AEMC

REVIEW

Australian Energy Market Commission

TECHNICAL SPECIFICATIONS PAPER

TRANSMISSION ACCESS REFORM (COGATI)

26 MARCH 2020

INQUIRIES

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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.

SUMMARY

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

2 This review is in response to terms of reference received in 2016 from the 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.

3 The inaugural COGATI 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). The second COGATI review - the subject of this technical specifications paper - outlines the path forward to a transmission access regime that integrates new technologies into the national grid in a way that is reliable, secure and works in consumers' best interests.

4 This report sets out detailed technical specifications or a blueprint for the proposed access model. This blueprint sets out a cohesive model that implements locational marginal pricing and financial transmission rights in the NEM. It incorporates stakeholder feedback received to date, the Commission's latest thinking and analysis, as well as the learnings from the accompanying NERA Economic Consulting report that looks at locational marginal pricing and financial transmission rights in a number of overseas jurisdictions. The blueprint has been set out for discussion, with the Commission welcoming further feedback and input on the blueprint over the course of 2020.

5 The blueprint sets out our current thinking on the model. The model has two key aspects – the introduction of locational marginal pricing and financial transmission rights. It also sets out a number of detailed design decisions that sit under these two aspects, with these incorporating the Commission’s latest thinking and stakeholder feedback. This blueprint therefore incorporates stakeholder feedback we have received to date, most notably represented by the financial transmission rights (FTRs) being longer in tenure and firmer.

6 A *Transmission Access Reform* update paper is published alongside this blueprint. That paper set out: the need for reform given the transition under way; the role the reform plays to re-purpose transmission frameworks for the future; and describes in detail the benefits of reform to market participants and consumers.

7 The reports outline the second of a two-part solution to improving transmission frameworks and supporting the ongoing transition to a lower emissions electricity sector. The first part is to action the ISP; the second is access reform.

8 It is a fundamental part of any future market design and will be further developed and refined over the coming year by the AEMC, through the Energy Security Board's (ESB's) existing processes for market design.

9 The first part of the solution is to improve **transmission planning and investment**

decision-making processes by actioning the Integrated System Plan (ISP). The work to do this is being led by the ESB.

10 The second and equally important part of the solution is to reform **transmission access arrangements** - the blueprint of which is set out in this paper. The AEMC will continue to develop a transmission access model as a key component of the ESB's market design work over the course of 2020. The reforms relating to the two-sided market, ahead markets and the COGATI access and charging reform are measures that need to be in place before 2025 to support increased variable renewable energy and the integration of distributed energy resources (DER).

11 A cohesive package of draft rules encompassing access reform will be delivered as part of this process. As a starting point, in response to stakeholder feedback, the Commission has also attached to the blueprint an initial set of high-level, indicative rule drafting principles that would implement the blueprint. These are provided for information purposes only and to inform further stakeholder engagement. Detailed rule drafting will be developed over the course of 2020 in conjunction with other reforms, as well as further stakeholder engagement.

12 We have conducted extensive stakeholder engagement as part of this review. We have considered 151 written submissions from 67 different stakeholders on four consultation papers; held six technical working group meetings; and two public workshops. We have also held more than 130 bilateral meetings and workshops with the ESB, Australian Energy Regulator (AER), Australian Energy Market Operator (AEMO), consumers, transmission network service providers (TNSPs), incumbent and prospective generators, existing and prospective investors, government departments and other interested parties. We have given all of this feedback careful consideration and taken it into account when developing this integral part of a future design for the NEM that will integrate new technologies into the power system in a way that is reliable, secure and works in consumers' best interests.

13 A report titled *Costs and Benefits of Access Reform* by NERA Economic Consulting, completed for the Commission, is published in tandem with this report and the update paper. This report provides a comprehensive assessment of the costs and benefits of locational marginal pricing and financial transmission rights as implemented in a number of overseas jurisdictions, and looks to cast these costs and benefits in the context of the NEM. NERA's best estimate of the total benefits for consumers of the reforms is $387m *per year* offset by a one-off implementation cost of $149m. NERA found that introduction of locational marginal pricing should not exacerbate market power. Across all jurisdictions examined, NERA found that local market power is rarely exercised in practice. NERA also found that contract market liquidity was not reported to substantially change as a result of the introduction of locational marginal pricing.

14 In addition to this report, and consistent with stakeholder views, we will continue to undertake quantitative modelling of the reforms, with NERA now in the process of conducting detailed forward modelling of the NEM, to be completed through 2020. This modelling will inform both specific design details (e.g. firmness of FTRs; market power considerations) as well as the costs and benefits of the reforms in general. The modelling will be undertaken in a transparent and consultative manner. A sub-committee of our technical working group has

been formed to provide input into this process. We will also likely hold a workshop on the modelling open to all interested stakeholders.

15 Over the course of 2020, the Commission will be further developing the detailed elements of the blueprint design for the reform, taking into consideration the outcomes of the quantitative analysis under way, as well as further stakeholder engagement and consideration of other market reforms.

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1 INTRODUCTION

1.1 Terms of reference

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

This review is undertaken pursuant to terms of reference received in 2016 from the Council of Australian Governments (COAG) Energy Council, which asked the Australian Energy Market Commission (the Commission or AEMC) to implement a biennial reporting regime on these matters.[1]

1.2 Purpose of this report

The inaugural COGATI review commenced in early 2017 and concluded with its final report being published in December 2018 (inaugural COGATI final report). The inaugural COGATI final report concluded that change to the transmission frameworks is needed at the present time so that the regulatory frameworks evolve to match the transition under way in the National Electricity Market (NEM).[2]

The second COGATI review commenced on 1 March 2019 with the publication of a consultation paper.[3] The aim of this review ("COGATI - access") was to develop and assess changes to the transmission access regime that were identified in the inaugural review, as well as to develop a proposed blueprint of the proposed changes.

This report outlines the current technical specifications of a model to change how transmission access occurs in the NEM. This model is one part of a two-part solution that is being progressed to improve transmission frameworks in order to facilitate the transition currently underway to a lower emissions future. This transition is moving us towards a system that is likely to be characterised by many relatively small and geographically dispersed generators, when compared to the network of generation and transmission assets in place today.

This two part solution involves:

1. immediate improvements to the transmission planning processes and expedited transmission investment, executed through rules to action the Integrated System Plan (ISP) and short term actions to progress renewable energy zones. These actions are being led by the Energy Security Board (ESB).
2. transmission access reform, to be implemented approximately four years after rule changes have been completed, and coordinated with other reforms under way, including

1 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-Terms-of-Reference.PDF

2 The final report is available from the AEMC website at https://www.aemc.gov.au/sites/default/files/2018-12/Final%20report_0.pdf

3 The consultation paper is available from the AEMC website at https://www.aemc.gov.au/sites/default/files/2019-03/Consultation%20paper_0.pdf

the ESB's 2025 work as well as work on two-sided and ahead markets. Access reform has been the focus of this review and this report.

Further details of the access model will be developed by the AEMC, as a key component of the ESB's market design work over the course of 2020. The reforms relating to the two-sided market, ahead markets and the COGATI access and charging reform are measures that need to be in place before 2025 to support increased variable renewable energy and the integration of distributed energy resources (DER). A cohesive package of draft rules encompassing access reform will be delivered as part of this process.

The purpose of this report is to present the current blueprint design for transmission access reform, including how this has been adapted in response to stakeholder feedback. This blueprint will be further refined during 2020 through stakeholder engagement, consideration of modelling outcomes, as well as consideration alongside other reforms currently underway. A cohesive package of draft rules encompassing access reform will be developed and delivered as part of this process.

This blueprint document in setting out the preferred design of the reform, does not address the need for reform and the benefits anticipated from implementation in the NEM. These are addressed in the *Transmission Access Reform* update paper published in tandem with this report and in NERA's report into the Costs and Benefits of Access Reform, also published alongside this blueprint. Findings from NERA's report have been incorporated into the report, where relevant. As noted earlier, as well as in the update paper, further modelling of the NEM specific costs and benefits will occur later this year.

1.3 Stakeholder engagements

The Commission has conducted extensive stakeholder engagement as part of this review and in developing the blueprint design for the reform. The need for close engagement with stakeholders on this reform was noted by the COAG Energy Council in its November 2019 communique.

To date, stakeholder engagement on the review has included:

- receipt of 151 written submissions from 67 different stakeholders on four consultation papers
- the formation of a Technical Working Group, which had 30 members and met five times
- two public workshops
- a webcast presented by AEMC staff (See: https://www.aemc.gov.au/news-centre/videos/dynamic-regional-pricing-explainer)
- numerous group meeting and workshops with various trade organisations and their members, including the Australian Energy Council, Clean Energy Council, Clean Energy Investor Group, Energy Networks Australia, consumer groups and investors
- bilateral meetings with consumers and their representative groups
- bilateral meetings with investors in renewable generation
- bilateral meetings with owners of existing generation and integrated retail businesses

- transmission network service providers, incumbent and prospective generators, existing and prospective investors, government departments and other interested parties
- regular meetings with the Australian Energy Regulator, Australian Energy Market Operator and the Energy Security Board.

Stakeholder feedback is addressed throughout this paper and has been carefully taken into account when developing the preferred blueprint design. Further stakeholder engagement is planned through 2020 as the work quantifying the net benefits of the reforms and some of the more detailed design specifications progresses. Updates on how stakeholders can be involved will shortly be provided. In the meantime, if stakeholders want to discuss anything arising, please contact Tom Walker at 02 8296 7829 or tom.walker@aemc.gov.au, or Russell Pendlebury at 02 8296 0620 or russell.pendlebury@aemc.gov.au.

1.4 Structure of the report

The remainder of the report is structured as follows:

- Chapter two provides a summary of locational marginal pricing and financial transmission rights (FTRs) regimes, their applications overseas and their advantages over alternative reform models
- Chapter three provides a summary of the preferred access model design to be applied to the NEM
- Chapter four presents the blueprint design for locational marginal pricing – a core component of the access reform model
- Chapters five and six present the blueprint design for financial transmission rights – a core component of the access reform model – in relation to congestion and losses respectively
- Chapter seven sets out the recommendations for implementation and staging
- Appendix A presents the drafting principles for required changes to the NER
- Appendix B provides an example of incentives for investment efficiency improvements under the access model.

2 LMP/FTR REGIMES

Markets with locational marginal pricing and financial transmission rights are common, well-established and highly regarded overseas, and operate with a wide variety of market designs. The proposed model aligns the NEM's access regime with international examples that have locational marginal pricing and financial transmission rights.

This chapter:

- discusses how LMPs and FTRs work in conjunction with one another to solve issues in the current regime (2.1)
- highlights that LMP/FTR markets are common and long-established overseas (2.2)
- outlines alternative access regimes (2.3).

2.1 Combined impact of LMPs and FTRs

The proposed access model involves two key changes to the current transmission access frameworks:

1. Under the proposed model, large-scale generators and storage would receive a spot price that would vary with their location (a locational marginal price or 'LMP'). This pricing would more accurately reflect the value of supplying electricity from their location on the network, accounting for both transmission congestion and losses. Retailers would continue to pay a regional price. Price differences will only arise between locations when there is congestion on the network. When there is not any congestion at a particular time or location, local marginal prices will equal regional prices.[4] This element is discussed in further detail in Chapter 4.
2. Participants would be able to purchase financial transmission rights (FTRs) which pay out on the differences in local prices that arise due to congestion and losses. FTRs would enable market participants to better manage existing transmission congestion and loss related risks, which, in turn, will allow them to have more revenue certainty and the confidence to invest. FTRs designed to hedge against congestion are discussed in further detail in Chapter 5; and potential FTRs designed to hedge against losses are discussed in further detail in Chapter 6.

The introduction of locational marginal pricing and financial transmission rights simultaneously addresses three problems inherent in the current market design:

- by pricing energy at the efficient LMP, rather than the regional reference price (RRP), market participants are provided incentives to invest in, and operate, assets in a manner which is consistent with the physical needs of the whole power system.
- market participants' revenue received from the energy spot market and FTRs is partially decoupled from physical dispatch. Market participants are able to manage the risk of congestion by acquiring FTRs. This allows them to enter into financial derivative contracts

4 Ignoring the effect of losses for simplicity of explanation.

with more confidence, because their revenue to back these contracts is less affected by the impact of physical transmission congestion.

- market participants have to purchase FTRs (other than those that are grandfathered), with any surplus proceeds going to consumers, directly lowering prices.

A comparison to the current wholesale market arrangements is provided in Box 1.

BOX 1: COMPARISON TO CURRENT WHOLESALE MARKET ARRANGEMENTS

The current dispatch process undertaken by AEMO through its NEM dispatch engine already takes locational marginal prices into consideration. When dispatching generators, it calculates a locational marginal price for scheduled and semi-scheduled market participants within a region to work out who to dispatch. But, generators are still paid a regional price, regardless of where they are located within a region. As all participants within a region are settled at the regional reference price, they are all paid the same price as generators located at the regional reference node, where prices are typically relatively high.

However, this creates an *implicit* settlement surplus under the current market design. Imagine that all scheduled and semi-scheduled generators are settled at their locational marginal price as determined in dispatch. Under the existing arrangements, generators receive the regional reference price for their physical dispatch. Implicitly, this means that any difference between their locational marginal price and the regional reference price is automatically allocated to generators in proportion to their physical dispatch.

A mechanism to allocate the surplus funds that (implicitly) arise due to price differences within each NEM region is therefore inherent in the regional pricing regime.

It is this implicit allocation mechanism that is becoming an increasing problem that access reform addresses. While each of these problems may not have been significant in the past, owing to the relatively low levels of congestion, as we see increased congestion going forward they will become more material:

- By allocating the surplus funds on the basis of physical dispatch, energy is not settled at a price that accurately reflects local supply and demand conditions. This creates distorted incentives in both operational and investment timescales for market participants to maximise their share of the surplus funds, increasing costs which ultimately flow to consumers.
- By allocating the surplus funds on the basis of physical dispatch, an individual market participant's revenues change as a consequence of being constrained off. This creates a risk that is difficult to manage for market participants, which ultimately flows through to consumers through higher bills.

- The surplus funds are allocated to market participants directly, despite the fact that consumers pay for the transmission infrastructure which gives rise to the funds. Consumers' bills are higher as a consequence compared to if the surplus funds were allocated to consumers (or sold, with the revenue generated from the sale of the fund allocated to consumers).

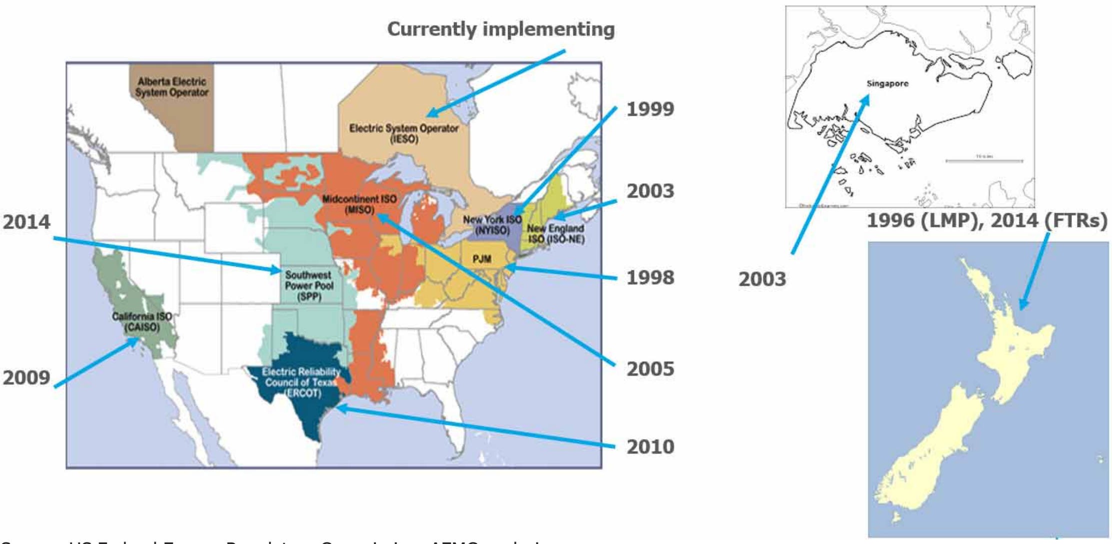
A more detailed discussion of the benefits of the model is provided in the *Transmission Access Reform* update paper that accompanies this report.

2.2 LMP and FTR markets overseas

The Commission acknowledges that implementing changes to the existing transmission access regime represents a significant change to the NEM design.

But far from being an unusual market design, LMP and FTR markets are common and well-established overseas in a variety of different settings. Figure 2.1 provides an overview of where and when LMP/FTR regimes have been implemented overseas.

Figure 2.1: LMP/FTR regimes overseas



Source: US Federal Energy Regulatory Commission, AEMC analysis

The *Transmission Access Reform* update paper accompanying this report provides further discussion of overseas experiences with LMP/FTR regimes.

2.3 Alternatives to the proposed model

Transmission frameworks and in particular, access arrangements in other jurisdictions have been reviewed. Some of these are summarised in the attached NERA Economic Consulting report.

As described in Section 2.2, the proposed access model is well-established overseas and widely considered to be best-practice. Typically, in those markets, access arrangements have two core features:

1. Generators are paid a local marginal price for dispatched generation.
2. Generators are able to acquire or receive financial transmission rights.

These are also the two core features of the proposed access model for the NEM.

As discussed earlier, there are a number of detailed design options that can sit underneath these core features. Some of these options are present in different jurisdictions. The details of these options, trade-offs between the different options and the proposal we have adopted are discussed throughout this report.

Alternative models to transmission access reform are often raised. These alternative options are:

- Build transmission infrastructure to alleviate all congestion - while it may be more appropriate to build more transmission infrastructure, particularly through periods of rapid transition, such as what the NEM is experiencing at the moment, it will never be efficient to build out all congestion. There is an efficient level of congestion, which is determined by balancing the cost savings of having less congestion and so being able to dispatch cheaper generation; against the costs of building more transmission. Moreover, it is likely physically impossible to build out all congestion given that there is always the likelihood that there will be some congestion on the network somewhere. To build out all congestion would involve consumers spending more on transmission infrastructure than is efficient.
- Generator reliability standard - this would establish a form of transmission network access standard for generators, determined through regulation. Generators would pay transmission use of system (TUOS) charges, in return for access rights that would be governed by the reliability standard chosen and which would be the same for all generators. While it may improve the ability of generators to manage their risk, consumers would continue to bear the risk that the standard, determined through a regulatory process, may not reflect what they themselves would choose and so, would be inappropriate.
- Generators funding physical transmission - under this approach, some generators would directly fund transmission infrastructure. However, in the absence of combining this with some form of 'access right', other generators could still free ride on transmission infrastructure that had been built by someone else.
- Physical transmission capacity rights - some parties have suggested that in return for paying for access, they could receive preferential dispatch. This option would potentially

distort dispatch outcomes and could result in the perverse outcome that higher cost and higher emission generators were being dispatched at the expense of lower cost and lower emission generators.

These models, on their own, would not promote the long-term interests of consumers, particularly when compared to the high-level design of the blueprint set out in this paper.

In contrast, the proposed access model, in combination with the actions to improve transmission planning and expedite transmission investment:

- provides the mechanism by which the appropriate size, location and timing of transmission investment can be made, which balances the cost of transmission investment with the cost of congestion, *and*
- allows generators to hedge the risk of congestion and potentially losses in the manner which most closely meets their requirements.

3 SUMMARY OF THE BLUEPRINT DESIGN

The summary table in this section sets out the key elements of the current blueprint design in relation to LMP and FTRs, including where there is optionality in design. This blueprint will be refined further over the course of 2020 incorporating stakeholder engagement, quantitative modelling to be undertaken, as well as consideration of other reforms being progressed, such as two-sided and ahead markets.

Table 3.1: **Summary of blueprint reform**

QUESTION	BLUEPRINT DESIGN	RATIONALE
What is the locational marginal price?	A locational marginal price is defined as the change in the cost of dispatch were there to be an incremental change of load at the specific transmission connection point in question. Locational marginal prices will be calculated at each transmission connection point where there are scheduled or semi-scheduled market participants, with the number of such transmission connecting points determining how many possible prices there will be. Locational marginal prices will vary from one another when conditions on the transmission network vary between locations, for example due to constraints on the flow of electricity.	This is a settled aspect of the blueprint design, since having some participants exposed to locational marginal pricing is a core tenant of any LMP/FTR regime. The extent to which congestion binds, and so locational marginal prices significantly vary from each other will be explored through the quantitative modelling being undertaken.
Who faces the locational marginal price?	Scheduled and semi-scheduled wholesale market participants (including scheduled loads) would be settled at the locational marginal price at their transmission connection point.	Parties that are responsive to changes in wholesale prices are currently largely 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.
Who faces the regional price?	Non-scheduled market participants (i.e. nearly all load) would continue to face the regional price for the region they are located in.	A regional price is retained in order to support contract market liquidity. Load would also have the option of becoming

QUESTION	BLUEPRINT DESIGN	RATIONALE
	There are a number of options for how the regional price can be calculated, discussed below.	scheduled if load wished to face the local price.
What is the regional price?	There are two options for how the regional price could be set: • the current regional reference price could be retained • we could move to a VWAP (volume weighted average price) - where a weighted average of locational marginal price for all load transmission connection points in the system is calculated.	Retaining the current RRP has the advantage that it may minimise the re-opening of existing forward contracts and power purchase agreements (PPAs) that have been struck by reference to the RRP. It also does not require any changes to the NEM dispatch engine (NEMDE). However, if this is retained, there may need to be modifications to the design in order to ensure revenue adequacy i.e. that the money being paid for energy by load is at least enough to cover payments to generators for energy. Moving to VWAP means that these issues with revenue adequacy do not arise. However, VWAP will likely incur costs associated with system changes to NEMDE. Consideration of the options will occur further over 2020. There is an opportunity to coordinate changes being considered with other reforms that are contemplated (such as those being considered by the ESB), which may minimise the cost of these changes.
How are losses reflected in the wholesale electricity price?	LMPs would reflect marginal losses that apply at each transmission connection point, consistent	There are a number of considerations as to how the losses should be reflected in the LMP:

QUESTION	BLUEPRINT DESIGN	RATIONALE
	with the recent final determination on *transmission loss factors*. Losses could be reflected in LMPs either as: • a static marginal loss factor, and applied over a year for each participant or • dynamically, varying in each 5 minute settlement period according to the output of generators and load on the transmission network at any point in time.	• some stakeholders consider that dynamic losses may increase risk for generators; other parties do not and consider that they would provide significant efficiency benefits • dynamic losses would require significant system changes to NEMDE. Consideration of the options will occur further over 2020. There is an opportunity to coordinate changes being considered with other reforms that are contemplated (such as those being considered by the ESB), which may minimise the cost of these changes.
What prices would FTRs correspond to?	FTRs would be available that pay out on the price differences between: • any LMP and any RRP ('local to regional FTRs') • an RRP and any other RRP ('regional to regional FTRs')	These FTRs allow market participants to manage congestion and loss related risk in the large majority of circumstances. This approach represents a middle-ground between making FTRs available between every possible pair of LMPs (resulting in increased complexity) and limiting the FTRs to between a small sub-set of pre-defined LMPs (reducing complexity, but also limiting the FTRs' effectiveness as a risk management tool). This decision has been made following learnings from the New Zealand experience.
What network constraints will influence locational marginal prices?	Locational marginal prices would differ across the network when constraints relating to the	Including all constraints that exist in NEMDE in the proposed design sets the regime up to be

QUESTION	BLUEPRINT DESIGN	RATIONALE
	shared network and that are included in NEMDE arise. These constraints include thermal, transient stability, voltage stability, oscillatory stability and potentially system strength. FTRs would hedge the full difference between LMPs and regional prices that arise due to congestion on the transmission network, including from non-thermal constraints.	flexible to whatever the future may bring. This means new constraints will be accounted for in locational marginal prices. It also means FTRs will payout relating to all these constraints.
What is the tenure and granularity of FTRs?	Under the current design option the FTR auction could offer products with a range of tenures, including up to 10 years. The granularity of these products (the length of the period that an individual FTR hedges over, such as over a month, quarter, or year) will be determined based on the tenures that are offered. This is a change from the position outlined by the Commission in its discussion paper published in October, in light of feedback provided by participants on what products they would find most useful.	The availability of longer term FTRs (i.e. to hedge for periods up to 10 years in advance) has been adopted in response to stakeholder feedback that a longer term product that better matched PPA length and the physical life of generation assets would be valued by investors/generators. Offering longer term FTRs has raised the prospect of potential hoarding concerns; as well as potential increased risks since the transmission capacity required to back the FTRs 10 years in the future is less well known. We consider that these potential downsides can be managed through detailed design.
Who can participate in the FTR auction?	Local-regional FTRs: Under the current design blueprint, only physical market participants would be able to purchase local-regional FTRs. An alternative would be to allow financial non-	Only allowing physical participants to purchase FTRs maximises the amount of FTRs that generators can purchase. However, this may lead to concerns about liquidity, hoarding and

QUESTION	BLUEPRINT DESIGN	RATIONALE
	physical participants to also purchase these FTRs. In addition, participants' ability to purchase these rights should be capped at some measure of their physical capacity in the market. Regional-regional FTRs: In contrast, all market participants (including non-physical participants) would be able to purchase regional-regional congestion rights. Any participant (physical or non-physical) would be able to resell the congestion rights they hold back into a subsequent auction pool. In addition, there would be no explicit restrictions on secondary trading (bilaterally or on a platform outside the auction).	lower revenue being realised in the FTR auction. To address these concerns, financial participants could be allowed to purchase FTRs. There are no restrictions on secondary trading, hence to the extent that physical participants are willing to trade FTRs on the secondary market, non-physical participants will be able to trade.
To what degree are FTRs grandfathered or auctioned?	The new arrangements should start somewhere close to most of the network being 'covered' by grandfathered FTRs. 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 FTRs would be sculpted back over time.	Grandfathering, over a transitional period, should help mitigate sudden changes to wholesale electricity prices or margins of market participants, provide learning time, and prevent abrupt changes in the amount of FTRs available.
How can FTRs be acquired?	FTRs can be acquired through: • grandfathering for incumbent participants,	As noted above, there are multiple avenues by which FTRs can be acquired, which promotes the liquidity of these products making sure that

QUESTION	BLUEPRINT DESIGN	RATIONALE
	• via an auction for those parties that are eligible to participate, or • on a secondary market by any party.	they are available to those parties who most value them.
How is market power dealt with?	Market power mitigation measures will be introduced.	Market power would not be exacerbated by the introduction of the reform, it would just become more transparent. Impact analysis is currently being undertaken to determine the significance of market power considerations under locational marginal pricing. Following this analysis, market power mitigation measures will be considered in the context of the detailed design specifications work.
What is the firmness of FTRs?	The current design blueprint is that congestion FTRs would be largely self-funded – funds would arise from the difference between what generators are paid at their location, and what load is paying at the RRP when congestion arises. In addition, revenue from the sale of the FTRs would be used to increase the firmness of FTRs	Utilising the revenue from the sale of the FTRs makes them a firmer, more useful risk management tool for market participants. We are undertaking modelling to assist in the design of revenue adequacy.
Would losses be hedged?	One alternative is for the development of a separate loss FTR that would allow market participants to hedge the risk of price differences arising from changes to marginal loss factors. This would be backed by the	Incorporating losses in FTRs allows market participants to manage revenue risk and basis risk arising from marginal loss factor volatility. This is analogous to the way in which congestion FTRs assist in managing price

QUESTION	BLUEPRINT DESIGN	RATIONALE
	surplus wholesale market settlement revenue that arises due to the application of marginal loss factors. Another alternative would be to combine the congestion and loss FTRs. A third alternative is to not have FTRs which hedge losses.	differences resulting from binding transmission constraints. While a combined FTR would appear simpler for FTR purchasers, it may make the auction process highly complex. Separate FTRs products also provide participants with greater flexibility to adopt a risk management approach that best suits their particular requirements. Revenue adequacy for loss FTRs is also under active consideration. Other markets with LMP/FTR do not commonly have products that hedge losses.
What is the implementation timeframe?	In the order of 4 years post finalisation of rule changes, coordinating with other reforms underway.	Based on stakeholder feedback this timeframe is appropriate. It would provide the sector with visibility of changes significantly in advance of implementation, to allow the necessary preparations to take place in an orderly way.

Source: AEMC

4 LOCATIONAL MARGINAL PRICING

The first element of the proposed access model is to change the wholesale electricity price that generators and storage are paid such that it more accurately represents the marginal value of supplying electricity at the particular location they are generating in the network. This is called locational marginal pricing. The key elements of this aspect are:

- scheduled and semi-scheduled market participants[5] would face an LMP for wholesale electricity. These participants would therefore either pay or be paid their LMP, which reflects the marginal value of producing electricity at their location[6]
- non-scheduled market participants (i.e. the majority of load) would continue to be settled at a regional price for wholesale electricity, promoting liquidity in the contract market by still having a common 'reference' point price in each region
- marginal loss factors (MLFs) would continue to be reflected in locational marginal prices, preserving the locational signals that MLFs currently send.

The proposed model would also introduce financial transmission rights for participants to manage differences in prices (i.e. basis risk) that arise where locational marginal pricing introduces differences in prices between locations due to congestion and losses. The detailed design of FTRs is discussed in Chapters 5 and 6 respectively.

The following sections discuss each element of the current design blueprint for locational marginal pricing in greater detail. The design blueprint is intended to set out an internally consistent access model proposal. This proposal is a starting point and will be further refined over the course of 2020 in response to stakeholder feedback, modelling results and coordination with other reforms underway.

Table 4.1: **Summary of the current locational marginal pricing blueprint**

ISSUE	CURRENT DESIGN BLUEPRINT
What participants would face the locational marginal price?	Scheduled and semi-scheduled wholesale market participants (including scheduled loads) would be settled at the locational marginal price at their transmission connection point. Non-scheduled market participants (i.e. nearly all load) would continue to face the regional price for the region they are located in.
How would the regional price be calculated?	There would still be a regional price which non-scheduled participants (i.e. the majority of load) would pay. There are several options for how this could be calculated - one option is to retain the existing regional reference; the other is to have a volume weighted average price.

5 This includes scheduled loads, such as storage.

6 See, for example, national electricity rules (NER) clause 3.9.2(b).

ISSUE	CURRENT DESIGN BLUEPRINT
What network constraints will influence locational marginal prices?	Locational marginal prices would differ between transmission network connection points when constraints relating to the shared network arise and these are included in the NEMDE. All transmission network connection points that have a scheduled or semi-scheduled market participant will have a locational marginal price.
Would losses be included in wholesale electricity prices?	For wholesale market settlement, locational marginal prices would continue reflect the MLF that applies at each transmission connection point.
How will issues of market power be dealt with?	Our initial conclusion is that market power will not be exacerbated by the introduction of the reform, it will just become more transparent. We are undertaking modelling to ascertain whether or not this is actually the case. The international study undertaken by NERA suggests that market power has not gotten worse in overseas jurisdictions that have adopted LMP/FTR regimes; but it has provided more evidence for market power concerns to be noticed. The AEMC and AER should work together to review the AER's existing monitoring and reporting functions under the NER to ensure they remain appropriate and fit-for-purpose. It should also consider what additional data should be available in order to address risks to the market, such as the potential for exercise of market power.

4.1 What is locational marginal pricing?

Locational marginal pricing prices the supply of electricity based on *local* supply and demand conditions. While this is a significant change to the existing NEM design, it is not a radical concept: it is entirely in keeping with our everyday experiences that prices for goods and services other than electricity vary based on local supply and demand.

When conditions vary between locations, for example due to constraints on the flow of electricity, locational marginal prices also vary across the network.

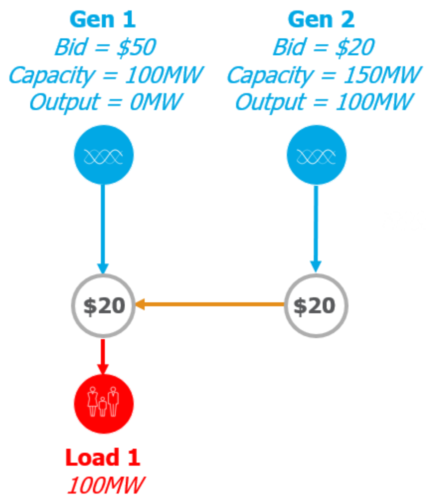
A locational marginal price is defined as the change in the cost of dispatch were there to be an incremental change of load at the specific location in question.[7]

Take, for example, a simple two-node network below. Absent congestion on the transmission system, and ignoring the impact of losses for simplicity, the locational marginal price is the

7 This concept of locational marginal pricing already exists in the NER, for example through the definition of 'mis-pricing' (NER chapter 10): "For a particular network node within a nominated region, the difference between: (a) the regional reference price for the region; and (b) an estimate of the marginal value of supply at the network node, which marginal value is determined as the price of meeting an incremental change in load at that network node."

same at both nodes. Were there an extra 1MW of generation at either node, then generator 2 would increase its output by 1MW, at an additional cost of dispatch of $20/MWh. Therefore, the LMP at both nodes is $20/MWh. Put another way, the supply and demand conditions at both locations are the same, because of the free flow of electricity on the transmission lines between the locations.

