residue backing them would remain the same
- not create perverse incentives for generators holding transitional FTRs to remain in the market beyond the time it is efficient for them to exit.

Since transitional FTRs would be allocated for free rather than purchased at an auction, there would not be any auction revenue from their purchase to back them (unlike for regular FTRs). Auction revenue from the purchasing of regular FTRs would not be used to back transitional allocations of FTRs that are provided for free. This is because if this was to occur, it would subsidise recipients of transitional FTRs by buyers of regular/'enduring' FTRs. If there is not enough settlement residue to back a transitional FTR, then the payments for that FTR would be scaled back to preserve revenue adequacy. This relative lack of firmness is consistent with how transmission access is currently provided in the NEM.

It is proposed to use the maximum transmission network capacity as of when the transmission access reform final rule is made as the basis for allocations. This is separate to the consideration as to when the cut off is for generators to receive transitional FTRs, which is discussed below in section 5.2.5. No transitional FTRs based on increased transmission capacity that becomes available after this date through augmentations would be allocated to market participants.

5.2.4 How long and how many transitional FTRs should be allocated?

The preferred design specification for how long and how many transitional FTRs are allocated is:

- **in the first year following the implementation period close to 100% of available network capacity**

76 This was noted by the technical working group as being an important consideration - in order to assist with learnings, the transitional product has to be as close as possible to the enduring product.

- **following this a four year period of progressively lower allocation of transitional FTRs.**

The reasons for this preferred design are set out below.

The first level of transitional FTRs allocated should be reflective of close to 100% of the available network capacity that is currently utilised for all of the pre-defined nodes between which FTR routes will be available.[77] This would approximate the implicit access that generators currently enjoy based on how they use the network.

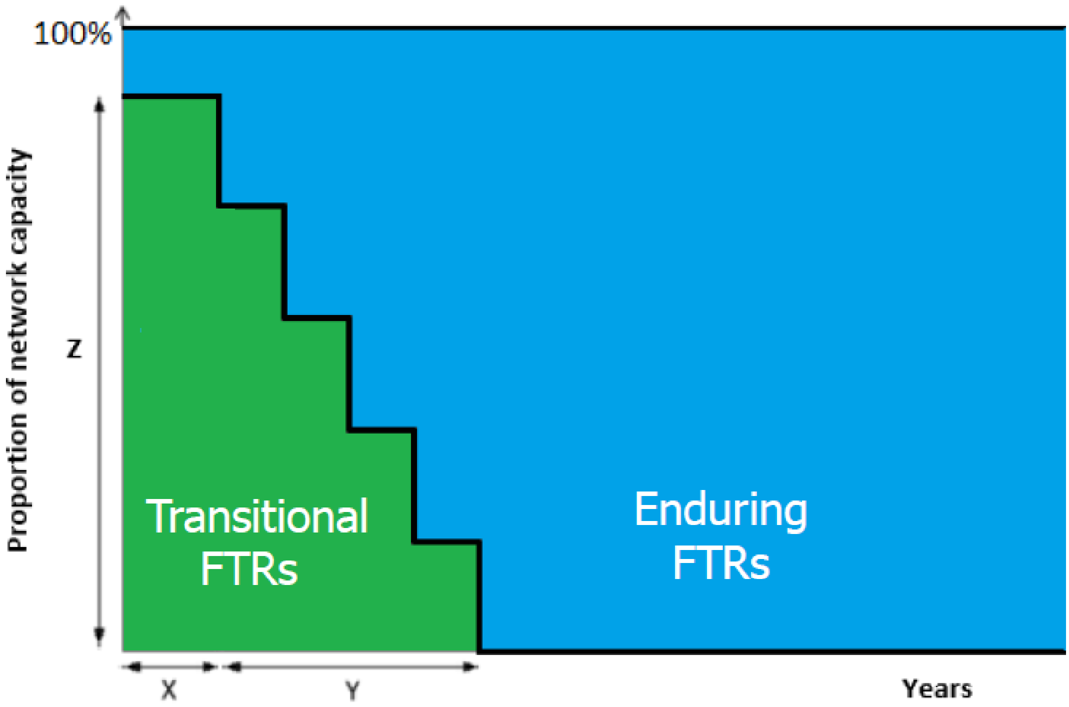
There is a strong case for adjusting this first allocation quantity over time by sculpting, i.e. reducing the allocation of transitional FTRs through the initial period. This would provide the following benefits:

