AEMC

REVIEW

Australian Energy Market Commission

CONSULTATION PAPER

# COGATI IMPLEMENTATION - ACCESS AND CHARGING

1 MARCH 2019

## INQUIRIES

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E aemc@aemc.gov.au
T (02) 8296 7800
F (02) 8296 7899

Reference: EPR0073

## CITATION

AEMC, CoGaTI implementation - access and charging, Consultation paper, 1 March 2019

## ABOUT THE AEMC

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

# EXECUTIVE SUMMARY

1 In 2016, the Council of Australian Governments (COAG) Energy Council asked the Australian Energy Market Commission (AEMC or Commission) to implement a biennial reporting regime on when the transmission planning and investment decision-making frameworks will need to change, given the state of the power system. 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.

2 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. Given that the AEMC is to report biennially, this paper commences the second review under the COAG Energy Council terms of reference.

3 The inaugural CoGaTI review concluded that actioning the Integrated System Plan (ISP) needs to be paired with the mechanisms necessary to allow generation to contribute to the enhancement of the networks and the management of congestion along it.

4 How generators access the transmission network, and how congestion of the transmission network is managed, underpin the transmission framework. The way that transmission and generation investment decision-making processes interact has been the subject of on-going discussion before the establishment of the national electricity market (NEM) in 1998. Since the start of the NEM, there have been at least thirteen major reports and reviews dealing with various aspects of congestion management and generator access – many of which have been undertaken by the Commission.

5 Generators currently have no right to be dispatched in the wholesale market. Therefore, there is no guarantee that the network will have the capacity to export the energy they generate to enable them to earn revenue in the wholesale market. In contrast, transmission businesses have an obligation to meet jurisdictionally-set reliability standards for their networks, and so are focussed on making investments to reliably supply *consumers.*

6 Under the current access regime, there are limited congestion related locational signals for generators, and increasing congestion in the network is resulting in unpredictable and volatile market outcomes. Transmission businesses do not plan their networks to provide a particular generator with a specific amount of transmission capacity. This is not sustainable for either generators or customers given increasing levels of congestion.

7 Currently, there is a significant amount of generation capacity that is seeking to connect to the network. Private sector investors are planning generation where transmission has limited or no capacity to connect it. This lack of coordination is increasing costs in the sector. Given that a significant amount of this new capacity is seeking to locate at the edges of the network, there is an increasing need to invest in and build transmission to reliably connect generators.

8 Therefore, the current access regime needs to evolve to allow the risk and cost of generation investment to complement planning and investment in transmission. Building transmission to benefit generators means that generators should pay for this transmission investment.

9 Reform to the access regime is proposed to occur through a phased approach to address generator connection and access to the transmission network, and to make congestion management fit for purpose for the energy transformation. Reform is needed now in order to be put in place for the future, however this reform should be phased in over time.

10 First, dynamic regional pricing should be implemented. Where congestion arises, and transmission constraints occur, pricing regions will be dynamically created through existing dispatch processes which will reflect transmission constraints that are actually occurring at that particular time. This will put a price on congestion and introduce a signal to generators that reflects the short-run costs of using the network, providing better information to generators.

11 Second, the information that is revealed through the dynamic regional pricing will be used in planning, such as the patterns of congestion, the dynamic location of regions, and costs associated with congestion. This information will be available to the Australian Energy Market Operator (AEMO) and the wider market, enabling: AEMO to develop future ISPs with increased accuracy; transmission network service providers (TNSPs) to make efficient transmission investments informed by an enhanced ISP; and the Australian Energy Regulator (AER) to assess the efficiency of transmission investments.

12 Under the final phase, generators will use the ISP, along with other sources of information, as an important guide to their generation and transmission investment decision-making and be able to compel TNSPs to provide transmission services consistent with the level of firm access (that is, guaranteed access to the wholesale market) underwritten by generators. This final stage is a significant reform to the NEM, but is necessary in the face of the rapid transformation of the electricity sector.

13 This final phase of access reform involves generators having the option to pay for transmission in return for firm access rights, which raises broader questions about the rest of the transmission use of system charging framework. Therefore, there is also a need for a holistic review of how network costs are recovered and from whom.

14 This review therefore builds on the inaugural CoGaTI review and seeks to develop the necessary regulatory reforms to implement the recommended phased approach to access and charging reform.

15 Reforming the access and charging regime is a holistic, long-term solution to current issues being experienced. The existing transmission framework is comprised of a set of elements that are internally consistent and highly interlinked. Addressing an element of the transmission framework in isolation would likely still result in considerable regulatory overhaul of other elements, but would have a high risk of inefficient outcomes, since it would not address the framework holistically.

16 As proposed in the implementation work plan published as part of the CoGaTI final report in December 2018, the Commission will provide the COAG Energy Council with a set of regulatory reforms to implement changes to the access and charging regimes at the end of 2019. Throughout 2019, there will be multiple opportunities for stakeholder consultation on the issues raised by the Commission's recommendations as the rule change requests are

developed. The intent is that these rule change requests, on submission back to us, will commence in 2020. Further stakeholder consultation will then occur through our usual rule change process. This is appropriate given the complexity of the reforms being considered.

