Australian Energy Market Commission

REVIEW

DIRECTIONS PAPER

COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT - ACCESS REFORM

27 JUNE 2019

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 In 2016, the Council of Australian Governments (COAG) Energy Council asked the Australian Energy Market Commission (the Commission or AEMC) to undertake biennial reporting on *when* the transmission planning and investment decision-making frameworks needs to change, and *what* they need to change to. This reporting focusses on evaluating the transmission frameworks in light of current and future conditions to see if there is a case for change to better coordinate investment between the transmission and generation sectors.

2 The Commission is of the view that change is needed at the present time, so that our regulatory frameworks evolve to match the transition in the national electricity market (NEM). Transmission access reform is vital in order for the NEM to effectively evolve and transition to a lower emissions power sector, whatever this future may look like.

3 The directions paper presents our proposed approach to reforming the current access framework for transmission networks across the NEM.

The need for transmission access reform

4 The NEM is currently undergoing a significant transformation, with an unprecedented level of generators seeking to connect to the system. Proposed generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years. This has meant that limitations inherent in the existing transmission and generation frameworks have become significant and more challenging to manage.

5 Due to the current limited locational signals in the transmission framework, as well as the speed and scale of connections, investors are planning to connect their generation assets where the network has limited or no capacity for the additional generation capacity to be dispatched.

6 The Commission has heard from many **generators and investors** that the current transmission access framework is no longer 'fit for purpose'. In light of the electricity market transition, prospective generators require greater certainty that their assets will remain profitable even if subsequent parties connect to the network and congestion arises. This is being reflected in the debate around the significant changes in annual marginal loss factors that are currently being experienced.

7 In other cases, the issues are less visible, but no less important. The need for efficient coordination of generation and transmission investment is crucial given the large amount of investment required to facilitate the sector's transition. This is heightened by the fact that consumers bear the majority of transmission investment risk in the current framework, so are shouldered with unnecessary costs if transmission lines become 'roads to nowhere'. **Consumers'** current concerns about projected costs and increased bills brings these issues into stark relief.

8 In addition, **network businesses** have voiced their concerns about changes to their rate of return, as well as uncertainty being created by the suggestion of asset write-downs. Network businesses are also being overwhelmed by the scale of connection enquiries, and both

networks and generators face challenges with the coordination required for the current 'do no harm' framework for system strength.

9 While these issues may, at first glance, appear unrelated, they are symptomatic of the current market design. The existing transmission access regime, where all generation and load is settled on a region-wide price for its physical output or consumption (net of losses), was a central design choice in establishing the NEM.

10 This market design choice abstracted away from the technical and economic realities of the system. When constraints arise on the transmission network within a region, the underlying cost of an additional unit of electricity differs from location to location. Numerous issues relating to the operational and investment incentives of generators, and how generators and transmission networks coordinate, arise because the region-wide price does not reflect this reality. Therefore, the original NEM design choice reflected a compromise between reflecting the underlying realities of the system and the benefits of a simple unified price model.

11 In the past, the problems of the existing access regime have tended to be modest, and so the cost of change has outweighed the benefits. In an environment of relatively low levels of generation and transmission investment, the benefits of improved investment efficiency and coordination are necessarily relatively low. Such an environment also means that transmission risks faced by generators are relatively predictable and stable. For the reasons outlined above, this is no longer the environment that the NEM finds itself in. Therefore, different design choices and trade-offs better suited to the current environment must be made.

12 The Commission is of the view that change is needed at the present time in order to facilitate the energy transition. Access reform would allow generators to receive greater financial certainty regarding their generation investment, in exchange for bearing a portion of the costs of transmission investment that are currently borne by consumers. In turn, this should facilitate better transmission and generation planning, investment and operations, making it easier for the NEM to transition towards a lower emissions' environment.

Our proposal for access reform

13 The Commission's proposed reform to the access regime is a holistic long-term solution to many of the issues raised by market participants, consumer groups and market bodies. It involves changing three inter-related aspects of the current transmission access framework.

14 The reform allows generators to receive greater financial certainty regarding their generation investment, in exchange for bearing a portion of the costs of transmission investment that are currently borne by consumers. In turn, this should facilitate better transmission and generation planning, operations and investment, making it easier for the NEM to transition towards a lower emissions' environment.

15 The first aspect of reform relates to the **wholesale electricity prices** that generators are settled at. Under the current framework, generators receive the regional reference price for each megawatt hour of electricity they are able to dispatch to market, regardless of where they locate in a region. We are proposing to change these arrangements so that generators

receive a dynamic regional price that more accurately represents the marginal cost of supplying electricity at their location in the network.

16 The second aspect of reform aims to improve the **financial risk management options** for market participants. Under current arrangements, a generator's ability to receive the regional reference price and earn revenue is a direction function of its physical dispatch. We are therefore proposing to enable generators to better manage the risks of congestion by enabling them to purchase transmission hedges. These products will hedge against the price differences that may arise under our proposed changes to wholesale electricity prices, allowing generators to rely on a particular revenue flow, regardless of other generator's locational decisions. This should improve investment certainty for prospective generators and may reduce the cost of capital for generation investment in the longer term.

17 The third and final aspect of reform relates to **transmission planning and operation**. Under the current regime, the fact that transmission network and generation investment decisions occur under different processes has the potential to result in infrastructure that does not minimise the total system costs faced by consumers. Additionally, no individual generator is able to guarantee that they will receive value from shared network assets, even if the generator itself underwrites the investment in the asset. This creates a free-rider problem. As a consequence of these two factors, consumers bear the risks of transmission investment decisions being incorrect, and so, bear most of the costs related to transmission network investment and maintenance. We are proposing to change this so that transmission planning is informed by generator's purchase of transmission hedges.

18 This will mean that transmission costs will be no longer solely recovered from consumers. A portion of these costs would instead be collected from generators through the purchase of transmission hedging products. This is possible because transmission hedges will be backed by physical transmission capacity, and set at a price that reflects the underlying cost of the provision of the transmission infrastructure required to back them. The option to purchase a hedging product will therefore make the cost of transmission part of a generator's investment decision. The investor should seek a location for a power station which minimises the combination of its operating and establishment costs and the cost of transmission. By doing this, transmission hedging should achieve a higher degree of co-optimisation of transmission and generation investment than under the current regulated approach to transmission planning.

19 The model the Commission is proposing shares considerable similarities with common electricity market designs elsewhere, particularly in the US and New Zealand. The underlying rationale for the designs elsewhere are the same as those outlined above: a desire to provide appropriate, location specific price signals for generation and transmission network service providers and to reduce the investment risk placed on consumers. However, the Commission's proposed design reflects the unique features of the NEM, including the fact that it is a relatively, long, stringy network.

20 In response to stakeholder feedback, this paper provides considerable detail on the wholesale electricity pricing aspect of our proposed reforms. While relatively little detail is provided on the transmission hedging, planning and operational aspects at this point in time, we intend to

continue to develop these parts of the access framework in the coming months in consultation with stakeholders, ahead of our draft report this September.

Our approach to access reform

21 The Commission understands that a large-scale and holistic reform of this nature introduces some amount of transitional uncertainty into the electricity market. The Commission considers that stable regulatory arrangements that evolve transparently are vital in order to ensure that the generation and transmission investment needed to support the transition of the electricity system materialises.

22 However, given the scale of generation that is forecast to connect to system in the coming years, and the transmission investment that is forecast to be required, it is also important to make sure that generation and transmission investment is as coordinated and efficient as possible. This coordination is for the long-term benefit of both industry and consumers, as it should manifest in the form of increased revenue certainty for generators as well as lower system costs for consumers.

23 Any regulated sector is, by definition, subject to change as the regulations and frameworks adapt over time to reflect learnings and changes within the industry. This is especially true during times of significant transition within a particular sector. The Commission recognises that regulatory stability occurs in a transparent manner where stakeholders have a clear understanding of how and when change occurs; and on what basis. This is something that the Commission is concious of in working through these proposed reforms.

24 To balance the need for stable regulatory arrangements that evolve transparently against the longer term benefits to industry and consumers of reform, the Commission intends to proceed with transmission access reform in a consultative yet expeditious manner. This review will undertake detailed design and testing of an access model that pairs transmission hedging with dynamic regional pricing, including developing proposed changes to the rules that are required. This will allow stakeholders clarity over our proposed access model, and a clear reform trajectory that will provide sufficient time for the model to be implemented and for participants to adapt.

Renewable energy zones

25 Renewable energy zones are also a continued focus for the Commission. We consider that renewable energy zones can enhance coordination *between* generators in order to achieve efficiencies of scale and scope with regard to procuring and using connection assets.

26 The Commission considers that renewable energy zones can be used as a transitional measure before a full access model is implemented. Therefore, ways to facilitate renewable energy zones by changing the regulatory framework should reflect simple and easy changes. We explore two ways in which they can be facilitated: through increasing coordination *between* generators, or by allowing the risks of constructing renewable energy zones to be *shared* between multiple parties.

27 It is important to note that renewable energy zones can necessarily only be transitional. This

is because, without access reform, there is no way to stop other generators locating at the entrance of a renewable energy zone and constraining off generators within the zone. Moreover, given trends in the network, it is likely that renewable energy zones will become looped and more meshed in the network over time, further diminishing their ability to be stand-alone connection assets. However, renewable energy zones can be used as an interim measure to facilitate access reform.

Implementation

28 The Commission proposes to implement dynamic regional pricing and transmission hedging concurrently in July 2022. This represents a change from the proposed implementation timing outlined in our consultation paper, and is in recognition of stakeholder feedback on this issue. Stakeholders considered that more benefits would arise from aligning the implementation of local pricing and transmission hedging, since the ability to purchase transmission hedges enables generators to manage the risks of local prices that diverge from the regional reference price when transmission congestion occurs.

29 The Commission agrees. We consider substantial benefits may accrue from aligning the implementation of local pricing and transmission hedging. Alignment may lower the costs of implementation by removing the need to design and implement bespoke settlement arrangements for a dynamic regional pricing regime without hedging. In addition, it could promote greater financial certainty amongst market participants by allowing them to hedge the basis risks of local prices.

30 Transmission access reform is needed sooner rather than later for the NEM to effectively evolve. Access reform is integrally linked with the key issues facing the market, which are affecting all types of market participants. The Commission agrees with the view expressed by the Australian Energy Market Operator (AEMO) that four years is too long to wait to resolve the challenges facing the NEM. This is why we have proposed a date of July 2022 for implementation of the new access regime.

31 However, we are also concious that transitional processes will be necessary to make sure that the introduction of access reform does not create sudden changes in the market, and to provide for a learning period. Access reform will have winners and losers, and so transitional arrangements - both in terms of timeframes of introduction and grandfathered rights - will be important to manage this effectively.

Stakeholder consultation

32 The Commission is holding a public forum on this directions paper on 8 July 2019 in Melbourne. Stakeholders should register via the Commission's website.

33 The Commission invites comments from interested parties in response to this directions paper by 2 August 2019. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

34 We would also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Jess Boddington on (02) 8296 0626 or at

jess.boddington@aemc.gov.au.

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1 INTRODUCTION

1.1 Terms of reference

In 2016, the Council of Australian Governments (COAG) Energy Council asked the Australian Energy Market Commission to implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. The standing terms of reference for this reporting were received from the COAG Energy Council in February 2016 under section 41 of the National Electricity Law (NEL).[1]

The rationale for this work was to help governments and industry participants consider when net benefits would be derived from adopting a transmission framework that would provide for better coordination of investment between the transmission and generation sectors, and what changes would be necessary to achieve this.

The inaugural *Coordination of generation and transmission investment review* (COGATI) commenced in early 2017, and concluded with its final report being published in December 2018 (inaugural COGATI report).[2] Given that the AEMC is to report biennially, the second COGATI review commenced on 1 March 2019 with the publication of a consultation paper.[3] This is the subject of this review.

1.2 Purpose and scope of this review

This COGATI review seeks to develop the necessary regulatory reforms to implement the recommended approach to access and charging reform as outlined in the inaugural COGATI report. The review is considering reforms to the way generators access and use the transmission network, as well as a review of the charging arrangements which enable transmission network service providers (TNSPs) to recover the costs of building and maintaining transmission infrastructure, both within and between regions.

The inaugural COGATI review recommended a comprehensive reform package in order to improve the planning, access, charging, connection and economic regulation elements of the transmission framework. This reform package will be progressed through the three separate work streams illustrated in Figure 1.1:

- this COGATI review will progress the Commission’s recommendations for reform to the current access and charging regimes
- the Energy Security Board (ESB) is progressing the work to action the Integrated System Plan (ISP), and published a consultation paper on this on 17 May 2019[4]

1 The terms of reference are available from the AEMC website at https://www.aemc.gov.au/sites/default/files/content/97164a7b09bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

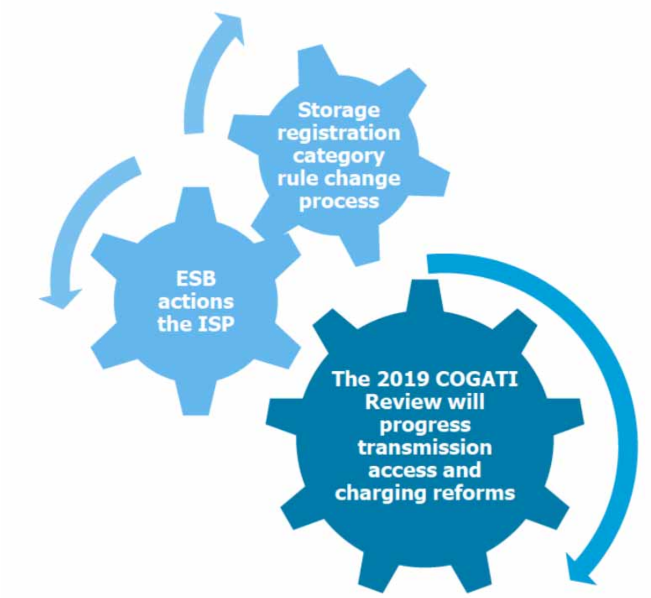
2 The final report is available from the AEMC website at https://www.aemc.gov.au/sites/default/files/2018-12/Final%20report_0.pdf

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

4 See: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/CONVERTING%20THE%20INTEGRATED%20SYSTEM%20PLAN%20INTO%20ACTION.pdf

- The Australian Energy Market Operator (AEMO) is developing a rule change request to submit to the AEMC to create a separate storage registration category. We expect this to be submitted shortly.

Figure 1.1: Progressing the COGATI 2018 recommendations through separate work streams



The key output for this review is for the Commission to provide the COAG Energy Council with proposed changes to the rules to reform the transmission access regime in December 2019. The proposed reforms include the implementation of dynamic regional pricing and transmission hedges. We anticipate that these proposed changes to the rules will then be submitted to the Commission as rule change requests in early 2020 in order to implement the changes.

Throughout the review process this year, there will be multiple opportunities for stakeholder consultation on the issues raised by the Commission's recommendations as proposed changes to the rules are developed. In addition, there will also be opportunities for further stakeholder engagement next year when the Commission assesses the reforms through any submitted rule change requests.

Given the majority of the feedback from submissions suggested that access reform should be progressed as a priority, the Commission will progress its work on that basis. That is, we will prioritise access reform ahead of considering charging reform. Given access reform involves generators paying for part of the transmission network it makes sense for this to be further developed before considering charging reform.

We understand that the issue of charging is of particular importance to Tasmanian stakeholders, given Project Marinus,[5] and so we are working closely with those stakeholders in order to better understand their concerns.

BOX 1: REVIEW TERMINOLOGY

As part of a more detailed discussion of the proposed access reforms, this directions paper uses slightly different terminology from previous papers to more clearly reflect the nature of the proposed reforms.

- **Local or locational marginal prices (LMP)** are referred to in this directions paper rather than **dynamic regional prices**. Both concepts refer to the price that *generators* would obtain without purchasing transmission hedges under dynamic regional pricing, instead of the regional reference price. However, the concept of locational marginal prices emphasises the fact that this price is the efficient cost of supplying an additional unit of load at the generator's local node.
- **Transmission hedges** are discussed rather than **firm access rights**. This is to more clearly indicate that the second component of these proposed COGATI reforms would provide generators with a tool they can use to manage congestion risk by financially hedging between their LMP and the regional reference price. It also avoids any confusion about what type of access may be given – these reforms do not propose to provide firm physical access to generators, but instead to allow generators to purchase a transmission hedge and receive financial payouts under this hedge. Transmission hedges are also commonly referred to as financial transmission rights (FTRs), particularly in the US.
- **Financial payout** or **financial returns under the transmission hedge** are discussed rather than **compensation payments.** Under the proposed reforms, there is no question of "compensation" relative to the RRP because generators are dispatched *and priced* with reference to the LMP. Instead, generators that purchase transmission hedges would receive financial payouts based on these hedges, regardless of whether these generators are dispatched or not.

1.3 Purpose of the directions paper

This paper builds on the consultation paper that was published on 1 March 2019 and the supplementary information paper that was published on 4 April 2019. The directions paper responds to stakeholder feedback received on the consultation paper and provides further detail on the proposed access reforms.

The detail presented in this directions paper will help stakeholders to consider and work through some of the potential impacts that the reform may have on their operational and investment decisions.

5 Project Marinus is investigating the case for further Bass Straight interconnection as part of Australia's future electricity grid. The project is being undertaken by TasNetworks and is considering a new interconnector, known as Marinus Link, to operate in addition to the existing privately-owned Basslink interconnector. See: https://projectmarinus.tasnetworks.com.au/

The directions paper also contains a discussion of implementation and transition issues.

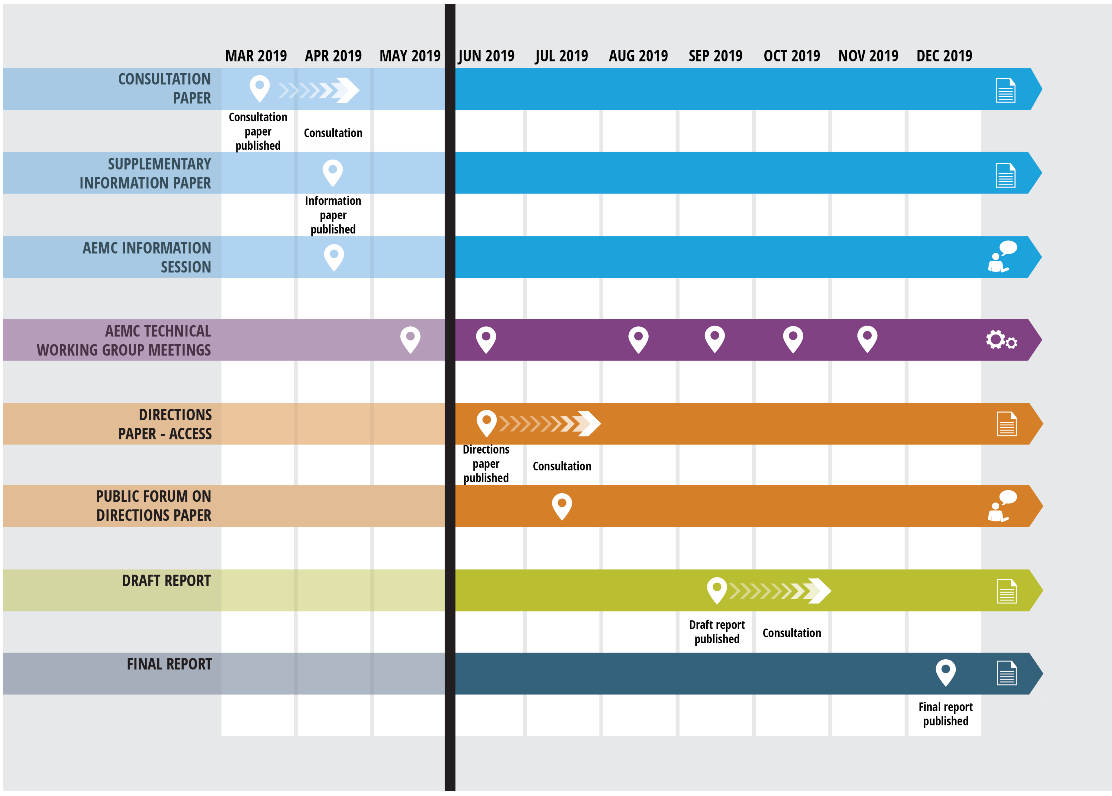
We are seeking stakeholder feedback on the matters raised within this paper.

1.4 Review timeline

Figure 1.2 shows a timeline that sets out the next steps for the second COGATI review during 2019, the consultation proposed and how stakeholders can be involved.

Through our second COGATI review, the Commission will develop the proposed reforms to implement access reform, including proposed changes to the rules. It is expected that the COAG Energy Council will submit rule changes for the reforms back to the AEMC in early 2020.

Figure 1.2: COGATI reform indicative timeline



A public forum on access reform will be held on 8 July in Melbourne. In late September, a draft report will be published, ahead of a final report in December.

1.5 Stakeholder consultation

1.5.1 Consultation paper

The Commission received a significant number of submissions to the consultation paper from a wide range of stakeholders. There was a general view from stakeholders that, given the transitioning power system, there is a need to explore changes to the transmission access framework. However, stakeholders differed on what the appropriate form of reform should be. This is consistent with the fact that such a reform will create winners and losers.

Many stakeholders supported a reconsideration of whether generators should be able to pay for transmission hedges. Some stakeholders suggested that further quantitative analysis may be required to test the AEMC's proposed approach and alternative firm access models. Stakeholders also suggested a range of options should be considered, not just those proposed in the consultation paper.

Stakeholders engaged much less on charging reforms than on access reforms. Around half of the stakeholder submissions did not discuss charging reforms at all. Stakeholders that did comment on this generally considered that any review of the charging arrangement should occur after reforms to access are further articulated.

In addition, a number of stakeholders commented on the potential overlap and interaction between this work and the Energy Security Board's post 2025 work that we had identified in the consultation paper. There was general agreement that it would be important for the AEMC to continue to work closely with the ESB on these issues.

1.5.2 Technical working group

A technical working group has been established to provide technical advice, and to assist the AEMC with the development of recommendations for this Review. This group comprises representatives from the market bodies, the ESB, transmission network businesses, generators and consumer groups to provide input into the proposed reforms and to help develop proposed changes to the rules that are needed to support the reforms.

The technical working group has met twice, in:

- May 2019, with the discussion focussing on the case for reform, access reform models and renewable energy zones
- June 2019, with the discussion focussing on dynamic regional pricing and the implementation of access reform.

Minutes from the two technical working group meetings can be found on our website. Comments and feedback from the technical working group have been incorporated into this report.

1.6 Related work

1.6.1 Transmission loss factors

Adani Renewables submitted two rule change requests relating to the transmission loss factors framework in the National Electricity Market (NEM):

- On 27 November 2018, Adani Renewables submitted a rule change request seeking to redistribute the allocation of the intra-regional settlement residue that arises due to losses on the network so it applies equally between generators and networks users.

- On 5 February 2019, Adani Renewables submitted a rule change request seeking to change the marginal loss factor (MLF) calculation methodology to an average loss factor methodology.

The AEMC initiated and consolidated these rule change requests on 6 June 2019 to enable consideration of the broader issues around how the transmission loss factor framework can continue to send the most appropriate signals to investors in the face of power system reform.

The COGATI review's scope is focused on a more holistic solution to making investment decisions for the electricity transmission and generator sectors through access reforms. Any reforms to the current access and charging arrangements for the transmission system could have implications for the appropriate approach to calculating MLFs.

For example, in markets elsewhere where there are locational marginal prices, MLFs are typically calculated dynamically at each location in real time. Therefore, the Commission will consider the interactions between Adani Renewable's rule change requests and the COGATI review through the rule change process.

Given the broader scope of the COGATI review, the rule change request is focussed on the transmission loss factor framework in the context of concerns being raised about it today.

1.6.2 Transparency of new projects

The Commission is also considering a rule change request which consolidated three separate rule change requests from AEMO, the Australian Energy Council and Energy Networks Australia, which seek to increase transparency of new generators connecting to the transmission network.

These rule changes come as significant changes occur in the NEM with the increasing penetration of renewable generation (such as wind and solar) being a key trend. TNSPs are receiving an unprecedented volume of generation connection enquiries, amounting to 50 GW of proposed (mainly renewable) projects in various stages of development, which is roughly equivalent to the current capacity in the NEM.[6]

The three rule change requests received relate to transparency of new projects in the NEM:

- On 15 December 2018, the Australian Energy Council submitted a rule change request to the Commission seeking to improve information provision in the NEM. There are four key elements in this request: codifying AEMO's generation information page in the National Electricity Rules (NER); imposing a requirement on intending participants to notify AEMO of any change to the information they provided during the intending participant registration process (for example, when the nature of their project changes); broad reforms to the intending participant category (for example, requiring new project developers to register as an intending participant), consistent with the proposals made by AEMO; and changes to assist AEMO in disclosing confidential information, where that information has subsequently reached the public domain.

6 AEMO, *Electricity statement of opportunities*, September 2018.

- On 31 December 2018, AEMO submitted a rule change request to allow a developer to register as an intending participant for the purposes of building a grid-scale generating system or an industrial development (e.g. a load), despite such a person never intending to register as market participant.
- On 15 March 2019, Energy Networks Australia submitted a rule change request to explicitly allow TNSPs to publish certain information (including proponent name, size, location, estimated completion date, primary technology and broad function) they have received from connection applicants regarding new and proposed connections.

The Commission consolidated these three rule change requests to best address the overlapping issues and facilitate efficient stakeholder engagement. A consultation paper was published on 18 April 2019.

The Commission will have regard to the progression of this rule change as it progresses its work on COGATI. Increased transparency could facilitate better coordination of generation and transmission, and, particularly increased coordination between generation and other generation.

1.6.3 The ESB's post-2025 work

The ESB is developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. By the end of 2020, the ESB needs to:

- recommend any changes to the existing market design, or
- recommend an alternative market design.

These recommendations will be made in order to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions' electricity system at least-cost. Any changes to the existing design or recommendation to adopt a new market design would need to satisfy the National Electricity Objective.

As a member organisation of the ESB, the AEMC is contributing to and assisting with this work.

The ESB notes that significant changes to the electricity market design would need to be well-considered, including substantial input from stakeholders and detailed consideration of alternative market designs, and conveyed well in advance of any change to ensure there is minimal disruption to the forward contract markets for electricity.

The ESB also notes that if changes are required to deliver a long-term, fit-for-purpose market framework by the mid-2020s, then consideration of any required changes should be concluded by the end of 2020 to enable sufficient time for the market to transition to the new market framework.

1.6.4 The ESB's actioning the ISP work

The ESB is also progressing its work on converting the integrated system plan into action.

In May 2019, the ESB released a consultation paper that seeks stakeholder input on governance of the ISP process, the Australian Energy Regulator's (AER's) revenue approval process, dispute resolution procedures and how the ISP and the Regulatory investment test for transmission (RIT-T) interface with and fit together with the rest of the planning and economic regulatory framework.

Following consideration of submissions made to the consultation paper, the ESB will finalise the detailed policy design and present it to the COAG Energy Council for determination at its mid 2019 meeting. Thereafter, the ESB will consult on the NER (and potentially NEL) legal drafting with a view to implementing the revised framework by the end of the year.

The Commission is assisting the ESB with this work. Further, the Commission notes that in its Integrated System Plan; Action Plan report,[7] the ESB identified the importance of access reform and noted that it will report back to the COAG Energy Council by December 2019 on its views on congestion and access reform.

The Commission is working closely with the ESB on these issues in order to make sure that a coordinated and cohesive plan is being developed.

1.7 Submissions

Written submissions on this directions paper must be lodged with the Commission by 2 August 2019 online via the Commission's website, www.aemc.gov.au, using the 'lodge a submission' function and selecting the project reference code EPR0073.

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

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

All enquiries on this project should be addressed to Jess Boddington on (02) 8296 0626 or at jess.boddington@aemc.gov.au.

1.8 Public forum

The AEMC will hold a public forum in Melbourne on 8 July 2019 to provide an opportunity for stakeholder discussion on the transmission access reforms proposed in this directions paper.

Interested participants should register for this event online.

1.9 Structure of the report

The remainder of the paper is structured as follows:

- Chapter 2 sets out the rationale for why transmission access reform is needed
- Chapter 3 presents the Commission's proposed plan for access reform and discusses why alternative reform models could not address the challenges that the NEM is currently facing

7 See: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/isp%20action%20plan.pdf

- Chapter 4 discusses dynamic regional pricing as one of the main components of access reform, including its design features and impact issues
- Chapter 5 discusses provisioning of transmission hedges as the other main component of access reform, including its design features
- Chapter 6 discusses the relevance of renewable energy zones to access reform, including how they might be useful as a transitional measure for transmission hedges
- Chapter 7 discusses implementation and transitional arrangements.
- Appendix A sets out our assessment framework.
- Appendix B presents worked examples of how dynamic regional pricing will operate.
- Appendix Cpresents more detail on how dynamic regional pricing could operate.

2 THE NEED FOR TRANSMISSION ACCESS REFORM

The NEM is currently undergoing a significant transformation, with an unforeseen level of generators seeking to connect to the network. Proposed generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years.[8] This means that limitations inherent in the existing transmission and generation frameworks have become significant and more challenging to manage.

Due to the current lack of locational signals in the transmission framework, as well as the speed and scale of connections, private sector investors are planning to place their generation assets where the network has limited or no capacity for the additional generation capacity to be dispatched. This occurs because transmission and generation investments occur under different processes, that now need to be better coordinated.

Generators and investors are concerned that the current framework is no longer suitable not only for the current environment, but for a variety of futures for a lower emissions' energy power sector. In light of the electricity market transition, prospective generators require greater certainty that their assets will remain profitable even if subsequent parties connect to the network and create congestion. This is being reflected in the debate around the significant changes in annual marginal loss factors that are currently being experienced.

In the current climate, it is also clear that **consumers** have concerns about projected costs and increased bills in order to pay for the new transmission necessary for the transition. This is heightened by the fact that consumers bear the majority of transmission investment risk in the current framework, so are shouldered with unnecessary costs if transmission lines become 'roads to nowhere'.

In addition, **network businesses** have voiced their concerns about changes to their rate of return, as well as uncertainty being created by the suggestion of asset write-downs. Network businesses are also being overwhelmed by the scale of connection enquiries being lodged by prospective generators.

While these issues may at first glance, appear unrelated, they are symptomatic of the current market design. The original NEM design choice reflected a compromise between reflecting the underlying realities of the system and the benefits of a simple unified price model.

In the past, the problems of the existing access regime have tended to relatively be modest, and so the cost of change has outweighed the benefits. In an environment of relatively low levels of generation and transmission investment, the benefits of improved investment efficiency and coordination are necessarily relatively low. Such an environment also means that transmission risks faced by generators are relatively predictable and stable. For the reasons outlined above, this is no longer the environment that the NEM finds itself in. Therefore, different design choices and trade-offs that suit the current environment must be made.

8 AEMO, *2018 Electricity Statement of Opportunities*, August 2018.

Transmission access reform is vital in order for the national electricity market (NEM) to effectively evolve and transition to a lower emissions power sector, whatever this future may look like.

The Commission's proposed reform to the access regime is a holistic long-term solution to issues raised by market participants, consumer groups, and observed and foreshadowed by the AEMC and other market bodies. It would promote efficiency in investment and operations in generation through more granular, location specific prices which better reflect the underlying cost of electricity.

The reform allows generators to receive greater financial certainty regarding their generation investment, in exchange for bearing a portion of the costs of transmission investment that are currently borne by consumers. In turn, this should facilitate better transmission and generation planning, operations and investment, making it easier for the NEM to transition towards a lower emissions' environment.

The Commission considers that stable regulatory arrangements that evolve transparently are vital in order to make sure that the generation and transmission investment needed to support the transition of the electricity system materialises. However, given the scale of generation that is forecast to connect to system in the coming years, and the transmission investment required to facilitate the transition, it is also important to have generation and transmission investment that is as coordinated and efficient as possible. This coordination is for the long-term benefit of both industry and consumers, as it should manifest in the form of increased revenue certainty for generators as well as lower system costs for consumers.

In its *Integrated System Plan; Action Plan report*,[9] the Energy Security Board (ESB) identified the need for urgent access reform:

> Recommendation 12: The ESB recommends that as part of their work they report back to the COAG Energy Council in 2019 on the REZ connections, access and congestion - and options for addressing them.