- consumers would benefit from the period of stability and learning provided to existing market participants through a period of changes in how the market operates. Consumers also benefit as transitional allocations decrease throughout the period and therefore face less time with reduced TUOS offsets from auction revenue
- existing market participants would be provided with a learning period where they are able to take part in the FTR auction for a progressively increasing portion of their capacity over time
- new entrants would have the opportunity to adjust to the new FTR framework as more capacity becomes available for auction earlier.

Sculpting would occur using a profile similar to the one in Figure 5.1 below.

77 See section 3.6 for more details on these nodes. We note that we do not propose allocating transitional FTRs to generators beyond their nameplate capacity in unconstrained areas.

Figure 5.1: Transitional FTR allocation and sculpting profile



Source: AEMC
Note: Z represents the first level of transitional FTRs allocated as a proportion of *network* capacity (not generation capacity) and X is the length of time where Z would be provided. Y would be the sculpting period.

The proposal is that the X period be equal to **one year** and the Y period be equal to **four years** in order to best meet the initial period objectives (providing a learning period and minimising sudden changes to incumbents), and to maximise the sharing of the benefits of the new reforms between consumers and both incumbent and new entrant generators.

A four year period is considered appropriate for Y because:

- A longer Y period would reduce the opportunities for new entrant generators to obtain FTRs for their own learning period using these risk management tools.
- A longer initial period with allocated transitional FTRs would cause the costs of this period (including the foregone benefits of TUOS charges being offset) to outweigh the benefits for consumers.
- This initial period will follow an implementation period of approximately four years, meaning the 'soft start' period would last for nine years in total, which is considered to be a long enough and suitable period for market participants to adjust to the reforms.

We welcome views on these design decisions as it continues to progress its transitional FTR arrangements model.

5.2.5 Who would qualify to receive transitional FTRs?

We are still exploring questions around who would qualify to receive transitional FTRs and welcome stakeholder views on these issues.

Existing physical participant eligibility

We consider that "existing" physical participants at the time that the final rules are made would qualify for transitional FTRs. However, the definition of "existing" needs to be considered carefully, particularly around new entrants during this time. The "existing" category for example could include generators that:

- are financially committed, but have not commenced construction
- are financially committed and have commenced construction
- have completed construction.

New entrant eligibility

The current position on new physical entrants during the implementation period (i.e. between the final rule change being made and the rules commencing with LMPs going live) and/or during the initial period is that they should not be eligible for transitional FTRs. This is because providing transitional FTRs to these parties would diminish their incentives to locate in parts of the network which minimise total system costs; the new transmission access frameworks should also be known by market participants at this point, particularly for new entrants during the initial period.

Eligibility for outgoing generators

Recipients of transitional FTRs would not be forced to sell or relinquish those transitional FTRs allocated for a specific generating system when they close that generator, provided they remain a market participant with another registered generating system.[78] To do so may have unintended consequences on closure decisions e.g. it could incentivise these participants to retire later than otherwise efficient.

Eligibility for market network service providers (MNSPs)

The single MNSP (the Basslink interconnector) would be eligible to receive transitional FTRs in both Victoria and Tasmania.

Eligibility for scheduled load

Since scheduled load will shift from paying the RRP to paying their LMP, we have considered whether scheduled load would be eligible for transitional FTR allocations. Currently the only loads that are registered as scheduled loads are storage. These parties would likely benefit from lower LMPs when they are charging. As a result, the proposed position is that scheduled load should not be allocated transitional FTRs.

78 As the allocation of transitional FTRs will require the holder to be a registered market participant, if a registered market participant ceases to be a market participant entirely, then they would be required to relinquish or sell their transitional FTRs prior to their registration ceasing.

5.2.6 How should transitional FTRs be allocated between parties?

We are also continuing to explore how transitional FTRs would be allocated between different parties. More details on the options that we are is currently considering are available in Appendix B.