17 Submissions on this paper are welcomed, and are due by 29 March 2019. We encourage stakeholders to meet with us to discuss the review. Please contact Elizabeth Bowron, ph: 02 8296 0619 or elizabeth.bowron@aemc.gov.au.

# CONTENTS



## APPENDICES



## TABLES



## FIGURES

# 1 INTRODUCTION

## 1.1 Terms of reference

In 2016, the Council of Australian Governments (COAG) Energy Council asked the Australian Energy Market Commission (AEMC or 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 intention was that the work would help governments and industry participants consider when future conditions might arise where net benefits would be derived from adopting a transmission framework that would provide for better coordination of investment between the transmission and generation sectors.

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. Given that the AEMC is to report biennially, this paper commences the second review under these terms of reference.

## 1.2 Energy Security Board's work on actioning the ISP

At the COAG Energy Council meeting on 10 August 2018, the Energy Security Board was requested to report in December 2018 on:

- how the group 1 projects in the Integrated System Plan (ISP) could be delivered as soon as practicable
- how group 2 and 3 projects, should be progressed
- how the ISP would be converted into an actionable strategic plan.[2]

On 19 December 2018, the Energy Security Board provided a report to the COAG Energy Council outlining how the points listed above should be addressed, and how ISP projects could be delivered as quickly as possible.[3] Responding to the report, Ministers noted that a rigorous cost benefit analysis will be an essential part of the process to ensure costs to consumers are minimised, and agreed that the Energy Security Board do more work on further measures to operationalise the ISP, including regular updates and reassessments of ISP group 2 and 3 projects.

## 1.3 Inaugural CoGaTI review recommendations

The 2019 review (*CoGaTI implementation - access and charging)* builds on the work that was undertaken in the inaugural CoGaTI review.

1 The terms of reference are available from the AEMC website. See: https://www.aemc.gov.au/sites/default/files/content/97164a7b-09bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

2 COAG Energy Council, Meeting Communique, Friday 10 August 2018, p.2.

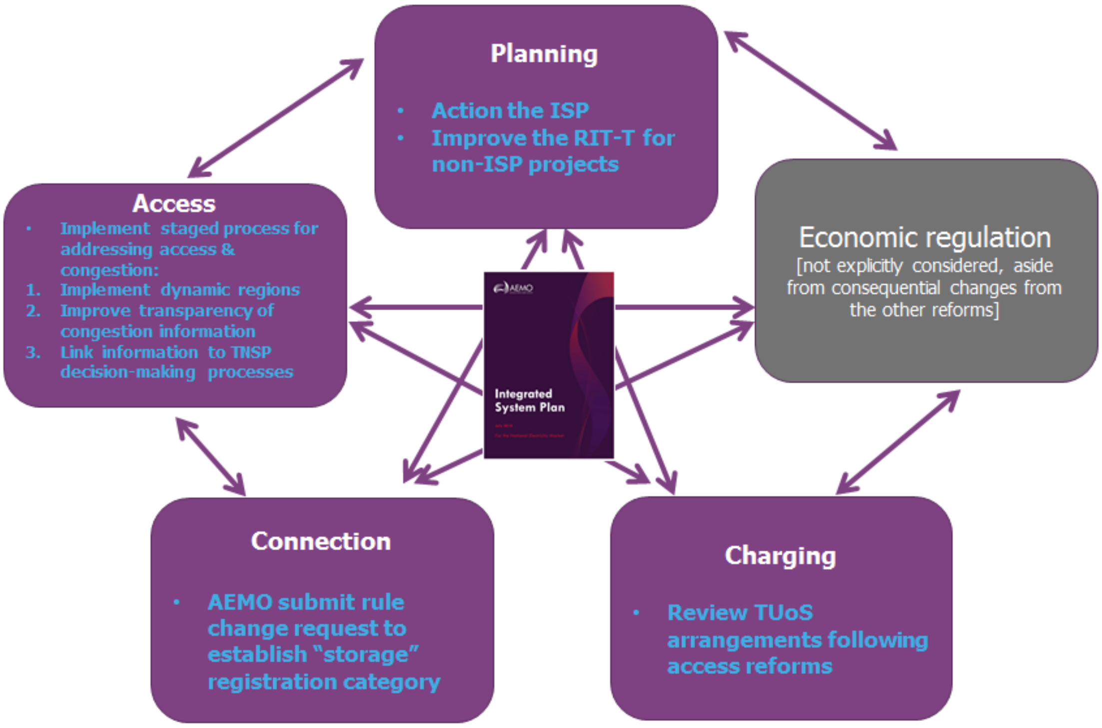
3 Energy Security Board, Integrated System Plan; Action Plan, 2018. See: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/isp%20action%20plan.pdf

The first cycle of reporting set out a number of intermediate and more long-term recommendations to the COAG Energy Council to make existing transmission frameworks fit for purpose and provide reliable and secure outcomes for consumers at the lowest cost. The final report made recommendations with respect to the five key elements of the transmission framework in the national electricity market (NEM):