As noted in the recent ESB consultation paper on actioning the Integrated System Plan (ISP),[10] the ESB's advice will be provided in December 2019 following the *COGATI - access and charging* market review.

The remaining part of this chapter sets out the need for access reform by providing an overview of:

- the history of reform initiatives
- how the existing access regime is contributing to a diverse range of issues in the sector
- the Commission's proposal for holistic access reform
- how this proposal will address the issues identified.

9 For more information, see http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/isp%20action%20plan.pdf

10 See: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/CONVERTING%20THE%20INTEGRATED%20SYSTEM%20PLAN%20INTO%20ACTION.pdf

2.1 History of reform

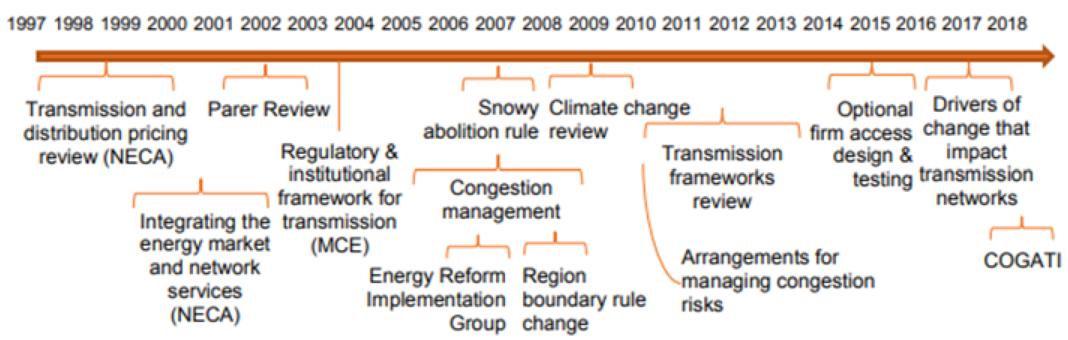
A foundational principle of the NEM when it was created was that decisions to invest in generation capacity are made by businesses operating in a competitive environment, rather than by vertically integrated monopolies. Investment in generation assets is market-driven and takes account of expectations of future demand, the location of energy sources, access to land and water and access to transmission. The result is that risks associated with generation investment rest with those businesses.

In contrast, transmission investment decisions remain the responsibility of regional, transmission network businesses, with these guided by AEMO's Integrated System Plan.[11] Transmission businesses are subject to incentive-based economic regulation of their revenues for the provision of transmission services, as well as various other obligations relating to reliability, safety and investment decision-making processes.

Generation and transmission are both complements and substitutes. They are part of an integrated system. This implies that investment and operational decisions by generators and transmission bodies should work together to achieve overall efficient outcomes. The way that transmission and generation investment decision-making processes interact, and in particular, their operational consequences, have been the subject of ongoing discussion since before the establishment of the NEM in 1998.

Since 1997, there have been fourteen major reports and reviews dealing with various aspects of congestion management and generation access, including nine projects undertaken by the Commission in addition to this COGATI review. The Commission has been the primary body leading this work since our establishment in 2005.

Figure 2.1: History of reform



Source: AEMO submission to the *COGATI - access and charging* review consultation paper.

Two of the most recent projects where the Commission has considered access reform include the:

11 The exception is Victoria where decisions to augment the transmission network are made by the Australian Energy Market Operator (AEMO).

- **Transmission Frameworks Review:** In 2013, the Commission released a final report for the Transmission Frameworks Review.[12] This report recommended both short-term and long-term reforms to facilitate coordination between generation and transmission investment. The longer-term reform model recommended was Optional Firm Access.
- **Optional firm access detailed design and testing:** In 2015, the Commission undertook detailed design and testing of the optional firm access model at the COAG Energy Council's request.[13] At the time, the Commission concluded that the implementation of optional firm access would not contribute to achievement of the National Electricity Objective. However, it noted that the model may be well suited to a future environment where there is a need for additional generation and transmission investment and the location and type of investment is highly uncertain.

In 2016, the COAG Energy Council asked us to report biennially on a series of drivers that could impact on future transmission and generation investment (the COGATI reviews). A key objective of the COGATI terms of reference is to consider, on a biennial basis, whether the timing is right for access reform. In light of emerging and likely future changes to the Australian electricity market, the Commission considers that reform is required now to address issues in the existing regime.

2.2 Issues arising from the current access regime

Under the existing transmission access regime, all generation and load, regardless of its location in a region, is settled on a region-wide price for its physical output or consumption.[14]

This region-wide price is called the 'regional reference price'. When the physical output of a generator is reduced - for example, due to the presence of a transmission constraint that results in it not being dispatched- its revenue is similarly reduced. This is because revenue is simply a function of the regional reference price and the volume of electricity that is physically dispatched.

While this approach is relatively simple, it also abstracts away from the technical and economic realities of the system. When constraints arise on the transmission network within a region, the underlying cost of an additional unit of generation (known as the 'locational marginal cost' of generation) differs from location to location. The marginal cost of an additional unit of generation tends to be relatively low in areas which have an abundance of generation versus load, and limited ability for generation to flow to other areas of the network.

Similarly, the marginal cost of an additional unit of generation is relatively high in areas where the opposite is the case: there is a scarcity of generation and limited ability for generation elsewhere to meet demand due to transmission congestion.

Numerous issues that, at first glance, may appear unrelated are actually symptomatic of the difference between the locationally specific *cost* of an additional unit generation and its

12 For more information, see https://www.aemc.gov.au/markets-reviews-advice/transmission-frameworks-review.

13 For more information, see https://www.aemc.gov.au/markets-reviews-advice/optional-firm-access%2C-design-and-testing.

14 Net of transmission losses.

region-wide *price.* Furthermore, because prices for electricity are not locationally specific, the *difference* in cost between locations (and hence the value of transmission capacity) is not explicit. Efficiency is promoted when prices reflect the marginal cost of the provision of a particular product or service. This is not currently the case. These issues are explored below.

2.2.1 Incentives to coordinate generation and transmission investment

Due to the current lack of locational price signals in the transmission framework, investors often locate their generation assets where the network has limited or no capacity for the additional generation capacity to be dispatched.

For example, a generator may choose a location optimal for fuel resources but which has poor levels of existing transmission capacity. While the generator faces the risk that its output is less than would otherwise be the case due to the likelihood that transmission congestion will arise, these signals are not explicit through the price it receives for its generation, and so are unlikely to be efficient.

Current locational signals such as transmission losses, congestion and inter-regional price variation do provide a degree of incentive for efficient generator location. However, these signals are incomplete and imprecise. Further, having made a locational decision, a generator is not readily able to manage the risks arising from transmission losses, congestion, and to a lesser extent, inter-regional price variation. This is particularly true of marginal loss factors. While we understand that historically investors have sought to forecast marginal loss factors, this is becoming harder given the current scale of generator connections, as well as the fact that these connections are typically at the outer edges of the grid.

Another issue under the current framework arises even when generators choose to connect where there is relatively good access to the transmission network and little current congestion. Under the current access frameworks, there is nothing to stop a subsequent generator connecting beside it and effectively constraining off that first generator, undermining its ability to earn revenue from the wholesale market and so its business case. When generators decide to locate in a congested area, the broader system benefits that result from the additional generation investment are also undermined.

2.2.2 Incentives for efficient generation and transmission investment

The current connection regime requires generators to pay for assets which enable them to connect to the shared network. However, shared transmission network assets are typically funded directly by consumers through transmission use of system (TUOS) charges. While generators are able to fund the construction of shared assets to minimise or eliminate transmission congestion, they have substantial incentives not to do so due to the existing regime.

Under the current framework, no individual generator has preferential access[15] to a shared network asset, even if the generator underwrote the transmission asset's construction. This is

15 In this context, preferential access means financial access to the regional reference price, which is gained through physical dispatch.

because access is determined by AEMO's national electricity market dispatch engine (NEMDE). This tension creates a free-rider problem. Each individual generator would prefer for other generators to underwrite transmission investment, to avoid the cost of doing so while enjoying the benefits that the transmission infrastructure provides to all generators.

This disconnect, as well as the fact that transmission and generation investment occurs under different processes, has the potential to lead to higher system-wide costs because generation and transmission are at times compliments and substitutes for one another. A generator may connect in a fuel rich area which in turn enhances the investment case for a transmission upgrade, even if the lowest overall cost solution was to invest in a less fuel rich area with better transmission infrastructure. Alternatively, a transmission network service provider (TNSP) may develop transmission assets whose timing (too early or too late), size (too big or too small) or location was inefficient. This flows through to impact consumers.

Of course, inefficient investment decisions could arise in any access regime. However, under the current arrangements, consumers, rather than market participants, bear much of the risk of transmission investment decisions being wrong. Investment decisions will be wrong when supply or demand factors are different to what was projected at the time the transmission infrastructure was built. If not enough transmission infrastructure is built, consumers may face higher costs associated with not having a reliable transmission network, as well as higher wholesale prices from costlier generation dispatch. If too much transmission infrastructure is built, consumers will be facing the cost of assets that may not have been required.

Consumers also face the risk of supply-side changes (for example, changes in marginal loss factors) rendering generating plants uncompetitive. These risks may manifest in the form of higher than necessary market prices as a result of reduced generation capacity. Under the current framework, this risk is exacerbated by the lack of locational signals for generation investment.

Specifically, consumers bear the primary cost of transmission network investment and maintenance by paying the TUOS charges component of their retail bill.[16] To minimise the risk of inefficient expenditure, Regulatory Investment Tests for Transmission (RIT-Ts) are used to assess the appropriateness of investments, and consumers only pay TUOS consistent with the AER's regulatory determination process.

In addition, system security is becoming a more important consideration for investment. For example, system strength in some parts of the power system has been decreasing as conventional synchronous generators are operating less or being decommissioned. This can mean that system strength is not sufficiently high to keep the remaining generators stable and connected to the power system following a major disturbance. The relative stability of the power system can also reduce when additional non-synchronous generators connect to the network.

16 The Australian Energy Regulator sets the maximum allowable revenue that TNSPs can earn from TUOS charges in each regulatory period, which is set to cover an efficient level of transmission investment and operating costs.

In 2017, the Commission made a rule that, amongst other things, requires new connecting generators to 'do no harm' to the security of the power system. The high volumes of connections we are seeing can mean a lot of little synchronous condensers being built for the purposes of system strength remediation. Multiple synchronous condensers are being built by multiple connecting generators, resulting in a potential degree of overbuild or cost inefficiency; that is, it may be more efficient for one larger synchronous generator to be built and its fault current to be "shared" between generators. Better coordination of generation and transmission investment could help resolve these issues.

2.2.3 Incentives to operate the transmission network efficiently

Transmission constraints arise due to the decisions taken by load, generation and TNSPs over both operational and investment time-scales. Under current arrangements, generators have a limited ability to manage the risk of transmission constraints once they have made the decision to invest in a particular part of the network. This is because their revenue is linked to physical dispatch; when transmission constraints arise, physical dispatch is reduced.

This is ultimately to the detriment of consumers. Investors in long-lived generation assets may require a higher cost of capital to account for the future risk of transmission congestion; forestalling investment that would otherwise be economic.

This risk is exacerbated under the current framework by a lack of strong incentives for network businesses to make available network capacity when it is most desired by the market. Under the current framework, TNSPs are required to maintain and upgrade their equipment in order to provide services in line with relevant network performance requirements. This occasionally requires outages to be planned on the power system to facilitate the safe maintenance and upgrade of network infrastructure. TNSPs must provide information on the timing of planned outages through AEMO's network outage scheduling tool and in 13 month plans.

For generators connected to network assets undergoing maintenance, there may be a period where there is a need to curtail output or disconnect to manage system security for the next contingency, or where network equipment is de-energised to allow safe work. Where unplanned outages are extended or prolific, this can cause significant effects on a generator's revenue, with no compensation currently available.

To incentivise transmission businesses to reduce the impact of planned and unplanned outages on wholesale market outcomes, the AER administers the Service Target Performance Incentive Scheme (STPIS). The market impact component on this scheme is designed to incentivise TNSPs to reduce the length of planned outages and scheduling outages to occur during those times when there will be the least impact on the wholesale market. Transmission businesses are also incentivised to improve reliability on those elements of the network critical to the wholesale market to reduce the incidence of unplanned outages.

However, the current incentive scheme has a limited scope. For example, it only applies at times of network outages; rather than incentivising TNSPs to maintain a minimum level of network capacity for generators at all times. Further, while there is some value indication in the scheme[17], this can be seen as a rather blunt measure of the value of transmission capacity.

2.2.4 Incentives to operate the generation assets efficiently

Under current arrangements, generators have a right to negotiate a connection to the transmission network, but no right to be dispatched to the shared network and so earn revenue in the wholesale market. The service that a connecting generator is ultimately negotiating for with a TNSP is power transfer capability at the connection point, not the ongoing use of the shared transmission network to access the market.

Given this, a generator's access to the market price is a direction function of its physical dispatch. When there is congestion on the transmission system, some generators are constrained off. As they are not dispatched, these generators do not receive access to the regional reference price. Conversely, other generators may be dispatched despite bidding at a price above that which would have been the market price were it not for the constraint. As a consequence, the regional reference price is likely to be higher than it would otherwise have been in the absence of congestion.

There is evidence that the current market design does not send the right incentives to generators to operate efficiently (that is, to bid in at a price reflecting their marginal costs) during times of congestion. This is because generators behind a constraint are often able to forecast that congestion is likely to arise. For example, AEMO publishes information in pre-dispatch systems that enable generators to identify the likely impact of transmission constraints on their generation assets.

When the system is congested, generators know that the regional reference price is likely to be higher than usual, and that they are not going to receive access to it unless they are dispatched. If a generator is not dispatched, it may risk losing significant revenue due to the position it has taken under hedge market contractual obligations.

These conditions can give rise to 'disorderly bidding' by generators. Disorderly bidding results when generators know that the offers they make will, in all likelihood, not affect the settlement price they receive as a result of congestion between them and the rest of the market. Disorderly bidding can involve a generator behind a constraint bidding at the market floor price (-$1,000) to maximise its dispatch quantity. This can result in inefficient dispatch through higher cost generation resources being dispatched instead of lower cost resources.

In the past, the AEMC has commissioned analysis to understand the magnitude and frequency of disorderly behaviour within the electricity market.[18] This analysis found that disorderly bidding may escalate as the transition of the electricity system proceeds, due to increased competition between newer renewable generation entrants with low short-run costs and thermal generation incumbents with relatively high short-run costs.

17 A TNSP can earn up to two per cent of its regulated revenue if it eliminates all relevant outage events with a market impact of over $10/MWh.

18 As part of the *transmission frameworks review* in 2013, the AEMC engaged ROAM Consulting to analyse the magnitude of disorderly bidding in the NEM. ROAM Consulting estimated that over the period June 2008 to June 2011, electricity dispatch costs were $21 million higher than they could have been due to race to the floor bidding behaviours. ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013.

Disorderly bidding may also become particularly prevalent and result in inefficiencies if grid scale storage devices become commonplace in the NEM. Storage devices behind a constraint have an incentive to disorderly bid (as a seller of electricity) in order to receive the regional reference price. Not only might this be more inefficient than were the storage not there (when the storage device has a higher resource cost than a generator which it displaces in dispatch), it is even more inefficient compared to a scenario where the storage device was charging instead of dispatching. By charging, the storage device would alleviate the constraint. Local, cheaper generation behind the constraint would be dispatched to meet local load. In turn, disorderly bidding of storage has an impact on the locational decisions of storage devices connecting to the transmission network.

2.3 The need for access reform now

At the first technical working group for this review, we asked for stakeholders to consider what has changed, if anything, in the NEM since access reform was last considered in 2015. These are summarised below:

Generation transition:

- The transition occurring in the type of generation, as traditional thermal plants close, and more renewable and asynchronous generators connect to the network, with these newer plants having a different generation profile
- Since 2015, we have seen a larger amount of capacity of renewable generation connect to the network, as well as a more diverse range of investors participating in generation development and operation
- It is also expected that storage will continue to play an increasing role in the electricity market
- Further, the introduction of the 5-minute settlement reforms have the potential to further drive the change in generation technologies over the coming years.

Network transition:

- There is a changing context for transmission network businesses as the NEM transitions to a more meshed and interconnected network (both within and across regions), this is combined with increased inter-regional trade and sharing of reserves between jurisdictions
- Networks are also concerned about changes to their rate of return, as well as being uncertainty being created by the suggestion of asset write downs
- In addition, the process that is under way to embed and action the integrated system plan in the regulatory framework is a key change since 2015, with this combined with an increased focus on speculative investment and renewable energy zones.

Consumer transition:

- There is an increasing debate and consumer focus on affordability of electricity bills, which is heightened by the fact that consumers bear the majority of transmission investment risk in the current framework, so are shouldered with unnecessary costs if the transmission lines become 'roads to nowhere'

- The increasing importance of the demand side of the electricity market was also noted, including the rise of distributed energy resources contributing to changing demand pattern in the network.

Focus on reliability and security:

- Over the past few years, system security such as inertia, voltage and system strength issues have been heightened and become a focus of debate
- There have also been concerns about reliability
- Both due to reliability and security reasons, there has been load shedding in nearly every state of the NEM since 2015: for example, the load shedding after 24 August 2018 event in Queensland; load shedding in Victoria in January 2019; and NSW in February 2017; and the system black event in South Australia in 2016.

The extent of changes highlighted in the technical working group reinforces the Commission's view that now is the time for access reform. Access reform is a holistic and efficient long-term solution to the issues outlined above.

2.4 The Commission's proposal for access reform

Holistic transmission access reform involves changing the following three inter-related aspects of the current transmission access framework:

1. **Wholesale electricity pricing:** As noted above, under the current framework, generators receive the regional reference price for each megawatt hour of electricity they are able to dispatch to market, regardless of where they locate in a region. We are proposing to change these arrangements so that generators receive a market price that more accurately represents the marginal cost of supplying electricity at their location in the network (the 'local marginal price').
2. **Financial risk management:** Under current arrangements, a generator's ability to receive the regional reference price and earn revenue is a direct function of its physical dispatch. We are proposing to enable generators to better manage the risk of congestion by introducing transmission hedges. These products will hedge against the price differences between locations that may arise under our proposed changes to wholesale electricity prices, allowing generators to rely on a particular revenue flow regardless of other generator's locational decisions. This should improve investment certainty for prospective generators and may reduce the cost of capital for generation investment in the longer term.
3. **Transmission planning and operation:** Under the current regime, the fact that transmission network and generation investment decisions occur under different processes has the potential to result in infrastructure that does not minimise the total system costs faced by consumers. Additionally, no individual generator is able to guarantee that they will receive value from shared network assets, even if the generator underwrote the investment in the asset. As a consequence of these two factors,

consumers bear the risks of transmission investment decisions being incorrect. We are proposing to change this so that transmission planning is influenced by generator's purchase of transmission hedges. In addition, transmission costs are no longer solely recovered from consumers. A portion of these costs would instead be collected from generators through the purchase of transmission hedging products.[19]

The access model recommended by the Commission will combine dynamic regional pricing for generation with transmission hedging. Dynamic regional pricing, discussed in chapter 4, is designed to address the first aspect of the transmission framework outlined above, reforming electricity pricing to more accurately reflect the costs of supplying electricity. Transmission hedging, discussed in chapter 5, is designed to address the second two aspects of the framework, by introducing a financial risk management tool for generators as well as greater coordination in the transmission planning and operational space.

2.5 How the access reform will address the issues faced by the market

The reforms proposed by the Commission are inter-related, and form a coherent and internally consistent package. Indeed, they are designed to resolve the issues identified in section 2.2.

2.5.1 Incentives to coordinate generation and transmission investment

The new transmission access model should improve financial certainty for generators who purchase transmission hedging products. Under the new arrangements, generators would be able to more effectively manage their dispatch risk during times of congestion in return for buying transmission hedges and so underwriting part of the cost of the transmission network.

These arrangements should improve investment certainty for prospective generators and may reduce the cost of capital in the longer term. This is because generators with a transmission hedge would no longer face the risk that other generators may undermine their business case by locating nearby and causing congestion in the local transmission system. Under the status quo, a generator's ability to earn the regional reference price is dependent on it being physically dispatched. In contrast, under a transmission hedging regime, financial outcomes would be decoupled from physical dispatch. If a generator had contributed to the cost of transmission infrastructure through purchasing a hedging product, then it would earn revenue even if it was not physically dispatched.

A transmission hedge should also achieve a higher degree of co-optimisation of transmission and generation investment than under the current regulated approach to transmission planning. The option to purchase a hedging product makes the cost of transmission part of a generator's investment decision. The investor should seek a location for a power station which maximises its profits, which are a function of the revenue it earns in the spot and contract market, as well as the combination of its operating and establishment costs and the cost of transmission.

19 This is possible because the financial transmission hedges are physically backed by transmission capacity. The purchase of hedges by generators creates a liability for transmission companies, who manage that liability by building and operating transmission infrastructure.

Transmission hedges would create a clear and cost-reflective locational signal for new generation investment that is currently missing in the NEM. Locational signals would be provided to generators through a price that reflects the incremental cost that the generator would impose on the transmission system. Generators would then trade off different locations, taking into account the relative costs of transmission, as well as the other factors such as fuel costs. While there are a number of other factors generators consider when making locational decisions, these signals may make a difference in some cases, and would result in more efficient generator locational decisions (and more efficient combined generation and transmission investment) being made in the longer term.

Improvements to current transmission access arrangements are critical given that the diversity of location and operating type of generators are changing rapidly. More types of renewable generation are entering the NEM, in addition to more generation being integrated with storage or other new technologies. For the transition to occur in an orderly and least cost manner, generators should have incentives to invest in new plant where and when it is efficient to do so. The transmission hedging model is intended to help the market adapt to changing and uncertain conditions, particularly demand and generation patterns, to deliver better outcomes for both consumers and industry.

Improvements to the access regime may also help improve coordination between generators and the transmission networks in relation to system security issues. For example, one possible way that access reform could assist is that access rights could include a product which meets the generator’s obligation in relation to system strength. Renewable energy zones can also assist in generator's meeting their 'do no harm' obligations in a more efficient manner, by promoting better coordination between generators when they are connecting.

2.5.2 Incentives for efficient generation and transmission investment

Under the final access regime, transmission investment costs would no longer be recovered solely from consumers through TUOS charges. A portion of these costs would instead be collected from generators through the purchase of hedging products.[20] This means that the TUOS component of a customer's bill should decrease.

Access reform should remove the free-rider problem inherent in the current connection regime by giving connecting generators a risk management tool in return for making a financial contribution that underpins transmission investment. Transmission hedges allow generators to better manage their dispatch risk when the transmission system is congested; essentially providing the generators with the full benefit of the transmission infrastructure they underwrite.[21] This increased financial certainty should incentivise generators to bear a potentially large portion of the costs of transmission infrastructure that are currently shouldered borne by consumers.

20 Consumers would need to pay the residual investment and maintenance costs that are required to deliver them with reliable electricity services.

21 Noting that the financial benefit received by generators with a transmission hedge during times of congestion would be paid by generators without a hedge. To raise an analogy, generators without a hedge would be paying to 'rent' the transmission infrastructure underwritten by those with hedging products when congestion arises.

Depending on the final design of the firm access model, the new regime could also reduce the cost to consumers of inefficiently located, sized or timed transmission investment. Under a generator led access regime, where generators make inefficient investment decisions, they would bear the cost of any expansion of the transmission network that was undertaken to physically back the transmission hedges they purchase. This would represent an improvement over the current planning arrangements, where consumers bear the risk of inefficient transmission decisions.

As noted above, transmission hedges would also create a clear and cost-reflective locational signal for new generation investment that is currently missing in the NEM. These signals should reduce the risk that generators locate in a congested or under served part of the transmission network. Over the longer term, this should result in lower wholesale prices for consumers as more generation capacity is able to be sustainably supported by the transmission network.

The allocation of transmission investment risk becomes more important in an uncertain and changing investment environment, as the risks associated with transmission investment may increase. Given changes being witnessed in the market, the Commission considers that now is an appropriate time to shift some risk to generators, given that they have the incentives, ability and information to improve risk management. However, in return, generators will receive better locational signals and an ability to manage price risks, whihc will provide them with more financial certainty.

2.5.3 Incentives to operate the transmission network efficiently

The Commission considers that, while the Service Target Performance Incentive Scheme has incentivised TNSPs to improve network performance,[22] it would be better to have an incentive scheme that covers all periods and is better tied to measures of market value. A broader incentive scheme could encourage TNSPs to maximise network availability at times of high market demand, which in turn would lower wholesale market prices for consumers over the longer term.

It should be noted that it is inefficient for a TNSP to operate and plan its network to provide capacity for intra-regional settlement residue to be sufficient to cover the cost of transmission hedge payouts at all times. There may be circumstances that affect capacity on the network that are caused by events outside the TNSP's control, such as a bushfire. Further, TNSPs need to reduce capacity at times when it is not valued (for example, during off-peak times) for actions such as maintenance. It would not be possible to require sufficient capacity to cover the cost of transmission hedge payouts under these conditions.

To account for this reality, the proposed access model would need to encourage rather than mandate TNSPs to operate their network efficiently in order to provide sufficient capacity to meet hedge payouts. Depending on the final design of the access regime, this could occur

22 As part of the *optional firm access, design and testing, review* in 2013, the Commission conducted analysis on the effectiveness of the STPIS scheme. It was found that, typically, incentives to TNSPs under the scheme have increased over time reflecting better performance in minimising outages. AEMC, *Optional Firm Access, Design and Testing, Final Report - Volume 1*, 9 July 2015.

through an incentive scheme targeted so that TNSPs efficiently manage their network with regard to congestion at all times. Under such a scheme, TNSPs would be obliged and financially incentivised to provide a level of physical capacity consistent with the amount of transmission hedges collectively held by generators. This collective level of transmission hedges would drive TNSP operational decisions.

The incentive scheme could include rewards or penalties for TNSPs depending on the amount of settlement residue deficits (or 'shortfall costs') that arise and so accrue to generators with a transmission hedging product over a particular period. These shortfall costs would account for the shortfalls of transmission capacity that mean there is not enough revenue to adequately pay all generators that hold a transmission hedge in a particular part of the system. Through the incentive scheme, the TNSP would be incentivised to manage the level of shortfall costs, and so the costs to generators, of network constraints.

Such a scheme would encourage TNSPs to minimise outages, and conduct them at times that would have minimal impact on generators. For example, if there were solar generators connected to a particular network element, an outage of this element would occur at night when the sun was not shining.

As noted above, a key aim of any transmission access regime should be to provide appropriate price signals to all parties (including TNSPs and generators) so that they make operational decisions that efficiently reflect the costs of generating and transporting electricity to consumers. The Commission considers that a new transmission access model could be designed to send the right incentives to TNSPs in order to lower long-term costs for consumers.

2.5.4 Incentives to operate the generation assets efficiently

The new transmission access model will combine dynamic regional pricing for generation with transmission hedging. This means that generators are paid (or pay) the local marginal price when transmission constraints bind. These parties receive (or pay) this local marginal price instead of the regional reference price.[23] Generators are then able to manage the risk of receiving the local price by purchasing transmission hedges.

Dynamic prices more accurately signal the value of supplying electricity at each location, and do not impose the same perverse incentives on generators and storage to disorderly bid. This regime also results in intra-regional settlement residue when congestion occurs, which effectively puts a price on congestion. This is due to the difference between the dynamic regional price and the regional reference price (which market customers pay). Under our proposed access regime, this residue would be allocated to generators with transmission hedges to compensate them for the transmission capacity they have underwritten, allowing them to hedge the risk of receiving the local price.

Exposing generators to the dynamic regional price removes the incentives to disorderly bid when transmission constraints arise. This is because doing so would expose the higher cost

23 Where there are no constraints on the transmission network, generators will be paid the existing regional reference price. Load would continue to be settled at the regional reference price.

generator to a low dynamic regional price instead of the higher regional reference price. Under these circumstances, the higher cost generator may lose further revenue if it places a disorderly bid, as such behaviour runs the risk of depressing the local price which they receive. Exposing generators to the local price means that generators are no longer incentivised to maximise their physical dispatch, even if the regional reference price is high (see Appendix B for an example).

This is a simple consequence of pricing being reflective of the marginal cost of supply. Generators with a higher cost of supply than the local price should rationally not bid lower than the local price in order to be dispatched, as to do so would mean that they received a price less than the cost of their operations.

A key aim of any transmission access regime should be to provide appropriate price signals to new generators such that they make operational decisions that efficiently reflect the costs of generating and transporting to consumers. Efficiency is promoted when prices reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities. At times of transmission congestion, the Commission considers that dynamic regional pricing should send the right incentives to generators in order to improve the prospect of the lowest cost combination of generation being dispatched.

3 REFORMING THE TRANSMISSION ACCESS FRAMEWORK

This chapter outlines the Commission's proposal for reform to the transmission access framework, including a discussion of stakeholder views.

3.1 Proposed reforms to the transmission framework

3.1.1 Background

In the inaugural *Coordination of Generation and Transmission Investment* (COGATI) review, the Commission concluded that the current access regime needed to evolve so that transmission could be built to reliably connect generators.[24] Such reform would represent an evolution of the current arrangements where the network is built to reliably supply consumers.

The Commission recommended a phased reform approach to the way in which generators access the shared transmission network. This phased approach is outlined below, and was further discussed in the consultation paper for this review as well as the supplementary information paper.[25]

Table 3.1: **Proposal for access reform in 2018 COGATI review**

PHASE OF REFORM	OVERVIEW	PROPOSED COMMENCEMENT
1. Dynamic regional pricing	The access arrangements would be changed to implement dynamic regions for determining the price payable to generators.	July 2022
2. Improved information	The information that is produced from dynamic regional pricing, including where congestion occurs and the costs of congestion, would be used to supplement the planning arrangements for transmission.	July 2022 to July 2023
3. Generators fund transmission infrastructure	In response to the information on network congestion, connecting parties would be able to purchase transmission hedges (called firm transmission rights or firm access' in the paper) that would allow them to more effectively manage dispatch risks. Generators' collective decisions to hedge would	July 2023

24 AEMC, *Coordination of generation and transmission investment, Final report*, 21 December 2018.

25 Both the consultation paper and the supplementary information paper can be found here: https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

PHASE OF REFORM	OVERVIEW	PROPOSED COMMENCEMENT
	guide TNSPs' planning decisions due to an obligation placed on TNSPs to provide sufficient transmission capacity. This capacity would be consistent with the collective amount of transmission hedges purchased by generators.	

Source: AEMC, *Coordination of generation and transmission investment, Final report,* 21 December 2018

Dynamic regional pricing

As set out in the consultation paper, the first phase involved the implementation of dynamic regional pricing. Under a dynamic regional pricing regime, generators (and potentially some forms of large load and/or storage) are paid (or pay) the marginal cost of supply at their transmission node. These parties receive (or pay) this local marginal price instead of the regional reference price. However, load still pays for energy at the regional reference price.

Dynamic regions introduce a price signal to generators that better reflects the short-run costs of using the network. In operational time-scales, dynamic regional pricing should remove the current incentives for a type of disorderly bidding known as "race to the floor" bidding when there is congestion.[26]

In investment time-scales, dynamic regional pricing should provide more appropriate price signals to generators to inform their locational decisions.

Dynamic regional pricing would also provide better information to transmission planners, such as transmission network service providers and AEMO, about where congestion occurs than exists under the current arrangement, contributing to improvements in transmission planning.

Information from dynamic regional pricing reveals congestion costs

The second phase involved various transmission planning processes being supplemented by the provision of additional information made available as a consequence of the phase 1 reform. This information could include patterns of congestion, the dynamic location of regions, as well as the costs associated with congestion on particular transmission elements.

It was the Commission's view that dynamic regional pricing would provide a greater level of information to the market about transmission constraints and their cost. This could better enable:

- AEMO to develop its Integrated System Plan in consultation with industry
- TNSPs to make efficient transmission investments

26 Dynamic regional pricing addresses incentives for one type of disorderly bidding; other incentives to disorderly bid exist and are not addressed by this reform.

- the Australian Energy Regulator (AER) to assess the efficiency of transmission investments made by TNSPs.

While the Commission recognises that some of this information is used today by TNSPs and AEMO in their planning; this data may not provide information that can be relied on for efficient decision making, due to the race to the floor bidding behaviour that occurs. This behaviour alters the pattern of constraints and locational prices within the market.