6 LODGING A SUBMISSION

Written submissions on the rule change request must be lodged with Commission by **19 October 2020** online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERP0073 | Transmission Access Reform.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions.[79] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Ben Davis on (02) 8296 7851 or ben.davis@aemc.gov.au, or to Russell Pendlebury on (02) 8296 1620 or russell.pendlebury@aemc.gov.au.

79 This guideline is available on the Commission's website www.aemc.gov.au.

A SUMMARY OF INTERNATIONAL DESIGNS

This appendix highlights some comparisons between the updated design decisions that were discussed earlier in this paper, and those design decisions made in other international markets that have similar access arrangements of locational marginal pricing and financial transmission rights.

Specific attention has been provided to:

- New Zealand, which is an energy only market like the NEM and which introduced locational marginal pricing in 1996 and financial transmission rights in 2014
- the Electricity Reliability Council of Texas (ERCOT), which is an energy only market like the NEM and which introduced locational marginal pricing and financial transmission rights in 2010,[80] which coincided with a substantial increase in new variable renewable generation connecting to the system; and
- PJM (which covers parts of the mid-Atlantic and Midwestern US), which was an early adopter of locational marginal pricing and financial transmission rights in 1998.

We have also included consideration of other international markets, where relevant, such as:

- US markets (e.g. California which introduced locational marginal pricing and financial transmission rights in 2009[81])
- Singapore (introduced locational marginal pricing in 2003) and
- Ontario, Canada which will introduce a similar regime in 2023 and is currently going through the implementation process.

Table A.1: **International comparisons**

	COMMISSION'S PREFERRED DESIGN DECISION	IS THIS CONSISTENT WITH INTERNATIONAL APPROACHES?
LMPs	Scheduled and semi-scheduled participants (generation, load and storage) would be settled at their LMP.	This is consistent with US markets where only the equivalent of scheduled participants face LMPs. In New Zealand, all generation and consumption is settled at their LMP. This means that retailers pass through different wholesale costs through to customers, reflecting the cost of meeting load where the load is located, or absorb the cost differences themselves.
	Non-scheduled loads and	As above, this is the approach taken in the US

80 ERCOT previously had FTRs that provided a hedge against zonal price differences.

81 The CAISO market in California previously had FTRs that provided a hedge against zonal price differences.

	COMMISSION'S PREFERRED DESIGN DECISION	IS THIS CONSISTENT WITH INTERNATIONAL APPROACHES?
	non-scheduled generation would continue to face a common regional price.	markets. However, in New Zealand, the equivalent non-scheduled participants pay the LMP (via a retailer).
	The regional price should be the VWAP. If in the fullness of time, related system changes are not required and more detailed cost estimates imply the cost of VWAP is greater than the expected benefit, then this design feature could be reconsidered.	Both ERCOT and PJM use volume-weighted averages of LMPs to form the equivalent of regional prices. No regional price is necessary in New Zealand as all participants face the LMP.
	LMPs should reflect dynamic marginal losses,. If in the fullness of time, related system changes are not reuqired and more detailed cost estimates imply the cost of dynamic marginal losses is greater than the expected benefit, then this design feature could be reconsidered.	Having LMPs reflect dynamic losses is generally consistent with overseas markets. For example, New Zealand and PJM reflect dynamic losses in LMPs. ERCOT, on the other hand, does not have losses reflected in its LMPs. In ERCOT, the system operator calculates a single average loss factor for the network and applies it equally to all generators and load regardless of location. In 2016, ERCOT considered the introduction of marginal losses. While it found there would be operational benefits of reflecting marginal losses in dispatch, it concluded the implementation costs would outweigh the benefits and in 2019 decided to not proceed with the proposal.
	Further analysis is necessary to determine the extent to which pricing mitigation for high price conditions is necessary under LMPs. This empirical analysis will occur over the rest of the year, as well as any resulting later rule change process. Where mitigation is required, an ex	New Zealand uses an ex post approach to mitigate inefficiently high prices by assessing bidding behaviours of pivotal suppliers or if an "undesirable trading situation" occurs. Both ERCOT and PJM have ex ante methods to mitigate against inefficiently high prices, generally consisting of a pivotal supplier test. Such a test looks at whether a particular supplier is needed to relieve constraints in the