- **Planning -** The ISP needs to be made actionable in order to better facilitate the transition that is occurring in the large-scale generation sector at present. In order to make this actionable, the ISP needs to be integrated into the regulatory framework, including planning that is undertaken by transmission network service providers (TNSPs) and distribution network service providers (DNSPs), such as the annual planning reports, regulatory investment tests for transmission (RIT-Ts) and joint planning, as well as the economic regulatory process. Our recommendations provided the nuts and bolts to the Energy Security Board’s approach to actioning the ISP.
- **Access -** Access and congestion underpins the transmission framework, and so changes to this are required as a necessary complement to making the ISP actionable, as well as to facilitate renewable energy zones (REZs).
- **Charging -** Transmission infrastructure creates costs, but benefits a large variety of parties. Who pays for transmission infrastructure is an important consideration, especially in light of the large amount of transmission (particularly interconnectors) that are currently being built. Charging arrangements for transmission need to be reviewed in order to make sure they are still fit for purpose.
- **Connection -** In order to reduce operational complexity and administrative burden, a stand-alone registration category for large-scale storage facilities needs to be created.
- **Economic regulation -** Transmission investment is made by monopolies, obliged by governments to meet government set reliability standards. Ensuring that the transmission investment is efficient is an important component of the existing framework which should be preserved. The arrangements for economic regulation may need changing in order to be seamlessly integrated with actioning the ISP and access and charging reform.

Figure 1.1 displays the five key elements of the transmission framework and the recommendations that sit under each of them.

**Figure 1.1: The transmission framework: overview of recommendations in CoGaTI final report**

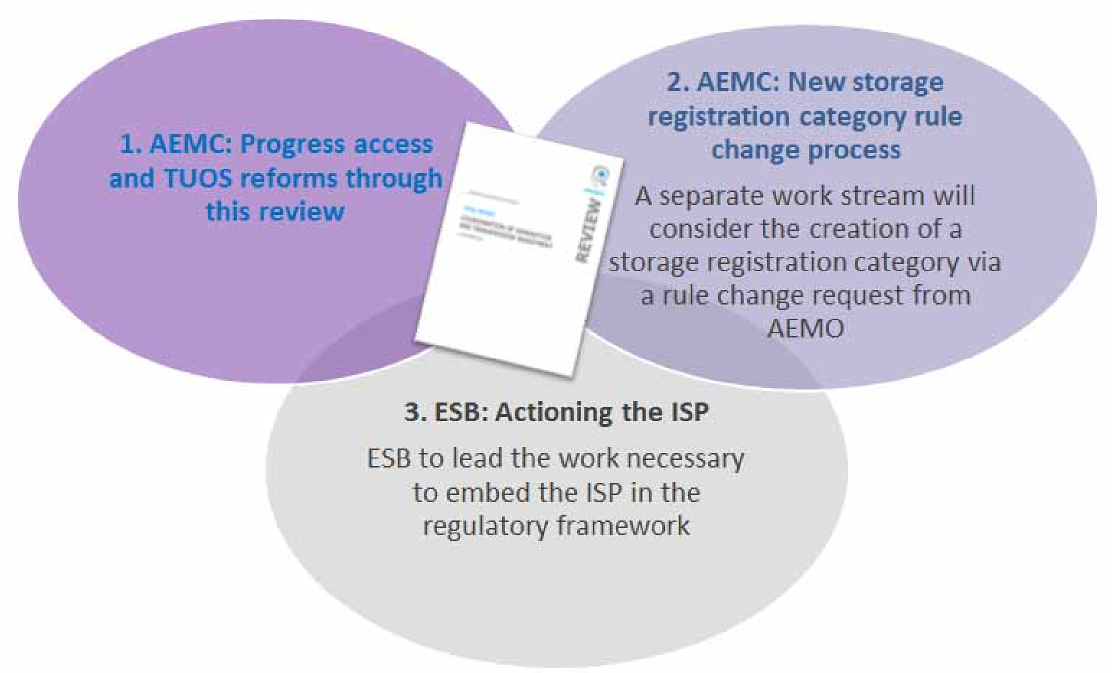



## 1.4 Scope of this review

The comprehensive reform package recommended by the Commission in the final report published as part of the CoGaTI review will be progressed through three separate work streams.

Figure 1.2 illustrates these three pieces of work, which are explained in further detail in the remainder of this section.

**Figure 1.2: Progressing the CoGaTI recommendations through separate work streams**




### 1.4.1 This review: progressing changes to the access and charging regimes

The Commission's recommendations for reform to the current access regime and a review of whether existing transmission use of system charging arrangements are fit for purpose will be progressed by the AEMC in 2019 as part of the *CoGaTI implementation - access and charging* work stream (i.e. this review).

The Energy Security Board made a recommendation in its Integrated System Plan; Action Plan report to the COAG Energy Council in December 2018 that congestion and access issues be considered in 2019, and options developed for how to address them. This recommendation will be progressed through the work being undertaken by the Commission as part of the *Coordination of generation and transmission investment implementation - access and charging* work stream. The Commission will collaborate with the Energy Security Board, the Australian Energy Regulator (AER) and the Australian Energy Market Operator (AEMO) in progressing this recommendation.