Generators fund transmission infrastructure

Under the final phase, generators would be allowed to purchase a transmission hedge (called a 'firm transmission right' in the paper) in return for contributing to the costs of the shared transmission network. Transmission hedging would allow generators to manage the risk of transmission congestion.

When congestion does not exist, the dynamic regional price would equal the regional reference price, and so generators would effectively be settled at the regional reference price. When congestion arises, the dynamic regional price that generators receive would differ from the regional reference price, but generators who hold transmission hedges would receive a payout equal to the difference between the regional reference price and the dynamic regional price. This would allow them to manage their exposure to the dynamic regional price.

The financial proceeds from the purchase of a transmission hedge would go towards underwriting transmission investment, as TNSPs would be obliged and financially incentivised to provide a level of network capacity consistent with the amount transmission hedges collectively held by generators. This approach would allow a greater reliance to be placed on commercial investment rather than the current processes for transmission investment that exist at the moment.

The Commission considered that this reform would provide an incentive for generators to underwrite the appropriate amount, location and timing of transmission investment. Generators would balance the costs of transmission investment against the costs of congestion, as well as other locational decision factors such as fuel resources. In addition, the reform would transfer the investment risks associated with new transmission infrastructure away from consumers and towards generators (who are better able to manage these risks). This would result in generators paying for some of the transmission infrastructure - a change to current arrangements. This is particularly important given the large focus from consumers on affordability at the moment.

3.1.2 Stakeholder views

In response to the consultation paper, many stakeholders echoed the Commission's view that the current transmission access framework needs to evolve:

- The energy market bodies were strongly supportive of access reform. AEMO emphasised that the need for reform is urgent in light of the transitioning electricity sector and the increasing number of generators seeking to connect to the grid.[27]
- Transmission and distribution networks were typically of the view there is a reasonably convincing case for change, with several noting that congestion remains an ongoing issue for networks and generators.[28]
- Consumer groups and large energy users generally acknowledged that the current investment framework does not appropriately incentivise effective coordination of generation and transmission investment.[29]
- Some generators and equity investors were supportive of access reform, on the basis that it may provide increased certainty to generators regarding their investment over the longer term.[30] In contrast, others were against access reform and argued that a strong case has not yet been made for reform, or that incremental changes to the access framework may be more efficient.[31]
- Whilst acknowledging that the current framework has issues, a handful of other stakeholders had reservations about the scale of reform and encouraged the AEMC to undertake a cost-benefit analysis on the proposal.[32]
- A few highlighted that there may be other access models that could be considered; for example, locational nodal pricing (i.e. where both load **and** generation are settled at the local marginal price) or generator reliability standards.[33]

Many stakeholders also expressed a view on the interaction between access reform and the Energy Security Board's (ESB's) review, *Post 2025 Market Design for the National Electricity Market (NEM).*[34] For example, Aurizon Networks, Intergen Australia, EnergyAustralia and the Clean Energy Council considered that any proposed access regime risks being made redundant in light of the wider reform that is being pursued by the ESB.[35] Intergen Australia

27 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Australian Energy Regulator, pp. 4-5; AEMO, p. 1.

28 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: AusNet Services, p. 1; Energy Queensland, pp. 4-5.

29 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Major Energy Users, p. 3; EUAA, p. 2; PIAC, pp. 2-3.

30 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Neoen, p. 2; Spark Infrastructure, p. 2; ENGIE, p. 2; Lighthouse Infrastructure Management, p. 1; Alinta, p. 3; ERM Power, p. 5; Flow Power, p. 1.

31 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: HydroTasmania, p. 3; Brickworks, p. 1; Delta Electricity, p. 2; Stanwell, p. 8; Infigen, p. 10; Meridian Energy, p. 6; Australian Energy Council (AEC), pp. 1-2; Snowy Hydro, p. 1; Tasmanian Department of State Growth, p. 2; EnergyAustralia, p. 2.

32 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: The Australian Financial Markets Association, p. 1; Aurizon Network, pp. 1-3; TasNetworks, p. 3; Energy Networks Australia (ENA), p. 1; CEC, p. 3; HRL Morrison & Co, p. 2; Tilt Renewables, p. 1.

33 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: The Australian Financial Markets Association, p. 1; Aurizon Network, pp. 1-3; TasNetworks, p. 3; Energy Networks Australia (ENA), p. 1; CEC, p. 3; HRL Morrison & Co, p. 2; Tilt Renewables, p. 1.

34 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Tasmanian Department of State Growth, p. 2; Aurizon Networks, pp. 1-3; Intergen Australia, p. 2, EnergyAustralia, p. 1; Clean Energy Council, p. 4; ENGIE, p. 5; Mondo Energy, p. 1; AEC, pp. 1-2; Delta Electricity, p. 1; Hydro Tasmania, p. 1; ENA, p. 2; AusNet Services, p. 2; AGL, pp. 1-2.

35 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Aurizon Networks, pp. 1-3; Intergen Australia, p. 2, EnergyAustralia, p. 1; Clean

argued that generators may also be unlikely to buy transmission hedges in an environment where there is an ongoing risk that a different market structure may subsequently be implemented.[36]

To address the interaction between the two work programs, Mondo Energy proposed ways in which the reviews could be aligned, including having the same technical working group.[37] In contrast, the Australian Energy Council (AEC) considered that access reform should be merged into the ESB's review.[38]

Stakeholders also held a wide range of views on the proposed phasing of access reform outlined in the consultation paper. Key comments included:

- The three stage phased implementation is both elegant and pragmatic, with incremental benefits being achieved along the way.[39]
- Separating and prioritising the role that transmission hedges play (for example, as a risk management tool versus a tool to underpin market-led transmission investment) may lead to a more transparent market design which might reduce contention in the way hedges are allocated.[40]
- The staged approach inherently introduces transitional uncertainty for market participants, which increases the risk that new generation is not financed until after all the changes are in place.[41]
- Increased information should occur as a first stage rather than second, as better information would enable participants to assess the magnitude of the benefits that are likely to be realised by moving to regional pricing.[42]

There were a diverse range of views on whether the proposed implementation dates for reform were appropriate. AEMO, ERM Power and Major Energy Users were of the view that the proposed timeframes to implement reform were too long.[43]

While AEMO acknowledged that successful access reform will take time, it considered that four years is too long to wait to resolve the challenges facing the NEM. Given the complexity of the potential reforms and necessity of long lead times, AEMO proposed that interim solutions, such as a framework for renewable energy zones, may be required.

Energy Council, p. 4.

36 Intergen Australia, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 2.

37 Mondo Energy, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 1.

38 AEC, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, pp. 1-2.

39 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: ENGIE, p. 2; ENA, p. 7, AusNet Services, pp. 2-3.

40 AEMO, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 12.

41 Neoen, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

42 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Delta Electricity, p. 2; Stanwell, p. 4; Energy Users Association of Australia (EUAA), p. 6.

43 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: AEMO, p. 4., ERM Power, p. 2; MEU, p. 5.

In contrast, generators and network businesses were generally of the view that the proposed implementation timeframes were too ambitious.[44] For example, InterGen Australia and EnergyAustralia were concerned that the proposal did not allow sufficient time for the market to adapt to and bed down 5-minute settlement before access reform was introduced.

3.1.3 Commission's views

The NEM is experiencing a period of significant change. In the transmission sector, the pattern of network flows is changing as the generation mix in the energy market continues to evolve. Wind and solar generation are replacing older coal-fired generators as they retire from the market. The patterns of demand are also changing as energy customers increasingly bypass the traditional supply chain by producing some or all of their own electricity. These factors will have significant impacts on the amount and location of transmission investment that is needed over the longer term, as well as on the management of network flows in operational time scales. In addition, these factors are being heightened given the large amount of connection enquiries and generation that is being proposed to connect to the network over the next few years.

It is against this background that the Commission is confident that there is a strong case for a transmission access reform, as discussed in chapter 2. The access regime needs to evolve to incentivise generators to locate in stronger, lower cost parts of the transmission network, and to reward them with increased certainty over their investment when they do so. It should also evolve to make sure that the right amount of transmission investment is built in the places that it is most needed. Most importantly, it should ensure that consumers do not bear undue risks or unnecessary costs of transmission investment that is built to service new generation. Building transmission to benefit generators means that generators should contribute to the costs of transmission investment.

The Commission acknowledges stakeholder comments that a large-scale and holistic reform of this nature introduces some amount of transitional uncertainty into the electricity market. We understand that stable regulatory arrangements that evolve in a transparent manner are vital in order to make sure that the generation and transmission investment needed to support the transition of the electricity system materialises. However, given the scale of generation that is forecast to connect to system in the coming years, and the transmission investment needed to support this, it is also important to make sure that generation and transmission investment is as coordinated and efficient as possible. This coordination is for the long-term benefit of both industry and consumers, as it should manifest in the form of increased revenue certainty for generators as well as lower system costs for consumers.

The Commission also notes that any regulated sector is by definition subject to change as the regulations and frameworks adapt over time. However, the Commission recognises that regulatory stability occurs where stakeholders have a clear understanding of how and when

44 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: ENGIE, p. 5; ENA, p. 2; AEC, p. 1; Intergen Australia, p. 1; TasNetworks, p. 7; EnergyAustralia, p. 3; AusNet Services, p. 2; CEC, p. 3; Meridian Energy, p. 2; AGL, p. 1; Snowy Hydro, p. 2.

change occurs; and on what basis. This is something that the Commission is conscious of in working through these proposed reforms.

To balance the need for regulatory stability and transparency against the longer term benefits to industry and consumers of reform, the Commission intends to proceed with transmission access reform in a consultative yet expeditious manner. Through our 2019 COGATI review, we will undertake detailed design and testing of an access model that pairs the introduction of transmission hedging with dynamic regional pricing, including developing proposed changes to the rules that are required.

This will allow stakeholders to have increased knowledge and understanding of the proposed reforms by the end of 2019, even if the actual implementation of reforms will not occur until a later date.

The access model will be developed in two stages over the 2019 COGATI review, namely:

1. Our draft report in September will outline a detailed design of changes to the settlement arrangements for generators under the new access regime. The existing settlement arrangements will be changed to implement dynamic regions for determining the wholesale price payable to generation. The draft report will also outline the key features of the transmission hedge model for stakeholder consultation. This will also detail implementation and transitional issues.
2. Our final report in December will outline a detailed design of changes to the access regime as a whole (including 1 above). The report will outline how the existing regime will be replaced with a model that combines dynamic regional pricing with transmission hedges for generators. Generators (and potentially other parties) will be able to purchase a hedge against their financial exposure to local prices within the wholesale market that may arise from transmission constraints in return for contributing to the costs of the transmission network. This will also detail the final implementation and transitional issues.

The Commission favours this approach because it allows some of the issues outlined above to be addressed in a timely fashion, while providing a pathway to address the detailed design questions relevant to transmission hedging through extensive stakeholder consultation. It is expected that the COAG Energy Council will consider the proposal outlined in the final report. Subject to agreement, the Council will submit a formal rule change request to the AEMC in early 2020 to implement the reforms consistent with the timetable to reform detailed in the draft and final reports.

It is important to note that, although the approach to the review is staged, it is the intention of the Commission that both dynamic regional pricing and transmission hedges will be implemented at the same time. This represents a change from the proposed implementation timing outlined in our consultation paper, and is in recognition of stakeholder feedback on this issue. Substantial benefits may accrue from aligning the implementation of dynamic regional pricing and transmission hedging. Alignment will promote financial certainty amongst market participants by allowing them to hedge the basis risks of dynamic prices. In addition, it will likely lower the costs of implementation by removing the need to design and implement bespoke settlement arrangements for a dynamic regional pricing regime without hedging.

The Commission is conscious that the proposed reform represents a holistic approach to resolving the challenge identified with the current transmission framework, and would ultimately result in fundamental changes to the NEM arrangements. We are working closely and continually with all energy market bodies, including the ESB, to ensure that access reform fits within the wider evolution of energy market regulation that is occurring.[45]

The Commission considers that it is not possible to address the deficiencies in the current transmission access framework effectively in a piecemeal or incremental manner. Implementing a holistic firm access model for transmission should improve the way in which transmission and generation investment decisions are made. It would allow generators to receive greater financial certainty of their generation investment, in exchange for bearing some of the costs of transmission investment that are currently held by consumers.

3.2 Other access models

As noted in section 3.1.2, several stakeholders requested that the Commission consider whether other transmission access models could meet the desired objectives of reform.[46]

The Commission has considered transmission frameworks, and in particular, access arrangements in other jurisdictions. Typically, 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 transmission rights.

Beyond these two core features, a variety of design options are possible. However, most access frameworks involve these two core features.

In order to facilitate discussion and analysis, the Commission presented a few of the design mechanisms proposed by stakeholders to our technical working group. These designs can all be considered to be sub-components, or variants, of the above core features outlined above. It was noted that these models were not mutually exclusive, and that combinations or other variations could exist.

3.2.1 Design mechanisms considered by the technical working group

The design mechanisms presented to the technical working group included two variations of local marginal pricing and transmission rights, respectively.

Variations of local marginal pricing

1. **Locational nodal pricing:** Under a locational nodal pricing model, market participants (both generators and load) would be settled at their locational marginal price. In this case, the concept of NEM regions and settlement against a regional reference price (RRP) would no longer be applicable. Differences in local prices would reflect the costs of network congestion.

45 Indeed, in its December 2018 report on actioning the Integrated System Plan, the ESB identified the importance of access reform and noted it will report back to the Council of Australian Governments (COAG) Energy Council by December 2019 on these issues. The 2019 COGATI review forms a significant part of this workstream.

46 See https://www.aemc.gov.au/sites/default/files/2019-05/Technical%20working%20group%20notes%20-%2028%20May%202019.pdf.

2. **Generator-only regional pricing:** Under a generator-only regional pricing regime (i.e. the proposed dynamic regional pricing that was set out in the consultation paper), generators are paid the marginal cost of supply at their transmission node. These parties receive this local price instead of the regional reference price. As with locational nodal pricing, differences in local prices would reflect the costs of congestion. In contrast, load would continue to be settled at the regional reference price under all network conditions.

Variations of transmission rights

1. **Generator reliability standards:** This model would establish a form of transmission network access standard for generators, determined through regulation. This standard would be similar to the reliability standard which already exists for load.

   Generators would pay TUOS charges, in return for access rights that would be governed by the reliability standard chosen. All generators would receive the same level of access rights.

   The standard would give generators greater visibility regarding their likelihood of being dispatched in a given location. In terms of transmission planning, TNSPs would be required to plan their networks to ensure that the generator access standard was met, in addition to the existing load reliability standard.

2. **Transmission hedging:** This model would allow generators to purchase a transmission hedge in order to manage the financial risks of congestion on the transmission network. This would allow generators to have different levels of transmission rights, depending on their preferences. This would necessarily need to be combined with dynamic regional pricing.

   The aggregate amount of firm access that would be available for purchase would be determined through a transmission planning regime, and would be equal to current transmission capacity plus planned transmission capacity. There are multiple design decisions regarding how the purchase of transmission rights could inform the transmission planning process.

3.2.2 Commission's views

The Commission considers that the above design variations can be considered as a range of design options that sit within a transmission framework that involves more granular pricing signals and transmission hedges (i.e. the two core features discussed in section 3.2). Most of these design features are discussed further in the two following chapters, including options for how they could be given effect.

However, it is important to note that the Commission considers that generator reliability standards are not the ideal access reform model for the NEM. This particular form of market design is not discussed further within the directions paper.

The generator reliability standards model lacks flexibility in that it mandates a uniform level of access for generators. Consumers would continue to bear the risk that the standard, determined through a regulatory process, is inappropriate. This may result in an inefficiently high amount of transmission (high TUOS charges without commensurate reductions in wholesale prices), or an inefficiently low amount of transmission (high wholesale prices without a commensurate reduction in TUOS charges), or a combination of the two in differing locations.

In contrast, a transmission hedge model allows generators to hedge the risk of congestion in the manner which most closely meets their requirements. This should better allow for co-optimised outcomes between generation and transmission, promoting overall efficiency in the market. More succinctly, it should put more of the risk of transmission planning in the hands of generators, rather than consumers.

4 DYNAMIC REGIONAL PRICING

This chapter provides:

- a summary of the approach to dynamic regional pricing put forward in the consultation paper
- stakeholder views on the proposed approach
- further detail on a potential high-level design for dynamic regional pricing
- a proposed framework for assessing the impacts of a dynamic regional pricing regime.

4.1 Introduction

In the consultation paper for this review, the Commission recommended an approach to reform the way in which generators access the shared transmission network. One aspect of the reform was to introduce the notion of dynamic regional pricing into wholesale electricity pricing and settlement.

Dynamic regional pricing would introduce price signals to generators that better reflect the marginal cost of supplying electricity in that part of the transmission network. These pricing signals should have the following benefits:

- They would improve the **efficiency of dispatch** by removing the current incentives for generators to engage in ‘race to the floor’ bidding behaviours.
- They would provide greater **transparency and visibility** of the costs of congestion in the NEM.
- They would assist in **defining the value of transmission hedging products** that would also be introduced under the access reform. They would do this by essentially putting a price of the cost of congestion within the system, which should in turn reveal the value of holding a hedge against the dispatch or congestion risks that generators currently face.
- They would contribute to **improved locational signals** in investment time-scales, as exposure to dynamic regional pricing provides better information on the value of locating in different parts of the network.

4.1.1 Current dispatch and settlement arrangements

In the NEM, there are key differences between dispatch and settlement:

- Generators are dispatched[47] based on their offers to the market, their location and the physical characteristics of the network. Therefore, dispatch can be considered to be a local market clearing process.
- Generators are paid for energy dispatched at the regional reference price. This payment is directed through central settlement arrangements that are operated by AEMO. Therefore, settlement can be considered to be a regional market clearing process.

47 That is, given instructions about how much to generate at a particular point in time in order to meet demand.

Dispatch arrangements

Load and generation need to physically balance at each point in the transmission system. The NEM dispatch engine (NEMDE) dispatches generators such that load and generation are balanced. It also dispatches generators in a manner that solves for the least cost way of meeting demand.

NEMDE is able to achieve this through determining the 'locational marginal price' of generation in each location. The locational marginal price is calculated by working out the cost (as proxied by the offer prices of local generators) of supplying an additional megawatt of electricity at a particular transmission node.

Generators are dispatched by NEMDE if they place offers at or below the locational marginal price of their transmission node. Generators with offers above the locational marginal price are never dispatched by the NEM dispatch engine. This is because these offers are above the marginal cost of supply and so would not result in total dispatch costs being minimised.

Settlement arrangements

Generators are paid for the production of energy by market customers. This occurs through the central settlement process that is operated by AEMO. Under the current settlement arrangements, all load and generation are paid the regional reference price for the amount of electricity they consume or dispatch, respectively.

Generators that are not dispatched in a given settlement period do not generate electricity and so do not receive payment i.e. these generators do not receive access to the regional reference price. Thus, revenue is a direct function of physical dispatch.

The regional reference price is determined just like any other locational marginal price. It represents the cost of supplying an extra megawatt of demand (as determined by generator offer prices) at the regional reference node. Therefore, settlement payments to generators can be considered to be the following:[48]

> **BOX 2: CURRENT SETTLEMENT ARRANGEMENTS**
>
> Settlement$ = RRP x G **(1)**
>
> Where:
>
> G = Dispatched output
>
> RRP = Regional reference price

However, we can also think about the current arrangements differently. Putting the concepts described above together, the above payment can be de-constructed into two settlement components:

48 Excluding the impact of losses.

- **Settlement against the LMP:** a generator is dispatched at its local node in accordance with its dispatch offer[49] and is paid its local marginal price for its output.
- **Settlement against the RRP-LMP differential**: for the quantity that it is dispatched, the generator also receives the difference between its local price and the regional reference price.

If there are no constraints on the transmission network within a region, a generator's locational marginal price would be the same as the regional reference price. Because there is no congestion, supplying one more unit at the regional reference node could come from the local generator if it has the lowest marginal offer. This means that the price at the regional reference node must be the same as the price at the generator's local node.

However, when congestion arises, locational marginal prices diverge from the regional reference price to reflect the transmission constraints that are occurring at a particular time. For example, if there is a constraint on the network, it is expected that a more expensive generator will need to be dispatched in order to supply consumers. This will increase the regional reference price. This displacement will be at the expense of lower cost generators located behind a constraint.

Since load is settled at the regional reference price, differences between the locational marginal prices that generators receive and the regional reference price that load pays effectively result in intra-regional settlement residues. This way of thinking about settlement clarifies that under the existing arrangements, these residues are *implicitly* allocated to generators based on their dispatched output.

Adopting this perspective, an alternative mathematical representation of the current arrangements is set out in the box below. This could be considered to better reflect the underlying dispatch and settlement processes.

BOX 3: ALTERNATIVE PERSPECTIVE ON CURRENT SETTLEMENT ARRANGEMENTS

$\text{Settlement\$} = \text{Settlement\$}_{\text{Dispatch}} + \text{Settlement\$}_{\text{Residue}} = \text{LMP} \times G + (\text{RRP} - \text{LMP}) \times G$ **(2)**

Where:

G = Dispatched output

LMP = Locational marginal price

RRP = Regional reference price

In this formulation, the second term, (RRP – LMP) x G, captures the current implicit allocation of intra-regional settlement revenues based on dispatched generation.

Note that this is mathematically identical to the more familiar equation 1 in the previous box.

49 That is, dispatched if their offer is equal to or below the local price.

As set out in the consultation paper, these arrangements give rise to several commercial and operational concerns in the NEM today:

- As dispatched generators receive an allocation of the intra-regional settlement residues at no cost, locational signals to generators are diluted.
- As the allocation of settlement residues is based on dispatch, which can be affected by congestion, the allocated quantity is uncertain.
- As generators are effectively paid the regional reference price rather than locational marginal price, bidding and dispatch outcomes may be inefficient when congestion occurs.

4.1.2 Dispatch and settlement arrangements under dynamic regional pricing

As described above, a generator's dispatched output currently determines both:

- the quantity of generation for which the generator will receive the locational marginal price; and
- their share of the settlement residues that accumulate as transmission constraints arise and locational marginal prices within a region diverge.

If dynamic regional pricing were to be implemented, generators would receive the locational marginal price at their transmission node for their dispatched output, rather than the regional reference price. As a result, the settlement residues that are currently *implicitly* allocated on the basis of dispatched output would need to be *explicitly* allocated on a different basis.

We are proposing that dynamic regional pricing is introduced at the same time as transmission hedges. This would mean that the allocation of settlement residues would be based on the level of transmission hedges held by generators, as shown in the box below. [50]

> **BOX 4: SETTLEMENT UNDER DYNAMIC REGIONAL PRICING (WITH TRANSMISSION HEDGES)**
>
> $$\text{Settlement\$} = \text{Settlement\$}_{\text{Dispatch}} + \text{Settlement\$}_{\text{Residue}} = LMP \times G + (RRP - LMP) \times H \quad \textbf{(3)}$$
>
> Where:
>
> G = Dispatched output
>
> H = Transmission hedge quantity
>
> LMP = Locational marginal price
>
> RRP = Regional reference price
>
> *Note that the hedges may be* ***options*** *contracts, and so only pay out if the RRP is greater than the LMP. If so, the holder of the hedge would not receive a negative payment (that is, have to make a payment) if LMP is greater than RRP.*

50 See Invalid Xref: target section not found. Please edit or recreate the link. for further discussion on approaches to implementing access reform.

An advantage of decoupling the allocation of intra-regional settlement residues from dispatch[51] is that it would remove the incentives for generators to engage in 'race to the floor' bidding behaviour, which currently creates costs to consumers.

BOX 5: WHAT IS MEANT BY 'RACE TO THE FLOOR' BIDDING BEHAVIOUR?

Race to the floor bidding arises when generators know that the offers they make will not affect the settlement price they receive because there is transmission congestion between them and the rest of the market. When a transmission constraint binds, NEMDE dispatches generators out of merit order (i.e. a more expensive generator before a cheaper one), which typically results in an elevated regional reference price.

Generators behind a binding constraint have an incentive to bid towards the market floor price (-$1,000) in order to maximise their physical dispatch. When multiple generators bid in at the market floor, the local price at the relevant transmission nodes can decrease to the floor price, because the price is determined by the marginal cost of supply as proxied by generators' offers.

In these circumstances, multiple generators' bid prices are equal to the locational marginal price of -$1,000 and there is insufficient transmission capacity to dispatch all of them, and so NEMDE applies 'tied-bid' rules. This can result in inefficient outcomes because the generators' bids do not reflect their actual costs.

AEMO publishes information in pre-dispatch systems that enable generators to identify the likely impact of transmission constraints on their generation assets. If a generator forecasts that they are likely to be constrained off due to congestion, it may have an incentive to rebid in at the market floor price to maximise its dispatch quantity - remembering that, currently, physical dispatch and financial access are linked.

This can result in inefficient dispatch; that is, higher cost generation resources behind the constraint being dispatched instead of lower cost resources that are available. This occurs because the NEM dispatch engine does not know the underlying costs of the two generators, and so pro rates dispatch outcomes.

Radial constraints

Radial constraints are where all generators share the same coefficient in the binding constraint. In radial constraints, physical dispatch is allocated in proportion to the generator's offered availability. In practice, this is frequently observed in some Latrobe Valley- Melbourne constraints.

Loop flow constraints

Loop-flow constraints are where generators do not share the same coefficient in the binding constraint. Almost 70 per cent of loop-flow constraints involve an interconnector.

51 In equation 3 above, this is expressed by replacing the 'G' in the second term of equation 2 with an 'H').

During times of expected transmission congestion, smaller coefficient generators are dispatched first followed by larger coefficient generators.

Interconnectors often suffer a complete loss physical dispatch, regardless of their coefficient. This is because they cannot rebid to the market floor price of -$1,000. Often their lack of physical dispatch provides enough volume for the other participating generators to be dispatched for their offered availability.

In some situations, the interconnector can even be dispatched below zero, implying a counter price flow. In these cases, AEMO is required to "clamp" the interconnector and limit exports from the higher priced region when the accumulation of negative inter-regional settlement residue reaches $100,000. NEMDE then backs off the generators with the largest coefficients in the binding constraint first, subject to their ramp rates and other technical inflexibilities presented in their bids.

Commission analysis

In the past, the Commission has commissioned analysis to understand the magnitude and frequency of race to the floor bidding behaviour within the electricity market. For example, as part of the *Transmission frameworks review* in 2013, the Commission engaged ROAM Consulting to analyse the magnitude of disorderly bidding in the NEM.

In their report to the Commission, ROAM Consulting forecast that the impact of race to the floor bidding on system costs would remain relatively stable in the short term. However, they predicted that system costs from disorderly bidding may escalate over the longer term due to increased competition between newer renewable generation entrants with low short-run costs and thermal generation incumbents with relatively high short-run costs.

ROAM Consulting's forward-looking modelling estimated that removing race to the floor bidding could save $8.8 million (in net present value terms) over the 18 years to 2030, with annual savings increasing to $3-6 million in the last five years of the period.

Since the analysis on the cost of race to the floor bidding was conducted in 2013, there have been a number of significant developments in the market. For example, the Commission is concerned that the rise of grid scale storage may further magnify the cost of disorderly bidding.

Forecast development of generation resources with zero or very low marginal cost is also likely to be relevant to this analysis. Consequently, the Commission is considering whether it may be appropriate to conduct similar analysis, in order to obtain more up-to-date figures that take into account recent market developments.

Dynamic regional pricing would provide generators with price signals that better reflect the marginal cost of supplying electricity in that part of the transmission network. This should remove the incentive for generators behind a constraint to bid to the market floor price. This is because higher cost generators would no longer benefit from engaging in race to the floor bidding behaviour. A higher cost generator may make a loss if it makes an offer at the floor price, since it may be dispatched and receive a locational marginal price that is less than its cost of dispatch.

Under dynamic regional pricing:

- If the generator's offer is *less* than the locational marginal price at its node[52], it will be dispatched and achieve an operating profit margin equivalent to the difference between its cost and the locational marginal price.[53]
- If its offer is *above* the locational marginal price, it will not be dispatched.[54] However, this should be preferable to being dispatched and receiving a locational marginal price which will not cover operational costs. Appendix B provides a simple worked example of the incentives that arise under dynamic regional pricing.

An alternative way to think about dynamic regional pricing is that it enables a more efficient allocation of congestion risks and costs. Under the current arrangements, generators currently face *volume* risk. Volume risk is the risk that, due to transmission constraints, generators may not be dispatched despite their offer price being less than the regional reference price. Under dynamic regional pricing, generators would no longer face this volume risk, as dispatch would be a direct function of their offer price and the locational marginal price at their local node.

However, generators would face *price* risk. Price risk is the risk of the generator's locational marginal price being different from the regional reference price. This risk will occur when transmission congestion is present. The implementation of transmission hedges through the access reform package provides a means for generators to manage this price risk.

It is important to note that dynamic regional pricing incorporates all type of constraints that currently exist in the NEM dispatch engine. So, to the extent that NEMDE currently includes non-thermal constraints - such as system security constraints - local prices will reflect this, and so the settlement algebra operates the same under dynamic regional pricing. For example, if a wind generator was constrained off due to a system security constraint, the relevant local price would diverge from the regional reference price.

4.2 Stakeholder views

Stakeholders provided a large number of detailed comments in relation to the dynamic regional pricing model presented in the consultation paper. These comments fell into two broad categories: design issues and impact issues.

In relation to **design issues**, many stakeholders commented that it was difficult to provide meaningful feedback on the dynamic regional pricing model without viewing a more detailed

52 Or equal to the locational marginal price, if it is the marginal generator.

53 In addition to a share of the settlement residue if they hold a transmission hedge.

54 But may still receive a share of the settlement residue depending on whether it holds a transmission hedge.

design proposal.[55] For example, several stakeholders raised questions in relation to how dynamic regional pricing would operate in the context of a meshed network. [56]

Other stakeholders proposed a range of alternative design options for consideration. The key issues raised in relation to the design of dynamic regional pricing included:

- The allocation of settlement residues.[57]
- The price at which load and storage would be settled.[58]
- The treatment of transmission loss factors.[59]
- Detailed issues in relation to the formulation of the locational marginal prices.[60]
- How interconnector flows would be dealt with in determining settlement residues and their allocation, and whether there would be changes to the existing settlement residue auction (SRA) process.[61]
- Appropriate governance arrangements under a dynamic regional pricing regime.[62]

Regarding **impact issues**, while some stakeholders considered that there may be benefits from introducing dynamic regional pricing,[63] others considered that it was not clear whether these would outweigh the costs.[64] Many stakeholders requested additional information on the overall costs and benefits of the reform and further detailed examples of how dynamic regional pricing would operate under 'real life' network conditions.[65]

4.3 Commission's views

As noted in chapter 2, holistic access reform involves changing the following three aspects of the current transmission access framework:

55 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: Delta Electricity, p.1; Aurizon Network, pp. 1-3; Meridian Energy Powershop, p.3; EUAA, p.5.

56 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: TasNetworks, pp.3-4, EnergyAustralia, p.7; AEMO, pp.9-10.

57 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: AER, p.4; Lighthouse Infrastructure, p.4; ERM Power, p.3; Energy QLD, p.7; Monash University, p.6; HRL Morrison & Co, p.4; PIAC, p.12; AEMO, p.9.

58 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: Lighthouse Infrastructure, p.4; Infigen, p.7; ERM Power, p.3; Monash University, p.3; AEMO, p.12; ARENA, p.1; TasNetworks, p.4.

59 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: Aurizon Networks, pp. 1-3; TasNetworks, p.4; Energy Networks Australia, p.7; ERM Power, p.4.

60 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: AEMO, pp.9-10, p12.

61 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: ERM Power, p.2; EnergyAustralia, p.7.

62 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: AEMO, p.10, AER, p.3.

63 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: TasNetworks, p. 2; AER, p. 2; MEU, pp. 3-4; Lighthouse Infrastructure, p. 4; Energy Networks Australia, p. 6; Monash University, p. 3; HRL Morrison & Co, p. 2.

64 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: EUAA, p. 4; EnergyAustralia, p. 9; Brickworks, p. 1; Snowy Hydro, p. 1; CEC, p. 5

65 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, consultation paper submissions: Alinta, p.2; AGL, pp. 3-4; AER, p. 3.