	COMMISSION'S PREFERRED DESIGN DECISION	IS THIS CONSISTENT WITH INTERNATIONAL APPROACHES?
	ante pricing mitigation measure should be introduced to apply an offer cap on LMPs in certain conditions.	network.
FTRs	Market participants would be able to acquire rights which pay out: • at all times of the day ("continuous rights"). These rights are "fixed volume" i.e. they pay out a fixed quantity multiplied by the price difference defined in the FTR (subject to scaling, discussed on the next row) • at specific pre-defined times of the day ("time of use" rights). These will pay out a fixed volume but only when they are "active" i.e. during the specified times of the day or night.	This flexibility in how the acquired rights pay out is consistent with the approach taken in US markets. For example, ERCOT has time-of-use blocks that pay out in peak and off-peak periods. Likewise, PJM has peak and off-peak products. New Zealand does not have specific rights set up to pay out at set times of day. This has been noted as an area for future exploration by the FTR Manager (which is responsible for managing the FTR auction process).
	FTRs are backed by settlement residue and auction revenue. Any remaining revenue after a defined period of time would be used to offset TUOS charges for consumers. Any shortfalls should be accounted for by reducing FTR payouts.	This is generally consistent with the approach taken internationally, and it has been generally demonstrated that this results in the FTRs being highly firm i.e. the FTR pays out. In ERCOT, the settlement residue is primarily used to back FTRs. Revenue from FTR auctions is collected in a balancing account and is used to firm FTR payouts. The residual revenue from the auctioning of FTRs is redistributed to consumers on a zonal basis (zones are equivalent to regions in the NEM). In PJM, FTRs are backed by settlement

	COMMISSION'S PREFERRED DESIGN DECISION	IS THIS CONSISTENT WITH INTERNATIONAL APPROACHES?
		residue. Excess revenue is used to make up shortfalls in other months. If the revenue over the course of the year is in deficit, FTR payouts may be scaled back. The revenue from FTR auctions is allocated to Auction Revenue Rights (ARR) holders. ARRs are generally allocated to consumers based on historical consumption and the preferences of consumers to obtain ARRs relating to where they are located. In New Zealand, FTRs are backed by a combination of loss and constraint settlement residue and income from the FTR auction. When a month is revenue inadequate, all FTR payments are scaled back to match the amount of money available in the FTR account. Excess revenue is returned to consumers. In New Zealand, revenue shortfalls for FTRs is part of the design of the FTR market, and is expected to occur up to once in a 12 month period. The payouts have typically exceed the expectations
	FTRs would be sold through a series of simultaneous feasibility auctions run by AEMO, with input from TNSPs being used to set the parameters of how many financial transmission rights could be sold. There would be a schedule of tranches ahead of real time.	This is consistent with the approach taken in New Zealand and in US markets.
	AEMO should maintain a register of the amount of financial transmission rights sold at auction and the associated clearing price. This register may also need to capture the sale of FTRs into the secondary market and	The approach outlined above is similar to the transparency and reporting arrangements for financial transmission rights in other jurisdictions. For example, the FTR manager in New Zealand is required to administer a list of the financial transmission rights held by participant and period (including secondary trades). Likewise, ERCOT provides reports on