As proposed in the implementation work plan published as part of the CoGaTI final report, the Commission will provide the COAG Energy Council with a set of regulatory reforms to implement reforms to the access and charging regimes at the end of 2019 that can then be submitted back to us to commence the rule change process. Throughout this year, there will be multiple opportunities for stakeholder consultation on the issues raised by the Commission's recommendations as the rule change requests are developed.

Further detail on the rationale for the recommendations made in the CoGaTI final report for reforms to the current access and transmission charging arrangements is provided in Chapter 2. The Commission is seeking stakeholder feedback on our recommendations for reform to the current access and transmission charging regimes that were provided in the CoGaTI final report, including the timing and sequencing of these changes.

### 1.4.2 AEMC consideration of AEMO rule change request: Implementing large-scale energy storage systems

The Commission's recommendation that a new NEM registration category be created to accommodate large-scale energy storage systems will be progressed through a rule change. AEMO intends to submit a rule change to the AEMC by March 2019 to create a new category for bi-directional technologies to facilitate the participation of energy storage systems in the NEM. This rule change process will need to consider the mapping of regulatory obligations to the appropriate parties throughout the National Electricity Rules (NER) framework, including whether large-scale energy storage systems should pay for use of the transmission system.

### 1.4.3 Energy Security Board work: Actioning the ISP

The Energy Security Board's recommendations for actioning the ISP will be progressed by the Energy Security Board over the first half of 2019. In line with the implementation work plan published as part of the CoGaTI final report, the necessary changes to the NEL and the NER that will be required to embed the ISP in the regulatory framework will be developed by the Energy Security Board and presented to the COAG Energy Council at its mid-year meeting in 2019. The Commission's recommendations for how the RIT-T process for non-ISP projects can be streamlined will also be progressed through the package of changes being developed by the Energy Security Board.

We will work closely with the Energy Security Board, AEMO and the AER as part of this process.

## 1.5 Purpose of the CoGaTI implementation - access and charging review

This review builds on the inaugural CoGaTI review and will seek to develop the necessary regulatory reforms to implement the recommended phased approach to access and charging reform. Progressing implementation of the phased reform through 2019, as well as through the subsequent rule changes, will allow consideration of whether the proposed implementation dates and sequencing of staging are appropriate.

This review will seek to refine the proposed reforms recommended in the final report, and will involve extensive stakeholder consultation at multiple stages of the rule change development process. To commence the consultation process on what has been proposed, the Commission is seeking stakeholder feedback on our recommendations for reform to the current access and transmission charging regimes that were provided in the CoGaTI final report, including the timing and sequencing of these changes. Chapter 3 of this paper outlines the recommendations, the issues they raise and asks stakeholders a series of questions to elicit feedback on the proposed reforms.

## 1.6 Process for this review

Table 1.1 provides a high level overview of the milestones for this review.

**Table 1.1: CoGaTI - access and charging implementation indicative timeline**

| MILESTONE | TIMING |
|---|---|
| Publication of consultation paper - **4 weeks consultation** | 1 March 2019 |
| Submissions close | 29 March 2019 |
| **Stakeholder workshops** on access reform policy | April/May 2019 |
| Draft access reform work stream published that includes draft access reform policy and proposed regulatory reforms for consultation - **6 weeks consultation** | July 2019 |
| Submissions close | August 2019 |
| **Stakeholder workshops** on charging reform policy | August/September 2019 |
| Draft transmission charging work stream published that includes transmission charging reform policy and draft rules - **6 weeks consultation** | October 2019 |
| Final report including NER change package on both access and transmission charging reform provided to the COAG Energy Council | December 2019 |

## 1.7 Consultation

The Commission invites comments from interested parties in response to the questions asked in this consultation paper. Submissions are due by 29 March 2019. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

We encourage stakeholders to meet with us to discuss the review. Please contact Elizabeth Bowron, ph: 02 8296 0619 or elizabeth.bowron@aemc.gov.au.

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting project reference code "EPR0073".

## 1.8 Structure of paper

The remainder of the paper is structured as follows:

- Chapter 2 sets out the rationale for why access and charging reform is needed
- Chapter 3 sets out an overview of the recommended access and charging reforms as published in the inaugural CoGaTI final report, and seeks stakeholder feedback on these.

# 2 RATIONALE FOR ACCESS AND CHARGING REFORM

## 2.1 Context and current arrangements

The NEM is undergoing a significant transformation, with an unforeseen level of generators seeking to connect to the network. The transforming generation fleet has implications for investment in the transmission network.

A foundational principle of the NEM is that investment in, and operation of, generation assets is market-driven, taking into account expectations of future demand and future spot prices in the NEM, location and supply availability of the energy source, access to land, proximity to transmission and characteristics of that transmission (e.g. local system strength), and the age and state of the generation fleet. The result is that risks associated with generation investment rest with those businesses, and not with consumers or taxpayers.