1. **Wholesale electricity pricing:** Under the current framework, generators receive the regional reference price for each megawatt hour of electricity they are able to dispatch to market, regardless of where they locate in a region. We are proposing to change these arrangements so that generators receive a market price that more accurately represents the marginal cost of supplying electricity at their location in the network.
2. **Financial risk management:** Under current arrangements, a generator's ability to receive the regional reference price and earn revenue is a direct function of its physical dispatch. We are proposing to enable generators to better manage the risk of congestion by introducing transmission hedges. These products would hedge against the price differences that may arise under our proposed changes to wholesale electricity prices, allowing generators to rely on a particular revenue flow, regardless of other generator's locational decisions. This should improve investment certainty for prospective generators and may reduce the cost of capital for generation investment in the longer term.
3. **Transmission planning and operation:** Under the current regime, the fact that transmission network and generation investment decisions occur under different processes has the potential to result in infrastructure that does not minimise the total system costs faced by consumers. Additionally, no individual generator is able to guarantee that they will receive value from shared network assets, even if the generator underwrote the investment in the asset. As a consequence of these two factors, consumers bear the risks of transmission investment decisions being incorrect. We are proposing to change this so that transmission planning is influenced by generator's purchase of transmission hedges. In addition, transmission costs are no longer solely recovered from consumers. A portion of these costs would instead be collected from generators through the purchase of transmission hedging products.[66]

As discussed in chapter 7, the Commission considers that dynamic regional pricing should be combined with, and introduced at the same time as, transmission hedging. Dynamic regional pricing is designed to address the first aspect of the transmission framework outlined above: reforming wholesale electricity prices to more accurately reflect the costs of supplying electricity. Transmission hedging is designed to address the second two aspects of the framework: introducing a financial risk management tool for generators, as well as facilitating greater coordination in transmission planning.

A key aim of any transmission access regime should be to provide **efficient price signals** to generators, such that they make operational and investment decisions that reflect the cost of generating and transporting electricity to consumers. Efficiency is promoted when prices reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities.

At times of transmission congestion, the Commission considers that dynamic regional pricing should send the right incentives to generators in order to improve the prospect of the lowest cost combination of generation being dispatched. In addition, the Commission considers that

66 This is possible because the financial transmission hedges are physically backed by transmission capacity. The purchase of hedges by generators creates a liability for transmission companies, who manage that liability by building and operating transmission infrastructure.

dynamic regional pricing would provide greater **transparency and visibility** of the costs of congestion in the NEM.

In the context of the broader access reform package, dynamic regional pricing would assist in **defining the value of transmission hedging products** that would also be introduced. This is achieved by essentially putting a price on the cost of congestion within the system, which should in turn reveal the value of holding a transmission hedge against the dispatch or congestion risks that generators currently face.

Finally, dynamic regional pricing could contribute to **improved locational signals** in investment time-scales, as exposure to locational marginal prices provides better information on the value of locating in different parts of the network.

The rest of this chapter provides more detail on dynamic regional pricing, before discussing how the impacts of dynamic regional pricing may be assessed. Given stakeholders have suggested that they need more information on a dynamic regional pricing regime before assessing the impacts, the Commission has focussed on first setting out *how* the design will work. This will allow stakeholders to consider the impact of dynamic regional pricing on their market operations, and for this to feed into their submissions to the Commission.

4.4 Detailed design of dynamic regional pricing

To provide stakeholders with further information on the settlement arrangements that might apply under dynamic regional pricing, Appendix C sets out key aspects of a high-level settlement design. This provides an explanation of how an access model that incorporates dynamic regional pricing and transmission hedges can be implemented in the context of a meshed network, rather than the simplified radial network models that have been used to illustrate the concepts thus far.

At this early stage of the design process, many design options still exist. In order to set out how settlement **could** operate, the settlement arrangements described in Appendix C are based on several assumptions in relation to the design of dynamic regional pricing. The Commission is open to feedback on these assumptions.

4.4.1 Priority design issues

In the following sections of this chapter, we highlight three design questions that may result in differences compared to the illustrative settlement model described in Appendix C:

1. How should settlement residues be allocated (section 4.5)?
2. Which price should different parties be settled at (section 4.6)?
3. How should losses be treated within the dynamic regional pricing model (section 4.7)?

Naturally, these are not the only design questions that will need to be addressed. Stakeholder submissions to the consultation paper raised many detailed issues that will require further consideration as the design process progresses, which are highlighted in the following section.

However, the three questions above have been highlighted by the technical working group as 'priority areas' for investigation and are therefore the focus of this section of the paper.[67]

Our draft report in September will provide further detail on changes to the settlement arrangements for generators under the new access regime.

4.4.2 Other design issues

The following sections focus on three priority questions in relation to the dynamic regional pricing design, as determined by feedback from the COGATI technical working group.

However, there are a range of other issues that have been raised by stakeholders, that the Commission intends to address through the design process. These issues include (but are not limited to):

- Whether locational marginal prices would be capped at the relevant regional reference price as a way to mitigate local market power. See Appendix C for a more detailed discussion of this issue.
- Whether the current market floor price would apply to locational marginal prices.
- Interactions between the dynamic regional pricing model and distribution networks. For example, it is important to make sure that incentives for parties to locate on either the transmission or distribution network are not distorted.
- Whether there would need to be improvements to the governance, oversight and transparency of constraint formulation in NEMDE.
- Whether there would need to be changes in the data made available to the AER to support its reporting on wholesale markets.
- Whether, under a staged implementation approach, there would be scope to implement a simplified version of dynamic regional pricing prior to the introduction of a more comprehensive package of access reforms (see box below).

The technical working group has also raised questions about whether there are any implications of moving from a 30 minute to a 5-minute settlement process. We consider that this would actually make implementing dynamic regional pricing easier, since 5-minute settlement is expected to remove another form of disorderly bidding that currently exists in the NEM.

BOX 6: AN INTERIM ALTERNATIVE TO DYNAMIC REGIONAL PRICING

Some stakeholders have proposed that the Commission consider the merits of a simplified variant of dynamic regional pricing that may present a pragmatic interim approach to congestion management before the introduction of a comprehensive access reform package.

Under the proposed dynamic regional pricing model, generators would be settled at the

67 See: https://www.aemc.gov.au/sites/default/files/2019-05/Technical%20working%20group%20notes%20-%2028%20May%202019.pdf.

locational marginal price at their transmission node. An alternative approach would be to adopt a more granular version of the existing regional pricing model.

This model would effectively create more NEM regions, with a corresponding 'zonal reference node' and zonal marginal price. These would be analogous to the existing regional reference node and regional reference price. Ideally, the new zones would be defined in relation to patterns of congestion; that is, zonal boundaries would reflect frequent binding constraints, within congestion relatively minimal within each zone.

Load could continue to be settled on the basis of the regional reference price. However, generators would face the zonal marginal price, based on the location of their transmission node within the defined sub-regional zones ('zonal reference nodes'). This model could include a process to auction the rights to the settlement residues that would accrue as the zonal marginal prices and regional reference price diverge.

The Commission is interested in stakeholders' views on whether there would be value in developing this model further, as a potential alternative to dynamic regional pricing under a staged progression to holistic access reform.

4.5 Allocation of settlement residues

Intra-regional settlement residues arise when transmission constraints bind and local marginal prices[68] diverge within a region. Under the current settlement arrangements, this is obscured by the *implicit* allocation of residues to generators based on the level at which they are dispatched.

Settlement payments under the existing market arrangements are recapped below.

BOX 7: CURRENT SETTLEMENT ARRANGEMENTS

$$\text{Settlement\$} = \text{Settlement\$}_{\text{Dispatch}} + \text{Settlement\$}_{\text{Residue}} = \text{LMP} \times \text{G} + (\text{RRP} - \text{LMP}) \times \text{G} \quad \textbf{(2)}$$

Where:

G = Dispatched output

LMP = Locational marginal price

RRP = Regional reference price

The quantity of the intra-regional settlement residue is exactly equal to the physical flow on the line multiplied by the price difference: *G x (RRP – LMP)*.[69] Under dynamic regional pricing,

68 This includes the local marginal price at the regional reference node - the regional reference price.

69 Ignoring losses at this stage, for simplicity.

the quantity of settlement residues would be determined in the same way. However, the allocation of these residues would be decoupled from dispatch:

- The first part of equation 2 above - *LMP x G* - would remain unchanged.
- The second part – which captures the allocation of settlement residues – would no longer be determined implicitly by a generator's dispatched output (G). Instead, if dynamic regional pricing were to be introduced, the allocation of these residues would be made *explicit*.

Under the current arrangements, settlement is always balanced in every dispatch interval, because available settlement residues are automatically allocated to generators in each settlement period.

Therefore, a key design parameter is that settlement should remain balanced under dynamic regional pricing. In order to make sure this occurs, there needs to be consideration about how settlement residues are allocated.

The question on how to allocate settlement residues depends substantially on the approach to **transmission hedges** and whether these are introduced at the same time as dynamic regional pricing.

If a market participant is settled at its locational marginal price, it will likely be exposed to price differences between the locational marginal price at its node and the price at the node(s) it is supplying or being supplied by during times of network congestion. To enable market participants to manage their exposure to the price risk that arises under dynamic regional pricing, the access model contemplated by the Commission would create the ability for participants to obtain a form of transmission hedge.

The transmission hedge element of the access reform package is not considered in detail in this chapter. In practice, how these hedges are created and operate will also impact how settlement residues are allocated (for example, this will depend on the 'firmness' of the transmission hedges).

For the purpose of the following discussion, we adopt a basic definition: that participants with transmission hedges would, in addition to receiving the locational marginal price for the quantity dispatched, receive the difference between the locational marginal price and the regional reference price for the hedge volume purchased.

The following sections consider how the approach to allocating settlement residues under dynamic regional pricing would occur if transmission hedges are introduced at the same time as dynamic regional pricing.

4.5.1 Concurrent implementation of dynamic regional pricing and transmission hedges

If transmission hedges are introduced at the same time as dynamic regional pricing, intra-regional settlement residues can be used to back payments against these hedges.

In this scenario, allocation of settlement residues is no longer determined by dispatch (G), but instead determined by the quantity of transmission hedges held by generators (H). The resulting settlement payments for a generator holding a transmission hedge are expressed below.

> **BOX 8: SETTLEMENT UNDER DYNAMIC REGIONAL PRICES WITH TRANSMISSION HEDGES**
>
> $\text{Settlement\$} = \text{Settlement\$}_{\text{Dispatch}} + \text{Settlement\$}_{\text{Residue}} = LMP \times G + (RRP - LMP) \times H$ **(3)**
>
> Where:
>
> G = Dispatched output
>
> H = Transmission hedge quantity
>
> LMP = Locational marginal price
>
> RRP = Regional reference price
>
> *Note that the hedges may be **options** contracts, and so only pay out if the RRP is greater than the LMP. If so, the holder of the hedge would not receive a negative payment (that is, have to make a payment) if LMP is greater than RRP.*

If the quantity of transmission hedges held (H) is different from the physical flow on the line (G) in a settlement period, settlement will not be balanced.

In particular:

- If the transmission capacity (G) is greater than the amount of hedges that are held (H) in a particular part of the network, there will be excess settlement residues. Put differently, there will be an amount of settlement residue that remains unallocated.
- If the transmission capacity is less than the aggregate amount of transmission hedges[70], then the quantity of settlement residue will be less than the amount needed to fully pay out the relevant generators.

However, as noted above, a key design parameter is that settlements should balance. Therefore, there needs to be choices made about how surplus and deficits of settlement residues are accounted for.

So, if there are surplus residues (i.e. cases where H<G), these would need to be allocated somewhere. If there are residue deficits (i.e. cases where H>G), payouts against transmission hedges would need to be scaled back accordingly. These are considered in turn below.

4.5.2 How could surplus settlement residues be allocated?

One approach discussed in the consultation paper was that the settlement residues that remain after taking transmission hedges into account could be allocated to generators on the basis of their **availability**.

70 For example, due to an outage on a network asset.

Potential advantages of this allocation approach are that:

- Availability could be considered to be a proxy for *preferred output*. Preferred output being the level of dispatch that a generator would choose if it were not dispatched, despite offering at a price less than the regional reference price. This could be considered a fair basis for allocating remaining settlement residues.
- It is similar to the *de facto* allocation of settlement residues under the existing arrangements. For example, when two generators behind a radial constraint both bid at the market floor price, NEMDE will dispatch them in proportion to their available capacity.
- It could assist in managing the transitional impact of access reform implementation on existing generators.[71] That is, even if generators opt not to purchase transmission hedges, they could still potentially receive a portion of settlement residues that may be similar to their existing allocation.

However, the Commission's analysis has identified a number of significant disadvantages with the approach outlined above. In particular:

- Whether generators without transmission hedges receive a share of settlement residues would depend substantially on the actions of other generators. Once transmission hedges are purchased, the quantity of unallocated settlement residues is reduced.

  Therefore, the effectiveness of this approach as a transitional measure to mitigate impacts on existing generators is likely to be limited. While the transitional objective is an important aspect of the reform package, this is likely to be best achieved through explicit and customised arrangements which are time-limited and do not impact the decision-making of future generators.
- Settlement arrangements to implement an availability-based allocation approach could be designed. However, availability may require careful definition.
- This approach provides generators that have not purchased transmission hedges with the potential to access a portion of settlement residues at no cost. As raised by stakeholders in response to the consultation paper, the existing transmission system has effectively been funded by consumers. This may provide an argument that unallocated settlement residues should instead be used to offset transmission use of system (TUOS) charges.
- Finally, the potential to receive an uncertain share of settlement residues at no charge complicates the decision of generators in determining the value of transmission hedges. Uncertainty around the value of transmission hedges could contribute to lower demand for these products, with potential implications for the level of trading and liquidity.

4.5.3 Alternative approaches to surplus settlement residue allocation

These factors suggest that it would be appropriate to consider alternative approaches. The alternative approaches identified by the Commission are based around a concept where generators that do not hold transmission hedges would only receive the locational marginal price at their node. The remaining settlement residue could then be either:

71 Note, other transitional arrangements are expected to be developed as part of the access reform package being considered through this process.

- allocated to consumers via a reduction in their TUOS charges, or
- allocated to a fund that could be then used to firm up transmission hedges for those generators that had purchased hedges[72] The need for this may arise because, during any given dispatch interval, the transmission capacity may be less than the aggregate amount of transmission hedges. This means that the quantity of settlement residue will be less than the amount needed to fully pay out against all transmission hedges held.

Either of these approaches could address the disadvantages noted under the availability-based allocation model outlined above. The main disadvantage of these approaches is that it removes a potential option to assist generators in managing the impacts of the new access model, were this to be implemented.

Both of the above approaches would also minimise TUOS charges. In the first case, this occurs directly. In the second case, this would increase the attractiveness of the transmission hedges, increasing their value, and so increasing the amount of money that generators may spend on them, with the proceeds from these being used to offset TUOS.

However, as noted above, the merits of an availability-based allocation approach as a transitional measure may be limited and other types of transitional mechanisms may be more effective.

4.5.4 Summary

The preceding sections have set out different approaches to allocating settlement residues under dynamic regional pricing. The approaches discussed are summarised in the table below.

Table 4.1: **Options for settlement residue allocation**

SCENARIO	OPTIONS
1. Concurrent implementation of dynamic regional pricing and transmission hedging.	A. Primary allocation on the basis of transmission hedges held. Surplus residues allocated to generators without transmission hedges, on the basis of availability.
	B. Primary allocation on the basis of transmission hedges held. Surplus residues used to offset TUOS charges.
	C. Primary allocation on the basis of transmission hedges held. Surplus residues support fund to increase the firmness of transmission hedges (i.e., to offset scaling back transmission hedge settlement payments when the hedge volume exceeds available transmission capacity).

72 A hybrid option could also be developed whereby these funds may be allocated to consumers via TUOS periodically if they became too large.

QUESTION 1: ALLOCATION OF SETTLEMENT RESIDUES

- Do stakeholders agree with the main advantages and disadvantages identified in relation to the different approaches for allocating settlement residues?
- Of the approaches identified under each implementation scenario, which do stakeholders think best meets the design principles (set out in Appendix A)?
- Are there alternative approaches that should also be considered under each implementation scenario?
- What other factors or information would stakeholders consider relevant to determining the preferred approach?

4.6 Scope of dynamic regional pricing

The preceding discussion on dynamic regional pricing has focussed on *generators* being exposed to the locational marginal price at their node. Under the current arrangements, load and storage are settled at the regional reference price.

Stakeholder submissions to the consultation paper provided a range of views on whether load and storage should also be subject to dynamic regional pricing. As noted inchapter 3, the locational marginal pricing approaches suggested by stakeholders are simply variants on dynamic regional pricing, where both generation and (some) load would face the local price.

In particular, there are options in relation to:

- What type of generators should be settled at locational marginal prices.
- Whether (some categories) of load or storage should be settled at locational marginal prices, or have the option to be settled at locational marginal prices.

To the extent that some market participants are not settled at their locational marginal price, there is a supplementary question of whether these participants should continue to be settled at the regional reference price, or at an alternative regional price. For example, this could be a volume-weighted average of the locational marginal prices (at nodes with load) in a region.

4.6.1 Relevant issues

The Commission's initial analysis suggests that the following issues are relevant in determining which parties should be settled at a locational marginal price or the regional reference price:

1. Impacts on forward contract markets and risk management.
2. Impacts on the complexity of settlement processes.
3. Implications for the settlement residues that are created through dynamic regional pricing.
4. The ability of different market participants to respond to the signals created by dynamic regional pricing.

5. The need to establish a technology neutral basis for determining which participants would be exposed to locational marginal prices or the regional reference price.
6. Distributional considerations.

These issues are explored in further depth below.

4.6.2 Forward contract markets and risk management

The NEM's existing regional pricing model was designed to promote liquidity in forward contract markets by allowing all generators and retailers in a given region to trade with each other on the same basis and facilitate contracting around a common 'strike price' at which all load and generation is settled.

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.[73]

If (some) load were to face a locational marginal price instead of the regional reference price, there may be a risk of splitting liquidity in the contract market, as forward contracts would potentially instead need to be struck against many different local prices. However, this may not be the case. The Commission understands that, in overseas markets with nodal pricing, contracts are still focussed around several key nodes.

The Commission is investigating this issue as part of its broader analysis on the implications of dynamic regional pricing for contract market liquidity. It will also be important to consider interactions with other aspects of the access reform package, for example, the structure of transmission hedges and how this might impact the ability of different participants to contract with one another.

In assessing which participants should face a locational marginal price, it is also relevant to consider broader implications for risk management. For example, a relevant consideration for whether load should be able to 'opt-in' to locational marginal pricing is the ability of different market participants to make an informed choice between their local price and regional reference price.

A decision on which price would be most advantageous depends on:

- the relative average levels of the pricing alternatives
- the ability of the participant to respond to these prices
- the opportunity and cost of obtaining hedges against the locational marginal price or regional reference price
- the risks of remaining unhedged, relating to the volatility of the locational marginal price or regional reference price.

73 Increased financial certainty should be reflected in a lower risk-adjusted cost of capital. The higher level of certainty should also make investment in the electricity sector more attractive than it otherwise would be.

However, these decisions are complex, and would add complexity to a retailer's hedging strategy. It is also important to recognise that loads are different from generation. Generation assets are built for the primary purpose of selling energy in the wholesale market. In contrast, loads are built by providing services or goods to be sold in different markets. Energy is an important input for load customers, but they may have limited choice over where to locate and what energy source to use. These considerations should also be taken into account.

4.6.3 Settlement processes

Under the dynamic regional pricing model, the settlement algebra will need to reflect which participants locational or regional pricing applies to.

Although the settlement algebra under dynamic regional pricing and transmission hedges may be considered to be mathematically complex, its implementation is expected to be relatively straightforward, because most of the information required is present in the existing NEM dispatch engine process (as described in Appendix C).

However, the Commission's initial analysis suggests that this only holds when all **non-scheduled** load and generation faces the regional reference price and all **scheduled (and semi-scheduled)** load and generation faces a locational marginal price. Because NEMDE is designed for scheduling, its constraint formulation separates these two categories, reflecting that non-scheduled load and generation are not controlled through the dispatch process.

As a result, if some non-scheduled load or generation were to face local prices, the existing information produced by NEMDE may no longer be able to be used in the settlement process. Therefore, allowing some non-scheduled loads to face the locational marginal price at their load would be likely to add significant complexity to the design of the access reform package. The Commission is continuing to explore the potential design and cost implications.

4.6.4 Settlement residues

When locational marginal prices diverge as result of transmission constraints, settlement residues arise due to differences in the price paid by load and received by generation. Settling (some) load at its local price may have implications for the quantity of settlement residues that arise, and so the level of financial payout that generators would receive under their transmission hedges.

Whether the quantity of settlement residue in any given dispatch interval would increase or decrease as a result of some load facing local rather than regional pricing is a function of whether the locational marginal price is greater or less than the regional reference price:

- If the local price is greater than the regional price, then the settlement residue will increase as load is paying more into settlement than would otherwise be the case.
- Conversely, if the local price is less than the regional price, then the settlement residue will decrease.

If dynamic regional pricing is introduced concurrently with transmission hedges, settlement residues would be used to back the payments that would arise as a result of these hedging instruments. To the extent that settlement residues are not sufficient to meet these payments, hedging payments may need to be scaled back, reducing the firmness of the hedge.

Therefore, the implications for settlement residues of settling some or all load at the regional reference price will need to be carefully considered. In determining these implications, it will be relevant to consider the circumstances under which settlement residue deficits could arise, as well as the potential magnitude of these deficits and the resulting implications for transmission hedges.

There are other aspects of the access reform package that will need to be taken into account. For example, TNSPs may have both obligations and incentives to avoid scaling back hedge payments.

The above discussion should not be taken to mean that settling load at a local price that is lower than the regional reference price would be inappropriate, purely because this might reduce settlement residues. By being settled at a regional reference price that is higher than its local price, load could be seen as contributing (arguably unnecessarily) to settlement residues. From this perspective, settling load at its local price would be simply unwinding these contributions.

4.6.5 Responsiveness to price signals

A key objective of introducing dynamic regional pricing is to improve the efficiency of dispatch by removing incentives for disorderly bidding. Differences between local and regional prices are also expected to provide additional locational signals in investment time-scales.

The extent of potential efficiency gains that could result from these signals depends on both the magnitude of the difference between the local and regional price, and the responsiveness of market participants. Therefore, a decision on the benefits of extending locational marginal pricing to a broad selection of market participants may depend on which participants are likely to respond to these locational signals.

One way that market participants could potentially respond to expected high or low local prices would be to choose a different location for a load or generation site. However, this is likely to be feasible only for new sites.[74] Further, given that there will be several factors affecting the choice of location, the impact of facing locational marginal pricing is likely to be a material factor only for a party whose costs or revenues are dependent on electricity.

4.6.6 Technology neutrality

It is desirable that the decision as to which market participants face local or regional prices be technology- and configuration-neutral, to avoid creating incentives for participants to make perverse decisions, simply to gain access to a more favourable price.

74 Although, it is possible that existing batteries could potentially be relocated to a different point in the grid.

As outlined below, the evolving nature of the energy market creates a number of potential complications in establishing a technology neutral definition.

Behind-the-meter resources

It is straightforward to identify an individual load or generator, where these are individually metered and separately sited. However, in some cases these parties may be co-located and/or co-metered.

A load that is co-metered with a generator might appear to be negative generation, or might result in the generator appearing to be a load. As a result, determining the price that a participant should face on the basis of whether they are a 'load' or 'generator' will be difficult in this context.

For example, if a decision was taken that generators would face locational marginal prices and load would face the regional reference price:

- A load that is co-located with a generator, appearing as negative generation, would face a local price, while an equivalent separate load would continue to face the regional price. On the other hand, ensuring that all load faces the regional price in both cases would require separate sub-metering within the party’s premises.
- If generation were to be defined based on a metric such as net positive output over a period (for example, 5-minutes or a year), the effect of a co-located load could potentially cause their status to switch from one status – and price – to the other, with the consequent effects on the settlement process.

Similarly, if the pricing decision were to be based on the size of different market participants (for example, larger generators would face local prices and smaller generators would face regional prices), a co-located load could reduce the apparent size and so affect the price that the generator faces.

Storage

Storage cycles between having characteristics similar to a generator (when discharging) and a load (when charging). Where storage is treated differently to load or generation, one or other of these components might be treated on a more or less advantageous basis than its simpler counterpart. This might encourage a party to design its storage resource to resemble a separate load and generator, or, conversely, to design a separate load and generator to look like storage.

A hydrogen electrolyser provides one example. It produces green hydrogen that can then be used to fuel a generator (gas turbine or fuel cell). Depending upon how storage was defined for the purpose of determining which parties face which price, the electrolyser load may or may not be treated as part of a storage scheme. For example, this could depend upon whether the generator is on the same site or whether the hydrogen is piped to a generator on a remote site. There might also be scope for other load or generation that is co-located with the storage scheme to be treated as part of that scheme, rather than as a separate entity.

Virtual Power Plants and Demand Response

The Commission is currently considering a rule change proposal that would effectively allow a consumer to separate its load into two components: conventional load and demand response (DR).[75] The former would be supplied by a retailer under the existing arrangements, while the latter could be sold to a demand response aggregator. A virtual power plant (VPP) involves aggregating and coordinating these DR components and trading them in the spot market similarly to a generator.[76]

A key aspect of VPP or DR that differentiates these resources from other co-located generation and load is that the load and DR components are not separately metered, or even (necessarily) related to distinct appliances or devices. Rather, the load is determined with reference to a baseline level, determined by applying an algorithm to the load history.

The DR component is then the difference between the baseline and the actual (metered) level. If VPP/DR and load were in different categories for the purpose of determining the application of regional or local pricing, this baseline would determine how much of the consumption would be settled at the regional reference price and how much at the locational marginal price.

It is also relevant to note that as VPPs co-exist with load, they will likely tend to be located in load centres rather than in remote parts of the network. Therefore, because most load is located in and around the regional reference nodes, price differences between locational marginal prices and the regional reference price are expected to be relatively small in most VPP locations.

4.6.7 Distributional considerations

In considering whether it would be appropriate for load to face the locational marginal price, questions of distributional equity arise. For example, fairness considerations and community expectations might mean that it is desirable for rural and urban customers to face similar wholesale prices (otherwise rural customers may face higher costs due to be further away from traditional load centres). Noting that local prices will vary to some extent based on location, this perspective might suggest that it would be preferable for load to continue to face a common regional price.

It is also worth noting that load is not like generation. Generation is built specifically to supply energy into the wholesale market. In contrast, load, while having electricity as a key input, is primarily occupied with whatever its key business is e.g. producing widgets.

4.6.8 Proposed approach

Based on the issues outlined above, the Commission has developed a proposed approach in relation to which market participants should face local or regional pricing in order to test this with stakeholders. Stakeholder feedback is welcomed in relation to this approach.

Under the proposal:

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75 *Wholesale demand response mechanism.*

76 It is not yet clear whether these resources would be scheduled or non-scheduled.

- All scheduled and semi-scheduled market participants (i.e. generation, load and storage) would face their locational marginal price.
- All non-scheduled participants - both load and generation - would face the regional reference price.[77]
- Parties would not otherwise be able to opt in or out of facing a locational marginal price. Parties would, however, have the option of becoming scheduled[78] should they wish to face their local price.

The rationale for this proposal is outlined below.

First, this approach provides for locational marginal pricing to apply to those participants which are most likely to have the **greatest ability and incentive to respond to spot price signals**, in both the short-term and the long-term. For example, scheduled and semi-scheduled generation are likely to be the most responsive to price: both in the long-term choice of investment location and in the short-term response to spot prices.

Non-scheduled generation may in some cases have similar price responsiveness to scheduled generation, although this response will be autonomous rather than being determined through the bidding and dispatch process. It is therefore possible that non-scheduled generators in certain zones might wish to face a locational marginal price, given that it might be higher on average than the regional reference price. Load is typically not as price responsive as generation, because many other factors affect the long-term choice of location and the short-term choice of consumption level.

Much load is located in the metropolitan regions of state capitals, where locational marginal prices are likely to be very similar to the regional reference price. Few loads currently face wholesale prices, with most subject to fixed retail tariffs, although in some of these cases the retailer may request that the load responds to the wholesale price on their behalf. However, as with non-scheduled generation, it may be the case that larger loads in certain zones might wish to face a locational marginal price, if this is expected to result in a more favourable price.

In these cases, the approach provides **flexibility** by allowing participants to access locational marginal pricing by **choosing to become scheduled.** As there are costs associated with being scheduled, it is expected that the choice to become scheduled in order to obtain a more favourable local price would only be taken up by the largest or most price-responsive loads or non-scheduled generation resources.

For example, if a specific local price was similar to the regional price on average but could sometimes be higher and sometimes lower, only a price-responsive load would benefit from being settled at the local price. This suggests that, under the requirement to become scheduled in order to access locational marginal prices, any migration from regional to local pricing should promote efficiency gains.

77 It would actually not be feasible in the current form of the NEM dispatch engine for these parties to be settled at the LMP, since NEM dispatch engine does not specifically account for these parties given they are not scheduled.

78 To the extent this is an option available to them in line with existing processes.

However, the Commission recognises that becoming scheduled is potentially a significant hurdle for an industrial customer, 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[79] and a scheduled load would need to constantly rebid in order to remain dispatch compliant.

Allowing only scheduled participants to access locational marginal prices may increase the incentives to become scheduled. A load or non-scheduled generator 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 to become scheduled (where this is likely to be efficient).

In principle, the *converse* might apply: in a zone with high local prices, a responsive load might be discouraged from becoming scheduled. However, given that only storage loads have opted to become scheduled under the current rules, and since these loads can easily avoid a high local price by not charging/pumping at those times, this effect may not be significant.

The approach outlined above also supports a **technology neutral** approach to the application of dynamic regional pricing. As described above, storage could be considered to consist of a pairing of generation and load. If, when part of a storage system, these two components are treated differently to their individual counterparts, perverse design incentives might be created.

Under the proposal, storage is treated in an analogous way to both generation and load, by facing a locational marginal price if it is scheduled and the regional reference price if it is non-scheduled. However, we expect that – as with generation and load:

- some categories of storage might be mandated to be scheduled
- other categories will have the choice of being scheduled or non-scheduled.

All large-scale storage load must currently be scheduled. Providing that scheduled storage faces a local price is likely to add further to the incentives to be scheduled, because local prices will typically be more volatile than regional prices and storage can benefit from price volatility.[80]

Finally, the proposed model aims to strike an appropriate balance in relation to the cost and complexity the dynamic regional pricing design. The Commission's analysis suggests that the scheduled / non-scheduled approach leads to the simplest algebra for settlement under dynamic regional pricing, as this means that the existing NEM dispatch engine constraint formulations can be used in the settlement process.

This approach also simplifies the design by having a single set of regulations for determining scheduling and pricing status. The rules for defining scheduled and semi-scheduled generation have been developed over time and are now robust and well-understood by market participants.

79 For example, the factory may need to consume electricity to meet an urgent order.

80 Through purchasing electricity when the local price is low and discharging when it is high.

As noted above, it is recommended that non-scheduled load continues to pay the regional reference price. The Commission's proposed approach is to align the treatment of VPPs and non-scheduled load. If VPPs were to face local prices, instead of the regional reference price faced by non-scheduled load, there would be a need to separate out the VPP and load components at the customer, retailer and transmission-node levels. This would likely lead to higher costs and complexity.

As regional-local price differences are expected to be small for VPPs, to the extent that they would tend to be located close to the regional reference node, it could be the case that the efficiency gains from allowing VPPs to face locational marginal prices would outweigh the costs. It may be prudent to revisit this position if the design and status of VPPs in other areas changes – for example, scheduling status.

QUESTION 2: SCOPE OF DYNAMIC REGIONAL PRICING

- Do stakeholders agree with the above analysis in relation to the advantages and disadvantages of allowing different categories of market participant to be settled at locational marginal prices?
- Do stakeholders consider that the scheduled / non-scheduled distinction offers a sensible basis for determining which parties should face local or regional pricing?
- Are there other impacts that should be considered in this decision?
- What additional information do stakeholders consider would be useful to inform this decision?

4.6.9 Choice of regional price

To the extent that certain market participants are not settled at the local marginal price, there is a supplementary question over whether these participants should continue to be settled at the regional reference price or at an alternative regional price.