	COMMISSION'S PREFERRED DESIGN DECISION	IS THIS CONSISTENT WITH INTERNATIONAL APPROACHES?
	maintain an ongoing record of the legal interest in an FTR.	the allocation of FTRs through auctions.
	No specific market design measures are required for the FTR market to address competition concerns. The proposed design addresses competition concerns by allowing non-physical participants to participate in the FTR auctoin.	This is consistent with the approaches taken with FTR auctions in overseas markets.
	FTRs would be option instruments only, at least initially.	International markets more commonly have both FTRs that are options and obligation instruments. Most markets started with obligations and later offered options as well. The large majority of FTR products sold in New Zealand are options (in the order of above 90%), although obligations are available and comprise the remainder.
	FTRs would start being available in small quantities up to 10 years in advance, sold in three month tranches.	This is generally a longer timeframe than is available in FTR auctions overseas. For example, FTRs are available 26 months in advance in New Zealand, 24 months in advance in ERCOT and 36 months in advance in PJM. Some markets, CAISO for example, do have limited FTRs available on longer timeframes i.e. up to 10 years for the long term FTR equivalent products.
	Physical and non-physical participants would be able to buy FTRs.	This is consistent with international markets where non-physical participants are able to participate in FTR auctions.
	There should not be a reserve price for FTRs.	This is consistent with approaches overseas where there are no reserve prices.
	Reduce the combination of FTRs available to between a relatively small number of	This is most consistent with the model in New Zealand. In New Zealand, there are a subset of "hubs" between which FTRs are available in

	COMMISSION'S PRE-FERRED DESIGN DECI-SION	IS THIS CONSISTENT WITH INTERNA-TIONAL APPROACHES?
	pre-defined nodes in the early phase of access reform. Nodes to be defined by the prevalence of congestion on the transmission network, thereby providing FTRs to cover the majority of participant risk and the majority of capcaity across key transmission lines on the network.	the auction. New Zealand has increased the number of hubs over time. Most other international markets, such as ERCOT and PJM, have a much larger number of nodes between which FTRs are available.
	Recommendation that AER adjust STPIS to be based on cost of congestion, not instances of material congestion	It is not clear how transmission performance incentives internationally are impacted by the sale of FTRs.
	At least initially, FTRs would not hedge price differences that arise due to marginal losses.	New Zealand is the only international market with FTRs to allow participants to hedge price differences arising due to marginal losses. Other markets with LMPs do not have FTRs to manage price differences arising due to losses.
Transitional FTR arrangements	The implementation date for the model should be coordinated with other reforms underway, and be in the order of approximately four years after the time the relevant access reform rules are made.	The New Zealand market did not have an implementation period between when the relevant rules were made and the initiation of their LMP regime. PJM had an implementation timeframe of approximately eight months. ERCOT had an implementation period of around four years from when the rule to adopt a nodal market design was made.
	The initial arrangements would involve the creation of 'transitional FTRs' provided for free. The transitional FTRs would be granted for five years with one year of near-full transmission capacity, followed by a four year	Generally, overseas markets outside of the US have not had an allocation of FTRs to incumbents. For example, New Zealand and Singapore did not have any FTRs backed by capacity allocated to incumbents and Ontario is not doing so through its current reforms. In US markets there has been more variability

	COMMISSION'S PREFERRED DESIGN DECISION	IS THIS CONSISTENT WITH INTERNATIONAL APPROACHES?
	sculpting period. Transitional FTRs allocated for 'free' would be backed by settlement residue. However, auction revenue would not back transitional FTRs. Secondary trading of transitional FTRs would be allowed. The Commission is currently considering the ideal methods for allocating transitional FTRs between participants.	in how transitional allocations of FTRs to existing market participants has been managed. Transitional arrangements in the US (which have included the equivalent of transitional FTR allocations) has generally occurred for the parties that paid for the transmission network/transmission access (consumers, paid via the equivalent of retailers) because they were moving from firm access frameworks. Furthermore, the transitional allocations generally seem to have lasted until the transmission access contracts that pre-date the LMP market's establishment expire.

Unless otherwise specified, the international jurisdictions used for comparison are ERCOT, PJM and New Zealand.

Information on the market rules for ERCOT are available at: http://www.ercot.com/mktinfo.

Information on the market rules for PJM are available at: https://www.pjm.com/library/manuals.aspx.

Information on the market rules for New Zealand are available at: https://www.ea.govt.nz/code-and-compliance/the-code/.

B TRANSITIONAL FTR ARRANGEMENTS - HOW SHOULD TRANSITIONAL FTRS BE ALLOCATED BETWEEN PARTIES?