In contrast, under the current framework, decisions about investment in, and operation of, transmission infrastructure occurs through a different process. Investment in transmission is centrally planned by jurisdictional TNSPs, through modelling to deliver a reliable supply to their customers, making assumptions about where and when generators may locate and retire, and informed by AEMO's National Transmission Network Development Plan (NTNDP). Transmission businesses are subject to incentive-based economic regulation of their revenues for the provision of transmission services, and to obligations relating to reliability, safety and investment decision-making processes. Efficient costs associated with the provision of shared transmission services are recovered directly from consumers, who also directly bear the risk of poor decisions to invest (or not invest) in transmission. The planning and economic regulatory framework is designed to mitigate this risk.

The underlying rationale for these different processes in part stems from the current way in which generators access the transmission network. Currently in the NEM, 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 framework, a generator's access to the market price (their ability to "get their product to market") is intrinsically linked to its physical dispatch. Physical dispatch is determined by the NEM dispatch engine which takes account of, among other things, generators' bids, and, the physical capacity of the transmission network.

When there are constraints (also known as congestion) on the transmission system, generators that would otherwise be dispatched as part of the merit order determined by generator bids are not dispatched (they are "constrained off"). As they are not dispatched, they do not receive access to the market price. However, because they do not have a right to be dispatched, they do not pay for any shared transmission infrastructure.

While generators are able to underwrite transmission investment on the shared network to reduce congestion, doing so would improve the access of all generators. 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: a free-rider problem. As a consequence, a regulated, centralised approach to transmission investment has been adopted to date, which may be poorly coordinated with the market-based approach to generation investment. As generators only pay the direct costs associated with facilitating their connection, the price they face does not fully reflect locational signals, and generators do not receive any guaranteed level of access to the transmission network.

There is currently a significant amount of generation capacity that is seeking to connect to the network. Investors are planning generation where transmission has limited, or no capacity for the generation to connect. Proposed generation roughly equal to the current size of the NEM is foreshadowed for connection to the grid over the next 10 years. This is testing the current arrangements, and highlighting the need for coordination as illustrated below.

## 2.2 Need for coordination

The differences between transmission and generation decision-making processes are manifesting in a range of issues currently being experienced by investors. These include:

- **Congestion** - Investors are planning generation where transmission has limited or no capacity for the generation to connect, which may limit the ability of the lowest cost generators to access the wholesale market. This exacerbates congestion, resulting in costs for consumers. In particular, given the scale of generators seeking to connect to the network is increasing so rapidly, businesses cases are often undermined before the generator has even connected. Generators, particularly those with a renewable fuel source, have noted that congestion risk is a major impediment to renewable investment.
- **Outages -** TNSPs are required to maintain and upgrade their equipment in order to provide services in line with relevant network performance requirements, which often requires planned outages on the power system to facilitate the safe maintenance and upgrade of network infrastructure. TNSPs 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 outages are extended or prolific, this can cause significant effects on a generator's revenue - with no compensation available. See Box 1 for a current example of this.
- **Marginal loss factors -** To investors, these represent a "multiplier" of revenue - the marginal loss factor calculates the difference between how much is produced by a generator, which is measured at its meter, and how much is estimated to be delivered to customers at the regional reference node. This then affects how much is paid by AEMO to the generators, which impacts its revenue stream and therefore the generator's

commerciality. Marginal loss factors are set annually[4] by AEMO, and are set using a forward-looking modelling approach. They are based on the expectation of what will happen in the year ahead, in terms of demand and dispatch patterns, and hence network flows and losses. This means there is not a perfect match between the loss factors, and what actually happens in a given financial year.[5] Given the large number of generators connecting at the moment, and the fact that marginal loss factors inherently change after a new generator connects to the network, this is resulting in significant year-on-year fluctuations in the marginal loss factors. For example, the Broken Hill GT 1 generator experienced a change in loss factors of more than 17 per cent between 2017-18 and 2018-19.[6]

- **System strength -** 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. 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. This is defined in relation to any adverse impact on the ability to maintain system stability, or on a nearby generating system to maintain stable operation. The rule would allow for remediation to be provided as a service to connecting generators. However, we understand that in practice, generators are increasingly being asked to build synchronous condensers for the purposes of system strength remediation. Multiple synchronous condensers are being built by multiple connecting generators, resulting in a potential degree of overbuild; that is, it may be more efficient for one larger synchronous generator to be built and its fault current to be "shared" between generators. Also, given these assets are private and operated only by the generators when they are exporting active power to the grid, this could result in a shortfall when the synchronous condensers are shut down (e.g. solar farms at night).
- **Disorderly bidding -** The absence of intra-regional price signals can give rise to disorderly bidding. Disorderly bidding arises when generators know that the offers they make will 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 to maximise its dispatch quantity. This can result in inefficient dispatch through higher cost generation resources being dispatched instead of lower cost resources.

4 This was a decision at the start of the NEM, representing the trade-off being using "postage stamp pricing" (charging the same price across the region, regardless of location or losses) which is easy to understand but ignores all losses; and fully dynamic nodal pricing, which would be mathematically pure, but harder for participants and others to understand. Adani Renewables have recently proposed two rule change requests to the Commission to amend the calculation of marginal loss factors. See: www.aemc.gov.au

5 Other key elements are that they are marginal as opposed to average, and calculated with respect to the regional reference node.