For example, stakeholder submissions have proposed that instead of being settled at the existing regional reference price, load could instead be settled at the volume-weighted average of the local marginal prices in a region[81]

This is similar to the approach taken in US markets that have adopted a form of locational marginal pricing (in this context, the approach is termed 'load aggregation pricing', or LAP).

The Commission considers are several issues that are likely to be relevant in assessing this approach in the context of the NEM.

First, there are implications for the amount of **settlement residue** that is created through dynamic regional pricing. This might depend on the differential between the regional reference price and a load aggregation price. The scale of the difference may depend on the location of load.

81 This would be calculating used the transmission nodes where load was located.

For example, in the NEM, most demand is located in the metropolitan region around each state's capital. In many cases, this corresponds with the regional reference node. Queensland and Tasmania are exceptions, given that they have substantial load remote from the regional reference node.[82]

In this context, the difference between the regional reference price and a load aggregation price (and therefore the actual impact on settlement residues of choosing either approach) is potentially smaller than would be the case in other markets. However, future patterns of load and generation will also need to be taken into account.

Potential implications for **market power** would also need to be considered. For example, stakeholder submissions have suggested that, if the RRP is preserved and generators are able to obtain a share of settlement residues, generators may have an incentive to induce congestion through their bidding in order to increase the size of these residues.

The impact on the **complexity** of the market design is a further consideration. The Commission's initial analysis suggests that, compared to retaining the regional reference price, adopting a LAP approach could potentially require more amendments to existing settlement processes and more complex settlement algebra. However, this requires further evaluation.

Finally, a shift to settlement based on LAP would likely have implications for the **forward contract market**, given that existing contracts reference the regional reference price.

The Commission intends to explore the combined impact of these factors with stakeholders during the detailed design phase.

QUESTION 3: CHOICE OF REGIONAL PRICE

- Under the proposed model, some categories of market participant would continue to face a common regional price. Do stakeholders agree that the issues outlined above are relevant for assessing whether this regional price should be the existing regional reference price or an alternative (for example, a LAP approach)?
- Are the other issues that should be considered?

4.7 Losses

In the electricity system, as electricity flows through transmission and distribution networks towards end customers, a portion of that electricity is 'lost' due to physical factors such as electrical resistance. These losses increase as more generation connects in locations that are distant from load centres.

82 In Queensland a significant proportion of load is remote from the regional reference node, which is in Brisbane. In Tasmania, the regional reference node is on the north coast, at George Town at the Tasmanian end of the Basslink interconnector, not in Hobart.

Marginal loss factors (MLFs) reflect the impact of electricity losses along the network and are applied to market settlements in the NEM, and thus affect generator revenues. They represent electricity losses along the transmission network between a connection point and the regional reference node.

The MLF at the regional reference node is set at 1.0 by definition. For the purpose of dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price, multiplied by the MLF. So if losses are included in the description of current settlement arrangements from section 4.1.1:

BOX 9: LOSS-ADJUSTED SETTLEMENT

Settlement$ = RRP x MLF x G

Where:

G = Dispatched output

RRP = Regional reference price

A higher MLF is beneficial from the perspective of the generator, because it means that more of the generator's electricity is reaching end customers. Therefore, generators with a lower MLF will appear to be more expensive at the regional reference node. This can lead to a generator being dispatched behind another generator who offers the same price, but has a higher MLF.

For renewable generators, MLFs affect their revenue not only in terms of wholesale market transactions, but also due to the large-scale generation certificates that are created if the generator is accredited under the federal large-scale Renewable Energy Target. This is because MLFs are a factor in determining how many certificates such a generator can receive for its output. As a result, changes in MLFs can impact the financial viability of a generator.

Because MLFs are calculated on a marginal rather than average basis, the MLF represents the electricity losses that would occur if one additional megawatt of electricity was generated at that connection point. The marginal approach is consistent with how most other aspects of dispatch and pricing operate in the NEM, on the basis that marginal pricing is considered to lead to the most efficient outcomes.

One consequence of applying marginal loss factors is that this leads to over-recovery relative to actual losses in the system. As a result, a settlement surplus accrues. Under the NER, settlement residues that arise due to intra-regional loss factors are distributed to or recovered from the relevant TNSP, and are used to offset TUOS charges paid by consumers.

Currently, AEMO calculates and publishes MLFs every year by 1 April as required under clause 3.6 of the National Electricity Rules (NER), ahead of the new MLFs applying from 1 July. These figures are forward-looking projections based on expectations of the demand and dispatch patterns of the upcoming year, as well as the network flows and losses that are expected to occur during that year.

While the Commission understands that historically investors have sought to forecast MLFs, this is becoming harder given the scale of investment and topography of the network. Consequently, there is a lot of concern within the industry regarding the potential for significant year-on-year fluctuations in MLFs.

MLFs are currently the subject of two rule change requests submitted by Adani Renewables. The first request relates to changes in the reallocation of intra-regional settlement residue (IRSR) under the NER. Adani Renewables has proposed that the allocation of IRSRs should apply equally to both generators and certain categories of network users. It has expressed the view that this change would lead to fewer losses for generators as well as more competitive generation bidding.

In a second rule change request, Adani Renewables is seeking to have the MLF methodology that is currently applied by AEMO replaced by an *average* loss factor methodology. Adani Renewables has expressed the view that this change would lead to fewer losses for generators and customers, as well as a more accurate reflection of the cost of generation.

4.7.1 Relationship to dynamic regional pricing and access reform

There are two potential ways in which the treatment of losses could interact with the access reform package:

1. There could be changes to the way that losses are incorporated into pricing and settlement.

Under dynamic regional pricing, dynamic loss factors could be used, with these factors varying with the level and direction of flows. In other words, the locational marginal price would reflect the loss factor at a particular point in time.

Other changes could also be considered. In the context of the Adani Renewables rule change requests noted above, the Commission is considering a range of alternative approaches to calculating loss factors, including the merits of marginal and average calculation approaches and forward- and backward-looking approaches. The Commission is also considering different approaches to applying loss factors, including:

- Continuing to apply a single intra-regional loss factor that applies over a financial year.
- Using different values for each week, month or quarter, which may potentially reflect seasonal effects on the flows in the transmission system.
- Using peak and off-peak loss values (potentially combined with seasonal values).
- Using loss factors that apply for multiple financial years.
- Using real-time loss factors that are calculated every trading interval to better reflect system conditions.

Stakeholders have proposed alternative approaches, including:

- Applying a 'collar and cap' mechanism to MLFs, such as setting a band within which MLF values must fall, or setting a constraint on the amount by which MLFs could change when revised by AEMO each financial year.

- Applying a grandfathering approach, by assigning more favourable MLFs to existing transmission connection points.

There will be close coordination between the COGATI review and the transmission loss rule change project, in order to ensure that consideration of these options is aligned between the two work streams.

2. The design of transmission hedges could, potentially, also provide opportunities for generators to manage their exposure to loss factors.

The Commission is currently exploring the scope for incorporating losses into the design of transmission hedging instruments and intends to test these options with stakeholders as this work progresses.

QUESTION 4: LOSSES

- Noting that the Commission will be considering the merits of different approaches to calculating and applying loss factors in relation to the Adani Renewables rule change requests, what are stakeholders' views of the advantages and disadvantages of the different approaches outlined above, in the specific context of the dynamic regional pricing model outlined in this chapter?

4.8 Assessing the impacts of dynamic regional pricing

This chapter has aimed to provide stakeholders with additional information on the high-level design options for the dynamic regional pricing model. In developing the detailed design, the Commission intends to carefully examine the potential impacts of different design choices, as well as the overall cost and benefits of the reform.

4.8.1 Expected impacts of the reform

As described in section 4.1, dynamic regional pricing plays four key roles in the context of the broader access reform package:

- improving the efficiency of dispatch;
- increasing the transparency of congestion costs within the NEM;
- defining the value of transmission hedges; and
- improving locational investment incentives.

The main 'standalone' benefit of dynamic regional pricing relates to the first role - improving the efficiency of dispatch by removing incentives for race to the floor bidding.

Any reform has to be in the long-term interests of consumers, and so the Commission will need to consider the impact of the reform on the market. In particular, the Commission considers the following issues to be key to the assessment of the impacts of reforms.

These issues were also raised by stakeholders in submissions to the consultation paper:

- The impact of dynamic regional pricing on **market power and bidding incentives**. For example:
  - The ability and incentives for market participants to exercise pricing power at their local node.
  - Whether dynamic regional pricing could create incentives for generators to manufacture congestion in certain situations.
  - The consequences of dynamic regional pricing in an environment where the marginal cost of generation at many nodes is likely to be close to zero (noting that dynamic regional pricing will not result in local prices diverging from the regional reference price unless there are transmission constraints).

  To examine these issues, the Commission will develop a set of 'reference scenarios' that will be used to better understand the impacts of dynamic regional pricing in terms of market power, bidding incentives and contracting incentives.

  For example, one such scenario will be a load pocket being a load centre remote from the regional reference node with relatively low levels of local generation resources and transmission links. In this scenario, when transmission constraints arise, local generation resources may be at times be dispatched to supply the local load, even though their offer price is above the regional reference price.
- How dynamic regional pricing would impact the extent of **settlement risk and volatility of revenues for generators**, compared to the current arrangements.

  The introduction of dynamic regional pricing does not introduce a new net risk to generators. Under the current arrangements, generators face volume risk i.e. the risk that, due to transmission constraints, they may not be dispatched despite their offer price being less than the regional reference price.

  Under dynamic regional pricing, generators would no longer face this volume risk, as their volume dispatch would be a direct function of their offer price and the locational marginal price at their transmission node. However, they would face price risk. The Commission is keen to under the implications of this.
- Impact on **race to the floor bidding behaviour,** as discussed earlier in this chapter.
- The overall expected impact on **forward contract market liquidity**. For example:
  - Whether the complexity involved in managing a 'three part' risk (congestion, local marginal price, settlement residue) reduces the willingness of supply-side participants to offer primary hedge capacity.
  - Whether addressing 'race to the floor' bidding would increase the ability of market participants to offer contracts.
- Whether the introduction of dynamic regional pricing would be likely to **trigger change of law clauses** under existing power purchase agreements (PPAs), and if so, the potential magnitude of this.

- The **time and cost** associated with required changes to AEMO and market participant systems and processes. The AEMC will work closely with AEMO to understand the cost implications of the proposed reforms.

QUESTION 5: EXPECTED IMPACT OF THE REFORMS

- Do stakeholders agree that these issues are relevant in assessing the impact of dynamic regional pricing?
- Other there other issues that should be considered?
- What scenarios should be used as reference scenarios in considering market power concerns?

5 TRANSMISSION HEDGING

This chapter provides:

- a summary of the approach to introducing transmission hedges put forward in the consultation paper
- stakeholder views on the proposed approach
- the Commission's position on how transmission hedges may be progressed forward.

5.1 Background

In the consultation paper for this review, the Commission recommended a phased reform approach to the way in which generators access the shared transmission network. The third and final phase of the reform introduced the notion of transmission hedging (which were called 'firm transmission rights' in the paper). Under this phase, generators would be able to buy a transmission hedge in return for contributing to the costs of the shared transmission network.

When there is congestion on the network, local prices diverge from one another (including the regional reference price, which is the local marginal price at the regional reference node). Transmission hedging would allow generators to manage the price risk they face at times when there is congestion within the network. Generators with transmission hedges would receive the difference between the local marginal price and regional reference price for the hedge volume purchased, regardless of the quantity of electricity they physically dispatch. They would receive this payment in addition to any wholesale revenue earned from dispatching electricity to the spot market.[83]

In contrast, generators without transmission hedges would be subject to basis risk. In cases where transmission constraints bind, the local price would likely be less than the regional reference price. The basis risk in the model is not a new risk - it is a recasting of the existing volume risk that generators face from being constrained off in the current arrangements. By having local marginal pricing we are able to create financial instruments which hedge the price differences between nodes, and so manage the risk of congestion. This is something that is not possible under current arrangements.

Under the model of transmission hedging outlined in the consultation paper, the financial proceeds from the purchase of transmission hedging products would go towards underwriting transmission investment. Transmission businesses would be obliged and financially incentivised to provide a level of network access consistent with the amount of transmission hedges there were held by generators. This will allow for better coordination between generation and transmission investment and operations.

83 This revenue would be paid at the local marginal price, rather than the regional reference price.

5.2 Stakeholder views

In response to the consultation paper, many stakeholders expressed support for a reconsideration of transmission hedging for generators.[84] However, they also noted that there are substantial design details that still need to be worked through in order for reform to be effective.

Several generators, networks and equity investors were opposed to considering transmission hedging for generators. This concern mostly arose around concerns about the uncertainty that the proposed reform may create in an already volatile investment environment.[85] Key comments from stakeholders on the design and impact risks of a hedging regime are summarised below.

5.2.1 Comments on the design of transmission hedges

Stakeholders provided the following detailed comments for the Commission on the potential design of a transmission hedging regime.

Transmission planning

AEMO, TasNetworks and Infigen Energy were of the view that it may be more prudent to allow the aggregate amount of hedges available for purchase by generators to be capped at the level of existing and planned transmission capacity that is identified through a regulated planning process.[86]

AEMO and TasNetworks noted that all international power systems continue to rely on a high degree of centralised coordination and decision-making. They were of the view that this international experience suggests that, due to the episodic and lumpy nature of transmission investment, the cumulative decisions of disparate commercial investors have not delivered optimal transmission investment.

AEMO considered that the NEM should be designed to incorporate the commercial decisions of market players so far as possible, but it should also use other sources of information to determine the optimal development of the power system. Changes to the access regime should enhance, rather than replace, the planning regime through the provision of clearer locational signals and the ability of generators to invest in transmission access.

Delta Electricity queried how the model would interact with the current regulatory investment test for transmission (RIT-T) process. The current cost benefit test requires cost-based modelling to determine net market benefits. Delta Electricity considered that while generators initially pay for transmission investment under the proposed reform, the ongoing costs are

84 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Alinta, p. 2; Flow Power, p. 1; ERM Power, p. 4; Lighthouse Infrastructure Management, p. 1; Neoen, p. 2; MEU, p. 3; EUAA, p. 3; AER, p. 4; AEMO, p. 5; ARENA, p. 1; ENA, p. 3; Spark Infrastructure, p. 2; Aurizon, pp. 1-3; PIAC, p. 11.

85 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Energy Queensland, p. 9; TasNetworks, p. 2; Infigen, p. 8; Stanwell, p. 8; HRL Morrison & Co, p. 5; Snowy Hydro, p. 5; Intergen Australia, p. 1.

86 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: AEMO, TasNetworks, p. 7; Infigen Energy, p. 10.

passed on to consumers and an assessment of the long-term market benefits should still be considered in some form.[87]

Firmness of transmission hedges

ERM Power was concerned about the level of firmness of the transmission hedges available for purchase by generators. ERM Power was concerned that the hedge might have the potential to be scaled back under some network conditions, leaving the generator exposed to basis risk between its nodal price and the regional reference price. It argued that this increased basis risk would be reflected in both the pricing and the level of volume offered for financial contracts to the market, and may result in the increased costs of supply to consumers.[88]

Security constraints

AEMO was of the view that an access regime that is focussed on thermal constraints only will not deliver investment certainty if generators are required to be constrained off for other reasons (such as thermal overloading, dynamic instability, system strength, voltage management or ramping constraints). A holistic view of all system limits is required in order for a generator's investment and operational decisions to be efficient.[89]

Similarly, Hydro Tasmania and TasNetworks noted that previous modelling undertaken by the Commission the last time it considered access issues was unable to produce indicative firm access pricing in Tasmania owing to Tasmania's unique power system characteristics (i.e. a greater presence of non-thermal constraints than thermal ones). They were of the view that the issues around system security constraints have become more complex with the passage of time. Moreover, these issues have become more prevalent in the rest of the NEM.[90]

Transmission augmentation

ERM Power argued that lower cost network augmentation could be achieved if generators were allocated transmission hedges in exchange for setting up run back or tripping schemes to better utilise AEMO's N-1 operation of network capacity. Any transmission hedging regime should incorporate this possibility.[91]

Transitional arrangements

Intergen Australia, Lighthouse Infrastructure Management, Delta Electricity and Infigen argued for a transitional access period for existing generators commensurate with their remaining life and set at a level consistent with their current access. This would recognise

87 Delta Electricity, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 2.

88 ERM Power, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, pp. 1-2.

89 AEMO, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 5.

90 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Hydro Tasmania, p.4; TasNetworks, p. 7.

91 ERM Power, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 5.

that existing generators are unable to mitigate the impact of transmission hedging through locational choices.[92]

Lighthouse Infrastructure Management noted that it will be important to distinguish between existing generators and those that become committed between now and the time the reform takes effect. If the market expected that generators existing when the reform took effect would enjoy better treatment than if they committed after the reform, it could lead to developers rushing through projects with higher congestion risk than they would have in the past at a cost to the system.[93]

Transmission hedge product

Lighthouse Infrastructure Management considered that transmission hedges should include a lifetime marginal loss factor, so that generators can internalise these costs when deciding whether to proceed with construction.[94]

5.2.2 Comments on the impact of transmission hedges

Many stakeholders also provided a view of the potential market impacts of a transmission hedging regime. Key comments included that:

- Transmission hedging may improve financial contracting between load and generation in the NEM. The present inability of either contract party to accurately predict, reduce or manage the risk of congestion is a barrier to efficient contracting that would be removed under the new regime.[95]
- The access model has the potential to mitigate other current market challenges identified by the AEMC, such as the challenges associated with accommodating renewable energy zones under the current framework. In addition, it may lead to better allocation between transmission networks and generators of the financial risk arising from network outages.[96]
- Access reform will not encourage transmission investment where it is needed. Factors such as availability of resources and political guidelines for renewable energy and availability of fuel often place new generation away from demand centres. These factors will only override the locational signals from the nodal price.[97]
- The decision by a transmission network service provider's Board and shareholders to fund transmission depends on the existence of either a creditworthy corporate counter party able to credibly enter into long-term contracts, or a sovereign entity (such as the AER), to

92 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Intergen Australia, p. 2; Delta Electricity, p. 3; Infigen, p. 8; Lighthouse Infrastructure Management, p. 3.

93 Lighthouse Infrastructure Management, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

94 Lighthouse Infrastructure Management, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, pp. 2-3.

95 Lighthouse Infrastructure Management, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 4.

96 Australian Energy Regulator, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 4.

97 Snowy Hydro, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 9.

provide a return on investment. Replacement of the AER with entities of a lower creditworthiness could increase the risks to the capital investment, via stranding and counter party risk.[98]

5.3 Commission's views

5.3.1 Transmission hedges are an integral component of transmission access reform

As noted in chapter 2, access reform will involve changing the following three inter-related aspects of the current transmission access framework:

1. **Wholesale electricity pricing:** Under the current framework, generators receive the regional reference price for each megawatt hour of electricity they are able to dispatch to market, regardless of where they locate in a region. We are proposing to change these arrangements so that generators receive a market price that more accurately represents the marginal cost of supplying electricity at their location in the network (the 'local marginal price').
2. **Financial risk management:** Under current arrangements, a generator's ability to receive the regional reference price and earn revenue is a direct function of its physical dispatch. We are proposing to enable generators to better manage the risks of congestion by enabling them to purchase transmission hedges, to assist them manage the risk of local prices that diverge from the regional reference price in the event of transmission congestion. These products will hedge against the price differences that may arise under our proposed changes to wholesale electricity prices, allowing generators to rely on a particular revenue flow, regardless of other generator's locational decisions. This should improve investment certainty for prospective generators and may reduce the cost of capital for generation investment in the longer term.
3. **Transmission planning and operation:** Under the current regime, the fact that transmission network and generation investment decisions occur under different processes has the potential to result in development that does not minimise the total system costs faced by consumers. Additionally, no individual generator is able to guarantee that they will receive value from shared network assets, even if the generator underwrote the investment in the asset, creating a free-rider problem. As a consequence of these two factors, consumers bear the risks of transmission investment decisions being incorrect. We are proposing to change this so that transmission planning is informed by generator's purchase of transmission hedges. In addition, transmission costs are no longer solely recovered from consumers. A portion of these costs would instead be collected from generators through the purchase of transmission hedging products.[99]

The proposed transmission access model will create a financial risk management tool for generators that should improve their investment certainty. Under the new arrangements, generators would receive a transmission hedge in exchange for underwriting part of the cost

98 HRL Morrison & Co, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 5.

99 This is possible because the financial transmission hedges are physically backed by transmission capacity. The purchase of hedges by generators creates a liability for transmission companies, who manage that liability by building and operating transmission infrastructure.

of the transmission network. This hedge would allow generators to manage the price risks they face at times when there is congestion within the network.

These arrangements should improve investment certainty for prospective generators and may reduce the cost of capital in the longer term. This is because generators with transmission hedges would no longer face the risk that other generators may undermine their business case by locating nearby and causing congestion in the local transmission system.

Under the status quo, a generator's ability to earn the regional reference price is totally dependent on it being dispatched. In contrast, under the new framework, financial outcomes would be partially decoupled from dispatch. If a generator had contributed to the cost of transmission infrastructure through purchasing a transmission hedge, then it would paid,[100] even if it was not physically dispatched.

This access model would also achieve a higher degree of co-optimisation of transmission and generation investment than under the current regulated approach to transmission planning. The option to purchase a transmission hedge makes the cost of the shared network part of a generator's investment decision. This means that the investor should seek a location for a power station which maximises its profits, which are a function of the revenue it earns in the spot and contract market, as well as the combination of its operating and establishment costs. These costs will include the costs of transmission; manifesting through low local prices or the cost of transmission hedges used to alleviate congestion.

The level of transmission hedges that generators purchase will also inform the transmission planning process, resulting in a closer coordination of generation and transmission investment. Access reform should also remove the free-rider problem inherent in the current connection regime by providing generators with a risk management tool in return for making a financial contribution that underpins transmission investment. This risk management tool would hedge them against the price differences between the local and regional reference prices that arise as a result of transmission congestion; essentially providing the generators with the full benefit of the transmission infrastructure they underwrite. This increased financial certainty should incentivise generators to bear a large portion of the costs of transmission infrastructure that are currently shouldered by consumers.

5.3.2 Design of a transmission hedging regime

As noted in chapter 1, we will consult further regarding the design of the transmission hedging regime in our draft report to be published in September. However, we have provided an initial high-level indication of key design features in Table 5.1, and further below. We are interested in stakeholder feedback on these design features. We look forward to providing more detailed design on this topic in our draft report, similar to the level of detail provided on settlement in chapter 4 and Appendices B and C.

100 This payment would be equal to the difference between the regional reference price and the local price multiplied by the volume of the transmission hedge.

Table 5.1: **High level design aspects of transmission hedging**

DESIGN ELEMENT	TRANSMISSION HEDGING
Transmission planning	• Complementing the ISP, the sale of transmission hedges would fund and guide the development of new network assets • TNSPs plan their network and are subject to a new planning standard in order to meet the aggregate network capacity of transmission hedges sold. • Reliability standards still apply for load. • Transmission investments are assessed through a cost-benefit process, consistent with actioning the ISP.
Products	• **Amount:** Transmission hedges likely to be in relation to a fixed MW amount. • **Location:** *Intra-regional* hedges may relate to the transmission capacity from a particular transmission connection point or node to the regional reference node. *Inter-regional hedges* may relate to transmission capacity from one regional reference node to the regional reference node in an adjacent region. Alternatively, hedges could be region-agnostic, which means that they could relate to transmission capacity between any two transmission nodes (not just the regional reference node and a local node). • **Duration:** Short- and long-term hedges are likely to be offered.
Product procurement	• Transmission hedging products could be procured through an auction process, given the current level of demand for generators to connect to the network.
Product pricing	• Fair value method of setting a reserve price for inter- and intra-regional hedges. This pricing method would take account of the costs of stability constraints. • Short-term hedges likely to have a reserve price of zero. • The Integrated System Plan would be integrated into product pricing.
Incentives on network businesses	• Incentive scheme on TNSPs to maximise access.

DESIGN ELEMENT	TRANSMISSION HEDGING
Transitional arrangements	• Some form of transitional arrangements will be necessary. (See chapter 7 for further discussion).
Wholesale settlement	• Dynamic regional pricing, with settlement residues allocated on basis of access rights purchased. (See chapter 4 for further discussion).

Transmission planning

Under the proposed access model, the sale of hedging products would fund and guide the development of new transmission assets both within regions and between regions. Therefore, commercial incentives from generators would form a greater input into the transmission planning process, informing decisions about future network development or asset retirement.

In order to achieve this, the collective sum of transmission hedges purchased would comprise a 'generator access standard' that AEMO and transmission network service providers would be required to plan the network to. That is, the transmission network would need to be planned to provide the agreed level of capacity consistent with the amount of transmission hedges that are sold.

The planning standard conditions would be designed so that network capacity would be provided when generators value it the most. The TNSP could provide this capacity in a number of ways: by developing its network, undertaking operational actions, or entering into network support agreements to enable more capacity. All of these options are currently allowed for under the regulatory framework.

Neither AEMO, nor network service providers, would be required to plan or operate their networks to transmission capacity for generators that had not purchased transmission hedges. This is because the network businesses would not receive financial compensation for doing so. However, they would still be required to meet their jurisdictional reliability standards for consumers. Thus, transmission network service providers would be required to plan their networks to meet both the reliability and access planning standards simultaneously.

In addition, the access regime would need to effectively and holistically interface with the Integrated System Plan. The ESB currently has a process under way to action the ISP to help streamline, remove duplication and de-risk the transmission planning and investment decision-making process.[101] This is to say that the ISP, as a plan for the entire transmission system, will need to be informed by and incorporate the transmission hedges that are bought by generators.

In order to achieve this, it is important that there is sufficient:

- transparency of transmission hedges being purchased, such that AEMO can incorporate it into its planning, and transmission network service providers can reflect this in their annual planning reports
- consultation on the ISP, including from generators, so that the ISP is closely aligned with what generators seek from the transmission system i.e. the transmission and generator sectors are effectively coordinated
- feedback mechanisms between the two processes, so that the finalised ISP can inform relevant aspects of the access regime. For example, the Commission considers that the ISP could assist with the transmission product pricing process.

101 For more information, see http://www.coagenergycouncil.gov.au/publications/energy-security-board-converting-isp-action.

We anticipate that other key aspects of the planning process would remain under a new access regime. For example, TNSPs would likely continue to need to both produce an Annual Planning Report and undertake a RIT-T for qualifying investments. It is worth noting that both of these documents are currently being modified in order to better incorporate the actioned ISP. The Commission will consider how these documents may need to be further modified in order to accommodate access reform once it is clearer how the actioned ISP will be incorporated into the regulatory framework.

QUESTION 6: TRANSMISSION PLANNING

Do stakeholders agree that access reform and the Integrated System Plan should be integrated? If so, do stakeholders agree with the Commission's assessment about how this could be achieved?

Hedging products

As noted above, transmission hedging products are designed to provide generators with revenue equal to the difference between the local marginal price and regional reference price for the hedge volume purchased. This revenue is provided regardless of the quantity of electricity the generator dispatches in any given market settlement period , and is provided in addition to any wholesale revenue earned from dispatching electricity, earned at the local marginal price.

However, there are a number of design questions that need to be resolved when creating these products. We are interested in stakeholder views on these design questions. It is important that any transmission hedging products offered are actually those products that are consistent with what generators *want* or would find *useful* in order to assist them with their financial risk management.

In particular, we seek stakeholder feedback on the following characteristics of the hedging products:

1. Amount

This relates to the volume and metric of transmission hedging products available for sale. The metric of hedging products would likely be in megawatts. However, hedging products could potentially be sold in other metrics if hedges were desired to manage the risks raised by system security constraints.

In addition, the volume of hedging products could either be capped at the generator's capacity or be unlimited in nature. Allowing generators and potentially other parties to purchase an unlimited amount of transmission hedges would introduce greater flexibility into the system. However, it may also cause issues of undue market power if market participants stockpile hedging products or use them to manipulate market prices.

2. Location

This characteristic relates to the physical location of where the transmission hedge is purchased. For example:

- *Intra-regional* hedging products may relate to the transmission capacity from a particular transmission connection point or node within a region to the regional reference node.
- *Inter-regional hedges* may relate to transmission capacity from one regional reference node to the regional reference node in an adjacent region.

Alternatively, transmission hedges could be designed to be *region agnostic.* This means that transmission hedges could relate to any *two* nodes in the network, rather than a local node and the regional reference node. This approach may be advantageous if certain categories of load or storage are charged the local marginal price rather than the regional reference price.

A region agnostic design would allow generators to be able to fully hedge their generation even if it was sold at a node other than the regional reference node. It would also negate the need to differentiate between inter- and intra-regional hedging products. However, this approach may result in significant complexity being added to the model.

3. Duration

This relates to the length of the transmission hedging product for sale. Based on initial stakeholder feedback, purchasers seem to want longer-term hedges since they may provide a greater level of investment certainty. Depending on the final design of the access regime, there may be some level of flexibility for generators to tailor the length of the hedge to their needs. For example, long-term hedges could be provided anywhere from three years to decades in length, consistent with the life of generation investments.

However, longer products present a challenge in that they are harder to price reflective of the underlying cost of transmission required to back them. The pricing methodology requires a view of the future which (presumably) becomes increasingly uncertain over longer term horizons.

In addition to this, short term hedges could be offered. Short-term transmission hedges would provide the same type of revenue as long-term hedges. However, the aggregate amount of short term hedges that were sold may be limited to the amount of spare network capacity at a given time. Short-term transmission hedges could also be supplied by generators engaging in secondary trading.

4. Type

This characteristic relates to the type of hedging product that is available for sale. For example, the hedging product may relate to a fixed MW quantity. This may be most appropriate for generators which produce or consume a relatively fixed quantity of electricity (such as a base load generator). Alternatively, it is theoretically possible that variable MW hedges could be purchased, which may allow intermittent generators to more accurately target the specific dispatch and basis risks that they face. A drawback is that a variable quantity product design may be challenging both for generators and TNSPs to manage, and also may complicate the market settlement process.

It is likely that the hedging products offered could be considered to be analogous to options rather than swaps. This means that generators with transmission hedges would never be required to *pay out* under the terms of the hedging contract. In other terms, the hedging product will only provide revenue when the regional reference price is higher than the local marginal prices. This design would preserve the risk management value of the products and limit the downside risk of holding the products.

> QUESTION 7: ACCESS PRODUCTS
>
> What access products - defined by duration, location, amount and type - do generators want?

Product procurement

The procurement process for transmission hedging products will need to be tailored to best fit a number of variables, such as the expected demand for the products as well as their availability.

For example, a procurement process could be designed so that generators purchase long-term hedges directly from the relevant TNSP at a price that reflects the tailored nature of the product. This procurement method may be best suited to an environment where there is a low frequency of competing access requests lodged with a particular TNSP at any given time. This is because the costs to the transmission network would fluctuate depending on the aggregate demand for generation investment and order in which procurement requests were processed.

If instead there were likely to be high demand for long-term access from multiple prospective generators within a region, or between regions, a regular auction process may be more efficient. This is because an auction process allows multiple parties to reveal their demand for firm access at the same time. It also allows for a limited amount of access rights to be allocated to those parties who would value it most highly. The Commission considers that it may be more efficient to run an auction process given the large number of connection requests currently being pursued by prospective generators.

> QUESTION 8: PRODUCT PROCUREMENT
>
> Do stakeholders agree that access products should be purchased via an auction?

Product pricing

As noted above, it is likely that there will be a number of different hedging products available that reflect the different risk profiles and preferences of generators. These products may need to be priced differently so that they can accurately reflect the incremental cost to the transmission system of the access they provide.

For example, it is likely that the pricing process for short-term versus longer-term transmission hedging products could differ. If short-term products reflect the spare capacity on the transmission network at a given time, it may be appropriate to set their reserve price at zero (assuming they are sold through an auction process). This would be in recognition that such access products do not impose additional costs on the transmission network through network augmentation or reinforcement.

In contrast, TNSPs would be required to provide a level of capacity on the network consistent with the quantity of long-term transmission hedging products sold. Therefore, longer-term transmission hedging products create costs that would need to be reflected in their pricing methodology. Other things being equal, the pricing methodology should reflect that:

- generators locating remotely from the regional reference node and from other major demand centres would pay a higher price than generators locating closer to the regional reference node or demand centres, due to the higher cost of long transmission lines to connect them
- generators locating where there is limited spare transmission capacity and where network expansion would be required immediately would pay a higher price than generators locating where there is plenty of spare transmission capacity and where no expansion would be needed for some time
- where network expansion would be required immediately as a result of a generator's purchase, generators would pay a lower price if any spare capacity resulting from the expansion was projected to be used up quickly, compared to the case where the resulting spare capacity was projected to be unused.