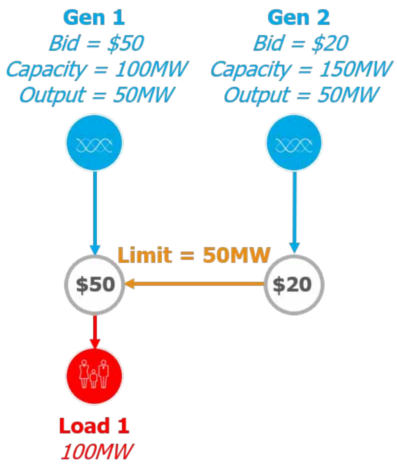
Figure 4.1: LMPs without congestion



Source: AEMC

Now assume there is some congestion on the network, as per the diagram below. No more than 50MW of electricity can flow from the right-hand side to the left-hand side. An extra 1MW of load on the left-hand side must be met by generator 1 at an addition cost of $50/h, because the flow on the line is already at that capacity. So the LMP of the left-hand node is $50/MWh. In contrast, an extra MW of load on the right-hand side can be met by generator 1 at an additional cost of $20/h, so the LMP here is $20/MWh.

Figure 4.2: LMPs with congestion



Source: AEMC

The key takeaway from this is that when there is congestion on the transmission system, locational marginal prices differ from one another. This reflects that local supply and demand conditions vary in different parts of the network, when transmission constraints restrict the flow of electricity between the locations.

The locational marginal price represents the marginal value of electricity at that location and at that time. It is the efficient price signal since it reflects what is happening in that location at a particular time, for example, the costs of congestion and losses. This incentivises behaviour that results in outcomes that benefit consumers - generators are incentivised to locate in areas which have a high price, which provides more supply, which drives down prices; generators may also be incentivised to locate away from areas that have low prices due to congestion. Price signals based on the locational marginal price strengthen incentives for behaviour that is efficient, and that ultimately results in lower costs.

BOX 2: ALGEBRAIC REPRESENTATION OF LOCATIONAL MARGINAL PRICING

The issues with the current arrangements can also be illustrated with some basic mathematics.

Currently, market participants are settled at the regional reference price (RRP) for their physical dispatch (ignoring losses for ease of explanation):

Revenue = RRP x physical dispatch [1]

This seemingly innocuous and fundamental equation in the current design of the NEM is the root cause of problems we are seeking to fix using our proposed access model:

- Market participants are settled at the regional reference price. This is not an efficient price signal because it does not signal the value of energy at their location in the network. Regional reference pricing therefore creates perverse incentives in both operational and investment time-scales.
- Market participants' revenue through the spot market is entirely a function of physical dispatch, which means that market participants are limited in their ability to manage the risk that their physical dispatch is curtailed in the presence of transmission congestion.

Rearranging equation [1], we get the following, mathematically identical equation:

Revenue = LMP x physical dispatch + (RRP — LMP) x physical dispatch [2]

The LMPs in this equation cancel out, so market participants are only exposed to the RRP (as per equation [1]). But LMPs are currently calculated by the dispatch engine, and the physical dispatch of market participants is determined in relation to these LMPs. This is the first term in the equation above. The second term is being implicitly allocated to market participants automatically, through the settlement process. It is so deeply embedded in the NEM design that many stakeholders barely give it a second thought. It creates a simple and intuitive (but ultimately inefficient) outcome: all generators and load in a region are settled at the same price, meaning there is no (visible) settlement residue (ignoring losses and inter-regional flows).

Under the current arrangements, all market participants face a region wide price (adjusted by their marginal loss factor).

The region wide price is known as the 'regional reference price' (RRP) and is defined as the change in the cost of dispatch were there to be an incremental change in load at a pre-determined node in the region - the regional reference node.[8]

Noting, as per the definition above, that the locational marginal price is the incremental cost of dispatch at a particular location, the regional reference price is defined as the locational marginal price at the regional reference node. That is, under the current arrangements, prices are not based on *local* supply and demand conditions, but on the supply and demand conditions at a specific, pre-defined location on the network - the regional reference node.

Assume in our example from Figure 4.2 that the regional reference node is defined as the left-hand node. Under the current arrangements, both generator 1 and generator 2 receive $50/MWh (the RRP), despite the locational marginal price for generator 2 being $20/MWh.

Since the beginning of the NEM, locational marginal prices have been determined by the dispatch engine for each node on the network in every dispatch interval (i.e. every five minutes). While these 'shadow' prices are used for the purpose of determining dispatch, all but one per region (i.e. the LMP at the regional reference node) is ignored for the purpose of settlement.

8 NER clause 3.9.2(d).

By ignoring local supply and demand conditions, the existing pricing arrangements in the NEM send inefficient price signals to generators and storage. In effect, the prices at all locations in a region are fixed at the price at a particular location in a region. Currently, locational signals to generators do not directly signal the long-term costs of transmission. As the power system transitions, more accurate locational price signals are important in order to have efficient investment and operational decisions, reflecting the marginal costs that a generator places on the transmission system.

The rest of this chapter explains individual elements of the blueprint design.

4.2 What market participants will face locational marginal prices?

BOX 3: SCOPE OF LOCATIONAL MARGINAL PRICING

Under the current blueprint design for locational marginal pricing:

- Scheduled and semi-scheduled wholesale market participants (including scheduled loads) would be settled at the locational marginal price at their transmission connection point.
- Non-scheduled market participants would continue to face the regional price for the region they are located in.
- Participants would have the option of becoming scheduled should they wish to face their locational marginal price. Market participants would, however, not otherwise be able to opt in or out of facing a locational marginal price.

Locational marginal pricing can be introduced for all, or a sub-set, of wholesale market participants, while retaining regional pricing for those participants not facing the LMP.

In deciding which market participants should be priced at their LMP and which should face the regional price, the following (competing) factors are relevant:

- the ability of participants to respond to locational marginal prices
- flexibility for participants to make a choice as to which price they face
- not creating perverse incentives for participants to gain access to a more favourable price
- the effect on liquidity in forward contract markets
- the cost and complexity of implementation
- distributional equity
- market power considerations.

This blueprint includes locational marginal prices where FTRs can be purchased which pay out on the price difference between any LMP and any RRP, or any two RRPs. Whether LMP or RRP should apply to scheduled and semi-scheduled market participants, non-scheduled generators and non-scheduled load is discussed below.

4.2.1 Scheduled and semi-scheduled market participants

Under the current blueprint design, scheduled[9] and semi-scheduled[10] market participants would face a locational marginal price. This is a settled aspect of the blueprint design, since having some participants exposed to locational marginal pricing is a core tenant of any LMP/FTR regime.

These parties include participants on the supply and demand side of the market. At the moment, the only scheduled loads currently operating in the NEM are large-scale storage. All large-scale storage must currently be scheduled as both a generator and load.[11]

Having large-scale scheduled storage face the same locational marginal price, regardless of whether it exports or imports, provides incentives for storage to locate in constrained areas of the network, where it is needed. This is because they will be provided with better incentives under locational marginal pricing to alleviate constraints i.e. to import at times of high congestion when the local price is low, and to export at times of load congestion when the local price approximates the regional price. It is precisely because of the difference in prices that storage is incentivised to locate in these areas, since it will be able to benefit from the arbitrage opportunity that arises there by exporting when the price is high and importing when the price is low.

BOX 4: INTERACTION WITH WHOLESALE DEMAND RESPONSE RULE CHANGE

The Commission has published a second draft determination for the *Wholesale demand response* rule change request, under which demand response service providers (DRSPs) will be able to aggregate loads and participate directly in the wholesale market.[1]

Under the second draft rule, DRSPs would participate in central dispatch in a transparent, scheduled manner. DRSPs are treated in a similar manner to other scheduled participants, i.e. a DRSP would submit dispatch bids and when cleared by NEMDE, receive dispatch instructions to provide wholesale demand response to a specified level. DRSPs would also be able to set the wholesale market price. Consequently, DRSPs would have a number of obligations and incentives consistent with the obligations imposed on scheduled generators, including compliance with dispatch instructions. These obligations and incentives are key to maintaining the integrity of the central dispatch and price setting process.

The October COGATI discussion paper noted that if DRSPs were scheduled, these parties would face the locational marginal price. Submissions received from some stakeholders raised concerns with these arrangements. Comments included that:[2]

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9 A generator with an aggregate nameplate capacity of 30MW or more is usually classified as scheduled if it has appropriate equipment to participate in the central dispatch process managed by AEMO. A rule change request from the Australian Energy Council is currently pending, which proposes to lower this threshold to 5MW

10 A generating system with intermittent output (such as a wind or solar farm) and an aggregate nameplate capacity of 30MW or more is usually classified as a semi-scheduled. Unless AEMO approves its classification as a scheduled or non-scheduled generating unit. AEMO can limit a semi-scheduled generator's output in response to network constraints, but at other times the generator can supply up to its maximum registered capacity.

11 In August 2019, AEMO submitted a rule change request to create a new scheduled market participant category for bidirectional resource providers, which would include large-scale storage.

- Retailers and DRSPs would face different prices (i.e. regional and local), and therefore the demand response behaviour of their customers may vary depending on the (differing) price signals they receive.
- The amount AEMO collects from retailers for the value of wholesale demand response provided will be passed to the DRSP. However, under the COGATI reform, DRSPs will receive the locational marginal price instead of the regional reference price. Stakeholders queried the implications for retailers when the locational marginal price is higher than the regional reference price.
- The Wholesale Demand Response Mechanism (WDRM) is designed to allow DRSPs to offer demand products to support the Retailer Reliability Obligation (RRO). Some stakeholders expressed concern that the proposed access model could undermine the RRO's objective of increasing voluntary demand response.

The Commission thanks stakeholders for providing detailed feedback on the potential interactions between the WRDM and the access reform proposal. Detailed consideration of the interactions between the two mechanisms will be further advanced as the access model design progresses over the course of 2020.

Note: 1) Australian Energy Market Commission, *Wholesale demand response mechanism*, second draft rule determination, 12 March 2020.
2) Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Energy Queensland, p. 10; Flow Power, p. 2.

4.2.2 Non-scheduled generation

Under the current blueprint design, non-scheduled participants (regardless of whether they are load or generation) will continue to face a regional price for wholesale electricity. There are various options for how this regional price can be determined, which are discussed in the section below.

The wholesale market settlement algebra will need to reflect which participants locational marginal pricing or regional pricing applies to. Most of the information required to implement the current blueprint is available in NEMDE.

Several stakeholders have expressed the view, however, that non-scheduled generation[12] should face a locational marginal price.

The rationale is that otherwise non-scheduled generators may game this design choice by 'picking' whatever price is best for them at a given location. Whilst favourable for the individual generator, this may not be the optimal arrangement from an overall market efficiency perspective because consumers may face higher costs.[13]

12 A generator will normally be classified as non-scheduled if: its primary purpose is for local use and the aggregate sent out generation rarely, if ever, exceeds 30 MW; or its physical and technical attributes make it impracticable for it to participate in central dispatch. Non-scheduled generators do not participate in the central dispatch process, but AEMO can specify additional conditions with which they must comply, usually for power system security reasons.

13 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: TasNetworks, p. 3; Energy Networks Australia, p. 13; Origin, p. 8.

The registration categories for non-scheduled, semi-scheduled and scheduled registration are currently defined, in part, by the nameplate capacity of the generator in question.[14] This means that, in practice, it is primarily only *prospective* generators who would have the ability to choose their registration category at the initial investment decision (i.e. the choice of nameplate capacity). While the participant registration categories limit the scope for discretion, imposing a distinction between the wholesale prices faced by different categories of generation could potentially impact the investment decisions of some prospective generators.

However, there may be practical difficulties associated with settling non-scheduled generators at their locational marginal price. Specifically, NEMDE currently only produces locational marginal prices for scheduled market participants. The ESB is looking at future market designs for the NEM, some of which may require NEMDE to be redeveloped, this would create opportunities for costs to be minimised. If this was the case, then it may be possible to settle some or all non-scheduled participants at a locational marginal price.

A further consideration is that a significant proportion of these non-scheduled generation facilities produce electricity as a by-product of an industrial or commercial process, rather than in response to electricity market conditions. For example, the AEMC found that 42 per cent of non-scheduled generation in 2016 could be characterised in this way.[15] As a consequence, the inefficiencies created from these market participants facing the regional price as opposed to the locational marginal price are likely to be less than scheduled and semi-scheduled participants, because non-scheduled market participants are relatively insensitive to changes in the electricity market price. This will be considered further over the course of 2020.

4.2.3 Non-scheduled load

Under the current blueprint design, non-scheduled load would continue to face a regional price for wholesale electricity, rather than the locational marginal price. Most stakeholders that have commented on this element of the design are supportive of the proposal.

The key reason why non-scheduled load would continue to face a regional price is to support contract market liquidity. If all load were to face a locational marginal price instead of a common regional price, there may be a risk of splitting liquidity in the contract market, as forward contracts would potentially instead need to be struck against different locational marginal prices. In contrast, keeping the regional price will preserve contracting around this price. Financial transmission rights (discussed in Chapters 5 and 6) will also support forward contracting, by allowing participants to hedge price differences between locational marginal prices and the liquid regional price.

Further, load is typically not as price responsive as generation, although this is starting to change as technology evolves. Many other factors affect the long-term choice of location and

14 Generators with a capacity less than 30 MW are registered as non-scheduled; whereas generators with a capacity of 30 MW or more are generally classified as scheduled or semi-scheduled.

15 Source: AEMC 2017, *Non-scheduled generation and load in central dispatch*, Rule Determination, 12 September 2017, p. iv. These types of generators could be considered to be effectively co-located with non-scheduled load, which may make them unsuitable candidates to face a local price.

the short-term choice of consumption level, most notably the characteristics of the market in which the load is supplying goods and services to, or the intrinsic value of electricity (for example in cooling and lighting homes). Load may have limited choice over where to locate, and even less choice over what energy source to use.

The ability of generators to sell forward contracts against their output allows them to hedge against the risk of spot price volatility, which increases financial certainty for investors. Ultimately, this should result in lower prices for consumers, with generators able to offer electricity (in both spot and contract markets) at lower prices than they otherwise would.

Load would have the option of becoming scheduled if they wished to face the local price

It may be the case that larger loads in certain areas of the network might wish to face a locational marginal price, if this is expected to result in a more favourable price. Under the proposed blueprint, non-scheduled load could opt in to the locational marginal price if they were willing and able to become a scheduled market participant.

Energy Queensland has expressed some concern that the distinction between scheduled and non-scheduled load (and the different prices that each faces) may create the potential for perverse market outcomes.[16]

However, only allowing scheduled load to access locational marginal prices may increase the incentives for some demand-side participants to become scheduled. A load becoming scheduled improves AEMO's ability to manage the power system. As a result, there are potentially flow-on system security benefits to providing additional incentives for load to become scheduled.

Becoming scheduled is potentially a significant hurdle for customers, and may discourage some price-responsive loads from facing their local price. Being scheduled is more difficult for a load than for a generator, because consumption levels naturally fluctuate for reasons unrelated to the spot price and a scheduled load would need to constantly rebid in order to remain dispatch compliant.

The blueprint therefore provides some flexibility by allowing non-scheduled market participants to access locational marginal pricing if they choose (and are able) to become scheduled. The responsiveness of non-scheduled load may evolve over time, as the NEM transitions to a two-sided market with a more active and flexible demand side.

Restrictions on moving between categories

Under the blueprint, market participants would have some flexibility to opt in or out of locational marginal pricing to the extent they are willing and able to change their market participant registration category.

This flexibility has some implications for settlement of the financial transmission rights discussed in Chapter 5. Under the blueprint, financial transmission rights are backed by the

16 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Energy Queensland, p. 10.

surplus funds that arise when load and generation are settled at different prices. The amount of surplus funds available in each dispatch interval will depend on:

- The available transmission capacity that allows power to flow between market participants located in different parts of the network.
- Which market participants are settled at the regional price or the locational marginal price at their connection point.

Changes in the registration status of participants that occur after financial transmission rights have been issued can therefore impact the surplus funds available to fund payments to the holders of those rights. Therefore, it may be desirable to prevent participants from frequently switching between registration categories in order to 'cherry pick' the most favourable price. Accordingly, in the October COGATI discussion paper it was proposed that once a market participant opts to change its registration category, it would be prohibited from reversing this decision for a period of 12 months.

Stakeholders had mixed views on this policy choice:

- The AER and Energy Queensland considered that this was a sensible proposal in order to prevent strategic switching between categories.[17]
- Energy Networks Australia and TasNetworks were not in favour of the proposal, on the basis that it did not go far enough to prevent potential gaming by load participants.[18]
- Aurizon Networks considered that a 12 month waiting period may be a blunt instrument which impacts efficient market behaviours.[19]

In conclusion, restrictions on the frequency of switching between registration categories are likely to be required. The specifics of these restrictions will be open to further consideration and consultation as the access model design is developed further over the course of 2020.

4.2.4 Current blueprint design

In summary, taking into account stakeholder feedback and the issues outlined above, the current design blueprint reflects the following elements in relation to which market participants will face locational marginal prices:

- All scheduled and semi-scheduled market participants would be settled at their locational marginal price. All non-scheduled market participants would be settled at a common regional price.
- Non-scheduled load or generation could opt in to the locational marginal price if they were willing and able to become a scheduled market participant.
- There would likely need to be some restrictions on how frequently participants could change their scheduling status.

17 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: AER, p. 10; Energy Queensland, p. 11.

18 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Energy Networks Australia, p. 14; TasNetworks, p. 3.

19 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Aurizon Networks, p. 3.

These design elements will be further considered as the access model design progresses.

4.3 How would the regional price be calculated?

> **BOX 5: REGIONAL PRICING METHOD**
>
> In the current design blueprint, non-scheduled participants would face the regional price. There are several options for how this could be calculated - one option is to retain the existing regional reference; the other is to have a volume weighted average price. The optimal choice depends on a number of factors including: implementation costs associated with changing the methodology for calculating the regional price; the modelled benefits of what this may mean in terms of consumer outcomes; and consideration of opportunities for system changes (e.g. NEMDE) that may occur through other changes being pursued through the ESB's market design work.

The introduction of locational marginal pricing means that generators are paid and consumers pay a different amount for the same electricity. As discussed in section 3.1, under the current design of the access model scheduled and semi-scheduled market participants would be settled at their locational marginal price. A common regional price would be maintained for non-scheduled market participants, in order to support liquidity in the forward contract market.

There are a number of options for what this regional price could be, including the existing regional reference price, or an alternative regional price. An example of an alternative regional price would be a VWAP. This section outlines key design considerations in relation to the choice of regional price.

4.3.1 Existing regional reference price

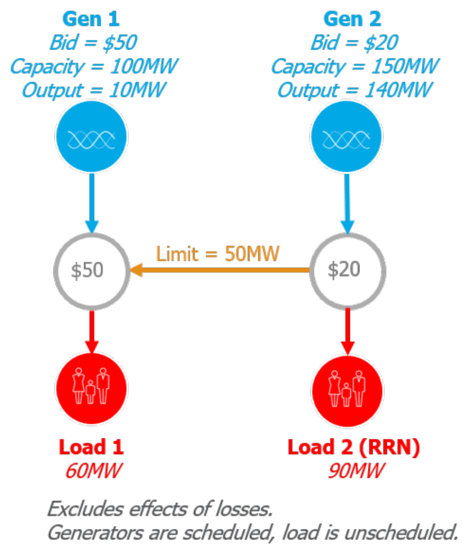
As noted above, one option to set the regional price could be to use the existing regional reference price. The regional reference price is the locational marginal price at the relevant regional reference node. An advantage of this approach is that it is relatively 'easy' to implement since existing systems and contracts are set up referring to the regional reference price.

However, a consequence of retaining the regional reference price for non-scheduled participants is that, under certain conditions, there may not be enough money coming in from load to pay generators the amount owed to them under wholesale market settlement. For example, this could occur when there is a significant level of demand situated away from the regional reference node, resulting in the regional reference price being *lower* than the locational marginal prices at other transmission connection points. An example of this is provided in Figure 4.3 below.

This is not expected to be a common occurrence, particularly in the near term. This is because most demand in the NEM is located in the metropolitan region around each state's capital, which is served by substantial transmission capacity. In many cases, this also corresponds with the regional reference node.[20] In this context, the conditions described in the example below are not anticipated to arise frequently. We will also test the frequency of this occurring over the course of 2020.

Figure 4.3: Wholesale market settlement and the regional reference price

Participant	Energy settlement ($)
G1	-500
G2	-2,800
L1	1,200
L2	1,800
Total	**-300**



With load facing the regional reference price ($20), settlement payments from load are not sufficient to cover settlement payments to generators facing their locational marginal price.

Source: AEMC

Nonetheless, modifications to settlement arrangements would be necessary to mitigate the small risk that wholesale settlement deficits could occur. Examples of potential modifications to the settlement process include:

- locational marginal prices could be capped at the regional reference price
- locational marginal prices could be scaled downwards, to the extent necessary, to ensure wholesale settlement balances during times of elevated local pricing
- the regional reference price could be scaled upwards to ensure there are adequate funds for wholesale settlement.

Each of these options involves trade-offs. For example, adjustments to locational marginal prices could reduce the accuracy of the price signals faced by large-scale storage and generation. On the other hand, scaling up the regional reference price changes what consumers pay. The likelihood and potential magnitude of wholesale settlement deficits is being explored through the quantitative analysis and can be considered further as the access model design progresses.

20 Queensland and Tasmania are exceptions, given that they have substantial load remote from the regional reference node.

4.3.2 Alternative regional price

Another option would be to use to VWAP as the regional price. A VWAP methodology would involve calculating a locational marginal price 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. The key advantages of VWAP are that:

- There would also always be sufficient money recovered from consumers to pay for wholesale settlement of that electricity. Under VWAP pricing, there would be at least enough money coming in from load to pay the locational marginal price for each megawatt of electricity supplied by generation. VWAP would also support the funding of financial transmission rights. Therefore, VWAP would remove the need for the modifications to wholesale settlement that were outlined above, and the compromises that these modifications involve.
- VWAP would more accurately reflect underlying local prices, compared to the existing RRP which captures the local price at only one node in a region. This method is 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.

However, the downsides of VWAP are that:

- changes to the existing NEMDE would be required in order to have load reflected at locations across the network in order to be able to calculate (shadow) locational marginal prices for this load, from which the VWAP would be calculated. That being said, there may be opportunities to minimise costs if other reform processes underway also look at changes to NEMDE
- in addition, there are likely to be a number of implementation costs given that existing systems are set up around the regional reference price (i.e. not VWAP)
- existing contracts, such as longer-term PPAs may also need to be renegotiated; feedback from participants indicates that a move to VWAP could require re-opening a large proportion of these contracts, which would likely be a costly and disruptive process.

These advantages and disadvantages have been reflected in stakeholder feedback to date. For example: 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.[21]

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.[22]

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,

21 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.

22 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.

Brickworks and Origin note that it is unclear upon which price existing power-purchase agreements and other agreements would settle.[23] Several stakeholders have also noted that the introduction of VWAP would require major changes to market and trading systems.[24]

In addition, some stakeholders consider that it is unclear what impact the move to a VWAP approach would have on regional prices.[25] 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.[26] Infigen Energy notes that the lack of clarity in relation to the impact of VWAP is causing uncertainty for both retail contract and power purchase agreement negotiations.[27]

4.3.3 Current blueprint design

There are several options for how the regional price could be calculated, including:

- retain the existing regional reference price
- the other is to have a volume weighted average price.

The optimal choice depends on a number of factors including: implementation costs associated with changing the methodology for calculating the regional price; the modelled benefits of what this may mean in terms of consumer outcomes; and other changes being pursued through the ESB's market design work that may amend NEMDE.

Future development of existing market systems, including the NEM dispatch engine, is being considered as part of the ESB's post 2025 review. This process will consider the systems that are required to support the energy transition, such as accommodating two-way flows across distribution networks and facilitating the move to a two-sided market. The outcome of this broader review will likely provide opportunities to consider potential refinements to the access model, including the approach to regional pricing, in order to minimise costs, which will be considered over the course of 2020.

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

24 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.

25 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.

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

27 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Infigen Energy, p. 10.

4.4 What network constraints will influence locational marginal prices under the proposed model?

> **BOX 6: CONSTRAINTS IN PRICING**
>
> Under the current blueprint design, locational marginal prices would differ across the network when certain thermal and non-thermal transmission constraints arise.
>
> To cause diverging local prices, these constraints must relate to the shared network and be included in the NEM dispatch engine (NEMDE).

The NEM dispatch engine (NEMDE) seeks to maximise the value of trade given the physical limitations of the power system. These physical limitations are otherwise known as 'constraints' and reflect, for example, the amount of electricity that can flow over a piece of equipment or across sections of the power system while preserving its integrity, safety and security.

4.4.1 What constraints should be included?

Locational marginal prices represent the marginal cost of supplying an additional increment of energy demanded at a given location[28] in the transmission system. Without any binding shared network constraints, the cost of supplying an additional megawatt of electricity would be the same at all locations, ignoring the effects of losses. This is because the same marginal generator could supply all connection points (i.e. because there is no congestion).

However, when transmission constraints bind, the same marginal generator would no longer be able to supply all locations in the system. This is because the transmission constraint will restrict the amount of energy that certain generators can supply to different locations.

For connection points located *downstream* of a binding transmission constraint, an additional megawatt can only be supplied by another, more expensive, generator. This means that the regional reference price for load (the locational marginal price at the regional reference node) would most often be higher than the locational marginal price of generators located *upstream* of (behind) a binding transmission constraint.

Only constraints that result in limitations on transmission flows on the shared transmission network would lead to different marginal generators across the network, and in turn result in differences between locational marginal prices and the regional reference price. This means that not all dispatch constraints will impact locational marginal prices.

For example, constraints that relate to individual generators, such as limitations on their maximum or minimum output and Frequency Control Ancillary Services (FCAS) provision, would not result in divergent local prices. These types of constraints will result in a more

28 That is, at a transmission connection point.

costly generator being marginal (and so setting the locational marginal price) across the power system.[29] However, because the constraint does not reflect transmission congestion within the shared transmission network, the same marginal generator could supply all connection points, providing there are not binding shared network constraints between them.

There are different types of constraints currently included in NEMDE that may impact on transmission flows within the power system:

- Thermal constraints are applied to prevent overloading of a transmission element (for example, a transmission line or transformer), either pre- or post-contingency.
- Transient stability constraints prevent pole-slipping of one or more generating units in the aftermath of a fault, which would likely cause it to trip and could damage the unit.
- Voltage stability constraints prevent voltage collapse in the aftermath of a contingency.
- Oscillatory stability constraints are designed to prevent a steady-state instability caused by undamped response to normal small perturbations occurring in the power system following a contingency.
- System strength stability constraints are designed to maintain sufficient fault currents to ensure post-contingent stability and proper operation of protection systems.

The NEM dispatch engine is currently able to account for some transmission constraints better than others. This is because some dispatch constraints are more idiosyncratic in nature and so are difficult to model effectively. For example, system strength constraints are not represented in dispatch in the same way as other stability constraints due to their complexity.[30]

To the extent that certain dispatch constraints are currently excluded from the dispatch engine, then they do not impact the regional reference price. They would also not be factored into locational marginal prices. Rather, AEMO must manage these physical constraints through a blunter method such as directions or instructions, with accompanying payments managed through the intervention pricing regime.

However, including all constraints that exist in NEMDE in the proposed locational marginal pricing design sets this regime up to be flexible in the future. To the extent that there are new constraints in future (e.g. related to system services) that can be incorporated in NEMDE, then this will mean that the locational marginal prices will account for them. It will also mean that financial transmission rights will payout on the risks of congestion relating to these constraints.

A number of stakeholders agreed with the above characterisation of how thermal and non-thermal transmission constraints could be incorporated into the locational marginal prices.[31]

29 Which would lead to a higher regional reference price, given that this is defined as the locational marginal price at the regional reference node.

30 AEMO is only able to set a simple limit on aggregate asynchronous generation within NEMDE to ensure that the system has system strength stability.

31 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: CS Energy, p. 5; TasNetworks, p. 2; Energy Networks Australia, p. 14.

Energy Networks Australia and TasNetworks were of the view that, to the extent practicable, all power flow constraints should be incorporated in NEMDE and accordingly in the calculation of associated locational marginal prices.[32]

Some stakeholders had further questions on this aspect of the proposal.

1. EnergyAustralia questioned how local prices would be formulated for a generator that appears in two or more constraint equations that bind simultaneously with different marginal values.[33]

   A generator's locational marginal price will reflect the impact of all relevant binding transmission constraints. For example, if a generator is in a part of the transmission network that is experiencing two different types of constraint, then its single locational marginal price will reflect the dual impact of both constraints on the capacity of the network.[34]

2. Neoen stated that the access model had not considered FCAS constraints and FCAS recovery.[35]

   As described above, only constraints that result in limitations on transmission flows on the shared network would lead to different marginal generators across the network, and in turn result in diverging locational marginal prices.

3. Tesla questioned how the new pricing components would be incorporated into pre-dispatch forecasts.[36] Pre-dispatch processes would need to change to reflect information requirements under the new model. However, precisely what changes will require further scoping in collaboration with stakeholders as part of the detailed design process.

4.4.2 Current design blueprint

Taking the points above into consideration, the current blueprint reflects that under the proposed access model, locational marginal prices would differ across the network when certain thermal and non-thermal transmission constraints arise. To cause diverging local prices, these constraints must relate to the shared network and be included in the NEM dispatch engine (NEMDE). The issues raised by stakeholders in the preceding section will be open to more detailed consideration as the access model design is further developed and refined over the course of 2020.

32 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: TasNetworks, p. 2; Energy Networks Australia, p. 14.

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

34 The locational marginal price for a generator would, effectively, be calculated as the regional reference price, less the sum of the shadow prices for each transmission network constraint multiplied by the generator's participation factor for each constraint. The 'shadow price' represents that marginal value of relieving a constraint, while the 'participation factor' reflects the generator's 'contribution' to a constraint. If a transmission network constraint is not binding, its shadow price will be zero (as there would be no dispatch cost saving if the constraint is relieved). Therefore, it would not affect the generator's locational marginal price. Similarly, the generator's locational marginal price would not be affected by constraints for which its participation factor is zero. A formal description of how locational marginal prices are calculated can be found in: M. Katzen and G. Leslie, *Revisiting Optimal Pricing in Electrical Networks over Space and Time: Mispricing in Australia's Zonal Market*, 10 December 2019.

35 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Neoen, p. 3.

36 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Tesla, p. 2.

4.5 Are losses included in wholesale electricity prices?

> **BOX 7: TREATMENT OF TRANSMISSION LOSSES**
>
> Under the current blueprint design, wholesale electricity prices (including locational marginal prices and the regional reference price) will continue to reflect the impact of marginal transmission losses. The current approach to calculating inter- and intra-regional losses would also be retained.
>
> As discussed in Chapter 6, it is intended that the design of the financial transmission right products that would be introduced under the proposed access model would allow participants to purchase a financial transmission right that would allow them to better manage risks associated with marginal loss factors, relative to the status quo.

Electricity transported across the transmission system is subject to losses. That is, if demand at one connection point is supplied by generation at another connection point, the quantity of generation produced needs to exceed that demand, in order to account for losses as electricity flows between the two locations. This means that it is more expensive to supply demand with generation located in different parts of the network away from load.

Under current NEM design, locational price differences *already* arise within each region due to the application of marginal loss factors. If locational marginal pricing is introduced, wholesale prices at different connection points across the NEM would also vary to reflect the costs of intra-regional transmission congestion.

The Commission recently considered a rule change request from Adani Renewables to change the approach to calculating marginal loss factors. A final determination was published on 27 February 2020. The final determination did not make the rule sought by Adani to change the way losses are calculated by averaging them out. The Commission found that using an average loss factor calculation rather than the current marginal loss factor calculation would shift the cost of losses onto consumers and onto generators who are located where losses are lower. The Commission instead made a more preferable rule that maintained the existing marginal loss framework, but provided AEMO with more flexibility around the way it calculates MLFs.[37]

4.5.1 Current arrangements

Transmission losses are currently reflected in dispatch on a marginal basis:

- **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.

37 AEMC, *Transmission loss factors*, final determination. https://www.aemc.gov.au/sites/default/files/2020-02/Final%20rule%20determination%20Transmission%20loss%20factors.pdf

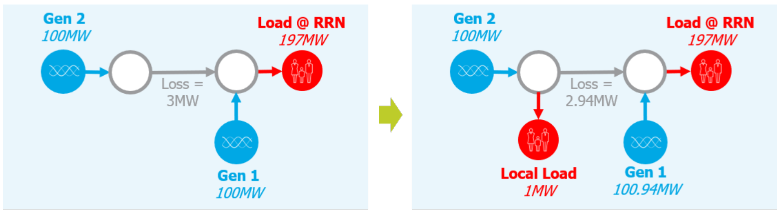
- **Losses that occur between regions ('inter-regional losses') are calculated quasi-dynamically in dispatch.** The calculation of inter-regional losses might be described as quasi-dynamic. This is because the inter-regional losses calculated in dispatch vary dynamically with flows on the system. However, the linear loss function is itself static and set on an annual basis by AEMO.[38]

Box 8 below summarises how intra-regional marginal loss factors are currently defined.

BOX 8: INTRA-REGIONAL MARGINAL LOSS FACTORS

Under the current framework, marginal loss factors are 'oriented' towards the regional reference node (RRN). This means that for a given load or generation connection point, the marginal loss factor is the amount of generation required at the RRN to meet a 1MW increment of load at that connection point. This is illustrated in the simple two-node example below, which shows one generator located at the RRN (Gen 1) and another generator located remotely (Gen 2).

Figure 4.4: Intra-regional MLFs under the current framework



Source: AEMC

Gen 2's output is 100MW and total losses between its connection point and the RRN are 3MW (0.0003 x 100MW^2). If 1MW of Gen 2's output is needed to supply a local load, the flow between its connection point and the RRN would reduce to 99MW, with losses falling from 3MW to 2.94MW. So that demand at the RRN continues to be met, Gen 1 would then need to generate an additional 0.94MW.