The best approach for how to allocate transitional FTRs is still being considered and stakeholder views are welcomed on both the approaches discussed here and any other approaches that could meet the transitional FTR objectives for the initial period. The main three methods under consideration are:

- a historical allocation method
- a forecast allocation method
- a dynamic allocation method.

The historical allocation method would use actual historical LMPs, RRPs and dispatch quantities to determine a quantity of FTRs for each qualifying recipient such that the financial outcome of the recipients over the historic period in question would have been unchanged had LMPs and FTRs been in use. An equation detailing this method is provided below.

Figure B.1: The proposed historical allocation method

$$\sum_{DI=1}^{DI=n}(Q \times LMP) + \sum_{DI=1}^{DI=n}(F \times \max(0, (VWAP - LMP))) = \sum_{DI=1}^{DI=n} Q \times RRP$$

Source: AEMC

The aim for this method would be to obtain a quantity of FTRs (F) for a market participant such that:

- had the quantity of physical dispatch (Q), LMPs and RRPs been the same historically, then:
- the financial outcomes summed over all the historic dispatch intervals in question (DI) for the generator under LMPs with transitional FTRs equals:
- the actual financial outcomes summed over all the historic dispatch intervals under the status quo.

The results may need to be adjusted to make sure that the FTRs collectively allocated are simultaneously feasible. This may take account of the approach considered for transitional access arrangements as part of the AEMC's Optional Firm Access (OFA) review.[82]

The pros of historical allocation are:

- it is relatively simple

82 AEMC, Optional Firm Access, Design and Testing, Final Report - Volume 2, Chapter 9 (July 2015).

- it uses actual data, meaning it is not subject to different views of the future NEM, although it would require an estimate of historic VWAPs.

The cons are:

- Allocating FTRs based on the past may not mitigate against sudden changes because LMPs, RRPs and physical dispatch quantities would have been different in the past were LMPs in place, due to different incentives to bid
- Regardless of the above, history is not necessarily a good indicator of the future. A number of other variables other than the market design will also change, such as patterns of load and generation.

The forecast allocation method would forecast LMPs, RRPs and dispatch quantities derived from a forward-looking model of the NEM. It would then determine a quantity of FTRs to be allocated such that the financial outcome for a generator over a future period of time is unchanged under LMP versus the status quo, or a world where the generator receives the RRP. An equation detailing this proposed method is provided below.

Figure B.2: The proposed forecast allocation method

$$\sum_{DI=1}^{DI=n}(Qc \times LMPc) + \sum_{DI=1}^{DI=n}(F \times \max(0,(VWAPc - LMPc))) = \sum_{DI=1}^{DI=n} Qs \times RRPs$$

Source: AEMC

The aim for this method would be to obtain a quantity of FTRs (F) for a market participant such that:

- the financial outcomes given forecast quantity of physical dispatch under transmission access reform (Qc), the forecast LMPs under transmission access reform (LMPc) and the forecast regional price under transmission access reform (VWAP), summed over n future dispatch intervals, equals:
- the forecast financial outcomes using forecast quantities under the status quo arrangements (Qs) and forecast RRPs under the status quo arrangements (RRPs), summed over n future dispatch intervals.

Similar to the historical allocation method, this method would not guarantee that the FTRs are simultaneously feasible and adjustments may be required.

The pros of this method are:

- it attempts to account for changes that would occur in future as a result of introduction of LMPs (and other changes)
- it is more consistent with likely changes in congestion patterns than the historical method. This is a key rationale for the reforms.

The cons of the forecast allocation method are:

- it is relatively complicated
- it is based on forecast information, subject to different views of the future NEM.

An alternative option is to use both methods and combine their results, to combine the different strengths of both methods. The Commission welcomes input on these options, as well as alternative transitional FTR allocation methods that would meet the initial period objectives.

A dynamic allocation model has also been considered that was raised by a stakeholder. This method would involve allocating transitional FTRs to participating generators in real time on a dynamic basis based on reported maximum availability of generators.

This dynamic allocation method has merit, as it may mirror the current allocation of settlement residue to generating units, meaning it would help to mitigate sudden changes to wholesale electricity prices or margins for market participants as the reform commences. However, a dynamic allocation method would not to provide a learning period to help market participants adapt to the reforms, as unlike with regular FTRs purchased at an auction, market participants would not obtain FTRs prior to dispatch under this method and therefore could not incorporate them into their risk management operations on that basis.