One method of pricing longer-term transmission hedges could be the long-run incremental cost (LRIC) method. This pricing model aims to account for the costs that are incremental to what transmission costs would have existed had the generator not sought to purchase a transmission hedge.

An advantage of this pricing method is that, if it incorporates the right assumptions about where and when transmission investment is needed, it should provide the signals listed above. An option to bolster this methodology so that it incorporates an efficient view of when transmission expansion and augmentation is likely to be required may be to explicitly link it to the Integrated System Plan.

A potential disadvantage of the LRIC method is that the long-run incremental costs to the transmission network may fluctuate depending on the aggregate demand for generation investment and order in which procurement requests are processed; which means that the model may not be as suitable for an auction-based model. In addition, it may be difficult to price thermal constraints into this model. Given the increase in system security and stability constraints since 2015, the Commission considers that it would be desirable for the pricing model to account for the cost of managing these constraints.

An alternative approach could be to estimate the 'fair value' of transmission hedges. This model would be based on long-run forecast difference between the regional reference price and local marginal prices. The key conceptual difference from LRIC is that the fair value approach does not attempt to explicitly calculate marginal transmission *costs*. Rather, it measures the marginal transmission *value* that would be captured[102]by building additional transmission capacity.

Similar to the LRIC model, the fair value method should provide the right signals to generation regarding their locational decision (as listed above). A key practical difference between the models is that the fair value method would necessarily include all types of constraints that are factored into the current NEM dispatch engine. Both thermal, system security and stability constraints are currently factored in to market dispatch, so they would automatically be included in the price of transmission hedges if a fair-value approach was taken.

QUESTION 9: PRODUCT PRICING

Do stakeholders agree that a fair value approach to pricing may be beneficial?

TNSP incentives and regulation

The collective sum of transmission hedges purchased would comprise a 'generator access standard' that AEMO and transmission network service providers would be required to plan the network to. That is, the transmission network would need to be planned to provide the agreed level of capacity consistent with the amount of transmission hedges that are sold.

This 'access standard' would be accompanied by an 'operating standard' to encourage the efficient operation of the transmission network. The operating standard would encourage TNSPs to operate their network efficiently to provide adequate transmission capacity for generation *under all* conditions. This would occur through an incentive scheme, which would incentivise TNSPs to efficiently manage their network with regard to congestion at all times.

The scheme may specify an annual dollar benchmark of shortfall costs for the TNSP to meet. This benchmark could be based on the amount of shortfall costs that an efficient TNSP would be expected to incur. Shortfall costs arise when the actual network capacity is less than the network capacity under the planning standard conditions, and (depending on how shortfalls are accounted for) constitute the cost to firm generators of receiving reduced revenue from their transmission hedges.

If the actual shortfall costs were less than the annual benchmark of shortfall costs, then the TNSP would receive an incentive payment from generators in the subsequent year equal to the difference. If actual shortfall costs were more than the annual benchmark, then the TNSP would be required to pay a penalty to generators equal to the difference.

It would be impossible for the TNSP to supply network capacity consistent with the collective quantity of transmission hedges purchased at all times, as events can happen outside the TNSP's control. Therefore, caps would apply, limiting a TNSP’s exposure to extreme shortfall costs in 'abnormal' operating conditions.

102 Measured as the forecast difference in price between the regional node and the local node.

The incentive scheme could be low-powered – TNSPs would be exposed to a small amount of their maximum allowed revenue under the scheme. TNSP incentive payments would be paid to, or collected from, generators that had purchased transmission hedges. The details of the incentive scheme, such as what the shortfall benchmark is, would be set by the AER. This incentive scheme would replace the existing market impact component of the service target performance incentive scheme.

Alternatively, a high-powered scheme would make the transmission hedges that were sold to generators firmer in nature. However, it would also expose TNSPs to potentially large and volatile costs when the network capacity is not able to be provided. The Commission is of the preliminary view that this is not desired since it is not consistent, nor commensurate, with the risks that TNSPs face.

QUESTION 10: TNSP INCENTIVES AND REGULATIONS

Do stakeholders agree that an operating incentive scheme on TNSPs is required?

6 RENEWABLE ENERGY ZONES

This chapter discusses the issue of renewable energy zones, including stakeholder feedback and the Commission's views on how they could be progressed further.

6.1 Background

Australia is very large, and the national electricity market is a long and sparsely connected power system, with concentrated load centres that are distant from one another. The current transmission network was primarily designed to connect large centres of thermal and hydro generation to major demand centres some distance away.

In order to support the transition of the electricity system, the transmission network will need to develop to efficiently connect and transport large amounts of energy from dispersed renewable generation across the NEM to where consumers want to use it. Many of the current connection applications are located at the periphery of the transmission network, where access to renewable resources is good but the network is weak, in terms of both capacity and system strength.

The Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment through the development of renewable energy zones (REZs). It was envisaged that renewable energy zones would facilitate the connection of new renewable generators to the transmission network in a scale- and cost-effective manner.

While a 'renewable energy zone' is not a defined term in the existing regulatory framework, the current framework does have mechanisms to allow for the development of transmission infrastructure between areas with abundant renewable resources and the existing network. Indeed, the NEM currently has clusters of renewable generation around particular parts of the network, which could be considered renewable energy zones of one form or another.

6.1.1 Current framework for renewable energy zones

In considering why the concept of a renewable energy zone may be a useful addition to the regulatory framework, it is necessary to consider the existing distinction between the shared transmission network and connection assets, including existing incentives for parties to coordinate.

Connection assets

Under the existing framework, connecting parties are directly responsible for the payment of costs associated with any new apparatus, equipment, plant and buildings, or upgrades to existing apparatus, equipment, plant and buildings, to enable their connection to the transmission network and to meet their performance standards. These assets are called as 'connection assets'.

Connection assets, which are used solely by one or more connecting parties, are paid for by that connecting party or parties. There are already mechanisms in place in the existing regime to facilitate the coordination of connection assets, including from prospective renewable energy zones to the shared network. These mechanisms are:

- information provision, for example through the Integrated System Plan (ISP) and transmission annual planning report (TAPR)
- the scale efficient network extensions (SENE) process and recent *transmission connection and planning arrangements* (TCAPA) rule, which allow for generators to coordinate with one another in the development of connection assets.

However, there may be barriers to the effective use of these mechanisms for the development of renewable energy zones, particularly those not identified through the ISP. For example, the existing SENE framework has been unused since it was established in 2013. We have previously received feedback from industry that competitive tensions and commercial challenges (including misalignment between generators' project timings) act as a disincentive for generators to facilitate coordinated connections through these mechanisms.[103]

Shared network assets

In contrast to connection assets, generators are not responsible for the payment of costs associated with any augmentations to the shared transmission network. While generators are able to fund the construction of shared network assets, they have substantial incentives not to do so.

Under the existing regime, no individual generator receives explicit value from a shared network asset, even if the generator underwrote the transmission asset’s construction. This tension creates a free-rider problem: each individual generator would prefer for other generators to underwrite transmission investment, to avoid the cost of doing so while enjoying the benefits that the transmission infrastructure provides to all generators.

As a consequence of this free-rider problem, shared network assets are typically funded directly by consumers through transmission use of system (TUOS) charges. To minimise the risk of inefficient expenditure, regulatory investment tests for transmission (RIT-Ts) are used to assess the appropriateness of investments, and consumers only pay TUOS consistent with the AER’s regulatory determination process.

While developing transmission to some renewable energy zones as shared transmission assets may be able to be justified through the RIT-T process, others may not. This is because renewable energy zones often involve a relatively large element of speculation as, by definition, generation has not yet connected and so is not considered committed. Therefore, it is harder for the benefits of extending the existing transmission system to be justified.

103 AEMC, *Coordination of generation and transmission investment, Final report,* 21 December 2018, p. 59.

6.1.2 Facilitating renewable energy zones

Commission's analysis

In our inaugural COGATI report, we explored a number of different ways in which renewable energy zones could be facilitated through changes to the regulatory framework.[104] These options are summarised in Table 6.1.

104 AEMC, *Coordination of generation and transmission investment, Final report*, 21 December2018, p. 54.

Table 6.1: **Summary of the range of options for renewable energy zones**

OPTION	OPTION 1: ENHANCED INFORMATION PROVISION	OPTION 2: GENERATION COORDINATION	OPTION 3: TNSP SPECULATION	OPTION 4: TNSP PRESCRIBED SERVICE	OPTION 5: TRANSMISSION BONDS
Features	Enhanced planning by AEMO and TNSPs to signal REZs for development by the market	Generators connecting in the same area coordinate connections	TNSPs undertake speculative investment to build the REZ	TNSPs invest to deliver a prescribed service in anticipation of generators connecting	Potential REZs would be identified through planning processes; TNSPs would undertake an estimate of costs; TNSPs would then issue bonds which generators could purchase. If sufficient bonds were sold, the investment would proceed.
Who pays?	Same as now - generators pay for connection assets	Same as now - generators pay for connection assets	TNSPs - but if investment meets the test for shared transmission in the future, costs would be recovered from consumers	Consumers	Generators in the first instance, with their money returned to them if the REZ went ahead
Who bears the risk?	Same as now	Generators	TNSPs - they would be rewarded if investment meets the test for shared transmission in future	Consumers - including facing the stranded asset risk	Generators
Changes to the existing framework	Minimal	Minimal - but significant commercial issues impede	Moderate	Substantial	Moderate

The Commission concluded that none of these alternatives were deemed to be in the long-term interests of consumers. This is for the following reasons:

1. **Option 1** involves the facilitation of renewable energy zones through enhanced information or cooperation between parties. This option is already accommodated within the existing regime, but is not being used.

   Generators are competitors in the wholesale market and so may be unwilling or unable to share details with respect to financing, forecasting and other commercially sensitive information. As a consequence, the Commission considered that this option would not sufficiently facilitate renewable energy zones, consistent with the recommendations of the Finkel Review.

2. **Options 2 and 5** involve generators contributing to the cost of shared transmission assets and taking on some risk of developing shared transmission assets.

   For these options to be effective, they would require that the generator receive some form of firmer access right than currently available under the existing access regime. Otherwise, generators will have an incentive to free-ride on investments contributed to by other generators, enjoying the benefits of access without having contributed to the costs. Given that each generator will have an incentive to free-ride, each individual generator will be reluctant to contribute to the cost of the shared transmission assets.

3. **Options 3 and 4** involve transmission network service providers (TNSPs) undertaking speculative investment in either shared network infrastructure or connection infrastructure. This would require either that:

   - consumers bear the risk of this investment, which the Commission did not consider to be in their long-term interest under the national electricity objective; or
   - TNSPs bear the risk. For this to be effective, network businesses would need to be compensated accordingly for taking on these risks. However, establishing how to appropriately compensate TNSPs is both practically and legally challenging.

Commission's recommendation

As a consequence of this analysis, the Commission recommended reforming the transmission access regime as a whole.[105] This recommendation was made on the basis that changes to the access regime would best facilitate renewable energy zones. This facilitation would be a natural consequence of generators and prospective generators' coordinating to make commercial locational investment decisions under the new framework.

As described above, the main barrier to facilitating renewable energy zones is the lack of incentives under the current framework for different generators to collectively fund shared network assets. These lack of incentives exist because access to the network is determined dynamically through dispatch. Generators are not guaranteed a return on any investment in

105 AEMC, *Coordination of generation and transmission investment, Final report*, 21 December 2018, p. 73.

shared transmission assets because they cannot guarantee that they will be dispatched and so earn revenue through the wholesale spot market.

Access reform would help remove the free-rider problem inherent in the current connection regime by giving connecting generators a financial risk management tool in return for making a financial contribution that underpins transmission investment. Transmission hedges would allow generators to better manage their risks of the local price being different to the regional reference price when the transmission system is congested; essentially providing the generators with the full benefit of the transmission infrastructure they underwrite. The Commission was of the view that this increased financial certainty should incentivise generators to bear a large portion of the costs of transmission infrastructure that are currently borne by consumers.

Under the final access regime, transmission investment costs would no longer be recovered solely from consumers through TUOS charges. A portion of these costs would instead be collected from generators through the purchase of hedging products.[106] This means that the TUOS component of a customer's bill should also decrease substantially.

6.2 Stakeholder submissions

A number of stakeholders agreed with the Commission's analysis that generators can already coordinate connection through the SENE and TCAPA frameworks. However, stakeholders were overwhelmingly of the view that competitive tensions and commercial challenges act as a disincentive for generators to facilitate coordinated connections to the transmission network.[107]

Several stakeholders noted that facilitating better coordination between generators is a worthwhile goal; however, its benefits will necessarily be capped if it is not accompanied by holistic access reform. This is because coordinating to develop a shared network asset will only guarantee that generators receive physical access to the nearest transmission node on the shared network (i.e. the point where the renewable energy zone meets the shared transmission network). Access to assets within the shared network would continue to suffer from a free rider problem. Generators are unlikely to fund enhancements to shared network assets (individually or in coordination with one another) to guarantee physical access all the way to the regional reference node.[108]

A number of stakeholders mentioned the interaction between the Energy Security Board's (ESB's) proposed adjustment fund to facilitate renewable energy zones and the Commission's work on access reform.[109] AEMO commented that the proposed fund could potentially provide

106 Consumers would only need to pay the residual investment and maintenance costs that are required to deliver them with reliable electricity services.

107 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: EnergyAustralia, pp. 3-4; ARENA, p. 3; Clean Energy Council, p. 8; Energy Users Association of Australia, p. 7.

108 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: TransGrid, p. 3; EnergyAustralia, pp. 5; PIAC, p. 7; Aurizon, p. 3; Energy Users Association of Australia, p. 2.

109 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: AusNet Services, pp. 2-3; Mondo Energy, p. 3; TransGrid, p. 2; AEMO, p. 7.

an interim solution to fix a few of the current problems associated with congestion and system security. However, AEMO was cognisant that the fund need not preclude future reforms to deliver a robust, resilient long-term framework that does not rely on government action.[110]

Other submissions also raised the concept of using renewable energy zones to facilitate the transition to a new transmission access regime. For example, Energy Networks Australia noted that any changes to the access framework should support the efficient location and size of future connections that may be facilitated through the proposed REZ adjustment fund.[111]

Some stakeholders were of the view that the Commission's approach to access reform did not adequately prioritise the need to support the development of renewable energy zones. For example, the Clean Energy Council noted that more work is required on how best to encourage developers to locate new generation in renewable energy zones and urged the Commission to incorporate this more fulsomely into our review.[112]

6.3 Commission's analysis

As noted in section 6.1, the NEM is a uniquely long and sparsely connected system in the context of international electricity markets. This is due to the size of the country, its population distribution and where the energy resources were. The design of the national electricity market was originally centred around connecting large centres of thermal and hydro generation to major demand centres some distance away.

The NEM transmission network will need to develop to efficiently connect and transport large amounts of energy from dispersed renewable generation across the NEM to where consumers want to use it. Many of the current connection applications are located at the periphery of the transmission network, where access to renewable resources is good but the network is weak, in terms of both capacity and system strength. As the energy sources are less intensive and geographically dispersed, they will require greater transmission to transport their energy to load centres.

Developing the transmission network to fully accommodate all the currently proposed renewable generation at sites spread across the NEM would not be economic. There are also significant implications if a large amount of generation connects to a weak part of the network. To manage power system security issues, generation in those areas will likely be prevented from generating at full capacity unless additional investment was made to remediate the impacts on system strength.

As identified in AEMO's Integrated System Plan, there are, however, a number of potential renewable energy zones across the NEM where high quality renewable resource overlaps with

110 AEMO, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 7.

111 ENA, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 8.

112 CEC, submission to the consultation paper, *Coordination of generation and transmission investment implementation - access and charging*, pp. 7-8.

locations where the transmission network is strong and there is good network capacity available.[113] The Commission considers that renewable energy zones have an important role to play to help address the challenge of coordinating transmission network planning and renewable generation investment in these areas.

In line with this, and as noted above, the ESB is developing a fund to facilitate renewable energy zones. This is recommendation 11 from the actioning the ISP paper. The ESB are currently preparing a report on this recommendation for the COAG Energy Council. The Commission's work supports this recommendation by considering changes to the regulatory framework that could be made to facilitate any development of REZs under the fund.

BOX 10: RECOMMENDATION 11

That the ESB examine the possibility of a Fund to extend transmission assets to connect to Renewable Energy Zones with the cost of this transmission progressively recovered from consumers if and when utilisation increases. The required size of the finance, the source of funds, and how funds should be recovered and managed should be part of the examination.

Source: Energy Security Board, *Integrated System Plan; Action Plan,* September 2018, p. 5.

6.3.1 Renewable energy zones can assist with the market transition

Renewable energy zones can be considered to be effectively large 'connection assets'; that is, they can take the form of any new apparatus, equipment, plant and buildings that are needed to enable a group of generators to connect to the transmission network. In line with this, the Commission considers that the issue of facilitating renewable energy zones is one of addressing coordination between *generators* and other *generators.* This is distinct from the broader objective of access reform, which is to facilitate more effective coordination between *generators* and the *transmission* sector.

Facilitating renewable energy zones can therefore be viewed as an important subset of access reform. Indeed, these zones have the potential to unlock significant value within the electricity system. Namely:

- If generators share connection assets, then they may benefit from economies of scale leading to a greater return on investment.
- In turn, these reduced connection costs would require less to be recovered by generators in the wholesale market. Part of the additional return on investment may therefore be shared with consumers in the form of lower wholesale prices.
- More generators sharing connection assets, rather than having multiple entry points into the network, is also likely to result in a more secure and stable power system.

Renewable energy zones have the potential to reduce the overall costs of integration in the NEM. The Commission therefore considers that it is important to consider how renewable energy zones can be facilitated as a first-step on the path to holistic reform. As many

113 AEMO, *Integrated System Plan,* July 2018, p. 49.

stakeholders alluded to, renewable energy zones are a complementary feature of access reform. Although they are not able to provide all the benefits that broader access reform would, there is clearly value within the electricity system that is waiting to be unlocked through greater coordination *between* generators.

It should therefore be possible to prioritise amending the frameworks to facilitate renewable energy zones ahead of the broader timetable for access reform. However, this comes with the caveat that the changes needed to enable renewable energy zones must therefore also be simpler and relatively more discrete to implement than the broader access regime in order for these to be a transitional measure on the way to broader access reform.

In line with this, we are seeking stakeholder feedback on two potential options for facilitating renewable energy zones that could be implemented in a faster timeframe than broad access reform. These are to:

1. develop ways to reduce the risk that the renewable energy zone will not be fully utilised
2. allow the speculative risks of the renewable energy zone to be shared between multiple parties.

These options are discussed in turn below.

6.3.2 Option 1: Develop ways to reduce the risk that the renewable energy zone will not be fully utilised

The models that the Commission set out in the COGATI report last year were focussed around *one* party bearing the risk of the renewable energy zones. The Commission concluded that none of these options were workable.

This is because renewable energy zones are, by definition, speculative. It is not clear at the time of building the renewable energy zone whether there will be sufficient generators signing up to utilise the connection asset, and therefore, whether the costs of the connection assets will be entirely covered. In addition, it is not clear how long it will take generators to sign up if they do arrive, which can potentially also undermine the business case for any particular zone.

One potential method to mitigate this risk is to allow transmission network service providers to 'group' connection applications from prospective generators. Rather than individual connection applications being approved on a sequential basis, the TNSP would establish a period (an 'open season') during which connection applications would be accepted, but not processed. This process would relate to a specific location within the shared transmission network that was deemed suitable as a site for a potential renewable energy zone. At the end of the period, the TNSP would then assess all applications received up to that point as a group.

The benefit of this option is that it may allow transmission network service providers to plan the system and provide connection offers on a jointly optimised basis. This should allow TNSPs to overcome at least some speculation risks outlined above to construct a renewable energy zone. An important point to make is that this option should still preserve the any commercial concerns that generators would have, given that the process would be coordinated by transmission network service providers.

As noted above, groups of generators would need to be clustered by both:

- **Time:** For example, all generators that put in an application between January and March of a particular year. To get the benefits, the season must be sufficiently long so that an appropriate number of connection requests accumulate but not so long as to unduly delay connection applications.
- **Location:** For example, all generators that wish to connect at a particular transmission node could be grouped. To get the benefits, the location must be sufficiently broad such that an appropriate number of connection requests accumulate, but not so wide as to not make it possible to group connection applications within a particular region.

The Commission considers that allowing the grouping of connection applications may reduce the risk that renewable energy zones and their assets will not be fully utilised. In addition, it may help with facilitating each generator's 'do no harm' obligations that exist in relation to system strength. This would allow one group of connection assets to build one large synchronous condenser to be built and its fault current to be shared between generators.

QUESTION 11: REDUCING THE RISK

Do stakeholders think that clustering of generators that wish to connect to the network would be valuable in assisting in development of renewable energy zones?

Do stakeholders consider that this model would be relatively simple and straightforward to implement? If so, how could this process be designed and administered?

6.3.3 Option 2: Potential shared cost recovery model

A second option to address the speculation risk inherent in renewable energy zones is to share the risk between multiple parties.

PIAC has developed a framework to help address these issues, which it presented to the COGATI technical working group in May 2019. This model provides for how the cost of investment in a renewable energy zone could be shared between consumers, generators and transmission network service providers. The Commission considers that this model could help facilitate renewable energy zones and should be subject to further stakeholder consultation as part of the COGATI review process.

PIAC's model allows for the location of a potential REZ to be determined through AEMO's Integrated System Plan. Consultation on the ISP would confirm via feedback from generators whether a particular location is a preferred area for a renewable energy zone. This process should ensure that a variety of sources of information are considered and the risk of speculation is lowered.

The outcome of the consultative ISP process is that a geographic zone would be identified as an efficient location for a REZ. The ISP would also have a prescribed 'efficient' capacity level, defined as the capacity to be covered by arrangements for transmission network service providers to recover costs from generators and consumers set out through a regulatory process. Capacity exceeding that level would be treated as speculative.

In order for the renewable energy zone to be developed, the risks, and costs, would then be shared between multiple parties:

- A fixed portion of the cost of investment (for example, 50 per cent) would be recovered from consumers in a manner similar to how transmission network service providers currently recover shared network costs.
- A further portion of the cost of prescribed capacity would be recovered from generators, who would pay a connection charge to connect to the renewable energy zone. This charge would be proportional to the generator's nameplate capacity and how early they connected. That is, at any given point in time, the cost for generators to access prescribed capacity would be a fixed rate in terms of $/MVA. The rate paid by generators would increase with time according to an escalation factor. Generators connecting early would pay lower costs compared to generators connecting later.
- If a TNSP thought the interest in a particular location was more than what was indicated in the Integrated System Plan as the 'efficient' capacity level, then TNSPs could set charges and negotiate with generators as unregulated revenue. TNSPs could then seek higher returns via generator connection charges to compensate for the additional risk of investing in capacity without guaranteed cost-recovery.

In this way, the costs and risks of a renewable energy zone would be shared between a number of parties. The Commission is interested in stakeholder views on whether a model that allows for shared cost recover should be pursued further. For example, such a model could be made consistent with the proposed access principles.

QUESTION 12: POTENTIAL SHARED COST RECOVERY MODEL

Do stakeholders consider that a model which enables risk sharing between a number of parties should be pursued further?

Do stakeholders consider that a risk-sharing model would be relatively simple and straightforward to implement?

7 IMPLEMENTATION

This chapter sets out the proposed implementation approach for access reform, including the introduction of dynamic regional pricing and transmission hedging.

7.1 Background

7.1.1 Proposed commencement date of access reforms

In the consultation paper, the Commission recommended a phased reform approach to the way in which generators access the shared transmission network. The phased approach is outlined below, and comprised three stages.

Table 7.1: **Proposal for access reform in 2018 COGATI review**

PHASE OF REFORM	OVERVIEW	PROPOSED COMMENCEMENT
1. Dynamic regional pricing	The access arrangements would be changed to implement dynamic regions for determining the price payable to generators.	July 2022
2. Improved information	The information that is produced from dynamic regional pricing, including where congestion occurs and the costs of congestion, would be used to supplement the planning arrangements for transmission.	July 2022 to July 2023
3. Generators fund transmission infrastructure	In response to the information on network congestion, connecting parties would be able to purchase transmission hedges (called firm transmission rights or firm access' in the paper) that would allow them to more effectively manage dispatch risks. Generators' collective decisions to hedge would guide transmission network service providers' (TNSPs') planning decisions due to an obligation placed on TNSPs to provide sufficient transmission capacity consistent with the collective amount of transmission hedges purchased by generators.	July 2023

Source: AEMC, *Coordination of generation and transmission investment, Final report,* 21 December 2018.

The Commission favoured a phased approach on the basis that it allowed some issues with the current regulatory framework to be addressed in an expedited fashion, while providing a pathway to address the remaining issues in a consultative and considered fashion.

The first stage of access reform would involve wholesale settlement arrangements being changed to implement dynamic regional pricing. Dynamic regional pricing would have the benefit of introducing a price signal to generators that better reflects the short-run costs of using the network, thus improving incentives for generators to operate efficiently.

It was considered that dynamic regional pricing would involve fewer changes to the broader regulatory framework than other aspects of access reform. For example, there would be no transmission charges levied on generators as all network charges would continue to be paid for by load. No changes to the transmission network service provider (TNSP) planning, investment or operational arrangements would be required to give effect to dynamic regional pricing. In contrast, some changes to the Australian Energy Market Operator (AEMO) and market participant's dispatch and settlement processes and systems would be required.

It was on this basis that the Commission considered that dynamic regional pricing could be implemented as the first stage in July 2022.

The second stage of access reform involved improved information produced from the dynamic regional pricing regime being used to supplement the planning arrangements for the transmission network. This information could include patterns of congestion, the dynamic location of regions, as well as the costs associated with congestion on particular transmission elements. This information would be a consequence of the first stage, and therefore would not require a specific implementation date.

The final stage of access reform proposed in the consultation paper involved generators being able to purchase transmission hedges between their local marginal price and the regional reference price. The purchase of these hedges was to directly influence transmission planning and operational processes. This stage was proposed to be implemented around June 2023. This final phase was recognised as involving considerable reform to all aspects of the current transmission access and planning regime. However, as noted in chapter 2, the Commission considers that holistic reform is necessary in the face of the rapid transformation of the electricity sector.

7.2 Stakeholder views

Stakeholders in response to the consultation paper expressed a diverse range of views on the implementation timing and phasing of access reform.

In regard to the timing of access reform, some stakeholders raised concerns that the staged implementation timeframes proposed in the consultation paper were too long.[114]

For example, while AEMO acknowledged that successful access reform will take time, it considered that four years is too long to wait to resolve the challenges facing the NEM. Given the complexity of the potential reforms and necessity of long lead times, AEMO proposed that interim solutions, such as a framework for renewable energy zones, may be required.

114 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: AEMO, p. 4., ERM Power, p. 2; MEU, p. 5.

In contrast, generators and network businesses were generally of the view that the proposed implementation timeframes were too ambitious.[115] For example, InterGen Australia and EnergyAustralia were concerned that the proposal did not allow sufficient time for the market to adapt to and bed down 5-minute settlement before access reform was introduced.

Stakeholders also expressed a diverse range of views on the staged implementation process for access reform discussed in the consultation paper.

Some stakeholders were supportive of the proposed three stage implementation process.[116] For example, ENGIE expressed a view that the three stage phased implementation is both elegant and pragmatic, with incremental benefits being achieved along the way.

Other stakeholders supported alternative implementation approaches to reduce transitional uncertainty or provide increased information for market participants.[117] Delta Electricity, Stanwell and EUAA considered that increased information should occur as a first stage rather than second, as better information would enable participants to assess the magnitude of the benefits that are likely to be realised by moving to regional pricing.

7.3 Commission's views

7.3.1 Implementation timing

The Commission proposes to implement dynamic regional pricing and transmission hedging concurrently in July 2022. This represents a change from the proposed implementation timing outlined in our consultation paper, and is in recognition of stakeholder feedback on this issue.

We consider that substantial benefits may accrue from aligning the implementation of dynamic regional pricing and transmission hedging. Alignment may lower the costs of implementation by removing the need to design and implement bespoke settlement arrangements for a dynamic regional pricing regime without hedging. In addition, it could promote financial certainty amongst market participants by allowing them to hedge the basis risks of dynamic prices.

The Commission considers that implementing both reforms in one holistic stage would make adapting to the new access reforms simpler for market participants. This will promote regulatory stability by making the proposed changes transparent, as well as by minimising the number of reform stages that stakeholders would need to adapt to as a part of the reform process.

As noted throughout this paper, the Commission is confident that there is a strong case for transmission access reform. The proposed access reform is a holistic and efficient long-term solution to the issues raised by market participants. It would allow generators to receive

115 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: ENGIE, p. 5; ENA, p. 2; AEC, p. 1; Intergen Australia, p. 1; TasNetworks, p. 7; EnergyAustralia, p. 3; AusNet Services, p. 2; CEC, p. 3; Meridian Energy, p. 2; AGL, p. 1; Snowy Hydro, p. 2.

116 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: ENGIE, p. 2; ENA, p. 7; AusNet Services, pp. 2-3.

117 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging,* consultation paper submissions: Neoen, p. 3; Delta Electricity, p. 2; Stanwell, pp. 4; EUAA, p. 6.

greater financial certainty of their generation investment, in exchange for bearing a portion of the costs of transmission investment that are currently borne by consumers. Improving the links between generator's investment and operational decisions with transmission should facilitate better transmission planning and investment, and lower costs for consumers.

Transmission access reform is needed sooner rather than later for the NEM to effectively transition to a lower emissions' environment, whatever this future may look like. Access reform is integrally linked with the key issues facing the market, which are affecting all types of market participants. The Commission agrees with the view expressed by AEMO that four years is too long to wait to resolve the challenges facing the NEM. This is why we have proposed a date of July 2022 for implementation of the new access regime.

The Commission also considers that there is an in-principle case for the information provision stage of access reform happening sooner than 2022. We understand that locational marginal prices are already implicitly calculated as part of the dispatch process, but disregarded for settlement. While the Commission is yet to consider the costs and benefits in detail, it does not expect that it would be particularly costly or onerous for AEMO to publish the following information before the wider changes to the access regime come into effect:

- historic and forward-looking locational marginal prices
- information about when transmission network constraint equations bind.

BOX 11: IMPLEMENTATION TIMING

Do stakeholders agree with the Commission's proposed approach to implementation?

Would stakeholders benefit from additional information on congestion prior to implementation of access reform?

7.3.2 Transitional considerations

In addition to *when* access reform is introduced, the Commission is also conscious that there will need to be a transitional period in which incumbent generators would be granted, rather than pay for, transmission hedges. Transitional processes would be necessary to ensure that the introduction of access reform would not create sudden changes in the market, and to provide for a learning period.

The nature and length of any grandfathering arrangements represents a trade-off. On the one hand, were the arrangements too generous to incumbent generators (for example, the transmission hedges provided excessive benefits, or were in effect for a long time), this could risk overcompensating existing generators. In turn, this could also deter otherwise efficient investment in both generation and transmission.

Conversely, if the grandfathered rights are insufficient (in nature or length), this could expose incumbent generators to significant, unforeseeable regulatory risk. This too would be likely to deter, or increase the costs of, future investment.

The form and length of the transitional transmission hedging products are yet to be determined. It is first necessary to work out what the detail of the proposed access model is, in order to work out how to transition towards it.

To guide consideration of these issues, the Commission has developed some high-level transitional principles. These principles are to:

- mitigate any sudden changes to prices and margins for market participants (generators and retailers) on commencement of the access reforms to encourage and permit (existing and new) generators to acquire and hold the levels of firm access 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 transmission hedges that could create dysfunctional behaviour or outcomes in access procurement or pricing.

BOX 12: TRANSITIONAL PRINCIPLES

Do stakeholders agree with our proposed principles?

Are there additional principles that should be included?