Therefore, the marginal loss factor for Gen 2's connection point is 0.94 (calculated as the change in generation at the RRN divided by the change in load at Gen 2's connection point).

Source: AEMC

Note: Transmission losses for a radial network element can be defined as: *Losses = k x P*^{2}, where k is a coefficient representing voltage and resistance and P is power flow. Under the current framework, P is defined at the end of the network element that is remote from the regional reference node (i.e. the receiving point, given the additional increment of demand is assumed to be supplied by a generator located at the regional reference node). P is positive when flowing towards the connection point at which the loss factor is being calculated. In this example, P is the flow at Gen 2's connection point, expressed as a negative number (-100MW). The example assumes that k is 0.0003. Therefore, total losses are 3MW (100MW^2 x 0.0003). A more detailed explanation is provided in AEMO, *Treatment of Loss Factors in the NEM*, 2012.

Marginal loss factors are applied to promote efficient dispatch outcomes.

In dispatch, generator offer prices are divided by the marginal loss factor that applies at their connection point, resulting in a 'loss adjusted' offer. This achieves more efficient dispatch by recognising the impact of losses on the marginal cost of delivering energy from generation

38 The loss function is a linear approximation of the quadratic loss function applied to estimate marginal losses based on the quantity of energy flowing between regions.

sources to where demand is located. In this way, dispatch minimises the total cost of supply by effectively co-optimising the cost of generation and the cost of the associated transmission losses.

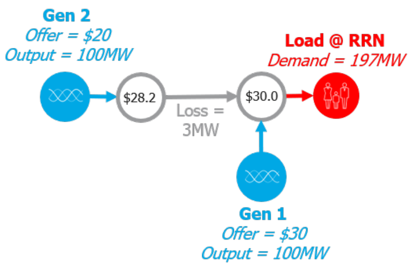
In settlement, the amount that loads pay and generators receive is calculated according to the following formula: *Regional Reference Price x Marginal Loss Factor x Measured Energy*. Application of marginal loss factors in the settlement formula is sometimes interpreted as a volume adjustment, that is intended to reflect how much energy each generator 'delivers' to the regional reference node. Because marginal losses are greater than actual losses, some participants have expressed the view that using marginal loss factors in this way overly reduces the settlement volume that they are paid.

However, the function of marginal loss factors in the settlement equation is as a price adjustment, not a volume adjustment. This means that the current transmission loss factor framework is already consistent with the principle that wholesale prices should reflect the marginal value of energy at different locations in the network.[39] Market participants are paid for the volume of electricity delivered to their connection point at the marginal loss factor adjusted price. The example in Box 9 below illustrates how applying marginal loss factors in both dispatch and settlement achieves this outcome.

BOX 9: INTRA-REGIONAL LOSS FACTORS AND MARGINAL PRICING

In the example below, Gen 1 and Gen 2 offer their output at $30/MWh and $20/MWh respectively. Gen 1 has a marginal loss factor of 1 (as it is located at the RRN), while Gen 2's marginal loss factor is 0.94. The loss adjusted offers of Gen 1 and Gen 2 are $30/MWh and $21.3/MWh respectively. Gen 1 is therefore the marginal generator for the region and sets the regional reference price (RRP) at $30/MWh.

Figure 4.5: Intra-regional MLFs under locational marginal pricing



	Energy	RRP	MLF	"Local price"	Settlement
Gen 1	100MW	$30.0	1.00	$30.0	$3,000
Gen 2	100MW	$30.0	0.94	$28.2	$2,821
Load	197MW	$30.0	1.00	$30.0	$5,910
Loss settlement residue					**$89**

Source: AEMC

In settlement, Gen 1 would be paid:

$RRP \times MLF \times Measured\ Energy$

$=\$30.0/MWh \times 1.0 \times 100MW$

39 While this is the existing arrangement for intra-regional losses, the same principle is not currently applied for intra-regional congestion. The introduction of locational marginal pricing will align the wholesale pricing approach for losses and congestion.

This is consistent with Gen 1 being paid the marginal cost of supply at its connection point. If Gen 1 supplies an extra MW of demand at the RRN, losses would not increase, and so the increase in system costs would be Gen 1's offer price of $30/MWh.

What is the situation for Gen 2? With a marginal loss factor of 0.94, Gen 2's local price is:

$RRP \times MLF$

$= \$30/MWh \times 0.94$

= $28.2/MWh

As explained in Box 8 above, a 1MW increment of load at Gen 2's connection point would require Gen 1 to increase its output by 0.94MW. The total increase in system costs from supplying an additional MW at Gen 2's connection point would be:

Gen 1 output × Gen 1 cost

= 0.94MW × $30/MWh

= $28.2/MWh

Therefore, the price paid to Gen 2 for output at its connection point is consistent with the marginal cost of supply at that location in the system.

In this example, load is assumed to be located at the RRN, with a marginal loss factor that is 1 by definition. In practice, the marginal loss factor framework currently results in locational price differences for loads as well as for generators.

Source: AEMC

The framework for inter-regional transmission losses is also consistent with the principle of locational marginal pricing, as the calculation of inter-regional losses reflects the change in network losses that would occur as a result of transmitting a marginal unit of energy between two adjacent regional reference nodes.

4.5.2 Options under the proposed model

There are two main options for losses:

1. the existing loss framework could be retained
2. dynamic losses could be introduced.

Existing loss factor framework

Retaining the current loss factor framework would mean that:

- AEMO would continue to calculate both inter- and intra-regional transmission losses on the same basis as today.[40] This means that intra-regional marginal loss factors would continue to be calculated on a static, *ex ante* basis.
- In dispatch, intra-regional marginal loss factors would continue to be applied to scheduled and semi-scheduled participants offers (or bids)
- In settlement, intra-regional marginal loss factors would be reflected in both regional reference prices and locational marginal prices. That is:
    - The settlement formula for participants settled at the regional reference price will be: *Regional Reference Price x Marginal Loss Factor x Measured Energy*.
    - The settlement formula for participants settled at the locational marginal price at their connection point will be: *Locational Marginal Price x Marginal Loss Factor x Measured Energy*.[41]

The advantage of this approach is that it minimises any implementation costs, since the existing approach would be the same. However, the downside is that the efficiency benefits from adopting dynamic, more reflective loss factors would be lost.

Dynamic loss factors

In the October COGATI discussion paper, it was proposed that the current static approach to setting intra-regional marginal loss factors could instead be replaced with marginal losses that are calculated dynamically in dispatch. This proposal recognised that because intra-regional marginal loss factors are currently fixed for a year, in practice there will be differences between the actual marginal loss factor in any dispatch interval and the static marginal loss factor set by AEMO. This means that the locational marginal prices derived from the static marginal loss factors would not necessarily be an accurate reflection of the marginal cost of supply at each node in each dispatch interval. Therefore, the application of static loss factors could lead to generators with higher loss-adjusted costs being dispatched ahead of lower-cost generators, since it would not reflect actual marginal losses as they occur in real time.

Currently NEMDE does not explicitly model transmission losses that occur *within* a region. To implement dynamic marginal losses, NEMDE would need to change so that losses could be simulated on each branch of the transmission network, to reflect how the level and cost of losses would fluctuate with the branch flow. This could be considered similar to the approach taken in the NEM dispatch engine for modelling inter-regional losses. Such an approach has been adopted in other jurisdictions where dynamic losses are part of the dispatch process, such as in the New Zealand electricity market.[42]

40 Allowing for the additional flexibility in AEMO's processes that are included in the *Transmission Loss Factors* rule change final determination.

41 Note, in this formula the locational marginal price reflects the impact of congestion only. If the current loss factor framework was retained, AEMO's dispatch process would continue to be based on *loss adjusted* bids/offers of scheduled and semi-scheduled participants. These loss-adjusted offers/bids would be reflected in locational marginal prices.

42 EnergyAustralia and Stanwell considered that further work was needed to assess the impact of dynamic marginal losses on the practical process of submitting dispatch offers.

As noted in section 4.2, the future development of existing market systems, including NEMDE, is being considered as part of the ESB's post 2025 review. Therefore, consideration of whether dynamic marginal loss factors are included will occur over the rest of 2020 alongside the ESB's market design process.

Stakeholders expressed mixed views in relation to the introduction of dynamic marginal losses. The AER, Energy Networks Australia, AusNet Services, TasNetworks, TransGrid, Goldwind and Tesla support the introduction of dynamic marginal losses, as this would more accurately reflect losses on the network.[43] Energy Networks Australia considered that dynamic marginal losses should be adopted irrespective of whether FTRs that hedge losses can also be introduced.[44] AGL agreed that a shift to dynamic marginal losses appeared economically sensible, in the context of the overall access model proposal (i.e., with an appropriate hedging instrument).[45]

Meridian Energy Powershop, the Clean Energy Council and SIMEC Energy Australia raised concerns relating to complexity, including in relation to forecasting dynamic marginal losses.[46] Infigen Energy noted that while real-time loss factors are more accurate in the short-run, they may be problematic for both operational, investment and contracting decisions.[47] Snowy Hydro considered that dynamic loss factors will increase risk for generators, as they will be unable to know in advance what contract volume they are able to sell.[48] While recognising the rationale of improving dispatch efficiency, Origin observed that as dynamic marginal losses would be more volatile and uncertain, it is not clear whether the gains would outweigh the costs.[49]

Lighthouse Infrastructure Management, Total Eren, ESCO Pacific, John Laing, BayWare Projects Australia, Powering Australian Renewables Fund, Windlab, Foresight Group, Canadian Solar and Palisade Investment Partners considered that dynamic marginal losses could increase volatility, relative to the current approach of static marginal loss factors.[50]

Other stakeholders noted aspects that should be further considered:

43 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.

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

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

46 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.

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

48 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Snowy Hydro, p. 2.

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

50 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: 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.

- AGL requested further clarity on how dynamic marginal losses would be calculated on a trading interval basis.[51]
- Tilt Renewables suggested that potential interactions between negative price offers and the nodal dispatch of losses required further exploration, referencing the New Zealand market experience.[52]

Alternative options

There are other options to incorporate marginal losses in dispatch. Static intra-regional marginal loss factors are currently set on an *ex ante* basis, a year ahead.

One option would be to maintain a static *ex ante* approach but calculate marginal loss factors on a more frequent basis. For example, in principle it might be possible to calculate marginal loss factors close to real time for each dispatch interval, to reflect expected network conditions (for example, 30 minutes before dispatch). The resulting marginal loss factors would then be incorporated in dispatch and settlement processes in the same way as currently. While such an approach could potentially be implemented without significant revisions to NEMDE, this type of modification would still require new interfaces and data transfers occurring close to real time. There would likely also be some changes required to existing bidding processes.[53]

Other alternative approaches could include refreshing marginal loss factors on a less frequent basis, such as monthly or quarterly.

These other options will be considered over the course of 2020, in conjunction with transmission access reform modelling and the ESB's market design work.

On the question of an *ex ante* approach to implementing more frequently determined marginal loss factors, Energy Networks Australia suggested that this could be dealt with as an implementation issue, based on an analysis of the relevant costs and benefits.[54] Energy Queensland considered that it is too early to abandon the option of *ex ante* dynamic marginal losses without further analysis.[55] Stanwell noted that the adoption of *ex ante* loss factors that are set for at least one trading day would overcome the potential issue of bid non-conformance with the market price cap and floor.[56]

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

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

53 For example, AEMO's spot market operations timetable currently requires generators to submit dispatch offers by 12:30 pm on the day before the trading day. Dispatch offers include prices for each price band, which are fixed for the trading day and may not be changed after the dispatch offer has been submitted. While offer prices are made at the generator's connection point, they must fall within the market price cap and market price floor once the marginal loss factor is applied (Clause 3.8.6(c) of the NER). Therefore, the interaction of dispatch offer/bid submissions with marginal losses that are calculated in or near to real time would need to be determined.

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

55 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Energy Queensland, p. 12.

56 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Stanwell, p. 12.

4.5.3 Current blueprint design

As outlined above, there are multiple options available for the treatment of marginal loss factors with the access model proposal. The current blueprint design set out in this report reflects the retention of the existing marginal loss factor framework, as a starting point for further development and discussion with stakeholders. However, there remains scope for exploration of the full range of options, including both dynamic marginal losses and alternative approaches such as *ex ante* static marginal loss factors calculated on a more frequent basis, particularly if changes proposed in the ESB's market design process would provide opportunities to make this option lower cost. The feedback received from stakeholders will be incorporated into the ongoing design process over the course of 2020, along with consideration of the future development of NEMDE.

4.6 How are issues of market power dealt with?

BOX 10: MITIGATING MARKET POWER IN THE WHOLESALE MARKET

Our initial conclusion is that market power will not be exacerbated by the introduction of the reform, it will just become more transparent. We are undertaking modelling to ascertain whether or not this is actually the case. The international study undertaken by NERA suggests that market power has not gotten worse in overseas jurisdictions that have adopted LMP/FTR regimes; but it has provided more evidence enabling market power concerns to be noticed.

The access model is therefore not expected to exacerbate the underlying conditions that give rise to market power in the NEM. Therefore, opportunities for participants to exercise market power are not expected to arise more often if the access model is introduced. It is possible that the introduction of locational marginal pricing could change the way that the exercise of market power manifests in wholesale market pricing outcomes. However, locational marginal pricing will also make this issue more transparent compared to the status quo, which will make it easier to tackle and resolve.

Therefore, the AEMC and the AER will review the AER's existing monitoring functions and processes to make sure they are fit for purpose for locational marginal pricing. The AER should also consider what additional data should be available in order to address risks to the market, such as the potential for exercise of market power.

In addition, quantitative modelling is being undertaken to assess how market power could potentially result in different pricing outcomes, relative to the current market design. This analysis will help to identify whether the consequences of market power being exercised are of greater concern compared to the status quo, even though this is not expected to occur more frequently. If market power is found to be a more significant concern under the proposed access model, this would be mitigated through elements of the proposed design that are aimed at curtailing market power:

- An ex ante offer cap would be introduced in the event that a generator was deemed to be pivotal.

- The offer cap would be set at a value related to the conditions in the wholesale market at the time the cap is applied.

As discussed in Box 11 below, opportunities for generators to exercise market power are not expected to occur more frequently if the proposed access model is implemented.

BOX 11: OPPORTUNITIES FOR THE EXERCISE OF MARKET POWER IN THE WHOLESALE MARKET

Generators use bidding strategies to influence their dispatch volume and price in the wholesale market. To the extent that a generator is able to increase the wholesale price it receives without reducing its dispatch volume, it can be considered to have a degree of market power.[1]

Transmission constraints can create opportunities for generators to exercise market power. This is because congestion effectively creates smaller 'sub markets', reducing the number of generators who are competing to supply load. The degree of concentration within these sub markets may mean that competition does not provide an effective constraint on generator bidding behaviour. Some stakeholders have expressed concern that the introduction of locational marginal pricing could worsen market power in the NEM, relative to the status quo.

Transmission constraints - and their effects on competition in the wholesale market - are an underlying feature of the NEM. There will be some level of congestion in the electricity system under both the current market design, and the proposed access model.[2] Therefore, the circumstances in which generators have the ability to exercise market power are not expected to be more frequent under the proposed access model is implemented. However, the proposed access model will provide more granular information about market pricing outcomes and transmission system capacity, which is expected to make instances of market power more transparent and therefore easier to address.

If locational marginal pricing is implemented, it is possible that the effect of market power on wholesale market pricing outcomes could be different than under the status quo (for example, depending on the pricing arrangements that apply where a generator is required to run for reliability reasons). However, this will depend on a range of factors, including generators' contract positions, which may tend to mute incentives to exercise market power. Other elements of the access model design will also have an effect. For example, section 4.3.2 discussed that locational marginal prices could potentially be capped in certain circumstances. Quantitative modelling is being undertaken to assess whether the impact of generators holding market power is likely to change under the proposed access model. If this is expected to be a greater concern relative to the current market arrangements, mitigation measures can be incorporated into the access model design.

Source: AEMC

Note: 1) Transient pricing power is an inherent feature of a workably competitive wholesale market and can result in occasional spot price spikes. This is only a concern if it occurs frequently enough and is sufficiently material to lead to average annual wholesale prices above the long-run marginal cost of generation.

2) The proposed access model is expected, over time, to lead to more efficient patterns of generation and transmission investment. Therefore, the overall level of congestion in the NEM could potentially be more efficient, relative to the status quo. Nonetheless, the level of congestion will not be zero.

We are undertaking modelling to substantiate or not the above considerations. Regardless of the modelling outcomes, it will likely be appropriate that the AEMC and the AER review the AER's existing wholesale market monitoring functions and processes, to make sure that they would remain fit for purpose in the context of the proposed access model. In the event that the modelling exercise identifies that market power would be a more significant concern if the access model is introduced, consideration would be given to additional mitigation measures. A more detailed discussion of design considerations related to these two elements of the access model is set out below.

4.6.1 What are current market design measures and how could they be adapted?

The AER has an existing obligation under the National Electricity Law (NEL) to monitor and report on the performance of wholesale electricity markets.[57] The NEL requires public reporting on the results of the performance of the AER's wholesale market monitoring functions at least once every two years.[58] This includes analysing and identifying whether there is effective competition in the market. In addition, clause 3.13.7 of the NER requires the AER to:

1. Determine whether there is a significant variation between the spot price forecast and actual spot price in each trading interval, review the reasons for the variation and publish a report quarterly
2. Publish a report on trading intervals where the spot price exceeds $5,000/MWh
3. Report on instances when prices at a regional reference node for a market ancillary service over a period significantly exceed the relevant spot price for energy, and prices for that market ancillary service exceed $5,000/MWh for a number of trading intervals within that period.

Under locational marginal pricing, the pricing information available to the AER will be much more granular relative to the status quo. Rather than there being a single spot price for each NEM region, when transmission constraints bind there will be multiple spot prices that apply at different transmission connection points. Accordingly, it would be appropriate for the AER and AEMC to review whether in the context of locational marginal pricing, the reporting requirements outlined above would remain fit for purpose and continue to provide useful information to the market. For example, it may be more informative for the AER to group pricing events that are of interest and report on these periodically (e.g. quarterly), as opposed to reporting on each event individually.

57 The obligation was introduced in 2016 under Part 3, Division 1A of the NEL.

58 See section 18C(2)(a) of the NEL.

In addition, the review of these functions could consider how the introduction of locational marginal pricing and financial transmission rights may change the behaviour of market participants, and what sort of data should be available in order to address risks of impact to the market, such as the potential for exercise of market power. This includes the potential to introduce more stringent provisions in the event of a material problem. Any new requirements should aim to ensure that the AER is able to detect if unforeseen or new instances of market power arise following the introduction of the access model.

Market power mitigation

Market power should not be a more significant concern if locational marginal pricing is in place, although it should also be more transparent. Depending on the outcomes of the modelling exercise, it may be appropriate to include *ex ante* mitigation measures as part of the access model design. This is consistent with the approach taken in other jurisdictions that have implemented more granular pricing signals.

Initial analysis indicates that the most suitable mitigation measure for the NEM could be to introduce an *ex ante* offer cap, in the event that a generator is deemed to be pivotal.[59] This approach is a bid mitigation mechanism, whereby a regulated offer price is automatically applied through dispatch if a generator fails a pivotal supplier test.[60] The cap would only apply when constraints bind and a generator is deemed pivotal. The offer cap could potentially be applied automatically through the NEM dispatch engine, rather than requiring specific intervention from the AER.

The main benefit of this option, relative to the alternatives, is that the outcome would be clearly defined and predictable for market participants. If applied as a relatively automatic process, the ongoing cost of applying the mitigation measure could also be lower. However, the effects of the mechanism would likely themselves require careful monitoring. In addition, an *ex ante* offer cap is broadly consistent with the current approach to intervention pricing in the NEM, whereby AEMO applies a transparent pricing methodology to remunerate generators that are directed on to meet reliability needs. An *ex ante* offer cap would typically need to be applied in the same circumstances that AEMO is required to direct generators to run to support reliability (i.e., the directed generators would likely be deemed pivotal, and therefore subject to the offer cap).

The exact nature of the cap would require further analysis. A key challenge with this approach would be designing an offer cap that avoids the risk of disrupting investment signals or preventing generators from recovering efficient costs. It may be most appropriate to set the offer cap at a value related to the conditions in the wholesale market at the time the cap is applied, rather than a value based on generators' costs. For example, the cap could be set at the price of the second highest bid in the wholesale market, with this made by another generator who was cleared.

59 This approach is currently used in the ERCOT (Texas) market.

60 A pivotal supplier test could be, for example, if the generator is required to meet demand at one or more transmission nodes.

There are alternative options. However, based on an initial analysis these options appear less appropriate for the NEM, as they would be less reflective of the prevailing market dynamics. The alternative options identified include:

- A pre-determined value, related to costs of the generator. The cap cannot be set at the short run marginal cost, since under the current NEM design generators also need to recover their *long-run* costs through their wholesale market revenue. This could take a similar approach to that recommended in the *Investigation into the intervention mechanisms in the NEM* review.[61]
- A fixed $/MW cap**.** The cap could be set at a fixed $/MW, although, this would risk over compensating some generators and under compensating others.

The *Gaming in rebidding* final report ruled out the introduction of a pivotal supplier test.[62] That decision remains appropriate in the absence of changes to the current market design. However, given the specific concern raised by stakeholders, an ex ante offer cap and pivotal supplier test could be introduced alongside locational marginal pricing.

Stakeholder feedback

Some stakeholders agreed with the characterisation of market power issues set out above and were in principle supportive of the identified approaches to managing market power under the proposed access model. Energy Queensland and Aurizon Network agreed with the assessment of the potential for market power to arise.[63] The AER noted that further work is needed to understand the issues and develop appropriate responses.[64] The ACCC considered that impact analysis is critical.[65]

Quinbrook Infrastructure Partners and Neoen believe that locational marginal prices would likely increase the market power of certain generators and create opportunities for gaming.[66] Mondo Energy was of the view that pre-emptive market power response mechanisms should not be pursued.[67] Origin considered that market power mitigation measures of the type proposed would be sub-optimal and could undermine the efficient functioning of the NEM.[68]

4.6.2 Current blueprint design

In order to address stakeholder concerns and to help inform potential design solutions to the issue of market power, the Commission has engaged consultants to conduct quantitative

61 AEMC, *Investigation into intervention mechanisms in the NEM*, Final report, 15 August 2019, p. 40.

62 AEMC, *Gaming in rebidding*, Final report, 28 September 2018.

63 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Energy Queensland, p. 13; Aurizon Network, p. 3.

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

65 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: ACCC, p. 2.

66 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Quinbrook Infrastructure Partners, p. 2; Neoen, p. 2.

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

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

market modelling to assess the potential frequency and magnitude of market power issues under locational marginal pricing. This will help determine how material this concern may be, and provide insight into the most suitable monitoring and mitigation approach. The outcomes of this analysis will therefore be incorporated into the ongoing design of the access model.

As was noted above, regardless of the modelling outcomes, it will be appropriate for the AEMC and the AER to review the AER's existing monitoring functions and processes to make sure they are fit for purpose for locational marginal pricing. Accordingly, such a review is included within the blueprint design proposal. The review will allow for the potential to introduce more stringent provisions in the event of a material problem being identified.

5 FINANCIAL TRANSMISSION RIGHTS FOR CONGESTION

The second element of the access model improves the financial risk management options for market participants. Market participants will be able to better manage the risks of congestion and transmission losses by purchasing FTRs.

This chapter discusses FTRs that pay out on the price differences that arise under locational marginal pricing due to congestion on the transmission network, ignoring the impact of losses for simplicity. Chapter 6 then discusses possible options in relation to the treatment of losses in the FTR design (which includes FTR design options that hedge the combined price impact of congestion and losses, separate loss and FTR products, or not having a FTR product for losses). The current blueprint design will continue to be refined over the course of 2020, in conjunction with stakeholder engagement and consideration of other reforms underway.

Table 5.1: **Summary of the current FTR blueprint design**

ISSUE	CURRENT BLUEPRINT DESIGN
What type of FTRs are offered?	The current design option is that the type of FTRs that would be offered would be option instruments, which only ever result in a positive payment. This means that the FTR would never result in a payment liability for the right holder. This has been informed by reviewing international markets, where, even if products were offered that had negative and positive payments, these are not popular and rarely purchased.
What prices do the FTRs refer to?	The current design option is that market participants would be able to buy FTRs that pay out on the price difference between: • an LMP and any regional price ('local-regional FTRs') • an regional price and any other regional price ('regional-regional FTRs'). That is FTRs will be available to be purchased from *any* node, but will only relate to certain specific nodes (i.e. the regional prices)
When do the FTRs pay out?	The current design option is that market participants would be able to acquire rights which pay out: • at all times of the day ('continuous' rights), or • during specified settlement intervals ('time of use' rights). The specified settlement intervals would be determined to suit the needs of market participants.

ISSUE	CURRENT BLUEPRINT DESIGN
Where does the revenue to back the FTRs come from?	Introducing locational marginal pricing would mean that FTRs would be largely self-funded. That means the funds to back the rights would arise from the difference between what generators are being paid and load is paying when transmission congestion arises. Due to the dynamic nature of the transmission system, there will be some settlement intervals where the volume of FTRs issued is less than the actual capacity of the transmission system, and instances where the volume is higher. The more concerning situation for a generator would be where the volume of FTRs issued is higher than the actual capacity of the transmission system. At these times, there would not be enough money arising from wholesale market settlement to pay FTR holders. The current design option to support the firmness of the FTR instruments is: • If in some settlement intervals there are excess funds remaining after FTR holders have been paid, this surplus would accumulate in a "settlement account" administered by AEMO. • In addition, proceeds of FTR auctions would be held in a separate "auction account" also administered by AEMO. After a defined time, any remaining balance in the auction account would be returned to consumers to offset their TUOS charges. • At times when the surplus revenue from wholesale market settlement is not enough to fully pay FTR holders, the two balancing accounts would be used to 'top up' FTR payments, so that FTRs would have a very low probability of being scaled back. • If both the settlement and auction accounts are exhausted, FTR payouts would then be scaled back to the extent necessary. Under the current design option, the firmness of FTRs would also be supported by enhancements to the existing market impact component of the Service Target Performance Incentive Scheme (STPIS), which would mean that transmission network service providers (TNSPs) have an incentive for network capacity to be made available when it is valued.
What risks do FTRs manage?	The financial transmission rights would hedge the full difference between LMPs and regional prices that arises due to congestion on the transmission network, including from non-thermal constraints.
How can participants acquire FTRs?	The current design option sets out that FTRs would be sold through a series of 'simultaneous feasibility' auctions run by AEMO. Input from TNSPs would be used to set the parameters for determining how many FTRs could be sold.

ISSUE	CURRENT BLUEPRINT DESIGN
	The auctions would determine the quantity and combination of FTRs sold, given market participants' willingness to pay for them and the expected physical characteristics of the network. The simultaneous feasibility auction is designed to provide the rights with an appropriate level of firmness. In addition to these auctions, physical market participants would be able to obtain grandfathered FTRs. The Commission also expects secondary trading would emerge as a way to purchase FTRs for both physical and non-physical market participants, and will need to consider options to facilitate secondary trading in the NER.
What is the tenure and granularity of FTRs?	Under the current design option the FTR auction could offer products with a range of tenures, including up to 10 years in advance. The granularity of these products (the length of the period that an individual FTR hedges over, such as over a month, quarter, or year) will be determined based on the tenures would be offered through the auction. This is a change from the position outlined by the Commission in its discussion paper published in October, in light of feedback provided by participants on what products they would find most useful.
Who can participate in the FTR auction?	The following restrictions on auction participation would apply, under the preferred option: • Local-regional FTRs: Only physical market participants would be able to purchase local-regional FTRs. In addition, participants' ability to purchase these rights should be capped at some measure of their physical capacity in the market. • Regional-regional FTRs: In contrast, all market participants (including non-physical participants) would be able to purchase regional-regional FTRs. Any participant (physical or non-physical) would be able to resell the FTRs they hold back into a subsequent auction pool. In addition, there would be no explicit restrictions on secondary trading (bilaterally or on a platform outside the auction). We will consider whether financial participants should be allowed to purchase FTRs or whether the secondary trading arrangements would be sufficient over the course of 2020.
What transparency arrangements would be introduced?	The current blueprint option is that AEMO should maintain a register of the amount of FTRs sold at auction and the clearing price. The register would also include information about the current holders

ISSUE	CURRENT BLUEPRINT DESIGN
	of FTRs, including where changes in ownership occur due to secondary trades. Transparency provisions are one element of the FTR design blueprint that is designed to address participants' concerns in relation to the potential for hoarding behaviour. This would operate alongside the provisions of the *Competition and Consumer Act 2010*.

5.1 What are financial transmission rights?

Locational marginal pricing means that generators are paid and consumers pay a different amount for the same electricity. Generators will be paid their locational marginal price, while consumers pay the regional price.

Consistent with figure 4.2 above, and reflective of the local supply and demand conditions, in the presence of constraints the regional price for consumers is typically higher than the LMP for generators. This results in more money being paid into AEMO's settlement system than out of settlement, and therefore, there is excess money left over.[69]

This excess money is equal to the difference between what generators are paid and what load pays for the same energy.[70]

This phenomenon currently occurs in the NEM because generators and load already pay different prices for the same energy as a result of regional price differences,[71] and price differences that arise within regions due to differing loss factors.[72]

Returning to the example in figure 4.2, the excess money that arises due to the difference between what consumers are paying and generators are being paid is equal to $1,500/h. That is, the flow on the line (50MW) multiplied by the price difference ($30/MWh). Or, equivalently, what consumers are paying for the energy ($50/MWh x 100MW) minus what generators are being paid for the energy ($50/MWh x 50MW + $20/MWh x 50MW).

FTRs are financial instruments which pay their holders based on the difference between locational marginal prices. They are (in normal circumstances) fixed volume instruments. They pay out on the price difference multipled by a fixed number - the number of FTRs held.

FTRs are backed (primarily) by the excess money that arises due to the difference between what consumers are paying and generators are being paid. As noted in section 4.2, FTRs would be available that pay out on the price difference between any LMP and any RRP, or between any two RRPs.

69 This money is usually known as "settlement residue".

70 Ignoring the effect of losses for simplicity.

71 Known as "inter-regional settlement residue".

72 Known as "intra-regional settlement residue".

BOX 12: ALGEBRAIC REPRESENTATION OF FINANCIAL TRANSMISSION RIGHTS

The changes to introduce financial transmission rights can also be illustrated with some basic mathematics. Continuing on from Box 2, the introduction of financial transmission rights means that the second term of equation [2], summed up overall generators, and reallocated to FTR holders is:

Revenue = LMP x physical dispatch + (Locational price 1 — Locational price 2) x fixed FTR quantity held by market participant [3]

This means that a market participant's revenue from the AEMO administered settlement will be defined as the sum of its revenue from energy plus its revenue from FTRs:

Revenue = LMP x physical dispatch quantity + (regional price - LMP) x fixed FTR quantity held by market participant [4]

When there is no congestion, there is no difference in local prices (ignoring the effects of losses), meaning that this equation collapses to:

Revenue = regional price x physical dispatch quantity

I.e. there is no difference to settlement outcomes compared to the status quo when there is no congestion.[1]

Note: 1) For simplicity, these equations ignore the effect of transmission losses. Depending on how transmission losses are reflected in the access model design, adjustments would be required to both the wholesale market and financial transmission right settlement formulas. For example, adjustments might be required to either the LMP and / or FTR quantity, depending on whether the FTR design allows participants to hedge both loss- and congestion-related price differences within a single instrument, or whether there are separate loss and congestion FTR products.

Market participants would compete to purchase FTRs through an auction run by AEMO. Grandfathering arrangements would also be put in place to provide some FTRs to incumbent generators for free for a period of time. This would assist the successful implementation of the reform and provide stakeholders with the time needed to adapt to these reforms.

The revenue received from the sale of FTRs would be used to firm FTRs.

FTRs are a congestion and loss risk management tool

Currently, when congestion occurs, generators are constrained down – their output is less than their preferred unconstrained output, despite offering their electricity at a price less than the regional reference price. This create risks for generators (or their counterparties, if contracting arrangements have allocated this risk to their counterparty) – either the opportunity cost of not earning as much money in the spot market, or financial loss if they have contracts which require a payout which are not backed by revenue received from the spot market.

Under both the current and the proposed access model, if there is no congestion, the generator's production is not reduced as a result of congestion. Locational marginal prices are the same everywhere (ignoring the effect of losses). Therefore, the generator receives the regional reference price for its preferred quantity of generation.[73]

If there is congestion, then the generator's production may be reduced as a consequence. Its locational marginal price may also drop below the regional reference price. However, it will also be paid the difference between the locational marginal price and the regional reference price for any FTRs it holds. This provides a hedge against the impact of congestion. This is discussed in more detail in section 5.3.

Under normal operating conditions, when the number of FTRs held by market participants is broadly equal to the physical capacity of the network, then:

- when there is no congestion, there is no price separation between the LMP and RRP. This means that there is no excess revenue, and also no FTR payouts. Settlement balances.
- when there is congestion, settlement once again balances. There is:
  - price separation and hence excess revenue between what generators are paid and load pays for electricity, but also;
  - the congestion simultaneously results in a payout for the FTRs equal to the excess revenue.

5.2 What type of FTRs are offered?

> **BOX 13: TYPE OF FINANCIAL TRANSMISSION RIGHTS FOR CONGESTION**
>
> The current blueprint design is that FTRs would be option instruments, which only ever result in a positive payment. This means that an FTR would never result in a payment liability for the holder.

Two simple types of FTRs that could be offered are options (meaning that they only ever result in a positive payout) or swaps (that could result in either a positive payment or a payment obligation on the part of the FTR holder). A decision needs to be made on whether FTRs are positive only or if FTR holders would sometimes be required to payout.