6 See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2018/Marginal-Loss-Factors-for-the-2018-19-Financial-Year.pdf

- **Storage -** Disorderly bidding may 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, i.e. analogous to a generator) in order to receive the region wide market 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 charged. By charging, it 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.
- **Connection enquiries -** AEMO, TNSPs and DNSPs are receiving an unprecedented volume of connection enquiries, which has created some resourcing issues at these organisations. As a result developers are experiencing increased uncertainty, costs and delays. This is exacerbated the current framework where parties have no right to be dispatched across the network. As more and more parties connect, a party's particular connection arrangements may change, undermining financing that has been previously agreed. This is a necessary consequence of the current open access framework, given that generators typically do not want confidential information to be shared with others, given they are competing for access to the transmission network.
- **Generators sharing the costs of transmission infrastructure or REZs -** Currently, connecting parties are directly responsible for the payment of costs associated with any new apparatus, equipment, plants and buildings, or upgrades to these, to enable their connection to the transmission network and to meet their performance standards. These are "connection assets", and are paid for by the connecting party or parties. There are existing mechanisms in place to facilitate the coordination of connection assets, including from prospective REZs in the shared network, such as the arrangements for scale efficient network extensions.[7] Given the large amount of generators seeking to connect, there is a lot of potential to develop shared connection assets to reduce overall system costs. The existing scale efficient network extension framework has been unused since it was established in 2013 due to generator commercial tensions and disparate generator project timing. In the inaugural CoGaTI review the Commission considered that part of the reason why this framework has not been used is because generators won't contribute to the costs of a connection asset that is shared by others unless the generator receives some form of firmer access right than is currently available. At the moment, generators have an incentive to free-ride on investments contributed to by other generators, enjoying the benefits of access without having contributed to the costs.

All of these issues could be considered to be symptomatic of how generators access the network, and how congestion on the transmission network is managed.

Currently, the NEM doesn't provide a mechanism for parties to enhance the shared grid in a way that enables them to manage and mitigate the effects of congestion. That is, generators

7 Similarly, the dedicated connection asset framework in the NER - particularly the requirements for large dedicated connection assets (those over 30km in length) to have access policies - is also relevant.

only pay the direct costs associated with facilitating their connection, the price that they face does not reflect locational signals, and they do not receive any guaranteed level of access to the transmission network.

### BOX 1: PLANNED OUTAGES IN THE NORTH WEST VICTORIA & SOUTH WEST NSW TRANSMISSION NETWORK

TNSPs in the NEM are required to maintain and upgrade their equipment in order to continue to provide services in line with relevant network performance requirements to maintain a safe, secure and reliable network for consumers. This often requires planned outages on the power system to facilitate the safe maintenance and upgrade of network infrastructure.

For generators who are connected to network assets undergoing maintenance, there may be periods when 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. Consistent with the current access arrangements, where generators are not guaranteed to be dispatched, these generators do not receive any compensation for this.

AEMO have recently released an industry communique in relation to planned outages in the North West Victoria & South West NSW transmission network. TransGrid and AusNet Services are undertaking a series of outages on the power system in order to maintain a safe and secure network or perform required upgrades. Replacement of communication infrastructure and upgrades to transmission line capacity are necessary to incorporate the significantly increased volume of generation in this area.

AEMO have undertaken a series of studies about what is necessary in order to maintain power system security in that area as a result of the outages. Power system security will be maintained for the planned outages in North West Victoria by applying constraints that will reduce the output of generating systems in the affected area. AEMO's communique goes into more detail, but in summary, there will be 111 outages, on average lasting for one day. Consequently, generators in this area will be impacted by constraints at various levels to maintain system security. Several generating systems will be constrained down to zero during some of the planned outages.

Note that AEMO's studies into how these outages will be managed will continue. In addition, conditions may change, and so these results could vary. Further information is available on AEMO's website.

Source: AEMO, Planned outages in the North Western Victoria & South West NSW transmission network, industry communique, February 2019.

## 2.3 Need for access reform

Generation and transmission are both complements and at times substitutes. They are part of an integrated system and are difficult to separate. This implies that investment and operational decisions by generators and TNSPs should work together to achieve overall efficient outcomes. Section 2.2 illustrates ways in which this coordination is not occuring under the current framework.

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 NEM start, there have been at least thirteen major reports and reviews dealing with various aspects of congestion management and generator access, including five reviews by the Commission in addition to the CoGaTI review, stretching back to 2005 when the Commission was created.

Currently, the NEM does not provide a clear mechanism for how:

- In an investment timeframe (longer-term), generation and transmission investment is co-ordinated. This can lead to limits on the ability of generators to transmit electricity, generators being forced to locate in less desirable locations or lead to inefficient investment in transmission networks to alleviate constraints. In particular, given the above, generator investment decisions are becoming more risky, which may decrease generators' willingness to invest in new generation or increase the price at which they are willing to contract with retailers.
- In an operational timeframe (shorter-term), that congestion is managed - congestion can result in unpredictable and volatile market outcomes, resulting in cost-effective generation being constrained off. In addition, during times of congestion, generators have an incentive to offer their electricity in a non-cost reflective manner, which may lead to the dispatch of needlessly costly generation.