ABBREVIATIONS

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
DR	demand response
ESB	Energy Security Board
FTR	financial transmission right
ISP	Integrated System Plan
IR-TUOS	inter-regional transmission use of system
LAP	load aggregation pricing
LMP	locational marginal price
MCE	Ministerial Council on Energy
MLF	marginal loss factor
MNSP	market network service provider
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
NSA	network support agreement
NSG	Non-scheduled generation
OFA	Optional firm access
PPA	Power purchase agreements
REZ	Renewable energy zone
RIT-T	Regulatory investment test for transmission
RRN	regional reference node
RRP	regional reference price
SENE	Scale efficient network extensions
SRA	settlement residue auction
STPIS	Service target performance incentive scheme
TCAPA	Transmission connection and planning arrangements

TNSP	Transmission network service provider
TUOS	Transmission use of system

A ASSESSMENT FRAMEWORK

This appendix sets out the framework the Commission will use to consider:

- how access reform might improve coordination between generation and transmission investment
- whether changes to the regulatory framework and market design are needed to enable access reform to proceed in a manner consistent with the NEO.

A.1 The National Electricity Objective

The overarching objective guiding our approach is the National Electricity Objective (NEO). The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the NEO. Similarly, with any related rule changes that may stem from this review, the Commission will have to consider whether the proposed rules promote the NEO. The NEO is set out in section 7 of the National Electricity Law (NEL), which states:

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

Based on a preliminary assessment of the issues raised by this review on the generation and transmission access regime, the Commission considers that the overarching promotion of **efficient investment, operation and use of electricity services**, as well as the areas of **price, reliability and security** are the relevant areas of the NEO for further consideration.

A.2 Principles of good market design

The Commission has set out a number of market design principles to guide the development of potential changes to market and regulatory arrangements that underpin the generation and transmission framework in the NEM. These principles were discussed in the technical working group, and reflect stakeholder feedback.

A.2.1 Appropriate allocation of risks to parties best placed to bear them

Good market design allocates risk and accountability for market investment and operational decisions to parties who are most able to manage them efficiently and have the greatest incentives to do so.

A key objective of the COGATI reforms is to minimise the risk of consumers carrying the risk of inefficient transmission investment decisions. Solutions that allocate risks to market participants are preferred where practicable because market participants have commercial incentives to manage such risks in an efficient manner.

Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Placing inappropriate risks on consumers, who are not best placed to manage these risks is likely result in higher prices while risk to market participants will only be passed on to consumers in terms of higher prices where competition permits.

Under arrangements where investment and operational decisions are made by a single entity such as a planner or system operator, risks are more likely to be borne by consumers. As a result, this single entity does not have sufficient commercial incentive to minimise costs (because the consumer tends to bear them instead), resulting in inefficiently high costs for consumers than they would be if the costs associated with decisions were incurred by market participants operating in competitive environments. Solutions that allocate risks to market participants, such as commercial businesses, who are better able to manage them are preferred, where practicable.

A.2.2 Promote signals that encourage efficient investment and operation of generation and load assets

Efficient market design arrangements maximise the provision of price signals that reflect the marginal cost of the provision of a particular product or service, as well as any positive or negative externalities, in order to encourage efficient decision-making by market participants in both investment and operational time-scales.

A key aim of any transmission access regime should be to provide appropriate locational signals to new generators such that they make entry and operational decisions that efficiently reflect the costs of generating and transporting electricity to consumers.

The right signals tend to lead to the minimisation of system wide costs. Price signals are preferred because they are the key signals that enable market participants to understand and incorporate the short-term and long-term costs of producing electricity into their commercial decisions. These signals would encourage prospective generators to establish their operations in locations where it would be efficient to do so and discourage them from establishing in locations where doing so would be less efficient. Appropriate price signals also provide incentives for market participants to operate in an efficient manner.

However, there may be other signals that can also be provided such as the greater provision of market information to participants.

A.2.3 Facilitating competition where feasible, and effective regulation where necessary

Competition promotes efficiency on a short-term basis by encouraging generators to offer prices that reflect production costs, as well as in the long-term by encouraging investment and innovation that supports the provision of cheaper electricity.

However, market design must also take into account the fact that no market is perfectly competitive, as well as any circumstances where the promotion of competition is impractical or not feasible.

In these cases, it is necessary to regulate and incentivise natural monopolies, such as TNSPs, to make efficient trade-offs between providing transmission services through additional investment in network expansion or through the use of operational (non-network) measures.

Such measures encourage TNSPs to provide the services demanded by their customers at the lowest sustainable cost.

A.2.4 Promoting simplicity, transparency and predictability

Any market design intended to reform the transmission framework should be simple, predictable and transparent, so that consumers, generators, TNSPs and regulators are adequately informed about the variables that affect investment and operation in the sector.

As a result, market participants would be able to make efficient investment and operational decisions that would minimise their transaction costs.

Such simplicity, transparency and predictability should also promote confidence in the market framework and encourage effective market participation.

A.2.5 Promoting the safe, secure and reliable supply of energy

Any new market design must take into account the need to support the safe, secure and reliable supply of electricity to consumers. Regulation may be required to safeguard these outcomes.

A.2.6 Maintaining a level playing field for different forms of technology and for market participants

Market design arrangements should be designed to account for a full range of potential market and network solutions. Market design should therefore focus on the goods that are being supplied, rather than the methods used to supply these goods.

Regulatory arrangements should be designed to take into account the full range of potential market and network solutions, as well as taking account of all possible technologies that could provide such solutions (e.g. generation or demand-side). They should not be targeted at a particular technology or business model, or be designed with a particular set of technologies in mind. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

Market design arrangements should also be designed to provide a level playing field for market participants. Market design reforms should provide transitional arrangements that mitigate adverse impacts on existing generators that made investment decisions based on the current regime, but also do not hinder the ability of new generators to enter the market.

A.2.7 Flexibility and adaptability

Transmission and generation frameworks must be designed to be flexible in response to changing market and external conditions, such as in the broader political landscape. These frameworks must also enable market participants to respond to such changes as they develop within the NEM.

Flexibility and adaptability are particularly important during times when major changes and other major reforms are occurring within the NEM. The NEM is currently experiencing rapid technological change. To the greatest extent possible, the framework delivers efficient solutions regardless of how the future pans out, rather than having to change the framework to adapt to a changing future.

Such frameworks seek to decentralise decision-making to the greatest extent possible, because market participants and customers typically have the information, tools and incentives to flexibly respond to changes in circumstances in ways that promote customers' long term interests.

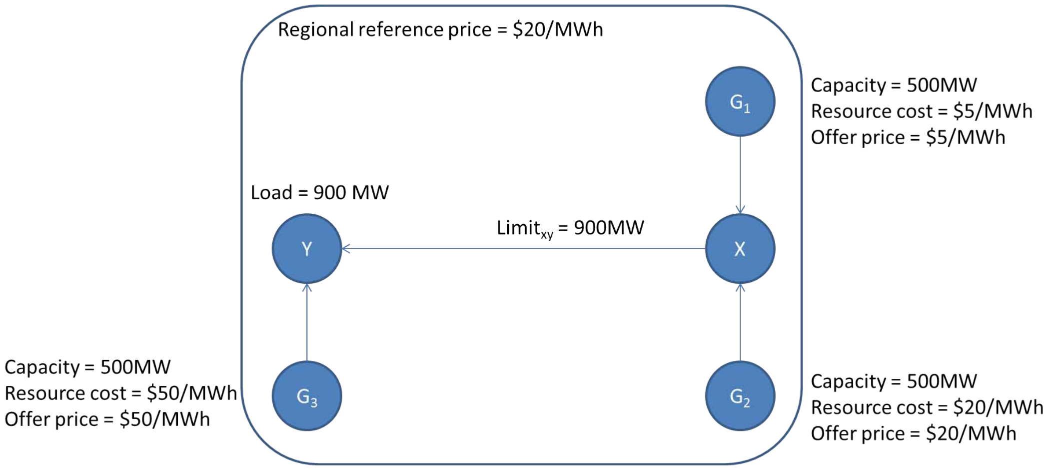
B DYNAMIC REGIONS FOR PRICING GENERATION

As discussed in section 4.1.2, where congestion arises and transmission constraints occur, pricing regions will be dynamically created which will reflect transmission constraints that are actually occurring at that particular time. This is different to the current arrangements, where dispatched generators receive the regional reference price, which is the same throughout the region.

An example of the mechanism is shown in the figures below.

Figure B.1 shows the arrangements under both the status quo and in dynamic regional pricing when there are no transmission constraints.

Figure B.1: No congestion



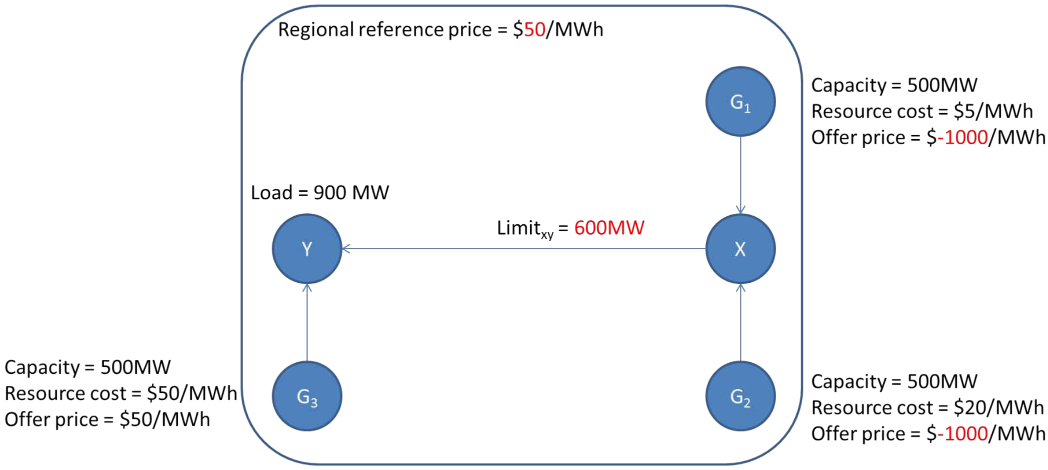
Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	0	5	500	10,000	2,500	7,500
G2	500	0	20	400	8,000	8,000	0
G3	500	0	50	0	0	0	0
Total	**1,500**	**0**		**900**	**18,000**	**10,500**	**7,500**

Source: AEMC analysis

In this simple example, all of the 900 MW load in the region (encircled in blue) is at point Y. Generator 3 is at point Y, and generators 1 and 2 are at point X. There is a transmission limit of 900 MW between X and Y. G1 and G2 have lower resource costs than G3 so bid at lower prices. The transmission limit is not violated because all the load (900 MW) at Y can be accommodated across the transmission network from generators 1 and 2 at X. Generator G2 is the marginal generator and so sets the regional price of $20/MWh. Generator 3 is not dispatched.

Compare this to the example in Figure B.2 below, where the transmission constraint is now 600 MW under the status quo open access approach. Here, all generators dispatched receive the market price, which is a region-wide price. Consequently, there are only limited intra-regional price signals reflecting congestion.

Figure B.2: Open access, transmission constraint binds



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	0	-1000	300	15,000	1,500	13,500
G2	500	0	-1000	300	15,000	6,000	9,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**0**		**900**	**45,000**	**22,500**	**22,500**

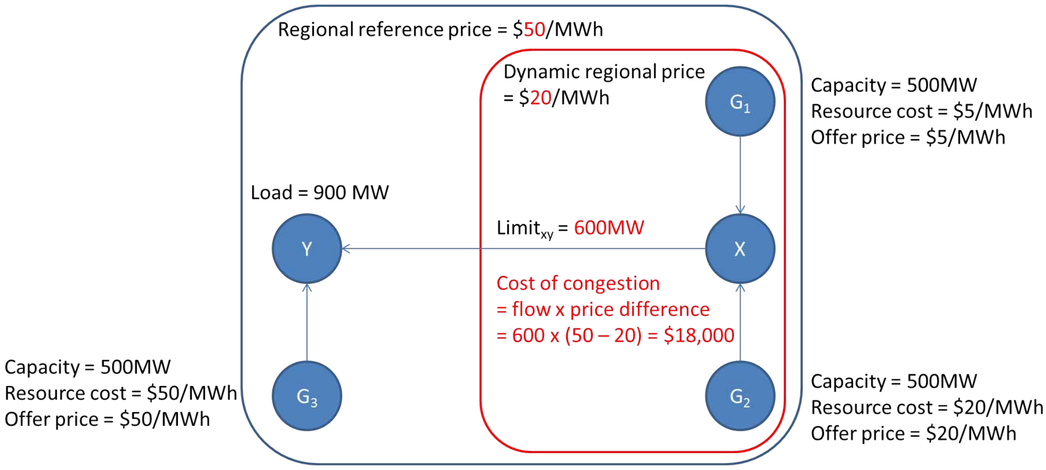
Source: AEMC analysis

In this example, generators 1 and 2 are constrained down due to the transmission constraint, and generator 3 is dispatched in addition to generators 1 and 2 to serve the load at Y now not served in full by generators 1 and 2. Generator 3 sets the regional price of $50/MWh. Here, the generators behind the constraint know that if they bid according to their resource costs, then they would not be dispatched. However, they know that the offers that they make will not affect the settlement price they receive as a result of congestion between them and the regional reference price. Therefore, each generator behind a constraint will bid at the market floor price to maximise its dispatch quantity.

This will result in inefficient dispatch - higher cost generation resources being dispatched instead of lower cost resources. Generator 1 has lower resource costs, so the optimal dispatch is generator 1 to be dispatched at its full capacity (500 MW) and generator 2 to then make up the remainder to the transmission limit (a further 100 MW). But because the market dispatch engine dispatches on the basis of bids, not underlying costs, this does not occur.

Now compare this to the example in figure B.3, where the transmission constraint is again 600 MW but dynamic regional pricing is in place.

Figure B.3: Dynamic regional pricing, transmission constraint binds



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	9,000	5	500	10,000	2,500	16,500
G2	500	9,000	20	100	2,000	2,000	9,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**18,000**		**900**	**27,000**	**19,500**	**25,500**

Source: AEMC analysis

Due to the transmission constraint, generators 1 and 2 are in a different dynamic region (circled in red) to the regional reference node.

There is no longer an incentive for generator 1 or 2 to disorderly bid. Doing so would expose the disorderly bidding generator to a low dynamic regional price.

In the example, generators 1 and 2 bid reflective of their resource costs.[118] Generator 2's dispatch is constrained down to 100 MW, so it remains the marginal generator in the dynamic region, setting the price in the dynamic region at $20/MWh. Generator 3 is dispatched to meet demand at Y, and so it sets the regional reference price of $50/MWh.

The cost of congestion is calculated as the flow on the line between X and Y (600 MW) multiplied by the price difference between the dynamic regional price ($20/MWh) and the regional reference price ($50/MWh): 600 x (50 - 20) = $18,000. This is the difference between what consumers are paying for electricity (at the regional reference price) and what generators are being paid for electricity (at the dynamic region price), directly analogous to settlement residue that arises from inter-regional settlement currently. This $18,000 of settlement residue is divided between generators 1 and 2 in proportion to their capacity as a compensation payment (in the example, half each as they have the same capacity, so $9,000 each).

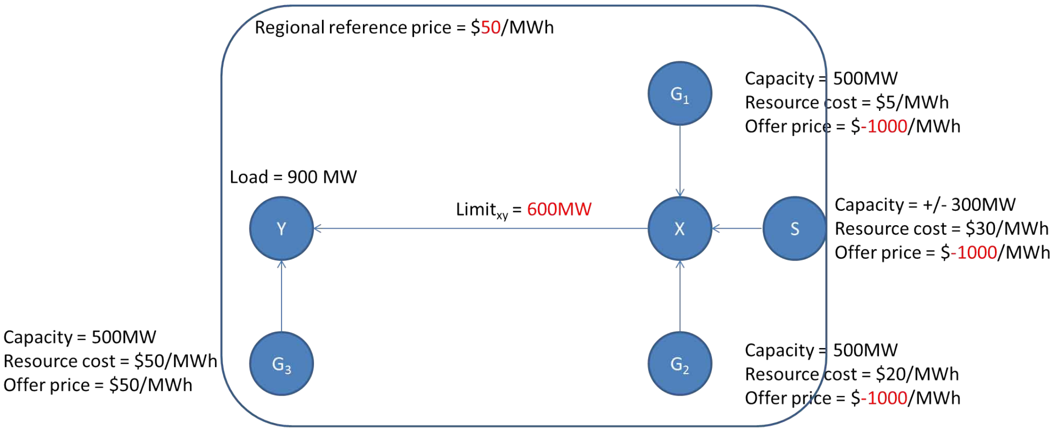
118 In this example, generator 2 would have an incentive to bid just above the bid of generator 1, in order to increase the compensation payment. This would allocate more of the margin to generator 2 and less to generator 1. However, physical dispatch outcomes are unaffected by this bidding behaviour and dispatch is optimal.

Exposing generators to the dynamic regional price removes the incentives to disorderly bid when transmission constraints arise. This means that at times of transmission congestion, the lowest cost combination of generation should be dispatched. The resource cost of dispatch is lower than under the status quo.

The key advantage of these changes is that it should encourage most cost reflective bidding, and so improve dispatch efficiency in the NEM.

These benefits may become particularly prevalent if storage plays an increasingly large role in the NEM. Figure B.4 shows this in practice for the status quo open access arrangements.

Figure B.4: Open access, transmission constraint, storage



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	0	-1000	200	10,000	1,000	9,000
G2	500	0	-1000	200	10,000	4,000	6,000
S	300	0	-1000	200	10,000	6,000	4,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**0**		**900**	**45,000**	**26,000**	**19,000**

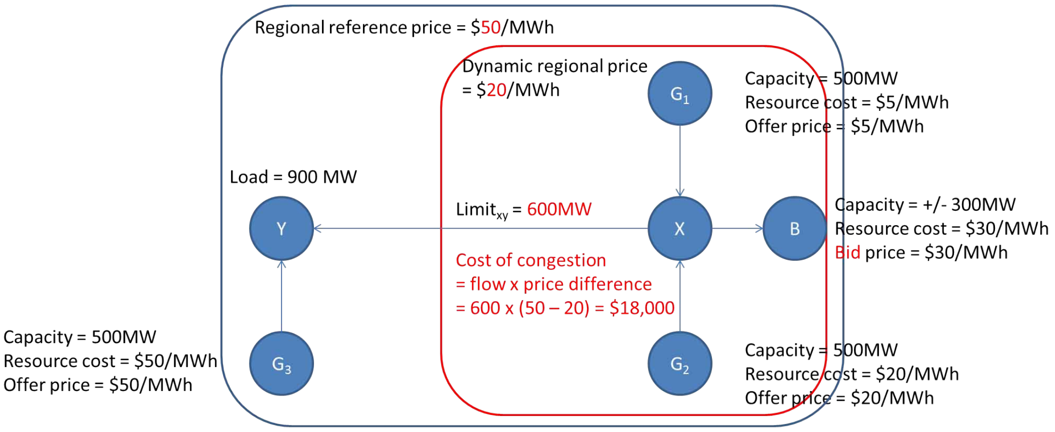
Source: AEMC analysis

In this example, storage (S) behind a constraint has an incentive to disorderly bid (as seller of electricity, i.e. analogous to a generator) in order to receive the region wide market price.

Not only is this more inefficient than if the storage was not there (because the resource cost of the storage device is in the example higher than generators 1 and 2, which the storage device partially replaces in dispatch) it's even more inefficient than if the storage facility was to charge instead of generating.

What might happen under dynamic regional pricing is shown in figure B.5 below, were storage to be charged the dynamic regional price when acting as load.

Figure B.5: Dynamic regional pricing, transmission constraint, storage



Generator	Capacity (MW)	Congestion hedge ($)	Offer ($/MW)	Dispatch (MW)	Dispatch revenue ($)	Resource cost ($)	Margin ($)
G1	500	9,000	5	500	10,000	2,500	16,500
G2	500	9,000	20	400	8,000	8,000	9,000
G3	500	0	50	300	15,000	15,000	0
Total	**1,500**	**18,000**		**1,200**	**33,000**	**15,500**	**25,500**

Source: AEMC analysis

Compared to Figure B.4, generator 2's output is increased in order to service this local load. This allows the storage facility to charge at a price less than its assumed resource cost ($30/MWh): an efficient dispatch outcome.

C HIGH-LEVEL SETTLEMENT DESIGN

Chapter 4 and Appendix B set out a simplified representation of the dynamic regional pricing model. However, were this model to be implemented, *actual* settlement arrangements would operate in a different (although analogous) way.

This appendix sets out a high-level overview of the settlement arrangements that would be required to implement the proposed access reform under realistic network conditions. The aim of this appendix is to present key settlement concepts and highlight key design choices for stakeholder feedback.

Consequently, this discussion does not present a fully-scoped settlement model. As the design work progresses, further specification and refinement will be undertaken, including detailed consultation with AEMO to test the practicality of the new settlement arrangements. The settlement arrangements will also evolve as the detailed design of the other two components of the proposed access reforms – transmission hedges as well as transmission planning and operation– are progressed.

The Commission welcomes feedback from stakeholders on any aspect of the settlement design outlined in this appendix.

C.1 Assumptions and dependencies

The discussion in this appendix assumes that dynamic regional pricing and transmission hedges are introduced **at the same time**. This is consistent with the view that the Commission set out in Chapter 7 regarding implementation. Under this approach:

- All generators that are dispatched would receive the locational marginal price (LMP) at their node for their output.
- Generators that hold a transmission hedge would, in addition, receive the difference between the LMP and regional reference price (RRP) for the hedge volume purchased.

As discussed in Chapter 4, there are multiple open design questions in relation to both dynamic regional pricing and other elements of the access model. In order to set out a high-level settlement design, it was necessary to make some assumptions on these detailed design questions, which are highlighted below.

The Commission notes that these design choices are still being actively considered and the assumptions should not be taken to represent the Commission's preferred option. If different design decisions are made on these issues, this will naturally result in changes to the settlement design.

Table C.1: **Design assumptions**

DESIGN CHOICE	ASSUMPTION FOR THE HIGH-LEVEL DESIGN BLUE-PRINT	POTENTIAL ALTERNATIVE OPTIONS
Allocation of settlement residues	Settlement is balanced in every settlement period. That is, the settlement residues that arise in each settlement period as a result of transmission constraints will always match the transmission hedge settlement payments made to generators. Under the model discussed in this appendix, this is achieved through two design features: (1) Generators that do not hold transmission hedges may still receive a share of any settlement residues that remain after payments associated with purchased transmission hedges have been settled. (2) In cases where the quantity of transmission hedges held by generators exceeds available transmission capacity, payouts against these hedges would be scaled back accordingly (that is, the hedges are not 'fully firm').	The Commission is not convinced that the assumption made in (1) is appropriate. Therefore, the Commission has set out a variety of different design choices that could be made. For example, an alternative option is that generators that do not hold transmission hedges do not receive any allocation of settlement residues. Instead, these residues could be used to offset TUOS charges for customers, or alternatively to increase the firmness of transmission hedges by making these funds available to reduce the impact of scaling in subsequent dispatch intervals. As discussed in Chapter 4, the Commission is interested in stakeholder feedback on these matters.
Settlement of generation, load and storage	This settlement blueprint assumes that only scheduled and semi-scheduled generation and storage are to be settled at the LMP. Non-scheduled generation and storage, and all load (whether scheduled or non-scheduled) are assumed be settled at the RRP, as is the case today.	Chapter 4 set out a range of alternative arrangements for different parties on whether they should be settled at the LMP or RRP. These all have implications for the settlement design. For example, scheduled load could also be settled at its LMP. The Commission is interested in stakeholder feedback on these matters.
Alternative regional prices	The settlement blueprint assumes that if participants are not settled at their LMP, they continue to be settled at the	Stakeholder submissions to the March consultation paper suggested that a volume-weighted average of load LMPs in a

DESIGN CHOICE	ASSUMPTION FOR THE HIGH-LEVEL DESIGN BLUE-PRINT	POTENTIAL ALTERNATIVE OPTIONS
	existing RRP.	region could be considered as an alternative regional price for settling load (i.e., 'load aggregation pricing', or LAP). The Commission is continuing to assess what the settlement implications of a LAP approach would be.
Losses	In the following discussion, no changes are assumed to the way that loss factors are currently calculated or applied.	The treatment of losses is an important consideration for the access reform package. Depending on the approach taken to losses, this could also impact settlement design.
Capping locational marginal prices	The settlement blueprint assumes that LMPs can never exceed the corresponding RRP in the region. This is to address concerns that generators in 'load pockets', who must be dispatched in order to meet local demand, would be able to exercise market power to raise the LMP above an efficient level.	Two recent trends in the NEM suggest that this choice should be considered: the prospective development of more loops in the NEM and the falling cost of utility-scale batteries. This issue is discussed further in appendix c.6.
Setting a floor for locational marginal prices	This settlement blueprint assumes that a floor would be set on LMPs, in order to ensure that generators do not face extremely low local prices, as could result in certain situations.	A detailed approach for setting an appropriate floor is yet to be determined. Development of a proposed approach is still under consideration.

Source: AEMC analysis.

Note: These assumptions form the basis of the design blueprint set out in this appendix. However, stakeholders should note that at this early stage of the design process, the Commission's preferred direction on these design choices has not been determined.

C.2 Introduction to intra-regional settlement

C.2.1 Overview of intra-regional settlement payments

Under the dynamic regional pricing framework, intra-regional settlement payments to generators that hold a transmission hedge can be thought of as comprising two elements - dispatch settlement and residue settlement. This is illustrated below.

BOX 13: INTRA-REGIONAL SETTLEMENT

$Settlement\$ = Settlement\$_{Dispatch} + Settlement\$_{Residue} = LMP \times G + (RRP - LMP) \times H$ (1)

Where:

G = Dispatched output

H = Transmission hedge quantity

LMP = Locational marginal price

RRP = Regional reference price

*Note that the transmission hedges may be **options** contracts, and so only pay out if the RRP is greater than the LMP. If so, the holder of the hedge would not receive a negative payment (that is, have to make a payment) if LMP is greater than RRP.*

However, this does not reflect how settlement payments would actually be made in practice. For this purpose, we need to rearrange the equation above to reflect:

- Payments that would continue to be made under the existing '**regional settlement'** process.
- Payments that would be made under an additional settlement process - **'transmission hedge settlement'** - that is needed to decouple the allocation of settlement residues from dispatch.

This is set out below.

BOX 14: REGIONAL SETTLEMENT AND TRANSMISSION HEDGE SETTLEMENT

$Settlement\$ = Settlement\$_{Regional} + Settlement\$_{Hedge} = RRP \times G + (RRP - LMP) \times (H - G)$ (2)

Where:

G = Dispatched output

H = Transmission hedge quantity

LMP = Locational marginal price

RRP = Regional reference price

In this formulation, the first term - *RRP x G* - is the same as occurs under the existing NEM design.[119] The second term - (*RRP - LMP) x (H - G)* represents the additional settlement payment that must be made in order to allocate intra-regional settlement residues on the basis of transmission hedges held by generators, rather than dispatch. The two settlement payments would be aggregated and settled together.

C.2.2 Settlement imbalances

The quantity of settlement residues that arise on a congested line are determined by the physical flow on the line and the difference in price between the two nodes where load and generation are being settled at. Under the existing market design, these residues are allocated on the basis of dispatched generation output (G).

This means that currently, settlement is always balanced. Under dynamic regional pricing with transmission hedges, the allocation of these residues is decoupled from dispatch, and linked instead to the quantity of transmission hedges held (H). If the quantity of transmission hedges held (H) is different from the physical flow on the line (G) in a settlement period, settlement would not be balanced.

In particular:

- If the transmission capacity is *greater than* the amount of hedges that are held (H) in a particular part of the network, there will be excess (unallocated) settlement residue. Put differently, there will be an amount of settlement residue that remains unallocated.
- If the transmission capacity is *less than* the transmission hedge quantity (for example, due to an outage on a network asset), then the settlement residue will be less than the amount needed to fully pay out against all transmission hedges held, resulting in a settlement deficit.

For the payouts against transmission hedges to perfectly balance with settlement residues, the hedge quantity that settlement is based on must be **equivalent** to the available transmission capacity.

However, even if the quantity of hedges made available to generators are carefully specified, in practice this still **may not match available transmission capacity** in real time because:

- Generators may not purchase the full quantity of transmission hedges that are made available by the transmission network service provider.
- There may be outages on the transmission system that exceed that allowance made when the volume of hedges that would be made available was determined.

119 Ignoring transmission losses at this stage, for simplicity.

However, a key design parameter is that settlements should balance. Therefore, there needs to be choices made about how surplus and deficits of settlement residues are accounted for. Chapter 4 discusses options for how this can occur.

There are a number reasons why a balanced settlement approach is appropriate for the NEM:

- The challenges associated with managing surpluses and deficits. In some markets, long-term deficits are funded by an uplift charge on consumers, which would be against the long-term interests of consumers.
- The potential magnitude of settlement imbalances, relative to other markets with firm FTRs. The relatively 'stringy' topography of the NEM could potentially result in larger settlement imbalances relative to a more highly meshed network. Further, as the NEM is an energy-only market, occasional extreme spot price spikes are needed for generators to recover their fixed costs. As a result, the NEM has a higher market price cap than many US jurisdictions that combine locational marginal pricing and FTRs with a capacity market. A higher market price cap could potentially lead to more substantial settlement deficits, relative to these jurisdictions.

C.3 Intra-regional settlement in practice

In practice, the implementation of transmission hedge settlement will be different to the simple model described in appendix c.2 above, in order to reflect the characteristics of the real, meshed transmission network. This section explains how this would operate and describes how the information required for transmission hedge settlement is already generated through existing dispatch and settlement processes.

C.3.1 Overview

Transmission hedge settlement would be implemented through a settlement algorithm that is based on the capacity available across each transmission line. In summary:

- Limitations on the flow across any given transmission line are determined by the constraint equations included in NEMDE to ensure secure generation dispatch.
- When transmission constraints bind, settlement residue accrues on each congested line. This residue is equal to the product of **available capacity** on the line and the **congestion price**.
- The settlement residue on each congested line is allocated to generators in proportion to their **capacity entitlement**, which is based on the quantity of transmission hedges that they hold.
- Transmission hedges fully hedge the difference between LMP and RRP, provided that there is sufficient available capacity. If transmission hedges exceed available capacity, hedge payouts would be scaled back. The required level of available capacity to avoid scaling is referred to as **target capacity**.

These concepts and processes are outlined in more detail below.

C.3.2 Congestion on the transmission system

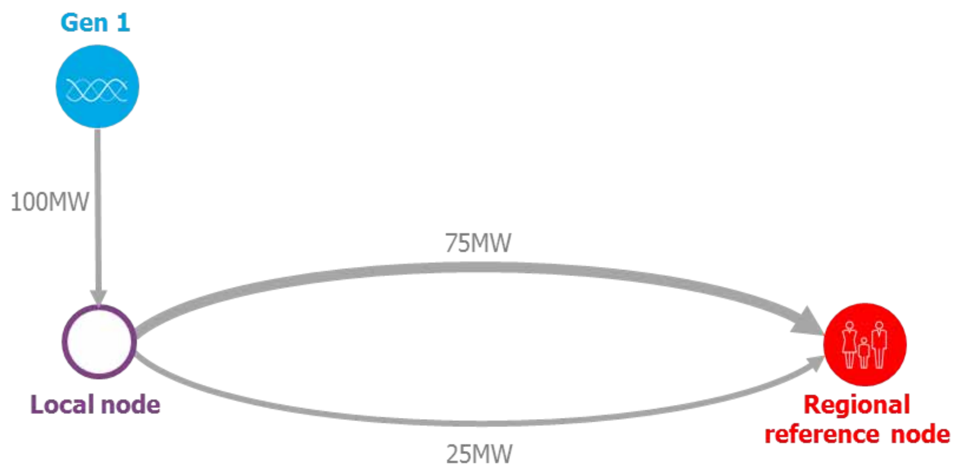
In a simple radial network, there is a single congested transmission line lying between the two nodes. In a real meshed network, there are hundreds of transmission lines. Congestion can potentially occur on any transmission line, and several lines may be congested concurrently.

Every transmission line and network transformer has a thermal limit*:* the maximum power that can flow through the line before it overheats. There are limits on power flows that do not relate to the overheating of a particular transmission asset, but instead are needed to prevent the power system becoming unstable. Both thermal constraints and non-thermal (stability) constraints are reflected in NEMDE constraint equations. Therefore, any type of constraint that limits the available capacity on a transmission line could impact pricing and settlement outcomes under the dynamic regional pricing model.