5.2.1 'Options' instruments

An option right would mean that the payout under the FTR is only ever positive e.g. holders of FTRs won't be required to payout if the LMP > regional price.

For example, if a generator has purchased an option that pays out on the difference between its LMP and the regional price when transmission constraints bind:

- the FTR would pay a positive amount to the generator when its LMP was below the regional price as a result of transmission congestion[74]

73 Of course, a generator's quantity may be reduced for other reasons, such as plant unavailability.

74 The payout would be equal to the difference between the RRP and the LMP (excluding loss effects), multiplied by the FTR amount purchased.

- the FTR would not pay out when the LMP was above or equal to the regional price.

For each pair of prices, two FTR option products would be available. Each FTR would be backed by the same transmission capacity, but relate to opposite 'directions' of electricity flow in the network. For example:

1. the first right might pay out when the LMP is lower than the regional price due to transmission congestion
2. the second right might pay out when the regional price is lower than the LMP due to transmission congestion.

The rationale for having option rights in both 'directions' is to accommodate the differing needs of the supply and load side of the market. The first 'direction' above is likely to be useful for scheduled and semi-scheduled generators, who are likely to want to hedge against relatively *low* LMPs at their connection point. The second 'direction' is likely to be useful for scheduled loads, who are likely to want to hedge against a relatively *high* LMP at their connection point.

The majority of stakeholders who commented on this aspect of the reform supported the introduction of FTR option instruments only. Specific comments included that:

- TasNetworks, Energy Queensland and Mondo Energy supported limiting FTRs to options instruments, based on their relative simplicity and usefulness.[75]
- Energy Networks Australia was of the view that there might be pragmatic reasons to limit FTRs to options instruments initially.[76]

BOX 14: OPTION INSTRUMENTS

FTRs for generation

FTRs that are likely to be useful for generation would be 'put' options. That is, they would pay out when the LMP at a connection point ('spot price') is below the regional price ('strike price') due to transmission congestion. The financial transmission right would otherwise be 'out of the money', and would not be exercised.

The mathematical payout of the FTR would therefore be (we have continued to assume the regional price is the RRP in the below examples for simplicity):

FTR payout= max(0, RRP – LMP excluding losses).

FTRs for load

Financial transmission rights that are likely to be useful for load would be 'call' options. That is, they would pay out when the RRP ('strike price') is below the LMP ('spot price') at a connection point due to transmission congestion. As above, the financial transmission right

75 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: TasNetworks, p. 5; Energy Queensland, p. 13; Mondo, p. 4.

76 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Energy Networks Australia, p. 18.

would otherwise be 'out of the money'.

The mathematical payout of the financial transmission right would therefore be:

FTR payout= max(0, LMP excluding losses - RRP).

5.2.2 'Swap' instruments

A swap instrument would simply pay out on any difference between prices, whether positive or negative. This means that FTR 'payments' could either be a payment or a liability for the holder. Swap instruments are not considered valuable at this point in time (although they could be introduced at some point in the future).

For example, if a generator has purchased a swap that pays out on the difference between its LMP and the regional price when transmission constraints bind:

- the FTR would pay a positive amount to the generator when its LMP was below the regional price due to transmission congestion
- the FTR would require payment from the generator when the LMP was above or equal to the regional price due to transmission congestion.

Some overseas markets with financial transmission rights offer both swap and option instruments, including New Zealand, ERCOT and PJM. In the New Zealand market, swaps are relatively rarely purchased.[77] This may reflect the fact that market participants may not want to pay for a financial instrument that includes a liability. This has also informed the view that swap instruments should not be introduced at the start of the regime.

Swaps would also require the development of prudential arrangements, given that FTR holders would be required at times to make payments into settlement. Introducing swaps would therefore create additional complexity for the market design.

Swaps could be subsequently introduced into the market if participants considered them to be of sufficient value.

Some stakeholders noted that there could be potential benefits from offering a swap FTR product. Energy Networks Australia was of the view that in the longer term, an FTR swap might prove to be a better hedge than an FTR option for risk management purposes.[78]

AEMO and the AER also noted that it is not necessary to make a firm decision on the type of FTRs that are offered at this stage.

77 In a 2017 review of the New Zealand FTR market, the Electricity Authority found that option FTRs have consistently accounted for between 90 and 100 per cent of all FTRs allocated. Source: Electricity Authority, *Financial Transmission Rights development - Issues and options paper*, 28 March 2017, paragraph 6.28.

78 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Energy Networks Australia, p. 18.

5.2.3 Current blueprint design

In light of stakeholder feedback and the discussion above, the current blueprint design reflects that the FTRs would be option instruments, which only ever result in a positive payment. This means that an FTR would never result in a payment liability for the holder.

However, the available policy options will remain open for further consultation and discussion throughout the design process over the course of 2020.

5.3 What prices do the FTRs refer to?

BOX 15: THE PRICES THAT FTRS REFER TO

The preferred option is that market participants would be able to buy FTRs that pay out on the price difference between:

- an LMP (i.e. any transmission connection point with a scheduled or semi-scheduled market participant) and any regional price ('local-regional' FTRs)
- a regional price and any other regional price ('regional-regional' FTRs).

FTRs would not be available between any LMP and any other LMP.

Together, FTRs relating to congestion and losses between two regional prices would replace the inter-regional settlement residue auction (SRA) distribution units that are periodically auctioned off under the current arrangements.

In developing the blueprint design, the Commission has considered a range of potential options for the prices that FTRs refer to. These include:

- Local to regional FTRs
- Regional to regional FTRs
- Local to local FTRs
- FTRs between pre-defined hubs.

As discussed further below, initial analysis suggests that the first two options are likely to be most suitable in the context of the NEM.

5.3.1 Local to regional FTRs

The Commission has consulted with stakeholders on the option that 'local to regional' FTRs would be available to hedge the difference between the LMP at a nominated transmission connection point in a region, and any regional price (including in another region). These FTRs would therefore allow both demand and supply side market participants to manage congestion risk.

This FTR design would provide market participants with the option to buy a FTR that relates to the LMP at their connection point and the regional price of a region in which they are not located. This is to reflect the fact that a market participant may be electrically 'closer' to the regional reference node of a different NEM region than the one they are located in.[79]

For example, a scheduled or semi-scheduled generator in south-west NSW may have an LMP that more closely approximates the regional price of South Australia. Under the proposed arrangements, this market participant may choose to enter into commodity contracts with counterparties settling on the South Australian regional price, in part because the risk of transmission congestion (and the cost of purchasing a right to address that risk) may be relatively low.

The AER, Energy Queensland, CS Energy and Mondo Energy supported enabling FTRs between an LMP and any regional price (local to regional rights).[80]

5.3.2 Regional to regional FTRs

The Commission has also consulted with stakeholders on the option for market participants to buy 'regional to regional' rights that payout on the difference between any regional price and any other regional price, even if those regions are not adjacent.

As described in Box 16, regional-regional FTRs would replace the existing inter-regional settlement residue products.

BOX 16: SETTLEMENT RESIDUE AUCTION UNITS

The Commission envisages that FTRs relating to congestion and losses between regions would collectively replace the existing inter-regional settlement residue auction products (colloquially known as SRA units). The need for, and design of, transitional arrangements for SRAs will be determined through 2020.

Under the proposed access model, funds arising from the difference in what loads pay and generators receive through wholesale market settlement would be managed by AEMO. Therefore, TNSPs will no longer have to manage the cash flow volatility that arises from their current role in managing SRA funds. This benefit is offset by AEMO having to manage settlement cash flows instead.

Potential to support liquidity

Currently, liquidity is already somewhat split in the NEM across the five regions. Generators and market customers may therefore be unwilling to enter into forward energy contracts where each counter-party is exposed to a different regional price. This is because of the basis risk that arises for each market participant if transmission constraints bind between regions, resulting in differing regional prices.

The use of inter-regional settlement residue auctions partially offsets this risk. However, SRAs

79 And hence the LMP at their connection point might relate more closely to the alternate RRP, rather than the RRP of the region they are geographically situated in.

80 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.

are currently not firm in nature (due to the inclusion of transmission losses and effects such as counter price flows).

Therefore, SRAs constitute imperfect hedges against basis risk. They are more typically purchased by speculators, rather than market participants for the purpose of basis risk management. Generators and market customers generally tend to contract with counter parties within their region.

The introduction of financial transmission rights - that replace SRAs - will further support liquidity. Market participants will be able to buy financial transmission rights which hedge:

- the price difference between an LMP and any regional price, including the regional price in another region, or
- the price difference between any two regional prices.

Regional-regional FTRs would be firmer than the existing SRA units, and so improve the ability for market participants to manage basis risk across regions. In turn, this should promote cross-regional trade, and improved liquidity in the existing regional markets. The reason why these financial transmission rights would be firmer than the existing SRA units is discussed in Box 17 below.

BOX 17: FINANCIAL TRANSMISSION RIGHTS WILL PROVIDE A BETTER RISK MANAGEMENT TOOL THAN SRA UNITS

Currently, participants that trade inter-regionally can partially hedge against inter-regional price risk.

They can do this by purchasing the right to a share of the inter-regional settlements residue (IRSR) that accrues when prices between regions separate. The value of the IRSR is equal to the difference between the price paid by retailers in an importing region and the price received by generators in an exporting region, multiplied by the amount of flow across the relevant interconnector.

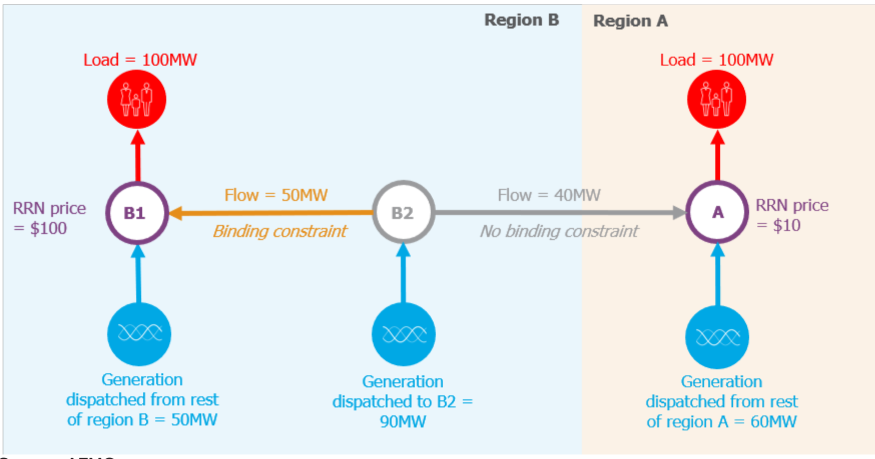
Such rights are known as settlement residue distribution units (SRDU), or more commonly, settlement residue auction units (SRA units).

SRA units provide an effective inter-regional hedge only when the interconnector is able to flow at capacity and in the direction equal to the volume of SRA units sold. This is because of a phenomenon known as counter price flows. Counter price flows describe the situation where electricity flows from a lower priced region to a higher-priced region.

For example, take the example shown in figure 5.1 below. Load on one side of a regional boundary in region A may be best served (from the perspective of dispatch efficiency) from generation on the other side of the boundary in region B. This will result in flows across the interconnector from region B to region A. This might occur even if the LMP at the regional reference node in region B (i.e. the RRP) is higher than that in region A.

This example of counterprice flow is efficient from the perspective of dispatch.

Figure 5.1: Counterprice flows under the current arrangements



Source: AEMC

Incentives to undertake race to the floor bidding behaviour in the presence of transmission constraints can exacerbate the instances of counterprice flows, resulting in counterprice flows which are inefficient.

Regardless of the reasons for counterprice flows, there will be negative settlement residue (paid for by consumers via TUOS) and no payout under the SRA, despite the price difference between region A and region B. In the example above, customers in both regions pay a combined total of $11,000/h into settlement (100MW of load in region A at an RRP or $10/MWh, and 100MW of load in region B at $100/MWh). However, generators in both regions are collectively paid $14,600/h (60MW in region A settled at an RRP of $10/MWh, and 140MW in region B settled at $100/MWh).

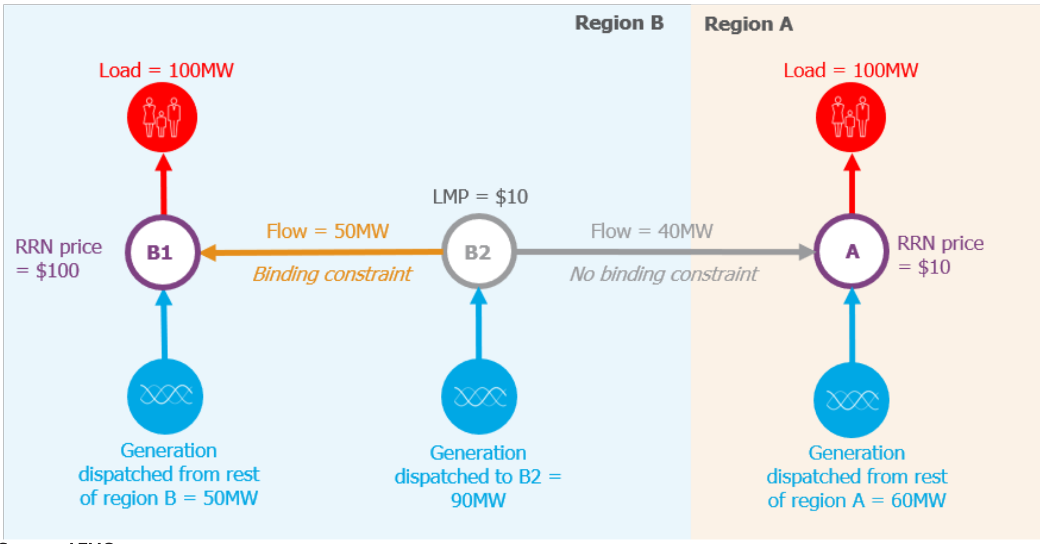
Therefore, there is an overall settlement deficit of -$3,600/h.

In contrast, under the proposed access model:

- there can be no counter-price flows between regional reference nodes (or between transmission connection points more generally). The dispatch engine will always dispatch from low to high priced connection points.
- the perverse incentive for race to the floor bidding behaviour is removed, for the reasons discussed in section 3.2.1 of the October 2019 discussion paper.
- provided that the number of FTRs sold is consistent with the physical capacity of the system, there will typically be sufficient surplus funds to back the issued FTRs, so that they will be paid out in full (refer to section 5.5.3 for a description of the limited circumstances when this might not apply).

To illustrate these outcomes, the same example from Figure 5.1 is replicated below, but with locational marginal pricing applying to connection point B2. In this case, customers in both regions still pay $11,000 into settlement (as the RRPs are unchanged). However, generators are settled on the basis of their LMP. This means that they are collectively paid $6,500 from settlement (as the generator at B2 is now settled at $10/MWh for its output of 90MW). This provides a settlement surplus of $4,500. It can be seen that the surplus revenue from wholesale settlement is equal to the flow on the constrained transmission line (50MW) multiplied by the price difference for the two connection points at either end of that line ($100/MWh at B1 less $10/MWh at B2 = $90/MWh).

Figure 5.2: Interconnector flows under locational marginal pricing



Source: AEMC

Financial transmission rights would therefore:

- introduce a new mechanism by which market participants would be able to manage the risks of congestion, better than they currently can[81]
- replace and improve upon the existing SRA units.

The AER, Energy Queensland, CS Energy and Mondo Energy also supported enabling FTRs between any two regional prices (regional to regional rights).[82]

5.3.3 FTRs between LMPs

It is possible to sell financial transmission rights that relate to the difference between the LMP at any two transmission connection points ('any-to-any' FTRs). This is a more granular approach than that currently proposed in the blueprint.

81 Noting that these risks currently manifest through reduced physical dispatch when transmission constraints bind.

82 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.

This approach might be useful, for example, if a scheduled load and a scheduled or semi-scheduled generator wanted to enter into a commodity contract based on a price other than a regional price. These parties might wish to do this if they are co-located behind a constraint that typically binds, meaning that the LMPs at their respective connection points are often similar. In this case, the price of a financial transmission right that managed any residual basis risk between the two LMPs would presumably be lower than the price of a financial transmission right that related to the regional price.

The rationale for excluding any-to-any financial transmission rights is that it would substantially increase the number of possible FTRs that would be offered in an auction (from hundreds or a few thousand combinations, to many tens of thousands). In turn, this increases the complexity of the auction for allocating the FTRs and increases concerns about the level of competition in the auction. It may also split liquidity in the secondary market for FTRs.

Some stakeholders suggested that further consideration could be given to alternative approaches. Energy Networks Australia considered it is too early to conclude that certain FTR configurations should be excluded from the access model.[83] AusNet Services suggested that the number of price pairs could be based on what is computationally possible.[84] In contrast, TasNetworks stated that if the computational complexity can be reduced, hedging between any two LMPs should also be adopted.[85]

5.3.4 FTRs that relate to a few pre-defined 'hubs'

Under this approach, FTRs can only be bought between a (small) number of pre-selected transmission connection points. This is the approach taken in the New Zealand FTR market.

In New Zealand, financial transmission rights can be bought and sold between eight pre-defined transmission connection points (known as 'hubs'). While this may increase competition and liquidity in the FTR market and reduce the complexity of the FTR auction, it leaves market participants with the risk of any remaining price difference between their connection point and the hub. The Commission does not consider that leaving market participants exposed to this basis risk, with limited ways to manage it, would be efficient.

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.[86]

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

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

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

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

5.3.5 Current blueprint design

As outlined above, most stakeholders who commented on this aspect of the reform supported the blueprint design that would enable market participants to buy FTRs that pay out on the price difference between:

- an LMP and any regional price ('local-regional' FTRs)
- a regional price and any other regional price ('regional-regional' FTRs).

Accordingly, the current blueprint design reflects both these options, but not the alternative options of making FTRs available between any LMP and any other LMP, or between pre-defined hubs. Nonetheless, these elements of the blueprint design will remain open for further consideration and consultation with stakeholders as the access model is further developed through the rest of 2020.

5.4 When do the FTRs pay out?

> **BOX 18: WHEN THE FINANCIAL TRANSMISSION RIGHTS PAY OUT**
>
> The current blueprint design is that market participants would be able to acquire financial transmission rights which pay out:
>
> - at all times of the day ('continuous rights'), or
> - during specified intervals ('time of use' rights). The specified settlement intervals would be determined to suit the needs of market participants.

This aspect of the FTR design considers the settlement intervals that market participants would able to acquire FTRs to hedge against their exposure to congestion. Multiple ways of determining when FTRs pay out were considered as part of this review including continuous rights, time of use rights, and a range of more sophisticate bespoke products.

5.4.1 Continuous rights

A continuous right would be active at all times of the day or night. It would payout the difference between the relevant price pairs specified in the financial transmission right, whenever this price difference is positive.

The main advantage of continuous rights (compared to the alternatives considered below in section 5.4.2) is that they are simple and generic. This makes them more fungible, easier to sell through the auction and more conducive to liquidity in the secondary market. A key benefit is that participants would more readily understand the FTR that they are buying, and the generic nature of the FTRs is likely to increase the prospective pool of buyers and sellers.

A drawback of continuous rights is they may not be the best instruments for some market participants to manage the risk of congestion, particularly variable renewable energy (VRE) generators. Whenever the quantity of FTRs owned by a market participant is different from their 'preferred output',[87] the FTR will pay out more or less than is required to perfectly hedge their congestion risk.[88]

For example, a continuous financial transmission right will pay out when:

- the generator is unavailable
- if the generator's preferred output is zero because the RRP is less than its short run costs.

In either case, the generator may receive a FTR payout despite the fact that - had that congestion not occurred - its output and revenue would have been zero. Therefore, continuous rights introduce an *upside* risk for generators.[89]

Some generators may choose to manage this upside risk by simply purchasing less financial transmission rights than their maximum capacity (in order to reduce their upfront costs). This outcome would be less than ideal, as it would necessarily introduce *downside* risk for the generator. That is, the financial transmission right may no longer be sufficient to optimally hedge against transmission congestion when the generator's preferred output is high.

Of course, there may be some correlation between the generator's preferred output and instances of transmission congestion. Consider, for example, a wind farm located near many other wind farms. If it is not windy, the preferred output of all the wind farms is low,[90] meaning that there is unlikely to be transmission congestion. Conversely, the preferred output of each individual wind farm may be high when it is very windy; however, if the transmission capacity in that part of the network is not able to accommodate all the wind farms, then there is likely to be transmission congestion.

Energy Queensland supported the introduction of continuous and time of use rights (discussed next).[91]

5.4.2 Time of use rights

Time of use rights could partially address the concerns described above. Time of use rights would only be active (i.e. only pay out) at certain pre-defined times of the day (or night).

Based on feedback from stakeholders (discussed below), a more granular product will be useful in addition to continuous FTRs. For example, time of use rights could be designed as a product that pays out in four-hourly time windows. A decision on the most appropriate configuration of time of use rights would be finalised later, as the detailed design of the model is further developed.

87 That is, the output that the market participant would have chosen absent of constraints.

88 For ease of explanation, throughout this section the term 'preferred output' is used and a focus is placed on scheduled and semi-scheduled generators. Preferred *consumption* would be the appropriate term for scheduled load.

89 That is, where the financial transmission rights pay out in excess of that required to make the generator indifferent to the presence or absence of transmission congestion.

90 In this context, 'preferred output' means the output of that the wind farm would have chosen given the price *had there been no transmission constraints*. The wind farm owner may have preferred it to be windier; however, availability risk is not a risk that can be hedged through the financial transmission right framework.

91 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Energy Queensland, p. 14.

Time of use rights may be particularly useful for some forms of variable renewable generators. For example, there is likely to be a high correlation between a solar generator's preferred output and the time of day when it needs to mitigate against transmission congestion.

Further, this approach may result in positive consequences for other types of market participants. For example, we expect that solar generators will exclusively purchase time of use financial transmission rights that are active during daylight hours. This would allow additional FTRs (at a potentially lower price) to be released outside of these hours. Depending on the circumstances, this may send an (appropriate) locational signal to other forms of generation whose output is *not* highly correlated with solar (such as batteries or wind farms) to locate in this part of the transmission network. This would encourage more efficient utilisation of available transmission network capacity.

EnergyAustralia considered that the inclusion of time of use FTRs unnecessarily complicates the auction process and would be expensive to assess and administer.[92]

5.4.3 Bespoke products

ERM Power was concerned that FTR products would not provide an attractive risk management tool for peaking, variable and firming assets.[93]

More sophisticated, bespoke products available as part of the primary FTR issuance process (i.e. the FTR auction) have also been considered to address this concern. Such products could better correlate with participants' risk management needs. For example, one possibility is an FTR instrument that is dependent on weather patterns (i.e. it is only active when it is windy).

However, such instruments are likely to dramatically increase the complexity of the FTR procurement process. As discussed in section 5.9, an auction is proposed which would determine the appropriate combination of financial transmission rights to sell, given the bids made by market participants and the physical capacity of the system.

Bespoke products make this process far more complicated, because the auction would have to assess the variable nature of the active quantity of each of the products, in order to ensure that the active quantity can be simultaneously accommodated by the physical transmission system.

It may also be the case that, in time, an active secondary market emerges that allows market participants to acquire bespoke products. That is, a market participant may purchase a continuous FTR and then on-sell a bespoke product on the secondary market. This would leave the primary seller with a financial transmission right which is better correlated with its preferred out. Its counter-party would also have acquired a bespoke FTR (i.e, the net of the generic product less the bespoke product sold), presumably suited to its needs.

92 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: EnergyAustralia, p. 10.

93 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: ERM Power, p. 7.

Were such a secondary market to emerge, this would reduce the need for bespoke products to be sold in the primary market, because market participants would be able to acquire them on the secondary market instead.

Some stakeholders provided additional suggestions for potential FTR options. Mondo Energy was of the view that there should be an option available for participants to purchase an FTR that exactly matches its generation output.[94] Enel Green Power noted that FTRs should accommodate the intermittency of renewable capacity.[95] The Clean Energy Council stated that we should consider more granular products, such as four-hour products, as they may align better with the generation profiles of solar and wind generators.[96]

5.4.4 Current blueprint design

In light of the feedback received, the blueprint design provides that market participants would be able to acquire financial transmission rights which pay out:

- at all times of the day ('continuous rights'), or
- during specified intervals (‘time of use’ rights). The specified settlement intervals would be determined to suit the needs of market participants. This could include a four-hour time of use product, as suggested in submissions.

Some stakeholders expressed their concerns in relation to this proposal. The AER, AEMO and Energy Networks Australia considered that the specific design of FTRs could be decided later in the process after further stakeholder consultation.[97]

The blueprint design is intended as a starting point for further discussion. Therefore, these elements can be further refined as the design process progresses.

5.5 Where does the revenue to back FTRs come from?

BOX 19: THE SOURCE OF REVENUE TO BACK THE FINANCIAL TRANSMISSION RIGHTS

The introduction of locational marginal pricing means that FTRs would be largely self-funded. Under the current blueprint design, funds to back the rights would arise from the surplus revenue arising from differences between what load pays and generators are paid when transmission congestion arises.

To support the firmness of the FTR instruments:

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

95 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Enel Green Power, p. 2.

96 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Clean Energy Council, p. 8.

97 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: AER, p. 16; AEMO, p. 5; Energy Networks Australia, p. 20.

- In settlement intervals where there are excess funds remaining after FTR holders have been paid, this surplus would accumulate in a "settlement account" administered by AEMO.
- In addition, proceeds of FTR auctions would be held in a separate "auction account" also administered by AEMO. After a defined time, any remaining balance in the auction account would be returned to consumers to offset their TUOS charges.
- At times when the surplus revenue from wholesale market settlement is not enough to fully pay FTR holders, the two balancing accounts would be used to 'top up' FTR payments, so that FTRs would have a very low probability of being scaled back.
- If both the settlement and auction accounts are exhausted, FTR payouts would then be scaled back to the extent necessary.

If locational marginal pricing is introduced, binding transmission constraints will result in differences in the spot prices at which load and generation are settled. These price differences mean that when congestion occurs, there will be typically be surplus funds remaining after spot market payments to generators are deducted from the amount load pays into settlement. This surplus would be used to fund payouts to holders of FTRs. Provided that the quantity of FTRs issued is consistent with the underlying physical transmission capacity, FTRs would be largely self-funded.

However, there will be settlement intervals when the volume of FTRs issued is less than the actual capacity of the transmission system (for example, due to a transmission outage that was not accounted for in the FTR auction). At these times, there would not be enough money arising from wholesale market settlement to fully pay FTR holders. The firmness of FTRs in these situations would be supported through the use of two balancing accounts that would be administered by AEMO, which would 'top up' funds so that the FTR payments have a very low probability of being of scaled back.

This section is focused on FTRs that payout on the differences in prices arising due to transmission congestion, as opposed to losses. Options to incorporate transmission losses within the FTR design are discussed in Chapter 6.

5.5.1 How will FTRs be funded?

This section outlines how the introduction of locational marginal pricing creates enough wholesale market revenue for FTRs to be largely self-funded.

As discussed in section 5.1, in the absence of binding transmission constraints and ignoring the effect of transmission losses for simplicity, the cost of supplying an additional megawatt of electricity would be the same at all connection points within a region. This is because:

- the same marginal generator could supply all connection points
- the quantity of energy injected into the system would be the same as the quantity withdrawn.

When there is a binding transmission constraint, the same marginal generator would no longer be able to supply all locations within the region. For connection points located downstream of the constraint, an additional megawatt of electricity could now only be supplied by another, more expensive, generator. This means that LMPs within the region would differ from one another. There would also be differences between some LMPs and the RRP.[98]

Typically, transmission congestion is expected to result in the LMPs for scheduled and semi-scheduled market participants behind the binding constraint being *lower* than the regional price. This is because transmission congestion often constrains off lower cost generators in a particular part of the network, meaning that a more expensive generator will need to be dispatched in order to supply consumers located elsewhere in the region (which would lead to a higher RRP).[99]

In these circumstances, the amount that load pays in to wholesale market settlement will exceed the amount that generators are paid. That is, there will be **surplus funds** available from wholesale market settlement. As described in Box 1 in Chapter 2, these surplus funds are also implicitly created under the current market design.

When price differences arise within and between NEM regions due to congestion, this *simultaneously* creates both:

- obligations to pay FTR holders, with the size of the payout being a function of price differences and the active quantity of the FTR, *and*
- surplus funds arising from wholesale market settlement, with the size of the surplus being a function of price differences and physical flows on the transmission network.

Providing the active FTR quantity is consistent with the physical capacity of the transmission network in any given dispatch interval, then the surplus funds arising from wholesale market settlement will be exactly the right amount to fund the FTR payouts.

5.5.2 How many FTRs will be sold?

The quantity of financial transmission rights that would be available for purchase relates to the expected physical capacity of the system. This process is discussed further in section 5.7.1.

The quantity issued should be set such that FTRs are largely self-funding. That is, such that the surplus funds arising from wholesale market settlement will typically be sufficient to meet the payouts due to FTR holders. Prudent issuance of FTRs will support firmness and improve the usefulness of FTRs as a risk management product, by reducing the prospect that FTR payouts would ultimately need to be scaled back.

This approach also reflects the likelihood that when excess revenue arises it might be relatively small, whereas when shortfalls arise they may be relatively large. This is due to, for

98 Noting that the RRP is defined as the LMP at the regional reference node.

99 Exceptions to this include load pockets, where there is high local demand in a transmission constrained region, such that the local supply and demand conditions result in high local prices. The Commission has engaged consultants to undertake quantitative modelling of the network in order to better understand this issue.

example, a network outage substantially reducing physical capacity and leading to a high RRP.

Clearly, however, there is a balance to be struck. The more conservatively the quantity of FTRs is determined, the fewer the FTRs that are available to generators to manage their risk: that is, more generators will be exposed to the LMP for more of their capacity. Over time, as confidence in the process for determining the appropriate number of FTRs increases, it may be possible to increase the number FTRs sold. As discussed in the following sections, the firmness of FTRs will also be supported by other measures.

5.5.3 How firm will FTRs be?

The surplus funds that would arise from wholesale market settlement if locational marginal pricing is introduced are a function of the transmission capacity available in any given dispatch interval. Conversely, the required payout to FTR holders is a function of the quantity of FTRs sold well in advance of the dispatch interval.

It is therefore possible that in any given dispatch interval, the required payout to FTR holders will not be exactly met by the surplus funds that arise from settlement. Therefore, the access model design needs to determine what happens when the surplus funds in a given dispatch interval are either more or less that the FTR payout. The following approach outlines a potential approach to support the firmness of FTR payouts:

- In settlement intervals where there are excess funds remaining after FTR holders have been paid, this surplus would accumulate in a "settlement account" administered by AEMO. The account would be drawn down to pay FTR holders when there are insufficient funds arising from wholesale market settlement in other periods.
- In addition, the proceeds of FTR auctions would be held in a separate "auction account" that would also be administered by AEMO. This account would be drawn down to pay FTR holders if the settlement account was exhausted. After a defined time, any remaining balance in the auction account would be returned to consumers to offset their TUOS charges.
- If both the settlement and auction accounts are exhausted, FTR payouts would then be scaled back to the extent necessary.

The existing market impact component of the Service Target Performance Incentive Scheme (STPIS) for TNSPs would be enhanced. This would be expected to increase the firmness of financial transmission rights by providing TNSPs with an incentive to provide network capacity when it is valued.

The combined effect of these measures is expected to make sure that FTRs issued have a high degree of firmness. However, financial transmission rights will not be *fully* firm, as the funding available to back FTR payouts is finite. Consultants have been engaged to undertake quantitative analysis to illustrate the firmness of FTRs under the blueprint access model. This will inform an assessment of whether the FTR products are sufficiently firm and effective for risk management purposes.

Further explanation and rationale for the current blueprint approach is provided in the following sections.

5.5.4 Settlement account

In each dispatch interval that transmission congestion occurs, there will be a difference between the wholesale spot market prices for load and generators. Typically, this will mean that the amount load pays in to settlement will be greater than the amount paid out to generators. The surplus funds arising from wholesale settlement will be used to back FTR payouts. In some dispatch intervals, surplus funds will exceed the required payout to FTR holders. These excess funds could be use offset shortfalls that occur in other parts of the network and/or in other dispatch intervals. Alternatively, the excess could simply be returned to consumers as an offset to their TUOS charges. These choices can be simplistically represented in the matrix below:

Table 5.2: **Treatment of excess funds from wholesale settlement**

	NOT OFFSET IN ANOTHER DISPATCH INTERVAL	OFFSET IN ANOTHER DISPATCH INTERVAL
Not offset in another area of the network	Not offset by time or by location. All excess funds returned to consumers.	Excess funds for a particular part of the network would accumulate over time and be used to offset shortfalls in the same part of the network in other dispatch intervals. Excess funds from one part of the network would not be used to shortfalls in another part of the network.
Offset in another area of the network	Excess funds would offset shortfalls in other parts of the network. However, excess funds above and beyond that required for FTR payouts in any given dispatch interval would be returned to consumers.	Excess funds would accumulate in an account and be used to offset shortfalls that occur both at other times and in other parts of the network.

The blueprint design is that any excess funds remaining after FTR payouts for a particular dispatch interval would be used to offset *both* shortfalls that occur in different dispatch intervals and shortfalls that occur in different parts of the network (i.e. the bottom-right hand box in the table above). This should occur across all constraints and time periods. That is, any excess funds would accumulate in a single account, which would rise and fall over time. This "settlement account" would be administered by AEMO.