All the concerns outlined above might be able to be addressed incrementally. Indeed, the Commission has recently received rule change requests from Adani Renewables which seek to address issues associated with marginal loss factors.[8] However, reforming the access and charging regime is a more holistic, efficient and elegant long-term solution to these issues. The existing transmission framework is comprised of a set of elements that are internally consistent and highly interlinked. Addressing an element of the transmission framework in isolation would likely still result in the need for considerable regulatory overhaul of other elements, and could have a high risk of inefficient outcomes, since it would not address the framework holistically.

Access reform would mean that there would be better signals between generators and transmission businesses regarding the impacts of investment, and it would help improve the coordination between transmission and generation investment in the NEM so that costs for consumers would be minimised. If generators can have more choice and certainty about the access they receive to the transmission network, they will factor this into their locational decisions, which will result in an efficient level of transmission development.

Therefore, the Commission considers that there need to be changes made to the access regime in order to facilitate this transition. The Commission has recommended a phased reform approach to make generator access to the transmission network and congestion management fit-for-purpose for the energy transformation. The approach will provide the

8 See: https://www.aemc.gov.au/our-work/changing-energy-rules/rule-changes

necessary tools for those who are best placed to bear the risk of resource investment to do so, facilitating the coordination of generation and transmission investment but doing so in a way that allows the time necessary to transition to reformed arrangements. In addition, the final phase of the access reforms involves generators having the option to pay for transmission in return for firm access rights. This raises broader questions about the rest of the transmission use of system (TUOS) charging framework. Therefore, there is a need for a holistic review about how network costs are recovered and from whom.

The need for reform has also been recognised by the Energy Security Board, who notes that:[9]

> Congestion risk is a major impediment to investment and the issue is whether the current open access regime provides investment certainty to generator developers and lead to efficient congestion management in the long term. There is an ongoing and related concern about marginal loss factors. These affect a generator's revenue stream and hence commerciality. One key issue is that marginal loss factors are set annually. There is significant year on year fluctuations due to the large number of generators connecting into the system; as well as marginal loss factors being challenging to calculate given the large number of generators.

The Energy Secutiy Board also recognises that the AEMC set out a path forward on addressing the issues during 2019 in its CoGaTI review.[10]

9 Energy Security Board, Integrated System Plan; Action Plan, 2018.

10 Ibid.

# 3 REFORMS TO ACCESS AND CHARGING ARRANGEMENTS

Actioning the ISP (which, as noted in Chapter 1, is being progressed by the Energy Security Board) needs to be paired with the mechanisms necessary to allow generation to contribute to the enhancement of the transmission networks and the management of congestion along it. The previous chapter set out the rationale for why the current access and charging regime needs to evolve to allow the risk and cost of generation investment to complement planning and investment in transmission.

This chapter provides a summary of the Commission's recommended approach to addressing access and charging. It also seeks stakeholder views on the recommended approach, in particular on how the reform will be facilitated, and the timing of it. It should be read in conjunction with Chapters 6 and 7 of the CoGaTI 2018 final report.[11]

## 3.1 Access reform

In the CoGaTI final report, the Commission recommended reforms to the way in which generators access the shared transmission network, with potentially significant consequences to the way in which transmission and generation infrastructure is planned, invested in and paid for.

### 3.1.1 A phased approach to access reform

Reform to the access regime should occur through a phased approach to address generator connection and access to the transmission network, and to make congestion management fit for purpose for the energy transformation. Reform is needed now in order to be put in place for the future. This reform should be phased in overtime in a number of stages, as outlined in Table 3.1. A more detailed discussion of each of the stages is provided in the remainder of this section.

Table 3.1: **Phasing of access reform**

| PHASE | OVERVIEW | ESTIMATED IMPLEMENTATION TIMING |
|---|---|---|
| 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 | July 2022 to July 2023 |

11 This can be found here: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

| PHASE | OVERVIEW | ESTIMATED IMPLEMENTATION TIMING |
| --- | --- | --- |
| | occurs and the costs of congestion, would be used to supplement the planning arrangements for transmission. | |
| 3. Generators fund transmission infrastructure | In response to the information on network congestion, connecting parties (e.g. generators) would be able to purchase firm transmission rights or firm access to the network, which in turn would be used to underwrite the necessary network investment needed to physically provide that access. Generators' collective decisions to purchase transmission rights would guide the preparation of AEMO's ISP's and TNSPs' planning decisions due to an obligation placed on TNSPs to provide sufficient transmission capacity consistent with the rights purchased by generators. | July 2023 |

Source: AEMC, CoGaTI final report, 21 December 2019.

### QUESTION 1: PHASING OF ACCESS REFORMS

1. Is our proposed approach to phasing access reforms appropriate?
2. Are the number and nature of the phases appropriate? How might access reform be phased differently?
3. What interactions with other market design reforms throughout the sector, and the energy transformation more generally, should be considered when developing and assessing transmission access reforms?
4. What should be taken into account when considering how to transition to these new arrangements?