C.3.3 Transmission line usage and capacity

In a meshed network, power flow from a generator to the RRN will be distributed across multiple paths. The figure below presents a simplified example where there are just two paths and the power flow is distributed between them in a ratio of 3 to 1. The proportion of the power from a generator that flows through a particular line is referred to as their **participation factor**.

Figure C.1: Two-path network example



Source: AEMC analysis

In the example above, the participation factors for Gen 1 are 75 per cent and 25 per cent on the two paths. Note that the output from Gen 1 is assumed to flow to the RRN, where there is 100MW of demand. The amount of power from a particular generator that flows through a particular line, on its way to the RRN, is referred to as that generator's **usage (U)**.

This is simply the product of the participation factor and the generator's output:

$U = a \times G$

Where:

U = usage

α = participation factor

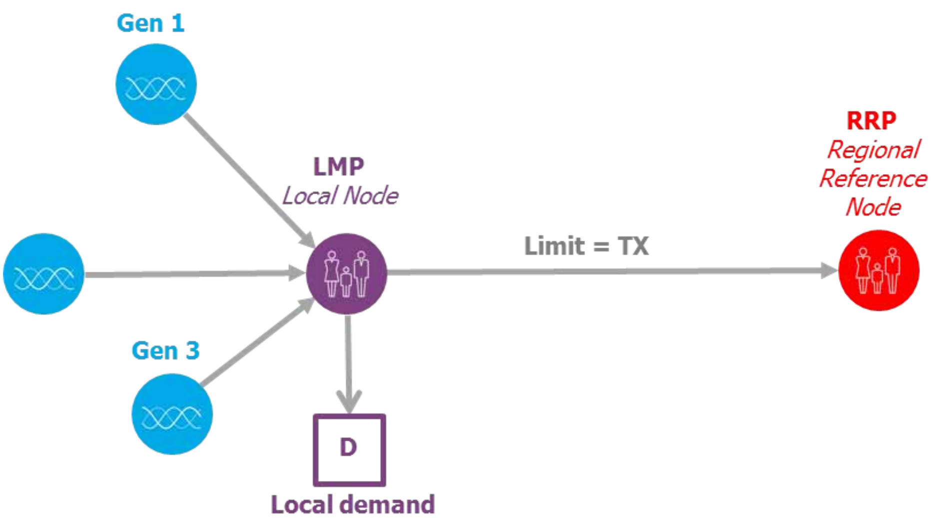
G = generator output

Where there are multiple paths to the RRN, a generator makes use of multiple transmission lines. Therefore, their usage will be defined in relation to each line.

Impact of local demand

In the simple network examples presented so far, the entirety of generation output flows through the transmission network to the RRN. When there is **local demand (D)** connected to the local node, some of the output will serve this demand, with the remainder flowing to the RRN. The figure below illustrates the effect of local demand in the context of a simple two-node network.

Figure C.2: Local demand example



Source: AEMC analysis

The flow through the network is the residual generation after the local demand has been served:

$Flow = G1+G2+G3 - D \leq TX$

Where

D = local demand

Rearranging this inequality gives:

$G1 + G2 + G3 \leq TX + D$

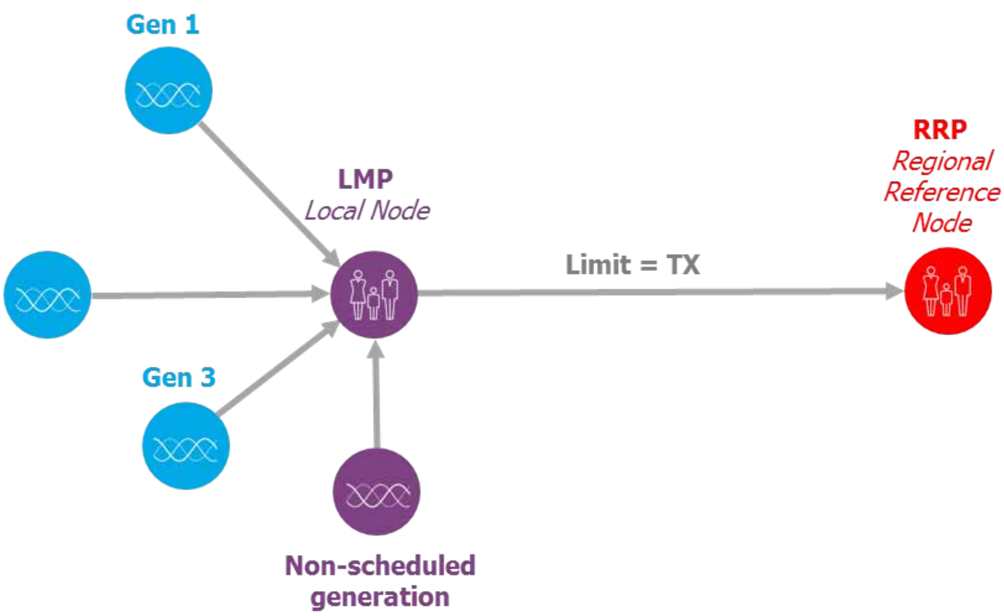
This is equivalent to a scenario where there is no local demand, but a larger transmission line with a thermal limit equal to TX+D, instead of just TX. Under the settlement model described in this appendix, **available capacity** is defined in this alternative way: local demand is treated as *enlarging* the available capacity and all local generation is considered to use this available capacity, rather than some serving the local demand.

The enlarged limit (TX+D) is referred to as the **available capacity (AX)**. In this example, the difference between available capacity (AX) and the physical flow limit on the line (i.e., network capacity, or TX) reflects the level and location of local demand.

Impact of local non-scheduled generation

Local non-scheduled generation has an equal and opposite effect to local demand. To illustrate, the figure below replaces local demand with local non-scheduled generation (NSG).

Figure C.3: Local non-scheduled generation example



Source: AEMC

In this case the flow inequality above becomes:

Flow = G1+G2+G3 + NSG ≤ TX

Because, like demand, the level of non-scheduled generation is not controlled by NEMDE, the variable is moved to the right-hand side (RHS) of the inequality, which then becomes:

G1+G2+G3 ≤ TX- NSG

The available capacity (AX) is now the difference between network capacity (TX) and the non-scheduled generation (NSG). That is, local non-scheduled generation *reduces* the available capacity.

C.3.4 Capacity entitlements

In a simple two-node example, a generator's share of settlement residue is based on the hedge it holds in relation to the transmission line between its local node and the RRN. However, in the case where there are *multiple* paths between the generator and the RRN, the generator's entitlement must be translated to *all* of the congested lines that lie on those paths.

Target entitlements

For a generator that holds transmission hedges, the **target entitlement (E)** to each line on its path to the RRN is equal to what its usage of the line would have been, if the generator was dispatched at its transmission hedge quantity. That is, the generator's entitlement to the capacity across a line is equal to its transmission hedge quantity (H) multiplied by its participation factor (ɑ) for that line:

$E = \alpha \times H$

For each line, target entitlements are calculated dynamically. As explained in appendix c.3.7 below, participation factors (ɑ) can be derived from existing NEMDE constraint equations. The aggregate of the target entitlements for all generators participating in a congested line is referred to as the **target capacity (CX)**.

This level of capacity is sufficient to provide the target entitlements to all generators on using the line. If the target entitlement can be provided on every congested line between a generator and the RRN, then the generator will receive a payout of the differential between its LMP and RRP against the full quantity of transmission hedges that it holds.

The settlement design outlined in this appendix assumes that generators that do *not* hold transmission hedges will also be allocated a target entitlement to a congested line, if spare capacity remains after transmission hedges have been taken into account. However, we are seeking stakeholder feedback on other options in Chapter 4.

Scaling of entitlements

The aggregate of all target entitlements on a congested line may at times *exceed* the actual available capacity, meaning that not *all* entitlement targets can be achieved.[120] In this case, an entitlement scaling algorithm would be used to determine *actual entitlements* on a congested line, based on the following principles:

- total actual entitlements must equal actual capacity;
- actual entitlements are non-negative and do not exceed target entitlements;
- actual entitlements are proportional to target entitlements; and
- entitlements for generators that hold transmission hedges are only scaled back after entitlements for generators without transmission hedges have already been scaled back to zero.

120 Assuming that the principle of requiring settlement to balance in each period applies.

C.3.5 Congestion prices

As described in appendix c.2, under dynamic regional pricing with transmission hedges, in addition to receiving the LMP for their dispatched output, a generator with a transmission hedge also receives a payment based on the formula:

$Settlement\$_{Residue} = H \times (RRP-LMP)$

In a simple two-node example, the price difference (RRP-LMP) represents the value, at the margin, of the transmission line capacity. If the line's capacity could be increased by 1 MW, then the marginal generator at the local node could have its output increased by 1 MW, at a cost of LMP.[121] Its output would displace the marginal generator at the RRN, resulting in a dispatch cost saving of the RRP. The net saving is the difference between RRP and LMP. The marginal value of capacity across a transmission line is referred to as the **congestion price (CP).**

If a line is uncongested, adding to its capacity simply increases the amount of unused capacity: it will not change the dispatch outcome and there is no associated cost saving. Therefore, the congestion price is zero (and the difference between the RRP and LMP is zero). On the other hand, if a line is congested, it will be causing some generation to be constrained and replaced by more expensive generation in dispatch. Thus, if the available capacity could be increased, there would be some cost saving. Therefore, when congestion arises, the congestion price is *greater* than zero.[122]

In the case of a meshed network with multiple lines, every line has an associated congestion price, also defined as the marginal value of the line's capacity. While the formulae for calculating congestion prices are complex, congestion prices are already calculated during the dispatch process.

C.3.6 Transmission hedge settlement

The discussion above has explained how the simple network example in appendix c.2 can be generalised to a complex, meshed, real-world network. A comparison between the simple and general models is summarised in the table below.

Table C.2: Transmission hedge settlement variables and their equivalents in a simple model

SETTLEMENT VARIABLES	ACRONYM	DESCRIPTION	VALUE IN SIMPLE MODEL
Congestion price	CP	The marginal value of capacity across a transmission line	RRP - LMP
Usage	U	The amount of a generator's output that flows through the	G

121 The marginal generator's offer price must be the LMP, since by definition it sets the price at the local node.

122 Congestion prices are never negative.

SETTLEMENT VARIABLES	ACRONYM	DESCRIPTION	VALUE IN SIMPLE MODEL
		transmission line	
Available capacity	AX	The maximum aggregate usage which the transmission line can accommodate	TX
Entitlement	E	The amount of line's capacity allocated to a generator, based on their transmission hedge volume held	H

Transmission hedge settlement takes place separately for every congested line. The settlement variables shown above are used in this process. In the stylised example presented in appendix c.2, transmission hedge settlement is given by the formula:

$Settlement\$_{Hedge} = (H\text{-}G) \times (RRP\text{-}LMP)$

Using the variables in the table above, the actual transmission hedge settlement equation becomes:

BOX 15: TRANSMISSION HEDGE SETTLEMENT

$\text{Settlement\$}_{\text{Hedge}} = (E - U) \times CP$

Where:

E = Entitlement

U = Usage

CP = Congestion price

As noted in appendix c.2, the working assumption for the settlement model described in this appendix is that transmission hedge settlement must **balance** in each settlement period. This is achieved by: (i) scaling back transmission hedge payouts if there are settlement residue deficits; (ii) allocating a portion of settlement residues to generators that do not hold transmission hedges, if there were surplus residues.

In the settlement model described in Box 15 above, the condition for settlement on each congested line to balance is:

$E_T = AX$

Where:

E_T is the total of all entitlements on a line.

AX = Available capacity

So long as the equation holds for all congested lines, then transmission hedge settlement will balance in aggregate. The following section describes how the information required for transmission hedge settlement can be derived from existing settlement processes.

C.3.7 Constraint equations

As part of the current dispatch process, AEMO prepares a set of constraint equations that reflect potential constraints on dispatch caused by limitations in the transmission network. These constraint equations are fed into the NEM dispatch engine, which then finds an economic dispatch solution which complies with these constraints. As explained below, these constraint equations already provide the information that is needed for transmission hedge settlement.

Form of constraint equations

The constraints are all *linear*. This means that all *intra*-regional constraints, those that do not involve interconnectors take the form:[123]

> BOX 16: ILLUSTRATIVE INTRA-REGIONAL CONSTRAINT EQUATION
>
> $\alpha_1 \times G_1 + \alpha_2 \times G_2 + \ldots + \alpha_N \times G_N \leq RHS$
>
> Where:
>
> α_1, α_2 etc are fixed coefficients
>
> G_1, G_2 etc are generation dispatch targets
>
> RHS is the "right-hand side" amount which is independent of generation dispatch

Use of constraint equations in transmission hedge settlement

Since each constraint equation relates to a potential limit on the transmission system, it represents available capacity across each transmission line.

Comparing the constraint equation above to the discussion of earlier discussion of transmission hedge settlement demonstrates that:

- the **coefficients** in the constraint equations are the **participation factors (α)**;
- the **RHS** is the **available capacity (AX)**; and
- the individual terms on the left-hand side, $\alpha_i \times G_i$, represent the **usage of each generator (U_i)**.

123 Inter-regional constraints, those involving interconnectors, are discussed in the following section.

When NEMDE runs, as well as calculating dispatch targets, it also calculates a "marginal value" for every binding constraint. This is the same as the congestion price (CP) discussed previously.

This means that the variables needed for transmission hedge settlement are already prepared or calculated as part of the existing dispatch process. The exception to this is each generator's entitlement, which is calculated based on the transmission hedges that generators hold.

C.4 Inter-regional settlement

The discussion thus far has focussed on the allocation of *intra*-regional settlement residues, that is, residues that arise due to differences between LMPs *within* a region. [124] However, the NEM comprises multiple, interconnected regions.

Interconnectors flow power between regions, from the RRN in one region to the RRN in a neighbouring region. As a result, *inter*-regional settlement residues also arise due to divergences between the RRPs that apply in different regions. As outlined below, the allocation of inter-regional settlement residues could operate in a similar way to the process described above for intra-regional residues.

C.4.1 Overview

Under the current arrangements, inter-regional settlement payments to an interconnector can be represented as follows:

BOX 17: EXISTING INTER-REGIONAL SETTLEMENTS

$$Settlement\$_{IC} = (RRP_M - RRP_X) \times I$$

Where:

I = Dispatched interconnector flow

RRP_M = The regional price in the importing region

RRP_X = The regional price in the exporting region

This is equation for existing inter-regional settlement residue (IRSR) payments to interconnectors.

124 Including the RRP, being the LMP at the RRN.

The equation above can be adapted to express inter-regional settlement payments to an interconnector, in the presence of an **inter-regional transmission hedge:**[125]

BOX 18: INTER-REGIONAL SETTLEMENT WITH TRANSMISSION HEDGES

$Settlement\$_{IC} = (RRP_M - RRP_X) \times H_{IR}$

Where:

H_{IR} = Representing the inter-regional transmission hedge quantity associated with the interconnector

RRP_M = The regional price in the importing region

RRP_X = The regional price in the exporting region

Interconnectors can flow power in either direction, and so a definition is needed to determine which region is importing and which exporting. To clarify this, an entity called a **directed interconnector (DIC)** is introduced. Each interconnector (e.g., the Queensland-NSW Interconnector, QNI) has a pair of associated DICs (i.e., "QNI north" and "QNI south"), oppositely directed. With this direction attribute, the exporting region and importing region are clearly defined.

Total inter-regional settlement payments to a DIC are outlined below.

BOX 19: INTER-REGIONAL SETTLEMENT FOR A DIRECTED INTERCONNECTOR (DIC)

$Settlement\$_{DIC} = H_{IR} \times (RRP_M - RRP_X)$

Where:

$Settlement\$_{DIC}$ = payment to directed interconnector

This equation can be rewritten as:

$Settlement\$_{DIC} = I \times (RRP_M - RRP_X) + (H_{IR}\text{-}I) \times (RRP_M - RRP_X)$

This illustrates that in practice, inter-regional settlement will be comprised of two payments:

*(i) The **existing inter-regional settlement residue payment** from Box X above (the first term of the equation above).*

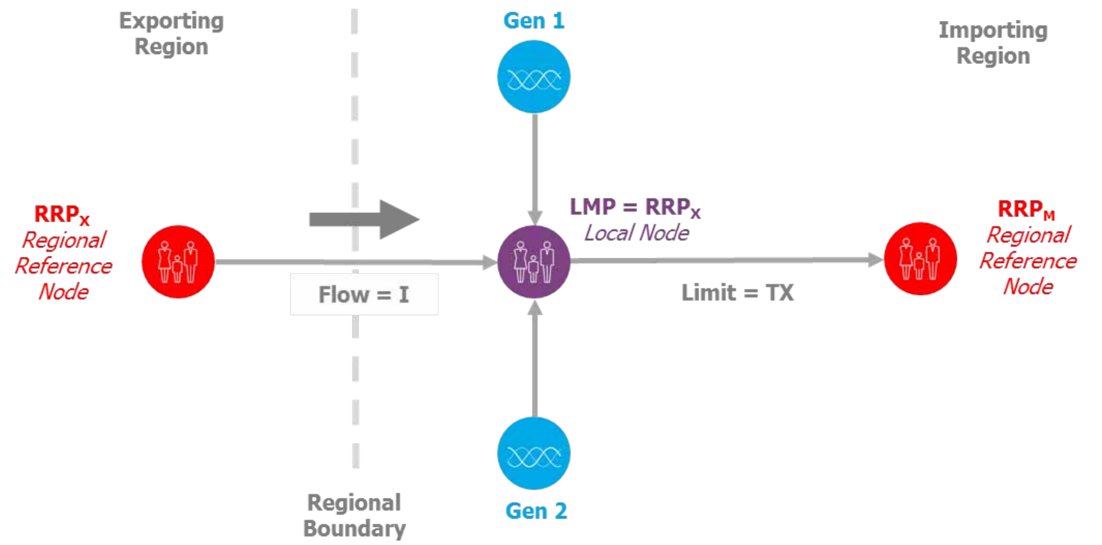
*(ii) A new **transmission hedge settlement** payment (equal to the second term of the*

125 More precisely, inter-regional transmission hedges would not be issued to interconnectors, as these are notional settlement entities rather than market participants. Instead, these hedges would be issued to market participants that could include, for example, generators, retailers or market network services providers (MNSPs). Inter-regional transmission hedges would give the holder the right to receive a corresponding share of the inter-regional settlement residue paid to the associated interconnector. In this respect, inter-regional transmission hedges are similar to the settlement residue auction (SRA) rights that are currently issued.

equation above).

The figure below provides a simple three-node example involving two RRNs and a DIC.

Figure C.4: Inter-regional network example



Source: AEMC analysis

For simplicity, it is assumed that there is no congestion between the exporting RRN and the local node, so the local prices are the same at these two nodes (that is, RRP_X = LMP). Substituting RRP_X for LMP in the usual intra-regional access settlement formula, the payment to each generator i from transmission hedge settlement is:

$$Settlement\$_{Hedge\ i} = (RRP_M - RRP_X) \times (H_i - G_i)$$

Therefore, the total transmission hedge settlement payment to the generators and the DIC is:

$$Settlement\$_{Hedge} = \Sigma_i Settlement\$_{Hedge\ i} + Settlement\$_{Hedge\ IC} = (RRP_M - RRP_X) \times (\Sigma_i H_i + H_{IR} - \Sigma_i G_i - I)$$

C.4.2 Inter-regional settlement in practice

As for intra-regional settlement (appendix c.3), in practice inter-regional settlement would also use information from the constraint equations already applied in NEMDE.

Inter-regional constraint equations

Constraints which involve interconnectors (which may also contain generators) are referred to as *inter*-regional constraints. The general form of an inter-regional constraint is:

BOX 20: ILLUSTRATIVE INTER-REGIONAL CONSTRAINT EQUATION

$$\alpha_1 \times G_1 + \alpha_2 \times G_2 + \ldots + \alpha_N \times G_N + \alpha IC_1 \times IC_1 + \alpha IC_2 \times IC_2 + \ldots + \alpha IC_M \times IC_M \leq RHS$$

Where:

$\alpha IC$is the participation factor for an interconnector

IC is the flow on an interconnector.

In NEMDE, the participation factor for an interconnector (αIC) may be positive or negative. The sign indicates whether the constraint limits the amount of inter-regional flow north or south, respectively.[126]

Inter-regional constraints refer to interconnectors but, as discussed above it is *directed* interconnectors (DICs) that participate in transmission hedge settlement. Therefore, whenever an interconnector participates in transmission hedge settlement, it must be determined which of the two DICs associated with that interconnector is the participant.

In normal circumstances, the DIC whose increased flow *exacerbates* the congestion is deemed to be the participant.[127]For example, suppose that $\alpha IC > 0$ in a particular inter-regional constraint equation. This means that increased northerly interconnector flows will exacerbate congestion. Therefore, in this case, the *northerly* DIC is the participant. On the other hand, if $\alpha IC < 0$, the southerly DIC is the participant.

Inter-regional settlement

In the simple three-node example described in appendix c.4.1 above, the total inter-regional settlement payment for a DIC was defined as:

$$Settlement\$_{DIC} = I \times (RRP_M - RRP_X) + (H_{IR} - I) \times (RRP_M - RRP_X)$$

Where:

$Settlement\$_{DIC}$ *is the total settlement payment to the DIC*

RRP_M *and* RRP_X *are the RRPs in the importing and exporting regions, respectively*

H_{IR} *is the transmission hedge quantity associated with the DIC*

I is the DIC flow

As was the case for intra-regional settlement, the formula for inter-regional settlement is derived from this basic form by substituting variables from NEMDE:

- $(RRP_M - RRP_X)$ is substituted with CP, the **congestion price**.
- H_{IR} is substituted with E_I, the **entitlement** allocated to the DIC.
- I is substituted with U_I, the DIC's **usage**.

126 This is based on the sign convention that AEMO uses for interconnector flow: a positive amount indicates a flow in a northerly or westerly direction.

127 This may be different in exceptional circumstances.

The settlement equation then becomes:

> BOX 21: INTER-REGIONAL SETTLEMENT IN PRACTICE
>
> $Settlement\$_{DIC} = U_I \times CP + (E_I\text{-}U_I) \times CP$
>
> *The first term this equation is paid out of the inter-regional settlement residue (IRSR) from existing settlement processes. The second term is calculated and paid under transmission hedge settlements.*

C.5 Summary of the settlement process

This section summarises the preceding discussion on both intra- and inter-regional transmission hedge settlement.

Under the proposed arrangements, the transmission hedge amounts payable to or from each generator or DIC (in addition to existing regional settlement payments) are determined by applying the two fundamental equations:

> BOX 22: SUMMARY OF INTRA- AND INTER-REGIONAL SETTLEMENT
>
> $Settlement\$_{Hedge} = (E\text{-}U) \times CP$
>
> and
>
> $E_T = AX$
>
> Where:
>
> E = Each generator or DIC's entitlement (E_T = Total entitlements)
>
> U = Each generator and DIC's usage
>
> CP = The congestion price for a given transmission line
>
> AX = The available capacity for a given transmission line.

There are three basic processes involved in transmission hedge settlement, presented in the table below.

Table C.3: **Transmission hedge settlement processes**

PROCESS	DESCRIPTION
Settlement Processing	Determines price, capacity, usage and other relevant variables for each congested line.
Entitlement Allocation	Allocates the capacity of each line between generators and DICs based on transmission hedges held, ensuring that total

PROCESS	DESCRIPTION
	entitlements equal available capacity.
Settlement Calculation	Applies the formula Settlement$ = CP x (E-U) to each generator or DIC for each congested line.

AEMO prepares constraint equations representing all potential constraints in the transmission system. Therefore, there are many thousands of constraint equations that could potentially be involved in transmission hedge settlement. However, the Commission's understanding is that it is rare for more than ten or twenty constraint equations to bind concurrently.

Therefore, whilst conceptually complex, on a practical level transmission hedge settlement is relatively straightforward and much of the data needed is already available. However, the Commission recognises that as with any settlement process, there are a number of practicalities still to work through. These will be considered further as the design progresses.

C.6 Capacity support generators

C.6.1 Overview

As described above, the proportion of the power from a generator that flows through a particular transmission line is referred to as their **participation factor**. Participation factors can be positive or negative:

- A generator with a *positive* participation factor has positive usage on a line. This means that in dispatch, congestion on a line can be managed by reducing the output - and therefore the usage - of these **'capacity usage generators'**.
- A generator with a *negative* participation factor has negative usage, meaning that congestion on a line can be managed by increasing the output of these **'capacity support generators'**.

Because they help to relieve congestion, capacity support generators have a high value in dispatch. This is reflected in an LMP that is higher than the RRP. Under dynamic regional pricing, generators are dispatched when their LMP is higher than their offer price. Therefore, a capacity support generator might be dispatched despite the RRP being below their offer price.

C.6.2 Pricing for capacity support generators

Under the US standard market design (SMD), all generators are paid the LMP at their node for their output. However, whether this approach is suitable in the context of the NEM requires further consideration - and has interactions with the Commission's investigation into intervention mechanisms and system strength in the NEM.

In particular, the Commission has identified several reasons why it may be appropriate to consider an alternative approach, under which the LMP for capacity support generators would be capped at the relevant regional reference price. In particular:

- concerns that, for nodes where there is insufficient competition, a generator paid at a high LMP could, by rebidding, raise the LMP to an extreme level;
- transitional issues; and
- the option to use network support agreements as an alternative means to incentivise capacity support generators to make themselves available for dispatch.

The Commission considers that two other recent trends in the NEM are also relevant to this design decision. In particular:

- the NEM is expected to become much more looped in future, which could result in LMPs that exceed the RRP becoming more common than might be the case today; and
- the increasing adoption of utility scale batteries, that could potentially provide some mitigation in relation to the risks of limited competition at some nodes.

The factors are discussed in turn below.

Pricing Power

A generator that is in a **load pocket**, a demand-rich area with limited transmission capability, may frequently be dispatched in order to maintain local reliability, even though its LMP exceeds the RRP. Some load pockets exist currently, such as in Far North Queensland. In these circumstances, a generator may have substantial, possibly extreme, **local pricing power** and, were it paid the LMP, might profitably use this power to raise its local price.[128]

It is common in SMD markets for this pricing power to be regulated as part of the market design. For example, caps may be placed on the local price or offer price of identified 'must-run' generators, based on an analysis of their operating costs. Further, the market price cap is typically lower in SMD markets, compared to the NEM. The market design approach in the NEM has tended to avoid regulating generating behaviour or payments, except in specific and infrequent circumstances (e.g. under AEMO directions). Therefore, measures applied in SMD markets to address local pricing power may not be well aligned with the broader NEM philosophy.

Transitional issues

Under current arrangements, capacity support generators are paid at the RRP (except when directed). Therefore, allowing these generators to capture a higher LMP under dynamic regional pricing could provide these generators with a windfall gain.

Network Support Agreements

The Commission recognises that capping the LMP for capacity support generators at the RRP could reduce incentives for generators to make themselves available for dispatch or to locate in weaker parts of the network where high LMPs are likely to arise. However, in the NEM currently, TNSPs are able to enter into Network Support Agreements (NSAs) with generators in load pockets where the TNSP needs them to run occasionally, in order to maintain network

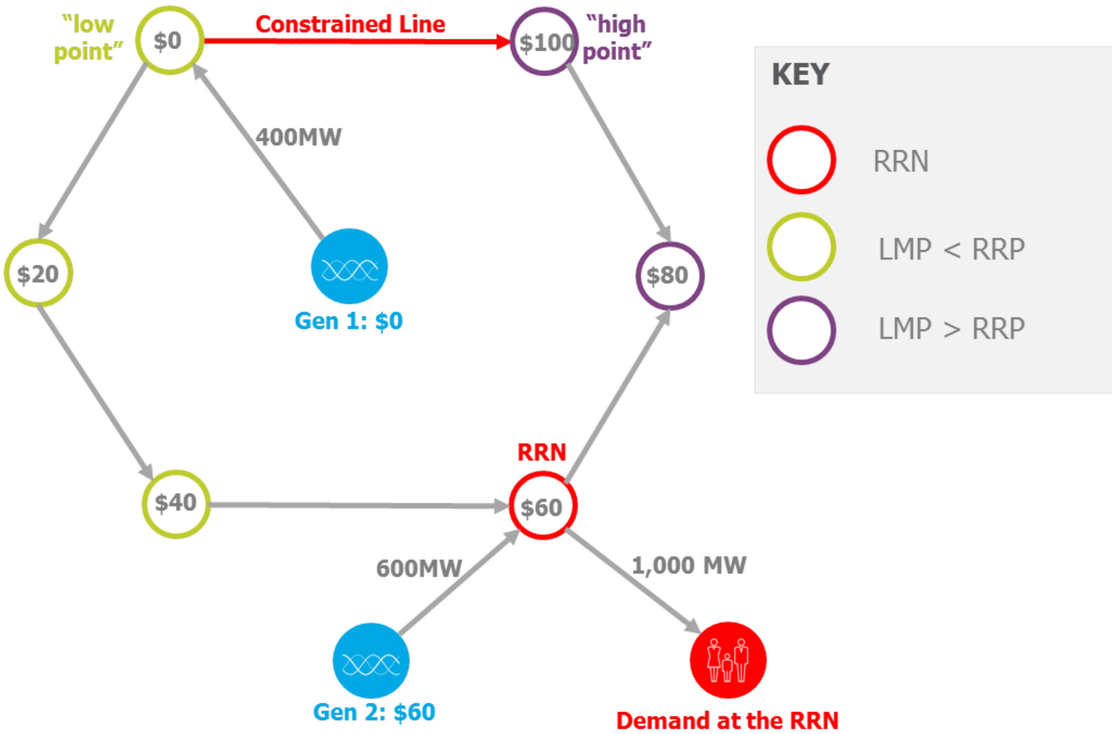
128 Pricing power means the ability to change the market price by varying its offer. Local pricing power means the ability to change the LMP in this way.

reliability standards. This approach could continue, or potentially be extended, depending on the incentives faced by TNSPs under a revised access model.

Transmission loops

When the RRN is located on a transmission **loop** and congestion occurs on part of the loop, an LMP profile known as a **spring washer effect** can occur. As illustrated in the figure below, in this situation, the LMP immediately *downstream* of the congestion (that is, closer to the RRN) will be at a *high point*. The LMP immediately *upstream* of the congestion will be at a *low point*. Because the RRN is on the loop, it is at an intermediate point between the high and low LMPs. As a result, all nodes between the high point and the RRN will have LMP>RRP, while all nodes between the RRN and the low point will have LMP<RRP. Load pockets may also occur on loops (**looped load pocket**).

Figure C.5: Spring washer pricing on a loop



Source: AEMC

Scenarios where LMP may exceed the RRP can also arise on an **interconnector** or where interconnectors form part of a loop (**looped interconnector**).

Historically, situations where high LMPs could have arisen from congestion on loops have been relatively rare, because the NEM's topology is generally radial. However, the NEM is anticipated to become **much more looped**. Currently, the Victoria-NSW interconnector flows on two paths, creating a loop. With the development of Riverlink, a regional loop would be created, formed by the Riverlink, Heywood and Snowy interconnectors. The potential development of a new southern Snowy interconnector via north-west Victoria could create further loops.

This creates the potential for situations in which LMPs exceed the RRP (as outlined in the example above) to become more common. This might appear to support a case for capping LMPs at the relevant RRP. However, this could also potentially increase the risk that capping LMPs in this way would create dispatch inefficiency, as higher cost generators at these nodes might bid unavailable if the RRP is below their cost of dispatch. The extent to which TNSPs could resolve these issues through network support agreements would also need to be carefully assessed.

Utility-scale batteries

Another relevant trend is the emergence of **low-cost utility-scale batteries**. This development could potentially increase the contestability of generation in high LMP areas, which could help to mitigate the pricing power concerns discussed above. Further, capping LMPs at the RRP might dampen signals that could indicate the appropriate location of new storage resources that could assist to relieve congestion on loops.

The Commission is considering the combined implications of these factors noted above, in determining the most appropriate pricing arrangements for capacity support generators. As noted, it also has interactions with the Commission's work on the investigation into intervention mechanisms and system strength in the NEM.[129] The Commission is considering the interactions between these two projects closely.

129 For further information, see section 6.3 of the consultation paper for the investigation.