The settlement account would not be permitted to have a negative balance. To the extent that the balance of the settlement account was not adequate to fully pay FTR holders in a given dispatch interval, funds would instead be drawn from the auction account (as available - see section 5.5.5), or FTR payouts would be scaled back as necessary.

The blueprint design is that the settlement account would be indefinite, in size and time. The alternatives would be to:

- cap the maximum settlement account balance at a certain dollar amount (beyond which any excess funds would be returned to consumers), or
- to redistribute the proceeds of the settlement account on a regular basis.

The approach of the blueprint design is simple. Although determining the quantity of the FTRs sold would be modelled with regard to each individual element of the network and over time, AEMO would not have to be concerned with tracking the availability of funds for each individual element of the network in each discrete time period. Over- or under-estimations of the capability of the network for the purpose of determining the quantity FTRs would, effectively, offset one another (although not necessarily perfectly).

Of course, this approach creates a degree of 'smearing' across both time and geography. Shortfalls in one part of the network would in effect be subsidised by excess funds in other parts of the system. Shortfalls that occur at one time would be subsidised by excess revenue at other times. This could potentially reduce the ability of market participants to accurately forecast the relatively firmness of FTR instruments (compared to, for example, the option of each FTR being funded only by settlement surpluses that arise in relation to constraints in a particular part of the network). While this is a potential downside, the Commission, on balance, favours a simple approach for the reasons provided above.

Furthermore, FTRs that precisely match the physical capacity of the system on a dispatch interval by dispatch interval basis are less important given the proposed approach to transmission planning. This is because the sale of FTRs is not directly influencing investment in the physical capacity of the network, and so the impact of smearing on the FTR buying behaviour of market participants does not directly flow through to transmission investment decisions.

The alternatives outlined in Table 5.2 above are not favoured. In each alternative case, the approach would reduce the firmness of the FTRs, as it would quarantine (either by time or geography, or both) the funds that could be used to support FTR payouts. Under the blueprint design, *all* funds arising from wholesale market settlement could be used to fund FTR payments.

Furthermore, quarantining funds by geography, network constraint or network element (while allowing smearing across time) would require *multiple* settlement accounts to be created and managed. Establishing and administering multiple settlement accounts is likely to be challenging.

5.5.5 Auction account

The Commission has also considered whether it is appropriate to treat the revenue raised from FTR auctions as another source of funds that could be utilised to reduce the prospect of scaling back payouts to FTR holders.

Many stakeholders were strongly of the view that the risk management benefits of the reforms can best be realised by making the FTRs as firm as possible. Comments included:

- The basis risk arising from the introduction of locational marginal pricing can be mitigated if generators can acquire sufficient FTRs and FTRs are firm. Using the auction revenues to support FTR firmness could be highly beneficial from a risk management perspective.[100]
- Deploying auction revenues for this purpose could add value for consumers, as auction proceeds could be expected to be higher if FTRs are firmer.[101]
- Participants at the 5 February 2020 Technical Working Group meeting also noted that if FTRs are very firm, the reform could simplify operational decisions for generators relative to the status quo. For example, holding a firm FTR would reduce the need for a generator to actively monitor and manage the risk of congestion through its bidding decisions.

In light of the feedback received from stakeholders, we have come to the view the benefits of utilising auction revenues to support FTR firmness could improve the usefulness of FTRs as a risk management product. This is because, when combined with the settlement account, this approach makes the issued FTRs firmer or allows more FTRs to be sold for a given level of firmness. In turn, this outcome should be in the interest of consumers, as it should both reduce market participants' cost of capital and increase the revenue generated through the sale of the FTRs (relative to FTRs that are less firm).

Therefore, under the blueprint design the proceeds of FTR auctions would be held in a separate account (the "auction account") that would be administered by AEMO. The auction account would be drawn down from to back FTRs, if and when the settlement account is exhausted. Both the settlement and auction accounts would not be permitted to have a negative balance. If both accounts are fully utilised, FTR payouts would then be scaled back.

At this stage, the Commission is not proposing to place time limitations on the settlement account.[102] However, the Commission considers that a time limitation is preferable for the auction account. This means that proceeds from an FTR auction would be held in the account for a pre-determined period of time. At the end of this period, the remaining balance would be transferred to consumers as an offset to their TUOS charges. This provision is intended to avoid large amounts of money remaining in the auction account indefinitely, when these funds could instead be reducing transmission charges.

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100 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: CS Energy, p. 7; AEC, p. 6.

101 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: AEC, p.6.

102 That is, the Commission is not supportive of placing a restriction on how long positive balances could remain in the account.

The Commission is currently undertaking quantitative analysis of FTR firmness over the course of 2020, the risk management benefits of FTRs and the implications of the access model for participants' cost of capital. The results of this analysis will provide a basis for further discussion and consultation with stakeholders on this aspect of the access model design.

5.5.6 Scaling of FTR payouts

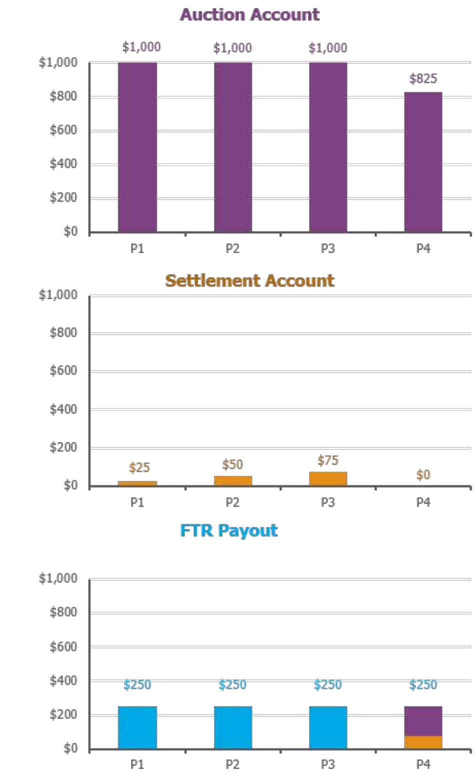
As discussed above, the settlement and auction accounts available to firm FTR payouts would not be permitted to have a negative balance. Therefore, if both accounts are exhausted, payments to FTR holders would then be scaled back to the extent necessary. This means that the FTRs would not be fully firm. The amounts available to fund FTRs would be finite and FTR holders would therefore retain some residual risk of payment shortfalls. The Commission finds this preferable to either TNSPs taking the risk (which would radically alter their risk profile), or consumers funding a potentially unlimited shortfall through TUOS. The Commission considers that the FTR funding arrangements outlined above strike an appropriate balance between providing an FTR product that has a high degree of firmness, while ensuring that consumers are not exposed to undue risk.

The Commission has not considered how the scaling of FTR payouts would happen in detail. However, we favour a simple approach where FTRs are scaled in proportion to their active quantity (with the overall amount across all FTR holders being determined to precisely maintain the settlement and auction account balance at zero).

5.5.7 Summary of FTR funding sources

Figure 5.3 below explains how the funding sources outlined above would arise and then be utilised to fund payments to FTR holders. While this example is highly simplified, it illustrates that if the FTR auction proceeds are used to firm FTR payments, the expectation is that FTR payments would be scaled back rarely. This depends to an extent on how the price paid for an FTR relates to its expected value over its term, and in turn how that expected value relates to the actual payout due to the holder in each settlement interval.

Figure 5.3: Illustration of FTR funding sources



1. A generator acquires a 50MW FTR between its connection point and the RRN. The FTR tenure is 4 hourly periods. The expected congestion-related price differential in each period is $5/MWh. The generator pays the 'fair value' of $1,000 for the FTR (i.e. 50MW x $5/MWh x 4 hours). **$1,000 goes into the auction account.**
2. Although the generator acquired an FTR of 50MW, the actual transmission capacity between it and the RRN is 55MW.
3. In the first three periods (P1-P3), the difference between the generator's LMP and the RRP is $5/MWh. Because capacity on the line is 55MW, a revenue surplus of $275 accrues in each period (55MW x $5/MWh). This is because the generator is being paid its LMP, which is $5/MWh less than the RRP that load is paying.
4. In P1-P3, the generator receives an **FTR payment of $250** (50MW x $5/MWh). The revenue surplus exceeds this by $25 in each period, so the **settlement account builds up to $75** by the end of P3.
5. In P4, there is an unexpected transmission outage, and the capacity on the line between the generator and the RRN is reduced to zero. Therefore, no surplus revenue accrues (at least, not in relation to that part of the network).
6. The price difference between the generator's LMP and the RRP is still $5/MWh, so in P4 the required **FTR payout is still $250**. There is no surplus revenue to back this. However, **$75 can be drawn down from the settlement account**.
7. As this is still not enough to fund the FTR payout, a further **$175 is drawn down from the auction account**. In this example, the FTR is fully funded. If the amount in the auction account had been less than $175, the FTR payment would have been scaled down.
8. At a future date, the remaining balance of the **auction account** would be returned to consumers as an offset to TUOS.

Source: AEMC

5.5.8 Stakeholder feedback

In relation to the source of revenue to back the financial transmission rights, stakeholders commented on the treatment of excess funds arising from wholesale settlement, the treatment of FTR auction revenues, and scaling of FTR payouts.

Treatment of excess funds

Most stakeholders that commented supported the proposal to establish a settlement account administered by AEMO:

- The AER, TransGrid, TasNetworks, Energy Networks Australia and the Energy Users Association of Australia supported the proposal.[103]
- TasNetworks and Energy Networks Australia suggested that the account should have a cap, with funds in excess of the cap being returned to consumers.[104]

103 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: AER, p. 11; TransGrid, p. 4; TasNetworks, p. 6; Energy Networks Australia, p. 21; Energy Users Association of Australia, p. 9.

104 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: TasNetworks, p. 6; Energy Networks Australia, p. 22.

Snowy Hydro and CS Energy did not support the idea of a settlement account on the basis that it would diminish locational incentives and increase the role of AEMO.[105] In contrast, the Energy Users Association of Australia were of the view that a single settlement account, administered by AEMO, has merit provided that the process is transparent and there are appropriate reporting requirements.[106]

Treatment of FTR auction revenue

The Clean Energy Council, Origin and EnergyAustralia were of the view that the Commission's position on auction revenue should be reconsidered:[107]

- The Clean Energy Council considered that there may be a more balanced approach whereby auction revenue is used to provide firmness to the FTRs and then can be redirected to offset TUOS at a later date. According to the Clean Energy Council, another potential option is to scale up the regional price rather than scale down FTR payments.
- EnergyAustralia questioned whether the Commission has considered the approach of scaling up the regional price.

The Energy Users Association of Australia were concerned that the amount paid by participants to acquire FTRs through the auction may not cover the total payouts to transmission right holders.[108]

Scaling of FTR payouts

The AER, Energy Networks Australia and TasNetworks supported scaling back FTR payments in the event that the proposed funding source is exhausted.[109]

Other stakeholders raised the following issues:

- In relation to scaling of FTRs payouts, many generators and investors suggested that consumers or TNSPs should pay to firm up the FTRs completely (CS Energy, Goldwind, Enel Green Power, Neoen, Lighthouse).[110]
- Spark Infrastructure considered that the formula and time period over which a shortfall is identified must be specified so that prospective generators can predict its likelihood and extent.[111]
- The Australian Energy Council thought that, while socialising FTR funding shortfalls (or excesses) across the NEM may have risk management benefits, impacts on locational

105 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Snowy Hydro, p. 9; CS Energy, p. 6.

106 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Energy Users Association of Australia, p. 9.

107 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Clean Energy Council, p. 7; Origin, p. 8; EnergyAustralia, p. 9.

108 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Energy Users Association of Australia, p. 8.

109 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: AER, p. 12; Energy Networks Australia, p. 22; TasNetworks, p. 6.

110 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: CS Energy, p. 6; Goldwind, p. 2; Enel Green Power, p. 2; Neoen, p. 3; Lighthouse Infrastructure, p. 5.

111 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Spark Infrastructure, p. 3.

signals and bidding incentives required further consideration.[112] The Clean Energy Council was of the view that smearing of shortfalls and surpluses would have flow-on effects to lightly constrained parts of the network.[113]

5.5.9 Current blueprint design

As outlined above, stakeholder feedback strongly supported making the FTRs as firm as possible, in order to increase the risk management benefits of the access model. Accordingly, the current blueprint design reflects the use of FTR auctions revenues as an additional source of funding to support the firmness of FTRs. While the modelling work being undertaken will provide further insight, it is expected that the measures proposed to support FTR firmness of will mean that FTR auction proceeds would be utilised relatively infrequently. Further, increasing the firmness of FTRs should be reflected in higher auction prices, as participants will have greater willingness to pay for firmer instruments.

As noted in section 4.3.1, further consideration will also being given to whether wholesale market settlement arrangements should be amended to deal with circumstances where an LMP exceeds the regional price, and this results in a wholesale market settlement deficit. There are a range of potential options that could be considered to manage this circumstance, which include capping or scaling down LMPs, or scaling up the regional price. Further analysis and consultation are required to determine the preferred approach.

FTRs would not be fully firm, as this would involve exposing consumers or TNSPs to an unknown liability. However, as noted above, it is expected that the use of FTR auction revenues to will result in an FTR product with a high degree of firmness. This will be further evaluated through the quantitative analysis that is being conducted to support further development of the access model design.

These elements of the blueprint design will be open to further discussion and refinement over the course of 2020.

5.6 What risks do FTRs manage?

BOX 20: RISKS THAT THE FTR INSTRUMENTS MANAGE

Under the current blueprint design, financial transmission rights would hedge the full price difference between nodes, including those price differences arising from non-thermal constraints.

112 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Australian Energy Council, p. 6.

113 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Clean Energy Council, p. 6.

5.6.1 Design considerations

As discussed in Chapter 4, LMPs will reflect the impact of all thermal and non-thermal transmission constraints that are included in NEMDE.[114]

Given that market participants will be exposed to LMPs which take into account all transmission constraints, the FTR products available to market participants will also hedge these risks.

However, complexities and difficulties arise in the development of financial transmission rights for non-thermal constraints.

As discussed in section 5.1, the quantity of FTRs sold would be determined with regard to the physical capacity of the transmission system. In each dispatch interval, physical transmission capacity also determines the volume of surplus funds that arises from the settlement of load and generation at different prices, which is available to back FTR payments. Therefore, the quantity of FTRs that can sold should, as closely as possible, be consistent with expected transmission capacity. If this is not the case:

- some market participants will (in hindsight) have been exposed to their LMP without being able to acquire a financial transmission right, despite the fact that the physical capacity of the network could have backed more FTR sales, or
- selling too many FTRs means there is insufficient revenue to back the FTRs, and the payment under the FTRs are scaled back accordingly (assuming all the funds described in section 5.5 are exhausted).

A number of design features are recommended to mitigate these risks, some of which are discussed in the subsequent sections on the FTR procurement process.[115]

These risks may be more acute for non-thermal constraints.

For example, system strength constraints are, in part, a function of the type of generation that is generating or not generating in parts of the network at any given time. This means that a system strength constraint may bind in a manner which is difficult to predict years in advance. While this does not present a challenge for the settlement algebra, it does mean that it is more difficult to determine how such a constraint would affect the quantity of FTRs that can be made available. As discussed in section 5.6.1, a more detailed study of this issue, and its possible impact on FTR firmness is being undertaken.

Having an effective system security framework is a priority. We have a number of work streams under way to promote system security, including improving the existing system strength frameworks.

114 Transmission constraints include thermal and stability constraints, such as transient, voltage, oscillatory and system strength stability constraints.

115 These measures include: gradually selling FTRs relating to a proportion of the expected capacity of the system in the future and continually reassessing how much should be released in subsequent tranches; the use of a settlement account and auction account to manage FTR firmness.

The Commission received limited feedback from stakeholders on this aspect of the blueprint. Enel Green Power stated that FTRs should capture both thermal and non-thermal constraints.[116]

5.6.2 Current blueprint design

As explained above, there are a range of complexities and difficulties arise in the development of financial transmission rights that capture non-thermal constraints. This is because non-thermal constraints may bind in a manner which is more difficult to predict than for thermal constraints.

A more detailed study of this issue, and its possible impact on FTR issuance and firmness is being undertaken. At this stage, the current blueprint design reflects that financial transmission rights would hedge the full price difference between nodes, including those price differences arising from non-thermal constraints. However, the design process will remain open to considering additional options that stakeholders propose over the course of 2020, if this is not considered to be the appropriate design choice.

5.7 How can participants purchase FTRs?

BOX 21: METHOD OF SALE

Under the current blueprint design, financial transmission rights would be sold through a series of auctions run by AEMO.

The auction would determine the quantity and combination of financial transmission rights sold, given market participants' willingness to pay for them and the expected physical characteristics of the network, in order to provide financial transmission rights with an appropriate level of firmness.

There would need to be a reserve price, which could either be zero or a positive value.

In addition to these auctions, physical market participants would be able to obtain grandfathered FTRs.

The Commission also expects secondary trading may emerge as a way to purchase FTRs for both physical and non-physical market participants, and will need to consider options to facilitate secondary trading in the NER.

Under the proposed access model, financial transmission rights would be sold through a series of auctions run by AEMO. TNSPs would provide input to AEMO on the physical characteristics of their network. The following sections provide an overview of the main elements of the auction process. However, further analysis and consultation with stakeholders is required to develop a detailed auction design.

116 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Enel Green Power, p. 2.

5.7.1 How many FTRs would be sold?

Under the current design blueprint, the auction (called a 'simultaneous feasibility auction') would be based on a detailed network model that calculates the amount of financial transmission rights that can be sold, based on:

- existing network capacity
- the investment decisions made by TNSPs with regard to committed transmission network capacity
- the existing financial transmission rights that have already been sold to other market participants.

The objective of this process would be to maximise the value of the financial transmission rights sold, while ensuring that issuance is consistent with physical transmission network capacity.

An auction of this nature would necessarily be complex, since the power system is complex. However, it is commonly applied in overseas jurisdictions which have FTRs (including New Zealand and in multiple markets in the US). Learnings from these jurisdictions will be assessed as it progresses the auction design.

Given the meshed nature of the network, the quantity of FTRs sold between a particular set of price pairs (implying utilisation of a particular 'pathway' on the transmission network) would impact on the quantity of FTRs available to be sold between other sets of price pairs. The trade off between financial transmission rights is unlikely to be one-to-one: it may be that selling eight more of one type of financial transmission right means that ten less of another type can be sold. To manage this, the auction algorithm would seek to maximise the revenue generated through the auction (as opposed to the quantity). This would mean that the FTRs are allocated in the combination which is most valued (collectively) by market participants, and so would best allow them (collectively) to manage transmission congestion risk.

It is important that a simultaneous feasibility method is employed, rather than a sequential auction approach. A sequential auction approach is where the quantity of a particular product is determined first, and then the quantity of another product determined next. Such an approach would not take into account the trade-offs between products, and would be unlikely to result in an efficient allocation of financial transmission rights.

The AER, Energy Queensland, TasNetworks and Energy Networks Australia supported the proposed method of sale for FTRs through a simultaneous feasibility auction.[117]

117 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: AER, p. 16; Energy Queensland, p. 15; TasNetworks, p. 6; Energy Networks Australia, p. 23.

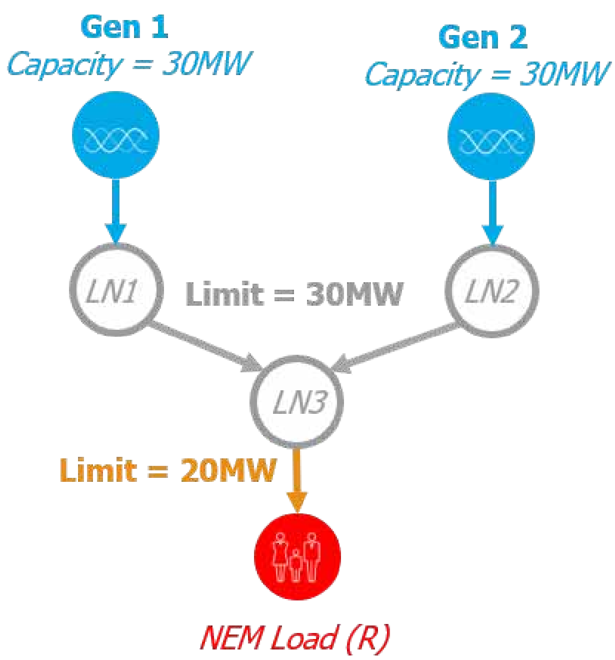
BOX 22: SIMULTANEOUS FEASIBILITY ON A SIMPLIFIED NETWORK

The figure below sets out a simplified example for how a simultaneous feasibility auction process could allocate FTRs between bidders.

In this example, each of the links connecting the generators to LN3 are 30MW, but the limit between LN3 and the regional reference node is 20MW. Therefore, the maximum available quantity of FTRs for the generators to purchase to manage differences between their LMP and the RRP will be limited by the LN3-R path (20MW). A quantity of FTRs higher than this cannot be sold, because otherwise the surplus funds arising from wholesale market settlement would be insufficient to back the rights. While FTRs are *financial* products, the wholesale market settlement revenue that supports them is based on the underlying *physical* capacity of the network.

The capacity of both generators (30MW) is greater than the amount of FTRs available in this example (20MW). Therefore, Gen 1 and Gen 2 would compete in the auction for this FTR quantity.

Figure 5.4: Simultaneous feasibility on a simplified network



Source: AEMC

5.7.2 Auction reserve price

The price of financial transmission rights would be determined through the auction. Negative bids would not be allowed (i.e. market participants would not be able to bid to be paid to acquire financial transmission rights). This is because the financial transmission rights are options, and so only result in positive payouts.

There would need to be a reserve price, which could either be zero or a positive value. A reserve price of zero would allow the price to be determined solely by competition among auction participants. This would increase the likelihood that most of the financial transmission rights available to the market would be purchased. On the other hand, if FTRs with a longer tenure are made available, it may be appropriate to consider a reserve price above zero, as the degree of competition for longer term FTRs would likely be lower, meaning that consumers would not receive an appropriate amount of revenue from the sale of FTRs to offset TUOS.

This detailed design element would require further consideration over the course of 2020.

5.7.3 Auction governance

AEMO is likely to be the most appropriate party to run the auction. This is for a number of reasons:

- The operation of the auction is a by-product of the existing operation of the market by AEMO. Surplus wholesale market settlement revenues arising from the difference between LMPs and the RRP are collected by AEMO. AEMO has direct access to these surplus revenues. At the same time, AEMO is the only party with a model of the entire network, required to determine the combination of possible financial transmission rights that should be sold.
- It is important that the auction process is as transparent to market participants as possible. Therefore AEMO, as the market operator, is likely to be the party best placed to ensure transparency in relation to all aspects of the auction including its interaction with other closely linked market processes.

However, if the auction is administered by AEMO, TNSPs would still have an important role to play. TNSPs will need to provide AEMO with detailed information about the characteristics and design of their network. This could be similar to the current development of constraints in the NEM dispatch engine. TNSPs currently generate limit equations, with AEMO converting these into the constraint equations. A similar process could occur here.

TNSPs would also be subject to an incentive scheme, which is discussed in Box 23 below.

BOX 23: TNSP INCENTIVE SCHEME

The market impact component of the current STPIS will be enhanced. The granular information from locational marginal pricing will 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.

Therefore, TNSPs will receive 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.

> The operating incentive scheme would enhance the existing market impact component of the STPIS. As such, the Commission expects that the 'strength' (i.e. the revenue at risk) of the incentive scheme would be the same. This is to avoid significantly altering the TNSPs' risk profile.

There would also need to be a consideration of what network conditions would be used to set the parameters of the transmission capacity under the auction. This would set the amount of financial transmission rights that would be sold.[118] It is important to set these parameters accurately, to avoid issuing an inefficiently high or low quantity of FTRs.

TNSPs would therefore need to provide AEMO with information about what the constraints would be under the conditions used in the auction. There would need to be a common set of principles governing provision of this information across the different TNSPs. For example, the conditions considered should be:

- nationally consistent
- coincide with instances where potential constraints would either occur frequently or lead to high divergence in prices
- take into account market factors that could materially influence transmission capacity (e.g. local loads)
- take into account ambient environmental factors that could materially affect transmission capacity (e.g. temperature).

As discussed in section 5.5, the quantity of financial transmission rights issued through the auction would target a desirable level of firmness for those rights.[119] Since it is impossible to fully guarantee the firmness of the financial transmission rights given the possibility, however remote, of severe transmission network outages or new constraints emerging, it is considered preferable for the auction to release a level of financial transmission rights that could reliably be funded through the surplus arising from wholesale market settlement. The risks of inadequate funding increase if too many financial transmission rights are released.

A number of stakeholders expressed their concern about the complexity of the auction (and the FTR instruments) and whether this advantages more sophisticated, larger players.[120]

ERM Power and CS Energy also raised the following concerns in relation to risk allocation and contracting under the proposed model:

- ERM Power considered that if auctions are intermittent, and there is no effective secondary market, retailers would either be required to speculate on load prior to winning

118 That is, given a specified set of conditions, the expected payout under any financial transmission rights purchased would be exactly met by the surplus funds arising from wholesale market settlement.

119 Balancing the need to sell an adequate number of financial transmission rights to allow generators to manage their risk.

120 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Tilt Renewables, p. 1; Quinbrook Infrastructure, p. 2; EnergyAustralia, p. 6; Alinta Energy, p. 4; Total Eren p. 2; ESCO Pacific, p. 2; Meridian Energy and Powershop, p, 2; Clean Energy Council, p. 8; BayWare Projects, p. 2; Powering Australian Renewables Fund, p. 2; Windlab, p. 2; Foresight Group, p. 2.

customers, or be required not to buy at auction and suspend retailing activities. According to ERM Power, this would create short-term buying pressure, which increases customer prices.[121]

- CS Energy were of the view that if generators are not able to acquire FTRs at the time buyers in the forward contracts market are seeking to contract, given the timing of the auction, this may have flow on effects for buyers of firm contracts (predominantly retailers).[122]

5.7.4 Other auction parameters

Many details of the auction design are still to be worked through, and trade-offs may need to be made along the way. Details that are yet to be determined include (but are not limited to):

- Whether the price paid is a clearing price or a pay as bid price.
- Whether 'linked bids' are feasible. For example, linked bids would allow a market participant to be able to specify that it only wants to purchase financial transmission right A if it also purchases financial transmission right B. Such linking could potentially be:
  - by location (e.g. I only want A to B if I also have B to C)
  - by time (e.g. I only want A to B this season if I also have A to B next season)
  - by product type (e.g. I only want time of use product A if I also secure time of use product B).
- How the auction could permit market participants to sell financial transmission rights they hold back into the auction, at a reserve price set by the seller. This feature is important to allow participants to release financial transmission rights if they no longer consider these valuable.

5.7.5 Current blueprint design

In other markets that have introduced FTRs, a simultaneous feasibility auction is the standard model for allocating these rights to market participants. Therefore, this broad approach has been retained as part of the preferred access model blueprint design. Nonetheless, as stakeholders have highlighted, there are a range of practical considerations that will need to be taken into account, including the timing of the auctions and how this will interface with contracting.

The detailed design of a simultaneous feasibility auction that is appropriate for the NEM will be considered further as the access model specifications are developed. Further stakeholder input regarding other potential options is welcomed as an input to this process.

121 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: ERM Power, p. 6.

122 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: CS Energy, p. 7.

5.8 What is the tenure and granularity of FTRs?

> **BOX 24: TENURE AND GRANULARITY**
>
> Under the current blueprint design, the FTR auction could offer products with a range of tenures, including up to 10 years in advance.
>
> The most appropriate granularity for FTRs, including those offered at longer tenures, will be considered further. The granularity is the length of the period that an individual FTR hedges over, such as a month, a quarter or a year.
>
> These aspects of the access model design will also need to be consistent with decisions on the auction reserve price and restriction of participation to physical market participants.

Granularity refers to the length of time that the financial transmission right applies to (covering a period such as a month, a quarter or a year), whereas tenure refers to how far in advance FTRs can be purchased (such as 4 or 10 years in advance). By buying multiple relatively short granularity FTRs in the auction via 'linked bids' (discussed in section 5.7.4), a market participant can effectively synthesise a relatively longer FTR.

The appropriate FTR tenure and granularity should be informed by what market participants would find most useful for the management of congestion risk. These design elements should also be consistent with the planning horizon and preparation of the ISP. This is because the ISP will inform expected augmentation of the transmission system, which will in turn determine the quantity of FTRs that can be made available in future periods.

5.8.1 FTR tenure

The FTR auction could offer products that are available up to 10 years in advance.[123]

In the October discussion paper, it was proposed that the tenure for FTR products would be three to four years. This tenure is consistent with forward sales of ASX-traded derivatives and is also consistent with the existing SRA auction process. The Commission also notes that this is the maximum tenure available in international jurisdictions with financial transmission rights.[124]

Products further into the future would be better for market participants to manage the risk of transmission congestion. However, this would also:

- increase the likelihood that the transmission network capacity may be different. This could make it harder to achieve sufficient revenue from the difference between what generators are paid and load pays to back the FTRs (which is a function of the physical capacity of the system in any given dispatch interval)

123 This will be referred to as **FTR tenures**.

124 In California, load serving entities (LSEs) are able to obtain congestion revenue rights (CRRs, equivalent to FTRs) with tenures of up to 10 years. However, the context is rather different to the NEM. In particular, these CRRs are allocated to LSEs in light of their contracting obligations under California's resource adequacy construct. Market participants who are not LSEs are only able to obtain shorter-term CRRs through a simultaneous feasibility auction process.

- make it difficult for participants to undergo a process of price discovery so far in advance.

Many stakeholders were strongly of the view that the risk management benefits of the proposed reform would be best achieved by allowing participants the opportunity to access FTRs with longer tenures (that could apply up to and beyond 10 years after the purchasing date). At the same time, stakeholders acknowledged the difficulties associated with making such a product available, given the increased uncertainty in relation to available transmission capacity as the FTR tenure is extended. Other stakeholders noted that participants might find it difficult to value a longer term product, given the challenges associated with forecasting price differences (and therefore the likely value of FTR payouts) further into the future.

With the exception of AGL, stakeholders were broadly unsupportive of the October paper's proposal for FTRs that would be available up to 3-4 years in advance.[125]

Many generators who commented on this proposal, as well as TasNetworks, suggested FTRs that could be purchased up to 3-4 years in advance (effectively creating 3-4 year FTRs by linking multiple three-month FTRs) would be too short to provide generators with investment certainty.[126] Infigen Energy thought that while sufficiently firm long-term FTRs (linked FTRs purchased a long enough period in advance) could increase revenue certainty for individual projects, they could also create a challenge for fairly allocating long-term transmission rights on the shared transmission network.[127]

To provide increased investment certainly, some of these generators recommended being able to purchase FTRs with a 10 year tenure.[128] Other generators proposed being able to make advance purchases of FTRs that would cover a generation asset's design life, which is generally longer than 20 years.[129]

In addition, Energy Networks Australia suggested that the tenures of FTRs are not generally expected to align with the tenures of generation projects in other markets that currently have FTRs.[130]

A smaller number of generators thought that neither short-term nor long-term FTRs (based on how far in advance they could be purchased) would decrease generator investment uncertainty. These generators expressed concerns that the shorter-term FTRs proposed in the October access model discussion paper would not provide additional long-term investor certainty, but also that it would be impossible to effectively price long-term FTRs due to

125 AGL, submission to the discussion paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 13.

126 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Goldwind, p. 2; Pacific Hydro, p. 1; Tilt Renewables, p. 2; Lighthouse Infrastructure Management, p. 4; Spark Infrastructure, pp. 2-3; Quinbrook Infrastructure Partners, p. 2; Innology, p. 4; Snowy Hydro, pp. 2-3; UPC, p. 2; Meridian Energy Powershop; Clean Energy Council, p. 6; Engie, pp. 3-4; TasNetworks, p. 7; Foresight Group, p. 2; Neoen, p. 2; Stanwell, p. 7; Infigen Energy, p. 3.

127 Infigen Energy, submission to the discussion paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

128 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Quinbrook Infrastructure Partners, p. 2; UPC, p. 2; Clean Energy Council, p. 6.

129 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Goldwind, p. 2; Lighthouse Infrastructure Management, p. 4; ENGIE, p. 3.

130 Energy Networks Australia, submission to the discussion paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 24.

uncertainty around the timing and locations for new generation and transmission developments.[131] In addition, Canadian Solar considered that longer-term FTRs would make it more difficult for intending generators to purchase FTRs.[132]

The challenges associated with offering a longer tenure FTR product to the market are substantial. There is an inherent tension between developing fungible products that can be liquidly traded, designing FTRs with characteristics that are adaptable to participants' operational requirements (i.e. time of use products), and making available FTRs with longer tenures. For example, a highly bespoke FTR with a 10-year tenure would likely be very difficult to sell back into the FTR auction, or trade bilaterally on the secondary market, should the holders' requirements change.

In considering this issue, it will also be important to ensure consistency with other aspects of the FTR design. For example, it might not be appropriate to set a zero reserve price for FTRs with a longer tenure, as there may be limited competition for these products, particularly if there are restrictions on the participants of non-physical entities.

On balance however, the FTR design should be responsive to the hedging requirements of participants. Given the feedback received, there may be risk management benefits from allowing participants access to products with longer tenures. This would provide a degree of flexibility. For example, participants who considered that they could not accurately value a longer term product, or who were concerned about their ability to on-sell a long-term FTR if their requirements change, would have the option of purchasing shorter term products.

Recognising the significant trade-offs involved, this aspect of the FTR design will require substantial further analysis and consultation.