We welcome views on these, and any other, transitional FTR allocation methods.

C FTR SIMULTANEOUS FEASIBILITY AUCTION AND TRANCHES

The funding and procurement arrangements that apply to FTRs seek to resolve two related questions:

1. How can you make sure that there is sufficient revenue to back FTRs?
2. How do you determine the quantity of FTRs that will be sold?

In most international markets (excluding New Zealand), the funding source to back FTRs is primarily the **congestion rent** that arises from the introduction of locational marginal pricing i.e. the settlement residue that arise because of congestion between the nodal prices that exist at either "end" of the FTR.[83]

The congestion rent can be viewed as the natural 'counterparty' to FTRs, and therefore as the 'primary' source of FTR funding.

Consistent with this perspective, many LMP/FTR markets aim to sell a quantity of FTRs that can be backed by the available congestion rent. The procurement mechanism to achieve this is a **simultaneous feasibility auction**. As described in Box 7 below, a simultaneous feasibility auction **will sell the most valuable combination of fixed volume FTRs that is also consistent with the underlying physical characteristics of the transmission network.** If the transmission network represented in the auction is consistent with the network represented in the dispatch engine at the time of dispatch, this will make sure that the congestion rent will be greater than or equal to payments due to FTR holders. That is, in a given dispatch interval:

Congestion rent $\geq$ *FTR payouts*

If this condition is met, the set of FTRs sold can be described as **'revenue adequate'**.

BOX 7: SIMULTANEOUS FEASIBILITY AUCTION

The purpose of a simultaneous feasibility auction is to make sure that – provided the assumptions underpinning the auction are correct – the congestion rent arising from dispatch is always greater than or equal to the payout for the set of FTRs sold.

The simultaneous feasibility test applies specifically to fixed volume FTRs (i.e. those that pay out on the price difference between locations multiplied by a fixed quantity).

In effect, the auction algorithm is set to maximise the *value* of the FTRs sold through the auction (as opposed to the quantity), subject to that set of FTRs being simultaneously feasible i.e. within the physical constraints of the network. This means that the FTRs are allocated in the combination that is most valued (collectively) by market participants, and so would best allow them (collectively) to manage any basis risk that would arise from the local

83 Hogan, W., 1992. "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics 4, pp. 211 – 242.

prices differing from one another (or differing from the regional price).

Based on our understanding of overseas markets, the simultaneous feasibility test is based on a detailed network model. The network model is, effectively, the same as that used in the dispatch engine – and so includes all of the constraints that exist in the dispatch engine, including details of the transmission network as well as any (but not necessarily all) constraints that would relate to system security.

Simultaneous feasibility is therefore tested by treating each FTR bid as an 'injection' and 'withdrawal' of energy at the two connection points specified in the FTR instrument. In other words, if a participant submits a bid to purchase a 100MW FTR from Point A to Point B, the FTR auction will treat this as a 100 MW injection at A and 100 MW withdrawal at B. The auction will therefore find the combination of FTR bids that maximises the aggregate value of FTRs sold (which is based on the auction bids), subject to the implied pattern of injections and withdrawals being feasible given:

- system constraints, including any system security constraints represented in the dispatch engine
- the investment decisions made by TNSPs with regard to existing and committed network capacity, and
- the existing FTRs that have already been sold to other market participants.

Mathematically, this has the effect that for the set of FTRs sold:

Congestion risk ≥ FTR payouts

It is important to note that this is only guaranteed if the network model used for the auction is consistent with that used in dispatch.[a] In practice, the transmission network assumptions that feed into the auction will not perfectly match actual conditions in dispatch, given the conditions in dispatch will dynamically adjust in response to conditions at a particular point in time.[b] For example, the network configuration might change, new transmission system constraints may be introduced, or there could be transmission network outages. Such differences will generally be more likely to arise the further ahead FTRs are sold in advance of real time dispatch. These differences can obviously be incorporated next time the auction is run, but there will be a period of time before this can occur.