5.8.2 FTR granularity

The FTR auction could offer products that hedge over a certain period.[133] The October 2019 discussion paper proposed that individual financial transmission rights would have a **granularity** of three months. This was because:

- three months (rather than shorter) reduce administrative costs and complexity, and is consistent with the typically traded wholesale market hedges and the existing SRA units. Shorter financial transmission rights could be sold on the secondary market if required.
- financial transmission rights for longer than three months (up to three years) could be acquired through the auction through linked bids (providing such an approach is accommodated in the auction design)

However, if FTRs are made available with tenures of up to 10 years, then a three-month granularity may no longer be suitable for all FTR products. For example, in the case of

131 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Total Eren, p. 2; ESCO Pacific, p. 2; John Laing, p. 2; BayWare Projects Australia, p. 2; Powering Australian Renewables Fund, p. 2; Windlab Ltd, p. 2; LocoParentis, p. 2; Palisade Investment Partners, p. 2; Stanwell, p. 8.

132 Canadian Solar, submission to the discussion paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

133 This period will be referred to as **FTR granularity**.

instruments with longer tenures, it may be more appropriate to initially release tranches on an annual basis, then move to a quarterly release of FTRs as real time approaches. This will need to considered further as the blueprint design is further refined over the course of 2020.

5.8.3 Progressive release of FTRs

The October 2019 discussion 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.[134] This approach is still considered appropriate, because it:

- limits the prospect of any particular market participant acquiring a large proportion of the financial transmission rights, and then having market power (either in the secondary market for FTRs or the energy market)
- equivalently, provides opportunities for new market participants to acquire financial transmission rights. Otherwise, there could be a barrier for entry created, whereby generators were 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.

The amount and sequence of the release of FTRs through the auction will need to be considered further as the design of the access model is progressed, in light of decisions made in relation to the tenures and granularity.

5.8.4 Current blueprint design

As noted above, the FTR design should be responsive to the hedging requirements of participants. Accordingly, the current blueprint design provides that the FTR auction could offer products with a range of granularities up to 10 years in advance. By purchasing multiple relatively short FTRs using linked bids, market participant would be able to synthesis FTRs up to ten years in length. This, and other aspects of the blueprint design, will be further assessed as the access model design is developed.

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

5.9 Who can participate in the FTR auction?

BOX 25: AUCTION PARTICIPANTS

The current blueprint design is that only registered participants who participate in the wholesale market ('physical' market participants) should be able to purchase through the auction run by AEMO financial transmission rights that hedge the price difference between an LMP and a regional price. In addition, their ability to use these financial transmission rights should be capped at some measure of their physical capacity in the market.

In contrast, other registered participants (who do not participate in the wholesale market), would be able to purchase through the auction financial transmission rights between two regional prices.

Anybody would be able to trade FTRs on any secondary market for FTRs that may emerge.

A variety of different types of entities could participate in the FTR auction and any secondary markets for FTRs that may emerge. Restrictions could be placed on entities that are not physical market participants.

5.9.1 Restrictions on entities which are not physical participants

The Commission has considered and consulted on different options for participation in the FTR auction. These include approaches where only physical market participants are able to purchase FTRs, and options where participation is widened to non-physical participants. If participation is limited to physical participants, it is also logical to include restrictions on the number of FTRs that can be purchased, based on a measure of physical capacity. Under options that provide for wider participation, such restrictions are less necessary given the increased degree of competition and the need for symmetric treatment across auction participants. There are trade-offs associated with both approaches.

Many market participants have indicated that they see value in restricting access to FTRs to physical players, at least initially, to ensure limited disruption to existing contracting arrangements. Allowing non-physical participants to buy hedges through the auction risks reducing the number available to physical participants, reducing their ability to manage risk.

A potential downside of an approach is that the revenue generated through the auction could potentially be lower than it otherwise would, as demand for the financial transmission rights would likely be reduced compared to a scenario where participation is less restricted. Clearly, this depends on how many market participants are seeking to connect to the power system and in what location, and hence the level of competition for financial transmission rights.

There are also considerations in relation to the current SRA auctions. Allowing non-physical players to purchase regional-regional FTR instruments would maintain consistency with the current arrangement for SRAs. To purchase SRAs, a non-physical participant must be a registered participant with AEMO – for instance registered as a "Trader". Therefore, it would likely be appropriate for the same provision to apply to the FTR auction.

Capping the amount of FTRs sold at the physical capacity of market participants also limits their ability to gain a large amount of FTRs which they might use to exert market power. However, determining 'physical capacity' for the purposes of capping the quantity may be challenging, particularly in the case of scheduled load and for intending, but not yet operational, market participants. The best way to implement a physical cap requires further exploration.

In light of these considerations, the October COGATI discussion paper consulted on a design proposal that included the following restrictions on auction participation that would apply:

- Local to regional rights: Only physical market participants would be able to purchase local to regional FTRs. In addition, their ability to purchase these rights should be capped at some measure of their physical capacity in the market.
- Regional to regional rights: In contrast, all registered participants would be able to purchase inter-regional FTRs. There would be no restriction on the purchase quantity of these FTRs.
- Secondary market: Separately to the primary market (the FTR auction), there would be no restrictions on any party participating in a secondary market for FTRs, should such a market emerge. All market participants (including non-physical participants) will be allowed to buy or sell FTRs in a secondary market. This includes physical participants who own primary products; physical participants who do not own primary products; physical participants who can back their position physically (for example, energy storage) and purely financial players. In the secondary market, there would be flexibility for products to exactly match the primary products or for bespoke products to emerge over time. It will also be possible to transfer FTRs to another entity bilaterally without needing to release them to the primary auction process.

In response to the October discussion paper, a number of stakeholders agreed with the proposals in relation to auction participants:

- Energy Queensland supported FTRs being restricted to physical participants.[135]
- Energy Networks Australia and TasNetworks agreed that initially there may be pragmatic reasons for restricting participation to physical participants. However, in the longer term, they did not see a compelling reason for this.[136]

Some stakeholder did however raise the following concerns regarding the proposal on auction participation:

- Spark Infrastructure was not clear why only physical market participants should be able to purchase FTRs or how a physical market participant is to be defined.[137] The AER stated that defining 'physical participants' and purchase caps is likely to be challenging.[138]

135 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Energy Queensland, p. 16.

136 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submissions: Energy Networks Australia, p. 25; TasNetworks, p. 7.

137 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Spark Infrastructure, p. 2.

138 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: AER, p. 15.

- Quinbrook Infrastructure was of the view that restricting access to physical participants may lock out developers and limit the scope and therefore liquidity in the market.[139]
- The Energy Users Association of Australia were concerned that large energy users might be unable to purchase transmission rights to maintain their contractual position.[140]

In relation to the stakeholders' ability to use FTRs and the proposed cap based on a measure of physical capacity, the Commission received the following comments:

- The Clean Energy Council stated that physical capacity of new developments is subject to change throughout the connection and construction process; establishing a cap on the quantity of FTRs that could be purchased would be difficult.[141]
- EnergyAustralia questioned how a retailer's FTR allowance would be set.[142]

5.9.2 Current blueprint design

For the reasons articulated above, the current blueprint design reflects that only physical market participants would be able to purchase financial transmission rights. Some stakeholders have suggested that including financial players will promote liquidity in the market and may increase the revenue from the sale of the FTRs, which is used to firm up the FTRs and then is passed to consumers. This needs to be considered further as the design is further refined over the course of 2020.

Many details of the auction design are still to be worked through. This includes developing the methodology for establishing a cap on the quantity of FTRs that could be purchased by generators and retailers. It will also be important to ensure that this design decision is consistent with other elements of the FTR design, including product tenure and the auction reserve price. As with other elements of the blueprint design, these elements will be open to further discussion as the detailed specifications are developed.

5.10 What transparency arrangements would be introduced?

BOX 26: TRANSPARENCY IN THE FINANCIAL TRANSMISSION RIGHTS MARKET

The blueprint design is that AEMO would maintain a register of the amount of financial transmission rights sold at auction and the clearing price. The register would also include information about the current holders of financial transmission rights.

139 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Quinbrook Infrastructure, p. 2.

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

141 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Clean Energy Council, p. 7.

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

Market transparency can be defined as the availability of relevant information to market participants. Transparency is an important component of a well-functioning market. In the context of a market for financial transmission rights, this information may include the:

- amount of financial transmission rights that were bought and sold in an auction
- price at which the financial transmission rights cleared
- parties that bought or sold financial transmission rights in the auction.

In addition, there is the added question of how transparent any secondary sales[143] of financial transmission rights should be. Competitive, efficient and reliable market outcomes are more likely to be achieved when current market participants, and prospective participants, have access to information about current and forward electricity prices and the factors driving those prices, including supply and demand conditions.

In the context of a market for financial transmission rights, publishing certain market information could assist with:

1. the **price discovery process** for market participants: If the outcomes of previous auctions are published, then market participants may be better placed to bid into future auctions in a competitive and well-informed manner. It may also be expected that the competitive discipline of the auction process may be more likely to lead to a fair value over time for the financial transmission rights that are sold.
2. determining whether **market power** concerns are likely to arise: Transparency may assist regulators and other participants in identifying whether the potential for market power exists. For example, a register that includes the identity of market participants and the corresponding amount of financial transmission rights they hold may illuminate whether there is an undue concentration of financial transmission rights to one or a few market participants in particular region or subregion. The transparency provisions are one of several FTR design blueprint elements that address stakeholders' concerns in relation to the potential for 'hoarding' behaviour (see Box 27 below).
3. providing an **educational benefit** for industry participants and the wider public: Publishing key market information may assist in lowering any barriers to entry that exist within the market for financial transmission rights. In addition, such information may serve a public policy benefit if it is available to the wider public, including policy-makers and academics.

However, transparency can also result in additional costs. For example, a high level of transparency may result in significant cost for the market participants that need to provide information. Therefore, the additional value of added transparency needs to be balanced against the costs to market participants.

5.10.1 Market transparency measures

There is a strong case to introduce transparency into the financial transmission rights market from the outset. This is because a financial transmission rights market with transparent prices

143 A secondary sale is where financial transmission rights are bought and sold outside the auction held by AEMO. This sale may occur through a bilateral trade or through a secondary trading platform.

and easy accessibility for new market participants should promote competition, reliability and efficiency in the wholesale and retail electricity markets.

The design specifications for financial transmission rights include a role for AEMO to maintain a register of the:

- price of financial transmission rights sold at each auction
- amount of financial transmission rights sold
- current portfolio of financial transmission rights held by market participants.

The aim is to provide complete transparency with regard to the outcomes in the primary market for financial transmission rights (i.e. the quarterly auction run by AEMO). This means that the price, quantity and purchaser of financial transmission rights would be published by the market operator. The bid and offer prices within the auction would not need to be reported.

In relation to transparency in the FTRs market, limited comments were received from stakeholders. Specifically:

- TasNetworks supported the proposal for FTR auction results to be published.[144]
- In relation to the primary FTR auctions, AGL supported public disclosure of the FTR clearing price and quantity, along with notification of the purchaser to the appropriate regulatory body for compliance purposes. However, AGL did not support publication of FTR holders at the company level, for reasons of commercial confidentiality.[145]
- EnergyAustralia were concerned that a proposed register would violate commercial sensitivities.[146]

For secondary trades, a lower reporting burden could be imposed. For example, market participants would be required to lodge the quantity sold and the identity of the purchaser with AEMO so that the holder of financial transmission rights can be updated within the register. This should ensure that the register is up-to-date and accurate. The price of secondary trades would not need to be reported. Further consideration is required in relation to the reporting requirements for non-physical market participants who acquire FTRs through the secondary market.

In relation to secondary trades, AGL supported confidential notification of the quantity and purchaser to AEMO for settlement purposes.[147]

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

144 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: TasNetworks, p. 7.

145 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: AGL, p. 13-14.

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

147 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: AGL, p. 13-14.

Zealand is required to administer a list of the financial transmission rights held by participant and period (including secondary trades).[148] It is also consistent with the Commission's recommendation and work to improve the transparency of the over the counter contract market, and to enhance the AER's powers to monitor contract market liquidity.

Some stakeholders expressed concern regarding the ability of market participants to 'hoard' FTRs. This concern related to the possibility that a participant might purchase all (or a significant proportion) or the FTRs available in a particular part of the network, preventing other participants from gaining access to these risk management instruments.

Specific comments in relation to the potential for hoarding of FTRs included:

- Origin and Canadian Solar noted the potential risk that participants could purchase FTRs with a view to adversely affecting the position of a competitor.[149]
- Snowy Hydro expressed concern that FTRs could create market power issues in some parts of the network if generators are able to purchase FTRs between another generator's connection point and the regional reference node.[150]
- The Clean Energy Council highlighted the potential for intending market participants to purchase FTRs without the intention of using them, in order to either dissuade other investments or to increase the FTR price (with a view to selling their holding at a later date).[151]
- The ACCC and Origin highlighted the role of an appropriate FTR auction design in mitigating the scope for hoarding and the acquisition of FTRs for anti-competitive purposes.[152]

5.10.2 Current blueprint design

Transparency is an important component of a well-functioning market, and a register maintained by AEMO will be a useful tool to ensure that the market is competitive and efficient. Therefore, the current blueprint design involves AEMO maintaining a register of the amount of financial transmission rights sold at auction and the clearing price. The register would also include information about the current holders of financial transmission rights. This aspect of the blueprint will be further assessed as the access model design develops.

148 See: https://www.ea.govt.nz/dmsdocument/22503-overview-of-the-ftr-market.

149 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Origin, p. 9; Canadian Solar, p. 5.

150 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission: Snowy Hydro, p. 8.

151 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission, p. 10; Origin, p. 9.

152 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion papers submission, p. 2.

BOX 27: ADDRESSING HOARDING CONCERNS

As noted in section 5.5, under the current blueprint design, the available quantity of FTRs would be limited by the physical capacity of the transmission network. This means that in congested parts of the network, by definition not all generators in that location will be able to obtain FTRs for all of their output. Therefore, the concern related to hoarding is not simply that some participants might not be able to acquire enough FTRs to fully mitigate their exposure to congestion. Rather, the concern is that participants could seek to acquire FTRs that *exceed* their risk management needs, or at a price that exceeds their risk management value, for the purpose of limiting competition in a related market (for example, the wholesale or retail electricity markets).

In response to these concerns, the Commission notes that the competition law prohibitions in the *Competition and Consumer Act 2010* (Cth) are of general application and would extend to conduct in the market that would be created for FTRs. Consequently, the AEMC anticipates that the ACCC would be able to enforce prohibitions against bid-rigging and anti-competitive concerted practices in relation to bids for FTRs and, where market power is found to exist, anti-competitive unilateral bidding strategies (such as hoarding of FTRs engaged in for the purpose of substantially lessening competition in related electricity markets). Further, the Commission notes that the NER are not intended to regulate anti-competitive behaviour by market participants which is subject to the provisions of the *Competition and Consumer Act 2010.*[1]

Certain elements of the FTR design blueprint may also mitigate against hoarding concerns. In particular:

- Granularity and tenure: To the extent that hoarding is a profitable strategy for some market participants (which it may not be), the effects of this behaviour could be exacerbated by the tenure and granularity of FTR products. For example, these concerns could be more significant in the context of longer-term products. While the FTR auction could offer products with tenures of up to 10 years, products with a longer duration would likely relate only a portion of the expected available transmission capacity. Further, available capacity would be progressively released in tranches, which would increase the difficulty of successfully executing a hoarding strategy.
- Competitive allocation: In addition, participants would compete for FTRs through the simultaneous feasibility auction. As noted in section 5.7.1, due to the meshed nature of the transmission network, there will still be competition among participants that do not 'utilise' precisely the same 'pathway' on the transmission network. Elements of the auction design may impact the degree of competition for FTRs; for example, whether there are restrictions on the extent to which entities without a physical position can participate.
- Purchase restrictions: The FTR design blueprint provides that only physical market participants would be able to acquire local-regional FTRs.[2] Further, purchases of these

products would be capped at some measure of participants' physical hedging requirements.

- Transparency: The transparency provisions discussed in this chapter would assist in the detection of an attempted hoarding strategy.

Source: AEMC

Note: 1) NER clause 3.1.4(b)

2) That is FTRs that relate to an LMP and any RRP

6 LOSSES AND FINANCIAL TRANSMISSION RIGHTS

6.1 Overview

Chapter 5 focused on the blueprint design proposal for FTRs which would hedge against price differences that arise due to **congestion** on the transmission network. For simplicity, this discussion ignored the effect of losses.

Differences between locational marginal and regional reference prices also arise because of **losses**. Despite being relatively unusual in market design compared to FTRs that hedge against congestion risks, we consider that it would be preferable for an FTR risk management tool should also be developed to help market participants to manage the price differences caused by losses. Alternatively, the design could continue to expose market participants to losses that are marginal *without* developing an FTR to hedge against loss variations.

If an FTR risk management tool is to be developed for losses, a key design decision is whether and how the FTR instrument is combined with, or separate from, the FTR instrument which manages congestion risk (and which was discussed in the preceding chapter). The two options are discussed below:

- **Separate products from congestion FTRs.** This would mean that market participants would have a choice between purchasing both FTR products, or potentially only one product, depending on their requirements. This option would require price differences to be separated into loss and congestion components.
- **Combined products.** This would mean that market participants would be able to purchase an FTR product that hedges the combined price difference between two connection points.[153]

This chapter, and the proceeding chapter, has been drafted on the basis that there are separate products. However, we want to discuss the above options (i.e. whether or not there should be an FTR that hedges losses, and if so, whether they should have been separate or combined), and views on pros and cons with stakeholders over the course of 2020. Initial thoughts on pros and cons of a combined or separate loss related FTR is discussed in section 6.4.1.

In addition to this key design feature, a number of other design questions must be determined, as outlined in table 6.1. Decisions on these design features are not mutually exclusive - that is, there does not appear to be an inherent reason why design choices from the same column must go together. These design choices are discussed in sections 6.4.2 and 6.4.3.

The table below summarises the spectrum of options for incorporating losses into the FTR design, for each design elements described above. These options have been developed as a starting point for further analysis and discussion with stakeholders, that will be considered further as the access model design progresses over the course of 2020.

153 Specifically, between a locational marginal price and any regional reference price, or between any two regional reference prices.

Table 6.1: Blueprint loss FTR design options

DESIGN ELEMENT	OPTION	OPTION
Product type	**Separate products from congestion FTRs.** This would mean that market participants would have a choice between purchasing both FTR products, or potentially only one product, depending on their requirements. This option would require price differences to be separated into loss and congestion components.	**Combined products.** This would mean that market participants would be able to purchase an FTR product that hedges the combined price difference between two connection points.[1]
Funding sources	**Funded by the available loss surplus revenue.** The aggregate quantity of FTRs sold would be set to equal the expected loss-related surplus revenue arising from wholesale market settlement[1]. This means that the overall volume of loss FTRs available for purchase would fall below the quantity required for all generators to exactly mitigate the revenue risk associated with fluctuations in their MLF.	**Funded by the available loss surplus revenue, plus FTR auction revenues.** The aggregate quantity of FTRs sold could be increased by including FTR auction revenues to fund FTR payouts (or an alternative source of funding), although it is unlikely to that these would be fully funded.
Fixed or variable quantity	**Defined as a fixed MW quantity.** The FTR quantity would be fixed for the term of the FTR. This would require a forecast of the funding that would be available to back the FTR over its term (whether this is the loss surplus revenue alone, includes FTR auction revenues, or another source of funding). In the event that the forecast is incorrect, the FTR payout would need to be	**Defined as a variable MW quantity.** The FTR quantity would be variable and scaled to match available loss surplus revenues in each dispatch interval. This would however mean that generators that hold a variable quantity FTR might not continue to face marginal price signals in the wholesale market.

DESIGN ELEMENT	OPTION	OPTION
	scaled back to match the available funds. The scaling methodology would be designed to ensure that generators that hold loss FTRs continue to face marginal price signals in the wholesale market.	

Note: 1) Specifically, between a locational marginal price and any regional reference price, or between any two regional reference prices.
2) That is, the surplus revenue that arises from settling load and generation at different wholesale prices, due to the application of MLFs.

These design elements outlined above involve some significant trade-offs that will require further consideration as the detailed design of the access model progresses. Given the limited international experience with issuing FTRs that hedge loss-related price differences, it will also be necessary to undertaken further testing and analysis of the substantial practical complexities that would be involved in establishing these products in the NEM. These complexities include the process for forecasting the available quantity of FTRs (potentially over multiple years) and incorporating these into the FTR auction.

A key consideration is also whether FTRs with the characteristics outlined above offers a more efficient means of managing the risk arising from MLFs, relative to the status quo or alternative options. Stakeholder feedback through the access model design process will be essential to inform this analysis.

There are advantages and disadvantages for each of the approaches outlined above. We are keen to work with stakeholders on what would be a preferable loss FTR design over the course of 2020, with a particular focus on what would improve the risk management options available to market participants without exposing consumers to undue risks.

The design choices are partly dependent on the approach taken to reflecting marginal losses in locational marginal prices, as discussed in chapter 4.

Consistent with the design of locational marginal pricing and financial transmission rights for congestion, the appropriate guiding principles for incorporating losses in the FTR design include that:

- market participants would continue to be exposed, on the margin, to wholesale market prices which include marginal losses, in order to provide market participants with the appropriate incentives in operational and investment time scales
- market participants would be able to enter into FTRs which allow them to effectively manage the risk of changing marginal loss factors

- loss FTRs would be backed by the available surplus wholesale market revenue that arises from the application of marginal loss factors.[154]

The current blueprint suggests that financial transmission rights (FTRs) should be developed that would allow market participants to hedge the risk of price differences arising from losses. These FTRs would be backed by the surplus wholesale market settlement revenue that arises due to the application of marginal loss factors. While there are various options for how these can be designed, the below assumes that it is a separate product to the congestion FTR.

6.2 Stakeholder feedback to the discussion paper

The majority of stakeholder feedback on loss FTRs focused on the loss FTRs concept and their usefulness for managing risk. Some stakeholders expressed in principle support for the concept of loss FTRs. These stakeholders suggest that loss FTRs could be a useful instrument that allows interested market participants to hedge against price differences caused by losses.[155]

Other stakeholders were supportive of the idea of loss FTRs, but raised questions about how these FTRs would operate in practice.[156] AEMO also expressed uncertainty over whether it would be possible to include dynamic loss factors in local prices and in loss FTRs, but was open to exploring these options further.[157]

However, a significant number of stakeholders who provided feedback on this issue were of the view that loss FTRs would not assist generators to manage their loss-related risks.[158]

Other concerns raised in relation to loss FTRs included that:

- Additional complexity introduced by loss FTRs would mean that it would likely not be worthwhile to introduce them.[159]
- Generators do not need loss FTRs to manage their risks associated with losses.[160]

These issues raised by stakeholders echo the design challenges noted throughout section 6.3.

154 This would apply regardless of whether the marginal loss factors remain static or become dynamic loss factors. The later would require changes to NEMDE that are being considered as part of broader ESB post-2025 market design and other reforms.

155 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: AER, p. 17; TasNetworks, p. 4; Neoen, p. 3.

156 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Australian Energy Council, p. 5; AGL; p. 14.

157 AEMO, submission to the discussion paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 4.

158 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Total Eren, p. 4; Lighthouse Infrastructure Management, p. 5; ESCO Pacific, p. 4; John Laing, p. 4; Clean Energy Council, p. 10; BayWare Projects Australia, p. 4; Powering Australian Renewables Fund, p. 3; Windlab Ltd, p. 4; Palisade Investment Partners, pp. 3-4.

159 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Mondo, pp. 3-4; Snowy Hydro, p. 7; Origin, p. 7.

160 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Lyon Group, p. 5; Infigen, p. 2.

6.3 Transmission losses and risk

As described in section 4.5, the application of the existing annually set MLFs effectively results in different wholesale prices for participants located in different parts of the network. The existing MLF framework effectively creates LMPs at each transmission connection point, although these currently reflect only losses and not congestion. This is due to the application of the settlement formula: *Regional Reference Price x MLF x Measured Energy*.

For the marginal generator, the effect of the settlement formula is that it receives its bid price for output at its transmission connection point (i.e., its LMP is equal to its bid price). The LMP that generators receive is determined by the offer of the marginal generator, the marginal generator's MLF and the MLF at their own connection point. In recent years, generators (particularly renewable generators) have experienced significant adverse changes in their MLFs.

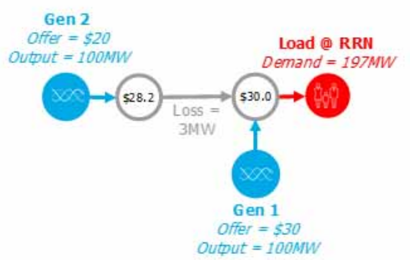
As illustrated in Box 28 below, if a new entrant connects next to an existing generator and reduces the MLF for that connection point, then the LMP at that connection point will fall (other factors held constant).

BOX 28: MLFS AND RISK

The simple two-node diagram below shows two generators - Gen 1 and Gen 2 - supplying a single load located at the regional reference node. Gen 1 is also located at the regional reference node. The load is non-scheduled and both generators are scheduled. Gen 1 and the load have, by definition, a marginal loss factor (MLF) equal to 1, because they are located at the regional reference node. Gen 2's MLF is 0.94.

Gen 1 and Gen 2 offer their output at $30/MWh and $20/MWh respectively. Gen 1 is the marginal generator and therefore sets the LMP at both connection points. There is no congestion in this example, so the difference between the LMPs for the two generators and the RRP for the load is due only to the effect of marginal losses.

Dispatch and settlement outcomes are shown below.

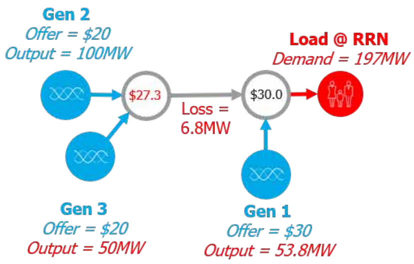


	Energy	RRP	MLF	"Local price"	Settlement
Gen 1	100MW	$30.0	1.00	$30.0	$3,000
Gen 2	100MW	$30.0	0.94	$28.2	$2,821
Load	197MW	$30.0	1.00	$30.0	$5,910
Loss settlement residue					$89

Source: AEMC

Note: For simplicity, this example assumes that Gen 2's static MLF of 0.94 (as calculated by AEMO), is equal to the actual MLF in this dispatch interval shown. In section 6.4.2, we discuss the implications for loss FTRs when this is not the case.

Now assume that another generator (Gen 3) builds next to Gen 2, at the same transmission connection point. When AEMO recalculates the MLF to take the changing patterns of generation into account, the MLF at Gen 2/Gen 3's connection point falls from 0.94 to 0.91. Accordingly, the LMP falls from $28.2 to $27.3.



	Energy	RRP	MLF	"Local price"	Settlement
Gen 1	53.8MW	$30.0	1.00	$30.0	$1,613
Gen 2	100MW	$30.0	0.91	$27.3	$2,731
Gen 3	50MW	$30.0	0.91	$27.3	$1,365
Load	197MW	$30.0	1.00	$30.0	$5,910
Loss settlement residue					**$201**

Source: AEMC

As illustrated in the figure above, although Gen 2's output is unchanged at 100MW, its wholesale settlement revenues have fallen by around 3%, due to the adverse change in its MLF resulting from the entry of Gen 3.

Therefore, the application of MLFs gives rise to both:

- revenue risk i.e. the risk that the LMPs generators receive change due to fluctuations in their own MLF, or the MLF of the marginal generator and
- basis risk i.e. the risk associated with buying and selling energy at different locations in the system, where the underlying wholesale price at those locations is different due to the application of MLFs.

6.4 How could MLF risk be hedged with an FTR?

As shown in Box 28 above, the application of MLFs already results in different LMPs for participants depending on their location on the network. Because prices are based on marginal losses, which exceed actual losses, this means that typically the amount that loads pay in to settlement exceed the amounts paid out to generators, resulting in a loss revenue surplus.[161] The loss revenue surplus arising from the application of MLFs in wholesale settlement is similar to that arising from transmission network congestion if locational marginal pricing is introduced (section 4.1.1).[162]

Currently, any loss revenue surplus that arises from the application of intra-regional MLFs is returned to consumers directly via a rebate on their TUOS charges. The application of inter-regional marginal losses (that result in differences between RRPs) is currently allocated to the holders of SRA units (section 5.2.2), with the revenue used from the sale of SRA units then being used to offset TUOS charges for consumers.

This section describes how and why the loss revenue surplus could alternatively be used to support loss financial transmission rights (FTRs), that allow participants to mitigate the

161 See AEMO, *Treatment of loss factors in the NEM*, 2012 for a more detailed description.

162 If the current MLF framework were replaced with dynamic marginal losses, the same revenue surplus would continue to arise.

revenue risk and basis risk arising from the application of MLFs. For simplicity, this discussion ignores the effects of congestion. However, as discussed above in 6.3.1, price differences due to losses and congestion could potentially be hedged within a single FTR instrument.

Loss price differences give rise to both revenue risk and basis risk. Similar to the approach for congestion price differences described in chapter 5, an FTR could also pay out on any positive *loss-related* difference between price pairs.

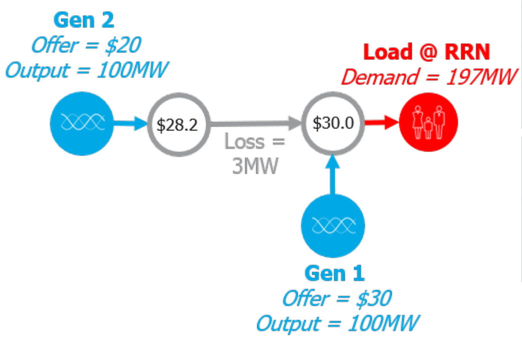
Such an FTR instrument could potentially help to address both revenue and basis risk:

- Basis risk: purchasing an FTR that hedges price differences due to losses would allow generators to effectively gain 'access' to the regional reference price, supporting contracting with retailers at this price. Alternatively, retailers could contract with a generator at the generator's local price, and then purchase an FTR to hedge the difference to the regional reference price at which its customers are settled.
- Revenue risk: Because the loss FTR payment would move in line with the change in local prices that results from changes in marginal losses, it provides the generator with an offsetting source of revenue, should marginal losses result in deterioration in that generator's local price.

An example of how this could operate is set out in box 29 below.

BOX 29: FTRS AND LOSS RISK MANAGEMENT

Returning to the example in box 28 above, assume that Gen 2 holds an FTR with a quantity of 100MW (equal to its output). The FTR pays out on the full loss-related difference between Gen 2's locational marginal price and the regional reference price. Settlement outcomes pre- and post-entry of G3 are shown below, including the FTR payout.[1] For simplicity, this example assumes there is no transmission congestion. Therefore, the price differences shown relate only to the application of MLFs.

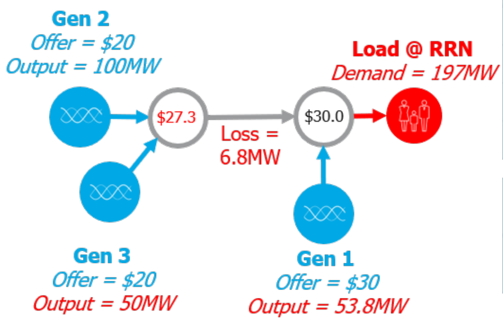


	Energy	LMP/ RRP	Wholesale settlement
Gen 1	100MW	$30.0	$3,000
Gen 2	100MW	$28.2	$2,821
Load	197MW	$30.0	$5,910

	Loss FTR	Price difference	FTR settlement
Gen 2	100MW	= $30.0 - $28.2 = $1.8	$179

Gen 2 total settlement
$3,000

Source: AEMC



	Energy	Local price	Wholesale settlement
Gen 1	53.8MW	$30.0	$1,613
Gen 2	100MW	$27.3	$2,731
Gen 3	50MW	$27.3	$1,365
Load	197MW	$30.0	$5,910

	Loss FTR	Price difference	FTR settlement
Gen 2	100MW	= $30.0 - $27.3 = $2.7	$269

Gen 2 total settlement
$3,000

Source: AEMC

As noted previously, Gen 2's output is unchanged at 100MW after the entry of Gen 3. However, its wholesale settlement revenues have fallen by around 3%, due to the adverse change in its MLF resulting from the entry of the new generator.

However, because the loss-related price difference hedged by the FTR has also increased, the FTR payout has increased proportionately, allowing Gen 2 to maintain the same total revenue. Effectively, the FTR provides Gen 2 with an MLF equal to 1.

Of course, Gen 2 would have paid some amount to acquire the FTR. A 'fair value' price for the instrument would be the actual payout over the 2 periods in question (in this case $179 + $269), plus an adjustment for the time value of money – assuming that the generator is risk neutral and does not place any additional value on managing the loss related risk. In turn, had Gen 2 paid 'fair value', the same amount of money that would otherwise have offset TUOS directly would instead offset TUOS via the sale of the FTRs.

If Gen 2 had paid the fair value, its net position would be the same as not purchasing the FTR. However, acquiring the FTR allows Gen 2 to 'lock in' a cost for offsetting the impact of future changes in MLFs on its locational marginal price upfront, ensuring that it will receive the regional reference price on the FTR quantity (assuming this is matched by Gen 2's output). Gen 2's fixed costs would be higher, but these would be known upfront and could therefore be factored into its investment, operating and contracting decisions.

Note: 1) Remember, in this example we are assuming that the static MLF is equal to the actual MLF in the dispatch interval depicted.

These examples illustrate how an FTR could theoretically allow market participants to manage revenue risk and basis risk arising from marginal loss factor volatility. This is analogous to the way in which the FTRs described in Chapter 5 assist in managing price differences resulting from binding transmission constraints.

However, due to the characteristics of loss settlement residues, there are some challenges involved in designing a product that would actually operate in the way described in these examples. These challenges are discussed in the next section.

6.4.1 Product type

In many markets with locational marginal pricing, market participants can purchase FTRs to manage the associated basis risk. However, in these markets, FTRs typically only pay out on price differences that arise due to congestion (as opposed to also including a payout due to price differences that arise due to losses). Stakeholders have noted during the COGATI review that FTRs which hedge against losses are not commonly used in other electricity markets with FTRs.[163] The concept of hedging both loss- and congestion-related basis risk is also discussed in academic literature.[164]

The Commission is aware of only one jurisdiction that offers an FTR product that hedges differences in prices that arise due to the effect of marginal losses. In the New Zealand FTR market, FTRs allow generators to hedge the *combined* price difference arising from both losses and congestion (i.e. within a single product, as proposed for the main alternative option). This design means that an FTR pays out on the full congestion- and loss-related price difference arising between the connection points specified in the instrument.

The Commission is not aware of any markets that offer a standalone loss FTR product (i.e. an FTR that pays out only on price differences that arise due to losses alone). Nonetheless, it appears at least theoretically possible to construct such a separate instrument, noting that in US markets with FTRs, prices can be separated into both loss- and congestion-related elements.

There are advantages and disadvantages associated with separate and combined products. For example, a combined instrument could be simpler for market participants. This is because participants would be able to purchase a single instrument that manages the full difference between two price pairs, rather than having to manage procurement of multiple products that hedge different components of wholesale prices. A combined product would also avoid the need to separate the loss- and congestion-related elements of wholesale prices. Further, there is an existing operating model for a combined product, in the New Zealand FTR market.

However, while the New Zealand combined FTR approach appears to work well for their market, the NEM differs in several respects:

- The New Zealand FTR market makes (combined loss and congestion) FTRs available between only eight connection points (termed 'hubs'). In contrast, the proposed access model for the NEM would allow FTRs to be purchased between any transmission connection point and any regional reference node, and between any two regional reference nodes. This would result in many more FTR combinations than are available for purchase in the New Zealand FTR market. As discussed further in section 6.3.3 below,

163 Australian Energy Market Commission*, Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Pacific Hydro, p. 2; AusNet Services, p. 2; Energy Networks Australia, p. 22

164 For example, the possibility of incorporating losses into the design of FTRs has been discussed (albeit in relation to FTR obligations) in S. Harvey and W. Hogan, *Loss Hedging Financial Transmission Rights*, 15 January 2002.

there are a number of factors that need to be considered when determining how many FTRs can be made available, where these FTRs also hedge loss-related price differences. This analysis is likely to be more complicated for a larger number of connection points.

- The New Zealand wholesale electricity market incorporates dynamic marginal losses, rather than static marginal loss factors as in the NEM.
- The topography of the New Zealand transmission network is different to the NEM.

Given these differences, there is a risk that the New Zealand model of combined loss and congestion FTRs might not be readily transferable to the NEM. The factors noted above could mean that while a combined product might be simpler for some market participants, this could involve significant complexity as part of the FTR sale process. Introducing separate loss and congestion FTR products would have the advantage of allowing congestion FTRs (a well-established product in other markets) to operate independently of loss FTRs, while practical experience of issuing these loss FTR instruments develops.

Separate loss and congestion products could also provide market participants with greater flexibility to adopt a risk management approach that best suits their particular requirements. For example, feedback received at the 5 February 2020 Technical Working Group[165] suggested that, depending on their expected pattern of operation, some types of generators might wish to purchase only loss FTRs or only congestion FTRs. Alternatively, some participants might wish to purchase both congestion and loss FTRs, but different quantities of each product. If participants wish to purchase a combined product, they might be able to put in a "linked bid" to the auction, stating that they want to simultaneously purchase both types of FTRs, effectively synthesising a combined product.

6.4.2 Funding

As described in section 5.5, congestion FTRs are funded by the surplus revenue that arises from wholesale market settlement, when load and generation have different spot prices due to binding transmission constraints.[166] The application of MLFs also creates different prices for settling generators and load within a region, and this also results in surplus revenues from wholesale settlement.

Currently, intra-regional loss surplus revenues are returned to consumers via a rebate on their TUOS charges, while inter-regional loss revenues accrue to the holders of SRA units. Alternatively, these surplus revenues could be used to fund FTR instruments that hedge loss-related price differences that, as described above, would allow participants to mitigate the revenue impact of changes in MLFs.

The example in Box 29 above allowed Gen 2 to purchase an FTR product with a quantity equal to its output (also equal to the pre-new entrant flow between its connection point and the regional reference node). The payout from the FTR allowed Gen 2 to fully offset the revenue impact of changes in its locational price due to the impact of Gen 3 on the MLF.

165 See: https://www.aemc.gov.au/sites/default/files/documents/twg_meeting_5_-_5_february_2020_-_minutes.pdf

166 The Commission is proposing that congestion FTR auction revenues could be used to firm payments to congestion FTR holders; however, this is not intended to be the primary source of funding.

However, in practice the surplus revenue arising from wholesale settlement would not be sufficient to back such an FTR. The ability to fund FTRs that hedge loss-related price differences is an issue that has been raised by stakeholders during the COGATI review process.[167]

Given the relationship between marginal and actual losses, if the FTR quantity is equal to the actual flow between the two connection points, the surplus revenue will not be enough to fund the full FTR payments. Box 30 below provides a simplified illustration of this, for a radial network example.[168]

BOX 30: LOSS SURPLUS REVENUE

Referring back to the wholesale settlement table in Box 29 (pre new entrant), while the payout on Gen 2's 100MW loss FTR is $179, available settlement residues are only $89.

In this simple radial network example, if loss FTRs were funded by the loss surplus revenue alone, Gen 2 would only be able to purchase an FTR equal to approximately *half* the flow between its connection point and the regional reference node (noting that this relationship may not hold for a non-radial case). In this case, Gen 2 would effectively be hedged against only *half* the revenue impact resulting from a deterioration in its MLF. This is shown in the table below.

Table 6.2: Loss surplus residue

GEN 2 REVENUE	WHOLESALE SETTLEMENT	FTR SETTLEMENT (FTR 50MW)	TOTAL SETTLEMENT
Gen 2 – (pre-new entrant)	$2,821	$90	$2,910
Gen 2 – (post-new entrant)	$2,731	$135	$2,865
Change post-new entrant	-$90	+$45	-$45

Source: AEMC

With the entry of Gen 3, flow between the two connection points would increase to 150MW.[1] Therefore, the total settlement residue also increases to $201. In practice, Gen 2 could improve its position by purchasing enough loss FTRs to capture *all* the available settlement residues (effectively, a loss FTR of 75MW, given the parameters of this example).[2] However, in this example, this is also not enough to fully mitigate the revenue impact of changes in Gen 2's MLF. Further, this would mean that no loss FTRs would be available for Gen 3 to purchase.

167 Canadian Solar, submission to the discussion paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

168 The relationship between loss surplus revenues and FTR payouts will be different for a meshed network. This will require further exploration as the access model design develops.

Note: 1) i.e. Gen 2 and 3 output of 150MW. Recall that under the current loss factor framework, flow is defined at the connection point that is remote from the RRN.
2) Whether Gen 2 could in practice purchase this quantity of loss FTRs would depend on how the available quantity is determined through the FTR auction. This is discussed further in section 6.4.3 below.

In order for a generator to exactly offset the risk of fluctuations in its MLF, it would require an FTR quantity equal to the flow between its transmission connection point and the regional reference node. However, by definition, the loss surplus revenue that arises would not be able to support the associated FTR.[169] This reflects the physical characteristics of the system: physical losses are real, and must be paid for out of wholesale market settlement.

In principle, it would be possible to fund an FTR product with a quantity equal to the *full* power flow between the two connection points, provided that an external source of funding is found to supplement the loss surplus revenue. As noted above, in the New Zealand participants are able to purchase an FTR that hedges the *combined* price difference arising from both losses and congestion. The Commission understands that, in addition to the congestion and loss surplus revenue that arises from wholesale market settlement, these FTRs are also funded by:

1. The FTR auction revenue.
2. A degree of conservatism in setting the available quantity of (combined loss and congestion) FTRs that can be purchased.

There are likely other ways that additional sources of revenue could be provided, although the Commission is not aware of alternatives that have been put into practice.[170]

As discussed in section 5.4.2, the blueprint design proposal includes FTR auction revenues as a source of funds that can firm congestion FTRs. In the case of FTRs that hedge loss-related price differences, slightly different considerations arise. For FTRs that hedge congestion-related price differences only, the auction revenue is expected to be drawn on relatively infrequently. In the case of FTRs that hedge loss-related price difference, a portion of the auction revenue would likely be needed to meet the full FTR payout required as a matter of course.[171]

This suggests that, at least initially, it could be prudent to fund loss FTRs with only the loss surplus revenue that arises from wholesale market settlement. This would effectively mean that the overall amount of FTR funding would not be sufficient for *all* generators to acquire an FTR that exactly offsets the impact of fluctuations in their MLF. However, the Commission

169 Assuming the FTR pays out on the full loss price difference between the two price pairs specified in the instrument.

170 For example, as part of the auction process, AEMO could purchase a 'loss hedge' at the regional reference node. This would pay out the regional reference price, multiplied by the total system losses. It can be shown that, mathematically, this would allow the FTR auction to sell a volume of loss FTRs that matched net injections at each node (i.e. equal to the full power flow). However, the cost of purchasing the 'loss hedge' would itself need to be funded. Stakeholder submissions to the October 2019 discussion paper also noted some other potential options. For example, the Australian Energy Council submission noted that one approach would be to apply a loss reserve price in the FTR auction and retain this from the auction proceeds in order to cover real losses (Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, discussion paper submissions: Australian Energy Council, p.5.).

171 This is assuming that (a) the auction revenue would equal the expected fair value of the FTR payout and (b) the actual payout is consistent with the expected payout. For example, if we assume that the auction revenue reflects fair value, it should be approximately twice the expected loss revenue surplus. Assuming the expected loss revenue surplus is $50, the auction revenue would then be $100. This would provide total revenue of $150 available to back the loss FTR payout. If the actual loss FTR payout is in fact consistent with the expected payout, half of the auction revenue would be utilised.

expects that this option would nonetheless improve the risk management options available to generators, relative to the status quo.

Based on initial feedback from stakeholders and analysis of the differences between hedging against congestion and loss risks, the current preference is that FTRs that hedge loss-related price differences would only be funded using the loss surplus revenue that arises from wholesale market settlement. We welcome stakeholder feedback on the options discussed here, as well as any other options raised by stakeholders.

6.4.3 Fixed or variable quantity

This section discusses the options for making FTR quantities fixed or variable with network flows.

As described above, a loss-related revenue surplus arises in wholesale market settlement due to loss-related price differences, and flows on the network. However, flows on the network change in each dispatch interval. This implies that the FTR quantity would also need to change, if FTR settlement payments were to be perfectly balanced by the loss surplus revenue in each interval.

However, allowing the FTR quantity to vary with network flows has implications for the wholesale market price signals faced by generators. This is because the loss surplus revenue is dependent on flows between connection points, and therefore also dependent on generator output. This would mean that at the margin, a generator that holds an FTR with a variable quantity would no longer be exposed to the locational marginal price at its connection point.

If FTR quantities are scaled to match flow, this could partly undermine the benefit of providing wholesale market price signals that accurately reflect the marginal value of supply at different locations in the network.[172] Stakeholders have raised similar concerns by suggesting that a product that could be used to hedge against losses would reduce the reflectiveness of the price signals provided by losses.[173]

Note, the same problem does not arise if the congestion-related FTRs discussed in Chapter 5 are subject to scaling.[174] In this case, scaling might be needed because transmission network capacity is less than the FTR quantity (i.e. it is independent of generator output).

Our initial view is that in order to maintain the principle of marginal cost pricing, a fixed FTR quantity is preferable to a variable FTR quantity (although the Commission is open to considering options for implementing variable quantity FTRs that would also maintain this principle). However, as outlined in the following section, determining what this fixed quantity should be introduces its own complications.

172 Noting that the use of static, annually determined marginal loss factors means there is already a degree of inaccuracy compared to dynamically determined losses which reflect conditions in a given dispatch interval.

173 Stanwell, submission to the discussion paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 8.

174 At least, this is the case for thermal constraints.

6.4.4 Setting a fixed quantity

Network flows will change in each dispatch interval. This means that setting a fixed MW FTR quantity would necessarily mean that in each dispatch interval there will be FTR payment surpluses and deficits, that would need to be managed. As noted above, this contrasts with the case of congestion, where in general the capacity (not the flow) of the network is what is relevant for determining the appropriate quantity of FTRs.

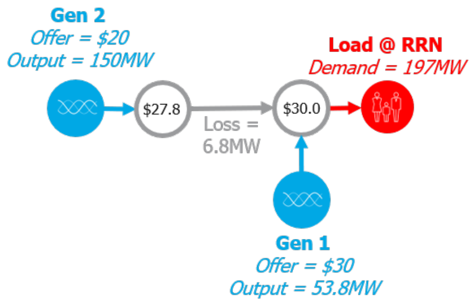
Further, setting a fixed FTR quantity would need to be based on a forecast of network flows over the term of the FTR (as this would determine the loss surplus revenue that is expected to be available). The inputs to this forecast would likely be similar to the process AEMO already follows for setting static MLFs. A conceptual example of this approach is set out in Box 31 below.

BOX 31: FTR QUANTITY

The examples set out above considered FTR payouts in one dispatch interval, assuming that the static MLF set by AEMO was exactly equal to the actual MLF in that interval. This simplified example considers an FTR with a term of two periods, with the following assumptions:

- Gen 2's output is 150MW in the first period and 50MW in the second period. Therefore, its average output over the period is 100W.
- The static MLF at Gen 2's connection point is set at 0.93 over both periods. This is the volume weighted average of the forecast actual MLF in each period. The forecast is (for the purpose of this example) assumed to be correct (i.e. AEMO correctly forecasts load and generation in both periods).
- Accordingly, the maximum available FTR quantity between Gen 2 and the regional reference node is set at approximately 50MW. This is because the example is based on a simple radial network configuration.
- For simplicity, no congestion is assumed. Therefore, the price differences relate only to marginal loss factors.

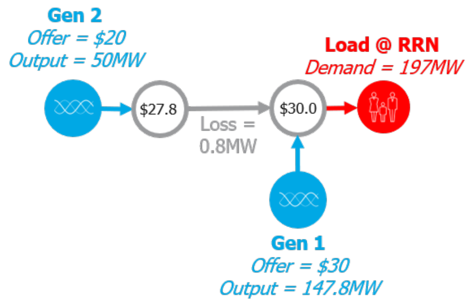
The examples below set out the wholesale market and FTR settlement outcomes in both periods.[1]



Wholesale market	Energy Qty	LMP/ RRP	Settlement $
Gen 1	53.8MW	$30.0	$1,613
Gen 2	150MW	$27.8	$4,164
Load	197MW	$30.0	$5,910
Loss surplus revenue			**$134**

FTR	FTR Qty	RRP - LMP	Settlement $
Gen 2	500MW	$2.2	$112

Gen 2 total settlement	**$4,275**



Wholesale market	Energy Qty	LMP/ RRP	Settlement $
Gen 1	147.8MW	$30.0	$4,433
Gen 2	50W	$27.8	$1,388
Load	197MW	$30.0	$5,910
Loss surplus revenue			**$90**

FTR	FTR Qty	RRP - LMP	Settlement $
Gen 2	500MW	$2.2	$112

Gen 2 total settlement	**$1,500**

Source: AEMC

Over both periods, the total FTR payout is $224, which is consistent with the total loss surplus revenue. However, there is an FTR settlement surplus in the first period and a deficit in the second period. These 'unders and overs' would need to be managed throughout the term of the FTR.

From Generator 2's perspective, holding the FTR instrument has allowed it to achieve an MLF of 1 (i.e., receive the regional reference price) on its output that is covered by the FTR quantity. The remainder of its output received the locational marginal price. Therefore, the generator retained a degree of exposure to fluctuations in its MLF.

Note: 1) Generator 2's LMP is the same in both dispatch intervals because its MLF is the same in both periods.

If forecast flows are not accurate, the difference between loss surplus revenues and FTR payouts in each dispatch interval would not net out to zero over the term of the FTR, resulting in an overall surplus or deficit. Returning to the example above, suppose the Gen 2's output in the first period was only 50MW. In this case, the total FTR payout over the two periods would still be $224, but the available loss surplus revenue would only be $179.

Therefore, some scaling of the overall FTR payout might be required if the forecast the quantity allocation is based on is incorrect. As discussed in section 6.4.3, making the FTR payout a product of a generator's output could obscure locational marginal price signals. The scaling approach would therefore need to take this effect into account, to avoid replicating the concern outlined above in relation to variable quantity FTRs. For example, if scaling of FTR payouts took place outside of dispatch interval timescales, the link between generator output decisions and the overall FTR payout would likely be weaker than would be the case for a variable quantity FTR.[175] However, the overall effect of such scaling on incentives, settlement complexity and the overall effectiveness of FTRs as a risk management tool will require careful consideration.

6.4.5 Additional design considerations

In addition to the design questions outlined above (product type, funding and quantity), there are a range of other design issues that would need to be resolved. These include:

- Tenure of the FTRs. For example:
  - Given that market participants already have MLFs that are fixed for a year, the tenure would need to be longer than this to provide a hedging benefit, relative to the status quo.
  - AEMO currently sets MLFs one year ahead. If a fixed quantity FTR with a lead time/tenure beyond one year was to be developed, this would require a longer-term forecast. The accuracy of this forecast and the implications of this for FTR issuance would need to be considered (for example, a forecast further into the future might imply a higher likelihood of the fixed FTR quantity being inconsistent with available loss surplus revenues).
- The procurement process. For example, if there are separate loss and congestion FTR products, these could potentially be sold through the same simultaneous feasibility auction. However, further consideration would need to be given to the interaction of the two products in the auction. Relevant considerations would include:
  - How the forecast for determining the appropriate loss FTR quantity would interact with the network model the auction is based on.
  - Whether it would be feasible for participants to make linked bids (for example, if they only wanted to purchase a congestion FTR if they could also purchase a loss FTR).

The Commission will consider these options through further analysis and engagement with stakeholders over the course of 2020.

175 For example, scaling that takes place 'outside of settlement timescales' could occur after a defined period of time, based on the total deficit that has accumulated in each settlement interval up to that point. This would be in contrast to an approach that scaled loss FTR payments down (or up) in each individual settlement interval to match the available loss surplus revenue.

7 IMPLEMENTATION AND STAGING

This chapter discusses implementation and staging considerations.

This chapter discusses:

- the timelines and process for implementing access reform
- grandfathering arrangements that would mitigate the financial impact of sudden changes in the market and provide for a period of learning
- possible staging options for the reforms, including by geography or design element.

7.1 Implementation

The access model will be progressed over the course of 2020. The reforms relating to the two-sided market, ahead markets and the COGATI access and charging reform are measures that need to be in place before 2025 to support increased variable renewable energy and the integration of distributed energy resources (DER).

This is consistent with the position in the December update paper that an implementation time period should be in the order of four years from when the final rules are determined, in order to be coordinated with other reforms underway. This was an extension of the proposed timeframe, and feedback from stakeholders has suggested that this has allayed a number of concerns.

This timeframe is also consistent with the lead time of three years of commonly traded ASX contracts and SRA units, reducing disruption to the contract market. Longer dated contracts may nevertheless be impacted.

Despite this, the current proposed timeframe seeks to appropriately balances the trade off between the benefits of reforms beginning to flow quickly and providing time to allow market participants and AEMO to adapt to and prepare for the changes.

It is nevertheless important to fully develop the detailed access model as soon as possible. We have received stakeholder feedback that the potential prospect of the reform is, in and of itself, creating uncertainty and disruption to the industry. Determining and finalising the detailed design of the reforms as quickly as possible will mitigate this concern. As such, the design will continue to evolve over the course of 2020 in light of further work by the Commission on the specifications of the reform model, in conjunction with stakeholders as well as other reform work underway.

7.2 Grandfathering

As with all reforms of this nature there will be disruption and costs associated with the change, and these issues are continuing to be investigated investigate the materiality of these issues.

The access model is likely to create winners and losers. The main winners are expected to be consumers, through a general increase in the efficiency of the market, and through the receipt of the revenue from the sale of the FTRs. Of course, this is the rationale for the reform, consistent with promotion of the NEO.

Other market participants may also benefit from the reforms, particularly generators whose locational marginal price is higher than the regional reference price, and storage and scheduled load whose locational marginal price is lower than the regional reference price.

Among those that may not be better off from the reforms, absent of grandfathering arrangements, are likely to be those market participants whose locational marginal prices are typically lower than the regional reference price. These parties will, absent of grandfathering arrangements, receive lower revenue from the wholesale market, and face potentially high prices for FTRs to hedge against low LMPs.

In order to assist the successful implementation of this reform and to provide stakeholders with the time needed to adapt to these reforms, incumbent generators would need to be granted some level of financial transmission rights for free. This would, in effect, mitigate against sudden changes to their revenues and profits as a result of the reforms.

Grandfathering of FTRs is also, in effect, a type of staging that can be used when implementing a reform. It allows for some effects of the reform to come in over-time. Grandfathering should help mitigate sudden changes to wholesale electricity prices or margins of market participants, provide learning time, and prevent abrupt changes in the amount of FTRs available.

The intent of the grandfathering arrangements are therefore to:

- mitigate any sudden changes to wholesale electricity prices or margins for market participants on commencement of the reform, in order to encourage and permit (existing and new) generators to acquire and hold the amount of financial transmission rights that they would choose to pay for
- give time for generators, transmission network service providers and other market participants to develop their internal capabilities to operate new or changed processes under the access reforms without incurring undue operational or financial risks during the learning period
- prevent abrupt changes in the amount of available financial transmission rights that could create dysfunctional behaviour or outcomes in financial transmission rights procurement or pricing.

It is difficult to work out the form and length of the grandfathered financial transmission rights prior to developing the proposed access model in more detail. Despite this, we recognise that this issue is important to stakeholders and therefore have set out the following considerations:

- The new arrangements should start somewhere close to most of the network being 'covered' by grandfathered 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 FTRs would be sculpted back over time.

This implies that existing generators would receive an amount of financial transmission rights for free that would taper off over time. Through the rule change process, quantitative modelling will look at distributional effects and will be used to further inform the transitional arrangements. This will take into account the impact of more generous grandfathering arrangements (in terms of quantity and time) on prospective generators and consumers.

Some additional detailed considerations are required on a range of related matters, including for example:

- who qualifies for grandfathered FTRs, including whether and how prospective/committed generators should qualify, as well as whether participants who have already gone beyond their expected life qualify
- what happens if a party with grandfathered FTRs retires
- whether the tapering time should be the same for all market participants, or reflect the specifics of the generator (for example, if it is old, or if it is expected to exit the market)
- whether and how (scheduled) load should qualify for grandfathered FTRs.

It will also be important to take into account the fact that there is a significant amount of generation that is seeking to connect to the network. Over 40GW of generation is expected to connect by 2040. Therefore, any grandfathering arrangements should also be conscious that there needs to be some levels of FTRs available to be purchased by new entrants, as well as a healthy secondary market.

Further detail on the grandfathering arrangements will be developed over the course of 2020.

7.3 Geographic Staging

In response to stakeholder feedback, we have also considered whether there are other options to stage the implementation of the reform. One such option is geographic staging (discussed in this section).

Geographic staging may mean that the reform is implemented across all regions in the NEM in a transparent, planned manner, but at different times. This could occur jurisdiction by jurisdiction, or in a sandbox environment.

The viability of geographic staging has only been considered at a high level. In general, it is likely to require less disruption and otherwise undesirable design changes to implement in a geographically staged manner in parts of the network which are radially connected to the rest of the network. That is, those parts of the network that are connected to the rest of the network by just one connection, rather than meshed/multiple connections.

While it may be possible, with changes to the design, to implement geographic staging of the reforms, it is not recommended. It is likely to:

- increase implementation costs for AEMO and market participants, by adding additional complexity to the system due to having different jurisdictions operating under differing regimes
- require many of the fixed transitional costs to be incurred regardless, in order for it to be implemented in any geographic area.

Furthermore, it is unlikely that this approach will have as many benefits for consumers as implementing across the whole NEM - simply because delaying the reforms in some regions delays all the benefits of the reforms, in both that region and other regions. While there may be some benefit in 'learning' from one region or geographic area before implementing more widely, in order to fine-tune the design, there are likely to be greater net benefits from implementing the reforms simultaneously everywhere (given the expectation that the net benefit of the reform is substantial), so that the benefits can start flowing. Subsequent fine-tuning as necessary is then possible consistent with the rule change proposal process, to further increase the benefits.

As such, geographic staging of the reform is not recommended. However, some type of sandbox or trial may be beneficial.

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
COGATI	Coordination of generation and transmission investment review
COAG	Council of Australian Governments
CRR	congestion revenue right
DER	distributed energy resources
DLF	dynamic (marginal) loss factor
DR	demand response
DRSP	demand response service provider
ESB	Energy Security Board
FCAS	Frequency Control Ancillary Services
FTR	financial transmission rights
IRSR	inter-regional settlements residue
ISP	Integrated System Plan
IR-TUOS	inter-regional transmission use of system
LAP	load aggregation pricing
LMP	locational marginal price
LSE	load serving entity
MLF	marginal loss factor
MNSP	market network service provider
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NER	National electricity rules
NERL	National Energy Retail Law
NEO	National electricity objective
NSA	network support agreement
OFA	Optional firm access
PASA	Projected Assessment of System Adequacy
PPA	Power purchase agreements
REZ	Renewable energy zone
RIT-T	Regulatory investment test for transmission
RRN	regional reference node

RRO	Retailer Reliability Obligation
RRP	regional reference price
SENE	Scale efficient network extensions
SRA	settlement residue auction
SRDU	settlement residue distribution units
STPIS	Service target performance incentive scheme
TCAPA	Transmission connection and planning arrangements
TNSP	Transmission network service provider
TUOS	transmission use of system
VRE	variable renewable energy
VWAP	Volume weighted average price
WDRM	Wholesale Demand Response Mechanism

A DRAFTING PRINCIPLES

If implemented, the access model will require a number of amendments to the national electricity rules (NER), particularly to Chapter 3, but also to chapters 4, 4A and 10. In response to stakeholders requests for more detail about how the model may impact the NER and so how contracts are being struck and negotiated, the table below sets out high level indicative drafting principles based on the current blueprint design, together with AEMC comments, policy notes and some specific examples of proposed amendments. This should not be taken to be a definitive approach, and the Commission may adapt this in the course of its work over 2020.

The table is provided at this stage for information purposes only and is based on the current blueprint design. Further refinement and drafting detail will be prepared over the course of 2020 in conjunction with further stakeholder engagement, modelling being undertaken and the development of other reforms.

Italicised words throughout this table are terms that are currently defined in chapter 10 of the NER.

This table has also been prepared on the basis of rules that have been made, but not yet commenced. Therefore, in considering and recommending amendments to the NER to implement the COGATI access reforms, changes made by the following amending rules are taken into account:

- Schedule 1 of the National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019 which will come into effect on 26 March 2020
- Schedule 2 of the National Electricity Amendment (Retailer Reliability Obligation) Rule 2019 which will come into effect on 26 March 2020
- Schedule 1 of the National Electricity Amendment (Five minute settlement) Rule 2017 which will come into effect on 1 July 2021
- Schedule 2 of the National Electricity Amendment (Participant compensation following market suspension) Rule 2018 which will come into effect on 1 July 2021
- Schedule 2 of the National Electricity Amendment (Intervention compensation and settlement processes) Rule 2019 which will come into effect on 1 July 2021
- Schedules 1-4 of the National Electricity Amendment (Global settlement and market reconciliation) Rule 2018 which will come into effect on 6 February 2022.

Table A.1: **Blueprint access model drafting principles - item 1**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
1	Scope of locational marginal pricing		
1.1	Wholesale electricity	Locational marginal pricing will apply to the wholesale electricity market in the National Electricity Market	For the purposes of this document, the term '***LMP***' is used to mean locational marginal pricing (as a general concept) and locational marginal price (being a price at a specific connection point), as relevant.
1.2	Market ancillary services	LMP will not apply to ancillary services	

Table A.2: **Blueprint access model drafting principles - item 2**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
2	**Nodes**		

2.1	Local node	There will be 'local nodes' which will correspond with every *connection point* that is either a *transmission network connection point* or a *distribution network connection point* located on a *dual function asset*.	• LMP will only apply to connection points that are market-facing.
			• The AEMC is proposing to retain the term *spot price* but to amend the definition to mean LMPs at local nodes or the regional price, as relevant (that is, depending on which price a participant faces). Each use of the term *spot price* throughout the NER will need to be checked to ensure that this approach works, bearing in mind the possible impacts on the contract market in relation to contracts settled by reference to the *spot price* as defined in the NER.
			• A new chapter 10 term 'local node' could be defined as 'A *connection point* that is either:
			  • a transmission network connection point; or
			  • a distribution network connection point located on a dual function asset.'
			For *generators* connected to the *distribution network* (*embedded generators*), the AEMC is

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			still considering which particular LMP they will face (that is, which *transmission connection point* applies to them). This approach may be based on the current methodology for working out how loss factors are applied to embedded generation.
2.2	Regional reference node	The existing concept of *regional reference node* will be retained if the regional reference price (RRP) is retained, but may no longer be relevant if a VWAP is used.	See section 4.2 for further details.

Table A.3: **Blueprint access model drafting principles - item 3**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
3	**Prices**		
3.1	Locational marginal price	At each local node, and for each dispatch interval, there will be an LMP which will be determined by NEMDE and will represent the marginal value of supply at that location and time. New clauses will be required to set out which types of *load* and *generation* (and wholesale demand response if this category is created) will be settled at the LMP and which will continue to be settled at the regional price: • *Scheduled generation, semi scheduled generation*, and *scheduled load* will be settled using the LMP; • *Non-scheduled load* and *non-scheduled generation* will be settled at the regional price.	• In many instances, the current requirements in Chapter 3 for AEMO to publish the details of prices or projections will not need to be amended as they will apply to LMPs and regional prices in the same way that these requirements currently only apply to RRPs. • The introduction of LMPs would significantly increase the number of reports the AER would need to produce under clause 3.3.17. The AEMC will consider whether the current requirements would remain appropriate and fit-for-purpose under the proposed new framework. For example, it may be more efficient and informative for the AER to group events and report on them periodically (e.g. reporting quarterly for a specified sub-set of local nodes), as opposed to reporting on all of them individually. The AEMC will consider this further throughout the Rule change

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			process. • Amend clauses 3.2.2(c) and 3.4.1 to require AEMO to determine and publish *spot prices* at each local node and for each region and *ancillary service prices* for each *region* for each *trading interval.* • Amend clause 3.13.4(g) to require AEMO to publish forecasts of the *spot prices* at each *local node* and for each region. • Amend clause 3.13.4(l) to require AEMO to publish the *spot prices* at each local node and for each region within five minutes of AEMO running the *dispatch algorithm*. • Amend clause 3.13.4(l1) to require AEMO to publish a *30-minute price* for each local node and region for each *30-minute period*. • Amend clauses 3.13.4(m) and (n) to require AEMO to publish the *spot price* at each local node and for each region within five minutes of the conclusion of each *trading interval*. • New chapter 10 term 'locational marginal price' could be defined as 'the marginal

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			value of *supply* at the local node, which marginal value is determined as the price of meeting an incremental change in *load* at that local node.' This is directly analogous to the way the *regional reference price* is currently defined as the *spot price* at the *regional reference node*, with the *spot price* determined under clause 3.9.1. • Consideration to be given to deleting the existing definition for '*local spot price*' which is only used twice, once in clause 3.6.2(c) and once in clause 3.9.1(c), and which currently relates to the effect of *marginal loss factors*.
3.2	Regional reference price	While there will continue to be a regional price it will be either the RRP or VWAP.	See section 4.3.
3.3	LMP cap and floor	Each LMP will be capped at the *market price cap.* The LMP for each local node will be no less than the *market floor price*.	• The AEMC is still considering how the *market price cap* and *market floor price* will apply under LMP. The AEMC's current expectation is that the *market price cap* and *market floor price* would apply at the LMP level, but precisely how this is achieved is to be determined. This may

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			have implications for how the existing scaling regime (which operates when the *market price cap* or *market floor price* is reached) would operate. See section 9.7.

Table A.4: Blueprint access model drafting principles - item 4

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
4	**Dispatch**		
4.1	Dispatch algorithm determines LMP	Each time the *dispatch algorithm* is run by AEMO it must determine an LMP for each local node and these will be shown in AEMO's *pre-dispatch schedule*.	
4.2	Aim of central dispatch process	The aim of the central dispatch process will remain as it currently drafted in clause 3.8.1(b).	
4.3	Update to NEMDE	No updates to NEMDE are required as NEMDE calculates local prices already for those entities that will face the local price.	

Table A.5: **Blueprint access model drafting principles - item 5**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
5	**Relevant market participants**		
5.1	Generation – scheduled, semi-scheduled and embedded	*Scheduled generators*, *semi-scheduled generators*, including *embedded generators* where applicable, will be settled at the LMP which applies at their local node.	For *generators* connected to the *distribution network* (*embedded generators*), the AEMC is still considering which particular LMP they will face (that is, which *transmission connection point* applies to them). This approach may be based on the current methodology for working out how loss factors are applied to embedded generation.
5.2	Generation – market and non-market	Only *market generators* will be settled at LMPs.	
5.3	Load	*Scheduled loads* will be settled at the LMP which applies at their local node. *Non-scheduled load* will be settled at the regional price for the *region* they are located in.	
5.4	Market network services	*Market network service providers* will be treated as akin to a *scheduled generator* at the node at which they are importing and a *scheduled load* at the node they export from and settled at the two relevant LMPs at each node.	