Notes:

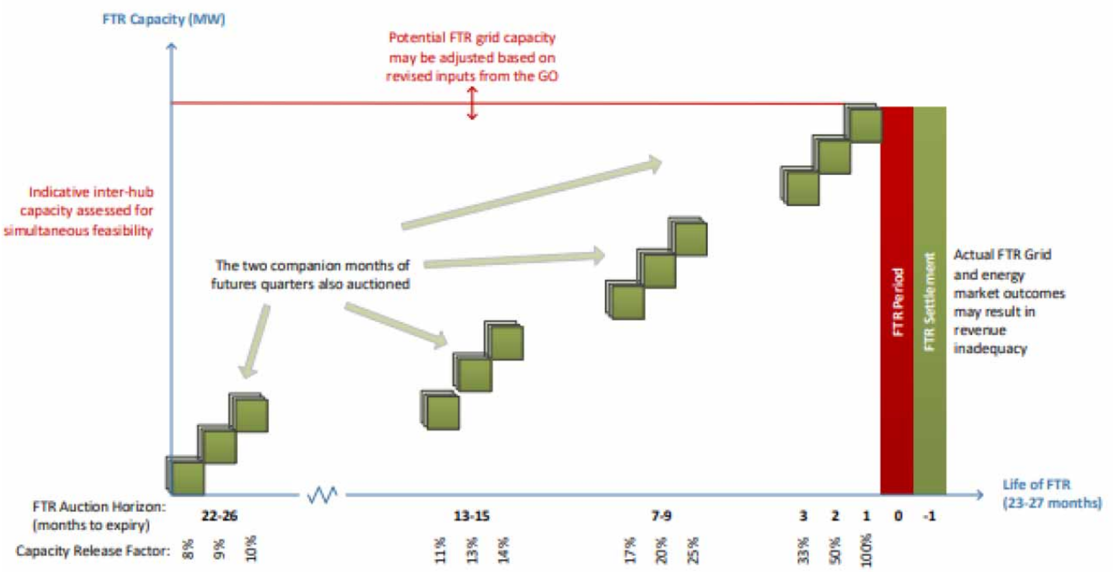
a) The simultaneous feasibility condition does not require the real time dispatch to be identical to the implied FTR injections and withdrawals. Simultaneous feasibility, and therefore revenue adequacy, are achieved as long as the system operator is able to set the controls and configuration of the network to make the point-to-point FTRs feasible.

b) The simultaneous feasibility auction model often contains some manual adjustments, such as a reduction in network capacity, to account for these potential network uncertainties.

The March paper also envisaged that FTRs would be progressively released in a series of tranches. A similar approach is currently used in the settlement residue auction.[84]

New Zealand also uses a similar approach, where they release 12 tranches of FTRs over a 26-month horizon, as illustrated in Figure C.1. They initially release a small percentage 2 years out (an 8% capacity release factor) and then progressively release more at each auction until they reach 100% of the capacity release factor 1 month ahead of when the FTR becomes operational.

Figure C.1: NZ FTR manager FTR auction tranches



Source: AEMC, modified from NZ FTR manager presentation to the Commission

This approach is still considered appropriate, because it:

- Provides opportunities for new market participants to acquire financial transmission rights. Otherwise, there could be a barrier for entry created, whereby generators would be limited in their ability to acquire financial transmission rights for an extended period of time. This would be of particular concern in the case of FTRs with longer tenures.
- Allows for the quantity of financial transmission rights released to be fine-tuned. The closer the auction is to real time, the more likely it is that the physical realities of the transmission system can be accurately forecast, and hence the appropriate number of financial transmission rights to be released. To the extent that the system is less capable than previously envisaged, proportionately less financial transmission rights would be sold in subsequent auctions, and vice versa. This allows for the trade-off between the quantity and firmness of the financial transmission rights to be fine-tuned.

84 This auction under rule 3.18 of the NER is for settlement residue distribution units relating to directional interconnectors.

The amount and sequence of the release of FTRs through the auction will need to be determined through the rule change process, in tandem with the development of the FTR auction process itself.