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
5.5	Other participants	Participants in the wholesale electricity market who are scheduled or semi-scheduled (such as storage or demand response if these categories of participant are created) will be settled at the LMP which applies at their local node. Any other non-scheduled participants in the wholesale electricity market will be settled at the regional price for their region.	
5.6	Changing from one participant type to another	*Market Participants* who are eligible to change from being non-scheduled to scheduled/semi-scheduled will continue to be able to do so. However, if a participant wishes to make a second change in relation to their status as scheduled or semi-scheduled they will be required to give at least 12 months' notice.	
5.7	Information, forecasts, etc. provided by AEMO to market participants		• As noted above, in many instances, the AEMC expects the current requirements in Chapter 3 of the NER for AEMO to publish the details of prices or

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			projections will apply to LMPs in the same way that these requirements currently apply to RRPs. • Broadly speaking, the AEMC considers that the information currently captured by the *Projected Assessment of System Adequacy* (PASA) remains fit for purpose for the purposes of implementing LMP. Some additional market information may be required, but the AEMC will consider this as further details of the model are developed. • The AEMC expects that AEMO may need to update the congestion information resource, for example to accommodate the increasing importance of '*mis-pricing*' (essentially the difference between an LMP and the regional price). The definition of mis-pricing will also likely need to be updated to refer to local nodes, LMPs and regional prices.

Table A.6: **Blueprint access model drafting principles - item 6**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
6	**Settlement mechanics**		
6.1	Spot market transactions	Refer to clause 3.15.6. The final LMP equation is to be confirmed. Additional clauses may be helpful to break the equations up into logical groups. Equivalent changes to those made to clause 3.15.6 will be made to the demand response transactions (if required). Participants' revenue or costs will be determined by adding the aggregate value of the electricity generated or consumed ($TA_{dispatch}$) and the aggregate value of the FTRs held by the participant (TA_{FTR}).	**Trading amounts** This is based on the blueprint design set out in the technical specifications report. The existing *trading amount* equation is: $TA = AGE \times TLF \times RRP$ Our current thinking is that the existing *trading amount* equation would be replaced with the following: $TA = TA_{dispatch} + TA_{FTR}$ Where: • TA is the *trading amount* to be calculated, in \$. • $TA_{dispatch}$ is the dispatch trading amount, in \$. TA_{FTR} means the sum of all FTR amounts which apply for the relevant *trading interval,* in \$.
6.2	Trading amounts - dispatch	Participants will be paid or charged for the aggregate electricity that they	The dispatch trading amount is determined by:

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
		generate or consume.	$TA_{dispatch}$ = SP × AGE Where: • SP is the settlement price (in $/MWh) which applies to a *Market Participant* at a given local node – for example, *scheduled generators* will face the LMP, while *non-scheduled load* will face the regional reference price. The settlement price will also reflect marginal loss factors. • AGE is *adjusted gross energy*, in MWh.
6.3	Trading amounts - FTR	Participants will be paid for the value of the FTRs that they hold. As noted below in row 11.4, FTRs will be able to be purchased in respect of each LMP and each regional price, or in respect of two regional prices. In relation to each pair of nodes, participants will be able to acquire FTRs that hedge against either P1 being higher than P2 or P2 being higher than P2. The FTRs will be options which mean they will not pay out if the	**FTR amounts** The TA_{FTR} amount for a given *trading interval* is calculated by: TA_{FTR} =max((P1 – P2), 0) x FTRQ Where: • TA_{FTR} is the FTR trading amount to be calculated, in $. • P1 and P2 are a price pair comprising prices at either one local node and one regional reference price or two regional reference prices, in $/MWh.

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
		difference between them is negative.	FTRQ is the quantity of FTRs held by the *Market Participant* in respect of the particular 'price pair', in MWh. Note, depending on the approach taken in relation to marginal transmission loss factors and how loss-related price differences are incorporated in the FTR design, the above equation may require modification.
6.4	Settlement residues	Insert new clauses to describe what is to happen to settlement residues	Intra-regional settlement residues currently implicitly arise when transmission constraints bind and local marginal prices diverge within a *region*. For intra-regional settlement residues relating to constraints, the accrual of settlement residues is currently obscured by the implicit allocation of residues to *generators* based on the level at which they are dispatched. Inter-regional settlement residues currently arise when transmission constraints bind on an interconnector and regional prices diverge in different regions. The residues are currently allocated via the settlement residue auction under rule 3.18 of the NER. Under LMP, settlement residues will arise

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			(and will be calculated) in the same way, but: • the implicit allocation of residues relating to constraints based on dispatch will be replaced with an explicit allocation of intra-regional residues based on the volume of FTRs held; and • the existing settlement residue distribution unit auction regime will be replaced by the FTR regime. Only participants that hold an FTR will receive an explicit allocation of the settlement residues (specifically, the difference between either any LMP and any regional reference price, or any two regional reference prices for the FTR quantity the participant has purchased – see above.
6.5	Settlement balancing	Insert new clauses which describe how settlement residues and deficits will be managed to ensure settlement balancing.	For the payouts against FTR to perfectly balance with settlement residues, the FTR quantity that settlement is based on must be equivalent to the available transmission capacity. In practice this is not possible (generators may not purchase the full quantity of FTRs made available by the

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			TNSP, there is variability in the transmission capacity based on factors such as ambient temperature, and it is not possible to predict outages). Settlement residues and deficits will therefore be created as follows: • If transmission capacity is greater than the amount of FTRs held in a particular part of the network, there will be excess (unallocated) settlement residue. • If transmission capacity is less than the amount of FTRs held in a particular part of the network, then settlement residue will be less than the amount needed to fully pay out against all FTRs held, resulting in a settlement residue deficit.
6.6	Allocation of settlement residues surplus or deficit to a fund (**settlement fund**)	Insert new clauses setting out how the settlement fund will operate, including in relation to any scaling.	Where there is surplus residue, LMP settlement surpluses will be allocated to a central fund that will be used to increase the firmness of FTR. This could be called a 'settlement fund'. This central settlement fund will accumulate residues (and have residues drawn down from it) in respect of each settlement period and in relation to each part of the

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			transmission network. Where there is deficit residue, payments to participants with FTRs will be drawn from the fund until it is exhausted. The fund will never be able to go negative. If the fund is exhausted, payments for FTRs would be drawn from the auction fund (see row 11.7). Any further shortfalls would be met through scaling of FTRs, using an FTR scaling algorithm. The settlement fund will be indefinite in size and time.

Table A.7: **Blueprint access model drafting principles - item 7**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
7	**Losses**		
7.1	Losses	In dispatch, intra-regional marginal loss factors will continue to be applied to scheduled and semi-scheduled participants offers (or bids). In settlement, intra-regional marginal loss factors will be applied to both regional reference prices and locational marginal prices. See the settlement equations above in section 6.	Losses will continue to be calculated as a marginal loss factor on a static basis annually by AEMO in accordance with the methodologies required by clauses 3.6.1 and 3.6.2. The AEMC also notes that other legislative schemes (such as the Commonwealth Government's Renewable Energy Target scheme) rely on marginal loss factors for the purposes of calculating entitlements and liabilities.

Table A.8: **Blueprint access model drafting principles - item 8**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
8	**Constraints**		
8.1	Type of constraint creating differential in prices between locations	The LMP at a particular local node will be determined by considering constraints that bind, as determined by NEMDE. That is, thermal constraints and system security constraints will be able to influence LMPs at local nodes provided they are included within NEMDE.	The AEMC expects that AEMO may need to update the constraint formation guidelines (clause 3.1.10(c)).
8.2	Capacity support generators	The concept of generators being constrained on will not exist under LMP as these generators will be simply paid their LMP.	

Table A.9: **Blueprint access model drafting principles - item 9**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
9	**Abnormal settlement**		
9.1	Intervention pricing (resulting from RERT exercise or AEMO direction)	Amend the RRN test for intervention pricing so that it refers to the setting of *spot prices* at relevant local nodes and does not include an assessment of whether an equivalent intervention with respect to plant connected at the RRN would have avoided the need for the intervention (that is, remove the geographic element of the test). In this way, intervention pricing would apply at any local node impacted by AEMO's direction or the exercise of the RERT, to preserve scarcity price signals at that local node.	The impacts of the exercise of the RERT or the issuing of an AEMO direction on LMPs and regional prices require further analysis. When AEMO intervenes in the market by exercising the RERT or issuing a direction, it must only apply intervention pricing if the RRN test is met. The (recently modified) RRN test effectively has two elements that determine whether intervention pricing should apply: (i) the economic element and (ii) the geographic element. The economic element considers whether intervention pricing is needed to preserve scarcity price signals. That is, intervention pricing should not apply if an intervention is made to address a shortfall for a service not traded in the market (e.g. system strength, inertia). The logic is that as these services are not market traded, there is no relevant price signal to

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			preserve. In these cases, applying intervention pricing would erroneously preserve a scarcity price for energy, although the intervention was not due to an energy shortfall. The AEMC's current view is that the economic element of the RRN test will still be relevant under LMP, specifically in deciding whether the circumstances in which an intervention was made should give rise to intervention pricing. The geographic element of the RRN test asks whether directing a plant at the RRN would have avoided the need for the direction actually issued by AEMO. If the answer is no, AEMO does not apply intervention pricing. The logic is that there is no reason to preserve scarcity price signals at the RRN, where a direction is issued to resolve a localised issue in a part of the network remote from the *regional reference node*. With LMP, price signals would be sent by LMPs at each local node, not the *regional*

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			reference price. Therefore, intervention pricing would ideally apply at any local node impacted by AEMO's direction, regardless of which *region* they are in, to preserve scarcity price signals at that local node. Given this, the AEMC considers that the geographic element of the test would no longer be relevant under LMP. The practical feasibility of this however will need to be tested with AEMO (there may be alternative ways to achieve the objective). The AEMC's current position is that FTRs would pay out during intervention pricing periods. The FTR payout would need to match the wholesale market prices used for settlement (i.e. the intervention prices derived from the 'what if' pricing run). FTR payouts could still be subject to scaling if settlement residues are not adequate (but this is a general provision, not specific to interventions and is discussed in item 6.6 above).

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
9.2	AEMO instructions	If an instruction is given by AEMO to a *Network Service Provider* or *Market Participant* to shed load, then AEMO must set the *dispatch price* at that *region's regional reference node* to equal the *market price cap* (clause 3.9.2(e)). That is, in contrast to AEMO directions and the exercise of the RERT, AEMO 'instructions' do not result in intervention pricing, per se. The AEMC's current expectation is that in this circumstance the *market price cap* would instead be applied at the LMP level. There might need to be changes to AEMO procedures to establish which LMPs would be impacted.	
9.3	Mandatory restrictions		The AEMC has received a rule change request to remove the mandatory restriction regime. Given this will be progressed through a separate process, the AEMC do not propose to consider changes through this process.
9.4	Market suspension	The AEMC has received a rule change request to remove the mandatory	The AEMC's expectation is that AEMO would need to have a process in place to

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
		restriction regime. Given this will be progressed through a separate process, the AEMC do not propose to consider changes through this process.	determine LMPs in the case of *market suspension* (LMPs would be required for both wholesale market and FTR settlement). However, this might not necessarily take the form of a *market suspension pricing schedule*. The approach would need to be determined as part of the detailed design process, with AEMO's input. The AEMC's current position is that compensation payable to *Market Participants* as a result of *market suspension* should not consider lost revenue from FTRs. As explained above, the objective of FTRs is to hedge basis risk that actually arises (not provide a hypothetical pay out that might have occurred if the market hadn't been suspended). If there are LMP differences that arise under *market suspension* pricing, and settlement proceeds on the basis of these LMPs, our current expectation is that the FTRs would still pay out as normal.

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			The AEMC also considers that the *market suspension* scaling regime will remain relevant under LMP. This is because the objective of clause 3.14.5(f) is to manage negative inter-regional settlement residues, by ensuring that the *market suspension pricing schedule* maintains a relationship between regional prices that is consistent with a 'normal' market outcome (i.e., energy flows from low price regions to high price regions). This issue will need further analysis, but the AEMC's current expectation is that the objective would still be relevant (although at the LMP, not regional price, level). However, the precise mechanism to achieve this might well be very different to the scaling approach currently specified in the NER. As above, the approach would need to be determined as part of the detailed design process, with AEMO's input.
9.5	Administered pricing	During an *administered price period*, the *administered price cap* ($300 / MWh)	The AEMC considers that the triggers for an *administered price period* under LMP

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		and *administered floor price* (-$300 / MWh) apply and AEMO must set the *spot price* in the *region* to the *administered price cap* or *administered floor price* if the *spot price* exceeds or is less than the *administered price cap* or *administered floor price*, respectively.	will require further investigation – in particular whether it will continue to be set by reference to a regional price or whether an *administered price period* will instead be triggered by the cumulative price threshold being exceeded at a local node. The objective of administered pricing is to limit participants' financial exposure to sustained high prices, while maintaining incentives for participants to supply energy once the *cumulative price threshold* has been exceeded. Under the current LMP proposal, different market participants will face different prices – for example, scheduled participants will face LMPs, and non-scheduled load participants will face the regional price. Therefore, some participants’ exposure to high prices would still be linked to the overall regional reference price. But, generators’ incentives to supply energy would be linked to the LMP. This suggests

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			that both LMPs and the regional prices would need to be considered in the administered pricing regime and the reliability standards and settings framework. This aspect of the policy is still being considered, as is the application at the LMP level of the *market price cap*, *market price floor* (and therefore in FTR settlement).
9.6	Compensation due to the application of an *administered price cap* or *administered floor price*	As noted above, given the purpose of FTRs is to hedge actual basis risk, the AEMC does not consider it necessary for this compensation payable as a result of administered pricing to include an amount which reflects any lost revenue from FTRs (due to changed price spreads between two different local nodes).	The AEMC notes that this cost recovery mechanism available to participants in respect of administered pricing is a bespoke process that requires a participant to lodge an application for compensation with the AEMC. To date this mechanism has only been used once.
9.7	Market price cap and floor	Currently, if dispatch determines that *spot prices* at a *regional reference node* would result in a price below the *market floor price* or above the *market price cap*, then the *spot price* is set to the	The AEMC is considering whether the market price cap and market floor price scaling regimes remain relevant under LMP, and whether these scaling regimes should be expanded to deal with local

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
		market floor price or *market price cap*, respectively.	nodes which have their prices set at the market price cap or market floor price. The AEMC's current expectation is that the *market price cap* and *market floor price would* apply at the LMP level, but precisely how this is achieved is to be determined. This may have implications for how the scaling regime would operate. As explained above in relation to administered pricing, the objective of the scaling regime may still be relevant, but the mechanism would likely need to change.
9.8	Manifestly incorrect output	Prices in 'affected dispatch intervals' are adjusted back to the last correct *dispatch interval*.	The AEMC considers that in principle FTR payouts should match the wholesale prices that *Market Participants* are actually settled at. Therefore, if settlement is based on the adjusted *spot prices*, the FTR payouts would also reflect this. The AEMC does not expect any amendment to this regime as a result of LMP. However, this could potentially change depending on if / how AEMO

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			develops the dispatch engine to implement LMP. That is, there would still need to be a process for adjusting dispatch / settlement outcomes in the case of an incorrect input, but it is possible that the preferred approach / process might be different to the current approach.
9.9	Pivotal supplier	Potentially insert new clause describing the nature and application of the pivotal supplier test. An ex ante offer cap will apply to *generators* in the event that a *generator* fails a pivotal supplier test.	The type and extent of market power mitigation measures will be informed by the AEMC's modelling of market power (to be conducted in 2020) and any relevant findings from any AER studies into this matter. If these studies reveal a need to implement market power mitigation measures, the AEMC's preferred mechanism is a pivotal supplier test. The pivotal supplier test would broadly involve: • An ex ante offer cap would be introduced in the event that a generator was deemed to be pivotal. • The offer cap would be set at a value related to the conditions in the

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			wholesale market at the time the cap is applied.

Table A.10: **Blueprint access model drafting principles - item 10**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
10	**Auxiliary loads**		
10.1	Auxiliary load guidelines	AEMO must prepare auxiliary load guidelines which prescribe what can be classified as auxiliary load by generators. Compliance with the auxiliary load guidelines will be mandatory.	The detail around auxiliary loads is to be developed, but the AEMC expect there will be grandfathering of existing participants' rights.
10.2	Access unit identifier	The detail around auxiliary loads is to be developed, but the AEMC expect there will be grandfathering of existing participants' rights.	
10.3	Mapping of auxiliary load to dispatchable units	There will be a concept of dispatchable units which will refer to the generating unit or units which are dispatched as one entity. AEMO will be required to map existing auxiliary loads and dispatchable units to access unit identifiers for existing *generators*. TNSPs will be required to map new auxiliary loads and dispatchable units to access unit identifiers for new generation connections.	

Table A.11: Blueprint access model drafting principles - item 11

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
11	**Financial Transmission Rights (FTRs)**		
11.1	Nature of FTRs	FTRs will be options which pay out on the price difference between (1) any LMP and any regional price; and (2) any two regional prices. Participants will be able to acquire FTRs that hedge the price difference that arises as a result of congestion and losses. FTRs will not pay out negative amounts. FTRs will be available for each 'direction' between the points above to allow generation and load to buy FTRs on the same transmission path but which pay out in different circumstances. FTRs will be available which pay out (1) continuously and (2) during specific pre-defined times during the day. FTRs will be primarily funded by settlement residues which arise due to congestion and losses (although see above in section 6 in relation to the scaling of FTRs to avoid a fund deficit).	A new framework will need to be inserted into the NER to set up the FTR regime, including clauses to: • Describe the purpose of FTRs; • Describe the types of participants able to acquire FTRs, any restrictions on the number of FTRs that will be made available (for example, by reference to the capacity of the transmission system) or able to be bought by participants; and • Describe the key design principles of FTRs, including the concept of price pairs and the form, tenure and nature of the FTR instruments. The Commission is yet to determine whether it would be preferable to hedge loss- and congestion-related price differences within a combined FTR product, or separate FTR products, or indeed no product at all.

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
11.2	Availability of FTRs	*Market Participants* who are exposed to the LMP will be able to acquire FTRs which will be used to determine the settlement amount when the regional price and LMP are different due to constraints in NEMDE or price differences that arise due to the application of marginal loss factors.	As above.
11.3	Amount of FTRs	The amount of FTRs that are offered for sale will be determined by reference to the capacity of the transmission system.	As above.
11.4	FTR auctions	FTRs will be sold through auctions run by AEMO with input from TNSPs. The FTR auctions will be detailed in the NER in more detail than the current auctions for settlement residue distribution units under rule 3.18. These rules will include not just process but algorithms, products, and the process for modelling the capacity of the system to determine the amount of FTRs available.	• Delete clause 3.13.5A and rule 3.18 as the settlement residue auction concept will be replaced by FTRs, although the AEMC may borrow from concepts in the existing settlement reside framework. Transitional provisions will be required to accommodate this change. • Insert new provisions to require AEMO to: • hold auctions for FTRs and to describe the requirements of

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			• those auctions • use the revenue from FTR auctions to offset TUOS charges • develop procedures for the procurement and settlement of FTRs • report on FTRs and provide information to TNSPs • develop and publish a register which records particular details of FTRs upon which persons who trade in FTRs must record their trades. The AEMC is still considering exactly how FTR revenue will be used to offset TUOS, and this will be set out in the NER. See section 11.7 below.
11.5	Tenure and granulatity of FTRs	The FTR auction could offer products with a range of tenures, including up to 10 years in advance. The granularity of these products (the length of the period that an individual FTR hedges over, such as over a month,	

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
		quarter, or year) will be determined based on the tenures would be offered through the auction.	
11.6	Right to buy FTRs	Only 'physical market participants' (that is Registered participants who participate in the *national electricity market*) can buy FTRs between LMPs and regional reference prices. All Registered participants, including non-physical market participants such as Traders (or a functionally equivalent category of participant) can purchase FTRs between two different regional prices.	
11.7	Revenue from FTR auctions	The revenue from FTR auctions will accumulate in an auction revenue fund (**auction fund**). This fund would be used when there are settlement deficits that cannot be met by the settlement fund (see row 6.6). However, the auction fund would be limited in time. This means that proceeds from an FTR auction would be held in the auction account for a pre-determined period of	• The AEMC has not yet determined a preferred approach for using auction revenues to offset TUOS charges, including whether the auction revenues would be assigned to the locational or non-locational components of TUOS charges. There are a number of trade-offs to consider, including the effect on locational signals and the

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
		time. At the end of this period, the remaining balance would be transferred to consumers as an offset to TUOS charges.	interactions with FTR sales.
11.8	FTR cap	Market participants who acquire FTRs will not be able to acquire more FTRs than their physical capacity across the system.	
11.9	Register of FTRs	AEMO must maintain a register of FTRs that includes the clearing prices of FTRs sold at each auction, the amount of FTRs sold, the current portfolio of FTRs held by *Market Participants*. Bid and offer prices for FTR auctions will not need to be published in the FTR register. Parties who engage in the secondary trading of FTRs will be required to notify trades to AEMO so that the register can be updated to record who holds FTRs and the quantities which are held. The price paid for FTRs on a secondary market does not need to be provided to AEMO. These requirements will be stated in the NER, with the potential for further details	

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		to be provided in a procedure.	

Table A.12: **Blueprint access model drafting principles - item 12**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
12	**Power System Security**		
12.1	General	As Chapter 4 of the NER does not on its face deal with the circumstances in which *generators* may bid unavailable (giving rise to the need for AEMO directions/instructions) or the inclusion of certain constraints in NEMDE, at this stage the AEMC consider only limited drafting changes will be required to this chapter.	The AEMC considers that the impacts of LMP most relevant for system security are: • Increase in the amount of capacity (due to both new connections and removal of the perverse incentive on existing generation to bid unavailable) • Reduction in the directions and instructions given by AEMO and related payments made through the intervention pricing regime (due to the LMP better reflecting the marginal cost of supply). Potential for constraints relating to system services to be incorporated in NEMDE and therefore reflected in both the LMP and FTR payout.
12.2	System strength impact assessment guidelines		The AEMC is considering in its system strength work program whether the system strength impact assessment guidelines and power system model are still fit for purpose given the type and

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			volume of new plant connecting to the grid. Note the Rule change process applies to any update of the guidelines (clause 4.6.6).
12.3	Load forecasting		If load forecasts and generation estimates will be used for the purposes of determining the quantity of FTRs that will be made available, this clause and/or the methodology for creating the forecasts (refer clause 4.9.1(d)) may need to be updated.

Table A.13: Blueprint access model drafting principles - item 13

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
13	**Retailer reliability obligation**		
13.1	References to spot prices	Amend the references to 'the *spot price* in a *region*' to 'a *spot price* in a *region*' to reflect that there will be multiple *spot prices* in a *region* (clauses 4A.E.2, 4A.E.3, and 4A.E.8).	With the introduction of locational marginal prices, there will be more than one *spot price* when congestion arises.
13.2	Adjustment of liability by losses		The AEMC is considering if the access model will affect the calculation of a *liability entity's* liable share for the purposes of the retailer reliability obligation (RRO).
13.3	MLO products		The AEMC is considering the impact of LMP on the RRO's MLO regime. On one view, there may not need to be any changes to the RRO's MLO regime. However, the AEMC is considering the extent to which, in practice, LMP may give rise to commercial issues related to: • the type and nature of derivatives that generators and retailers are willing and able to buy and sell if they are settled at different prices and the related question of how will the risk of

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
			price differences be allocated or managed if FTRs are non-firm; and • the extent to which derivative contracts must be based on individual connection points and the resultant effect of this on their fungibility and suitability for trading on an exchange.

Table A.14: **Blueprint access model drafting principles - item 14**

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
14	**Transmission planning and incentives**		
14.1	Transmission planning	The NER (likely in Chapter 5) will require TNSPs to consider FTRs in their network planning.	
14.2	Transmission incentive scheme	The TNSP service target performance incentive scheme (STPIS) will be amended to incentivise TNSPs to manage the physical capacity of the transmission system.	

Table A.15: Blueprint access model drafting principles - item 15

ITEM	CONCEPT	DRAFTING PRINCIPLES	AEMC COMMENTS, POLICY NOTES AND SPECIFIC EXAMPLES OF PROPOSED AMENDMENTS
15	**Transitional arrangements**		
15.1	Transitional provisions and grandfathering		• There will be transitional provisions and that there will be some grandfathering (including the provision of FTRs to existing generators for free). • The detail of this will be developed throughout the rule change process as further details of the model are developed. • The grandfathered FTRs will be sculpted back over time.

B INCENTIVES FOR EFFICIENT INVESTMENT

The following worked example demonstrates how the existing access regime provides incentives for inefficient locational investment decisions and how the proposed access model improves these incentives. Addressing these incentives is one of the key benefits of the reforms.

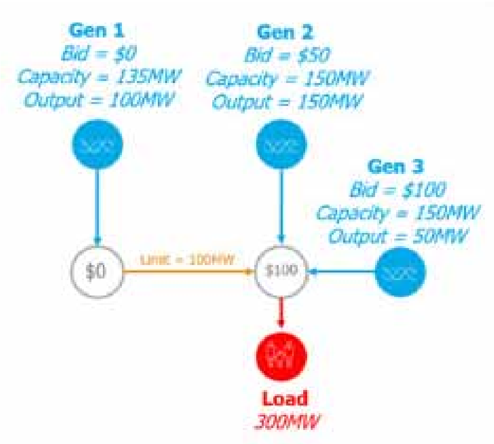
The example is highly simplified. Its purpose is to demonstrate that inefficiencies can occur under the existing arrangements which are addressed by the proposed access model. Of course, real-life examples will be more complicated.

In this example, the system before an investment is made is arranged as follows:

- Generator 1: 135MW generator is connected to the demand centre by 100MW of transmission capacity. Generator 1 bids reflective of its fuel costs at $0/MWh.
- Generator 2: 150MW generator is connected near the demand centre and bids reflective of its fuel costs at $50/MWh.
- Generator 3: 150MW generator is connected near the demand centre and bids reflective of its fuel costs) at $100/MWh.

Figure B.1 demonstrates the network configuration before an investment is made.

Figure B.1: System configuration before investment



Source: AEMC

To meet the load, the generators will be dispatched as follows:

- Generator 1: 100MW with fuel costs of $0/MWh[176]
- Generator 2: 150MW with fuel costs of $50/MWh
- Generator 3: 50MW with fuel costs of $100/MWh.

The total fuel costs are $12,500/h for the dispatch interval.

176 100MW because of the transmission capacity limit.

A wind farm investor is considering two locational options.

- Option 1: Install a 15MW wind farm in a location which is windy (with a capacity factor of 1 - (i.e. it can produce output all the time)) but is behind a constraint.
- Option 2: Install a 15MW wind turbines in a less windy location (with a capacity factor of 0.6, i.e. it only produces at 60% of its capacity) but in an unconstrained area.

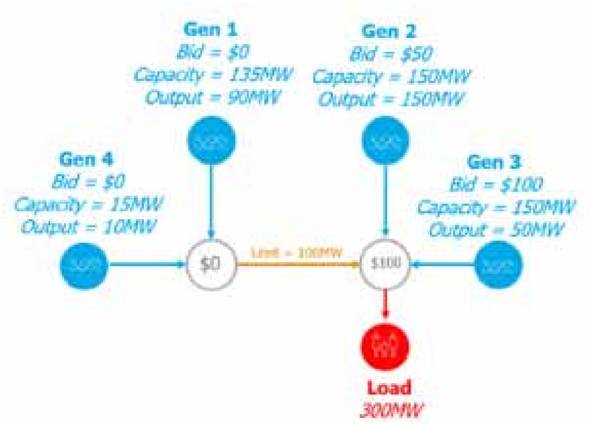
The capital cost (for example, cost of land) and any other considerations (for example, environmental approvals, land options, planning approvals) is identical for each option, for the sake of simplicity.

Option 1

Under option 1, the wind turbines have a capacity factor of 1, so generates a maximum of 15MW (assuming no transmission constraints).

Having made the investment, the system is as follows:

Figure B.2: System configuration in option 1



Source: AEMC

The generators are dispatched as follows, with generator 4 replacing 10MW of generator 1's capacity that would have been dispatched were it not for generator 4's investment:[177]

- Generator 1: 90 MW with fuel costs of $0/MWh
- Generator 2: 150 MW with fuel costs of $50/MWh
- Generator 3: 50 MW with fuel costs of $100/MWh
- Generator 4: 10 MW with fuel costs of $0/MWh.

The total fuel costs are unchanged, at $12,500/h, because generator 4's and generator 1's fuel costs are the same.

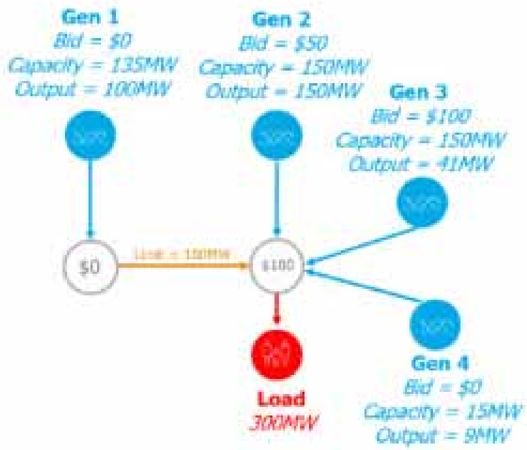
177 Generator 4 is dispatched by 10MW because generator 1 and 4 receive a share of the 100MW of transmission capacity in proportion to their generation availability (ie, two thirds of their availability each). This would occur under both the status quo arrangements (where both generators would be incentivised to bid at -$1,000) or under the proposed access reforms (where both generators would be incentivised to bid at $0) because the dispatch engine pro rates equal bids in proportion to availability.

Option 2

Under option 2, the investor would not connect behind the constraint, but instead electrically close to the demand centre. As was noted above, the area is unconstrained but not as windy.

The capacity factor of the windfarm is 0.6 and so 9MW of power is generated. The new system configuration is displayed below.

Figure B.3: **System configuration in option 2**



Source: AEMC

The generators are dispatched as follows, with generator 4 replacing 9MW of generator 3's capacity:

- Generator 1: 100 MW with fuel costs of $0/MWh
- Generator 2: 150 MW with fuel costs of $50/MWh
- Generator 3: 41 MW with fuel costs of $100/MWh
- Generator 4: 9 MW with fuel costs of $0/MWh.

Total fuel costs are $11,600/h, a reduction of $900/h. This is equal to the cost difference of generator 4 and 3 ($100/MWh) multiplied by the amount of generation 4 displaced generator 3 (9MW).

Analysis and results

Let's consider the private profit of the generators in question under each option, under both the status quo arrangements and the proposed reforms.

Results are provided in Figures B.4 and B.5, below.

Figure B.4: Change in outcomes for generators and total system costs in option 1

	Change in outcomes for generators ($/h)								Change in total system cost ($/h)
	Generator 1				Generator 4				
	Energy settle't	FTR settle't	Cost	Profit	Energy settle't	FTR settle't	Cost	Profit	
Status Quo	-1,000	NA	0	-1,000	1,000	NA	0	1,000	0
Proposed access model	-10,000	10,000	0	0	0	0	0	0	0

Source: AEMC
Note: The figures above represent the *change* in outcomes compared to without the investment, not the absolute settlement, profit and cost of the generators.

Figure B.5: Change in outcomes for generators and total system costs in option 2

	Change in outcomes for generators ($/h)								Change in total system cost ($/h)
	Generator 3				Generator 4				
	Energy settle't	FTR settle't	Cost	Profit	Energy settle't	FTR settle't	Cost	Profit	
Status Quo	-900	NA	-900	0	900	NA	0	900	900
Proposed access model	-900	0	-900	0	900	NA	0	900	900

Source: AEMC
Note: The figures above represent the *change* in outcomes compared to without the investment, not the absolute settlement, profit and cost of the generators.

Comparing figures B.4 (option 1) and B.5 (option 2) shows that under the status quo arrangements:

- it is most profitable for generator 4 to invest "behind" the constraint, even though this results in no reduction in total system costs.
- Generator 4's profit from investing behind the constraint comes at the expense of the profitability of generator 1. Generator 1's profits are reduced – demonstrating the risk inherent in the status quo arrangements to incumbent generators.

In contrast, under the proposed reforms:

- Is it most profitable for generator 4 to invest in the location which minimises total system costs. Generator 4's profits are exactly aligned with the total change in system costs under the proposed reforms, promoting efficient investment.
- Generator 4's profits from investing "in front" of the constraint are derived from the reduction in cost from generator 3, whose profits remain unchanged.

This example illustrates that the status quo arrangements send inefficient signals to generators to invest in areas of the network which are constrained, because they are able to profit at the expense of incumbent generators, while adding no or limited value to the system as a whole.

Furthermore, to the extent that generator 1 and 4 are renewables, and generator 3 is a fossil fuel generator:

- under the status quo arrangements the privately profit maximising investment has no impact on emissions (generator 4's output replaces that of generator 1)
- while under the access model, the privately profit maximising investment reduces emissions (generator 4's output replaces that of generator 3).

Let's also consider the effect of FTRs. Assume that generator 3 holds 100MW of FTRs (ie, all the FTRs available on the line). If, despite its incentives, generator 4 were to invest behind the constraint, then generator 3's revenues would be unaffected. It would continue to receive $0/MWh on the energy it produces, and continue to receive an FTR payout of $10,000/h equal to the price difference ($100/MWh) multiplied by the flow on the line (100MW). In this way, FTRs manage the risk of congestion for their holders.