### 3.1.2 Phase 1: Dynamic regional pricing

Phase 1 involves the implementation of dynamic regional pricing. Where congestion arises, and transmission constraints occur, pricing regions will be dynamically created through existing dispatch processes which will reflect transmission constraints that are actually occurring at that particular time.[12]

Dynamic regions introduce a price signal to generators that reflects the short-run costs of using the network. This will provide better information to generators about where congestion occurs, which they can consider when making their locational decisions, as well as removing the current incentives for disorderly bidding by generators when there is congestion.

In any individual dispatch interval, dispatched generators will be paid the new, dynamic regional price that applies where they are connected, rather than the existing regional reference price. Where there are no constraints on the transmission network, the new, dynamic region will include the regional reference node, and so the price generators receive will be the existing regional reference price.

Market customers (e.g. retailers) would continue to be settled at the regional reference price.

In addition to receiving the dynamic regional price, generators would also receive a share of the revenue that arises due to the difference between the dynamic regional price (which they are receiving) and the regional reference price (which market customers are paying). Generators' share of "settlement revenue" will be allocated dynamically on the basis of their capacity.

The treatment of storage requires further consideration. When exporting electricity to the grid, it appears appropriate that, like a generator, storage should receive the dynamic regional price. When importing electricity from the grid, it may also be appropriate that storage devices pay the dynamic regional price, unlike market customers. As with generators, this will provide signals to storage devices that reflects the short-run costs of using the network, for both imports and exports.

Examples of dispatch and settlement outcomes are provided in section 6.3.2 of the CoGaTI final report.

In this phase, there would be no transmission charges levied on generators - all network charges would continue to be paid for by load. No changes to the TNSP planning, investment or operational arrangements would be required to give effect to this phase. Some changes to AEMO and market participant's dispatch and settlement processes and systems would be required.

12 The Commission is still considering how losses will be incorporated into these dynamic prices (if at all). The Commission will consider interactions between this piece of work and the rule change requests it currently has on foot related to marginal loss factors.

> QUESTION 2: PHASE 1: DYNAMIC REGIONAL PRICING
>
> 1. What is the nature of the risk on generators from being settled at the dynamic regional price in the event of congestion? To what extent is this risk different from (and greater or less than) the current risk to generators of being constrained off/down in the event of congestion? What impact may these changing risks have on the contract market, both in terms of products, liquidity, and risks businesses are exposed to?
> 2. Is generator capacity an appropriate metric on which to allocate the settlement residue which arises from dynamic regional pricing? If not, what alternative metric should be used? Which particular measure of capacity should be used (e.g. nameplate capacity, maximum output in previous X years)? How might the use of capacity or another metric create distorted incentives for generators and/or storage devices?
> 3. Should storage, when importing from the grid, be settled at the dynamic regional price? What might the effects of this be?
> 4. What issues or unintended consequences might arise?
> 5. What are the nature and extent of implementation costs, such as system changes (e.g. settlement reallocations), that would be required to implement phase 1?

### 3.1.3 Phase 2: Information from dynamic regional pricing reveals congestion costs

Next, various transmission planning processes will be supplemented by the provision of additional information that will be made available as a consequence of phase 1. This information would include:

- patterns of congestion and the dynamic location of regions
- costs associated with congestion, including the costs of congestion on a particular transmission element.

Dynamic regional pricing, and the better information that flows from it, will assist with actioning the ISP by providing a greater level of information to AEMO and the wider market about transmission constraints and their cost. This will better enable:

- AEMO, informed by stakeholder views, to develop future ISPs
- TNSPs to make efficient transmission investments informed by the ISP and the information provided by dynamic regional pricing
- the AER to assess the efficiency of transmission investments, again informed by an improved ISP as well as the information provided by dynamic regional pricing.

> QUESTION 3: INFORMATION FROM DYNAMIC REGIONAL PRICING
>
> 1. What information is likely to be revealed through dynamic regional pricing?

2. How valuable is the information from dynamic regional pricing likely to be in the various transmission planning processes? Will it have other uses?
3. How should the information revealed by dynamic regional pricing be revealed to the market?
4. How might AEMO, TNSPs and the AER integrate the information into their processes?
5. Should the rules be modified to require these parties to take this information into account, and if so, how?

#### 3.1.4 Phase 3: Generators fund transmission infrastructure

Under the final phase, generators would be able to buy firm transmission rights in order to manage the risk of congestion. In return for purchasing access, generator's would receive access rights that would provide them with more clarity and control over their participation in the wholesale market. Instead of generators' compensation for being constrained off being related to the capacity of generators (as under dynamic regional pricing), or receiving no compensation (as is the current arrangements), the compensation would be related to the quantity of firm transmission rights they hold.

TNSPs would be obliged and financially incentivised to provide a level of access consistent with the firm transmission rights collectively held by generators, meaning that the purchase of firm transmission rights by generators would underwrite transmission investment. Because the transmission rights are a firm hedge between the dynamically determined regional price and the existing region-wide price, generators receive the full benefit of the transmission upgrade they underwrite - avoiding the free-rider problem in the current access regime explained in section 2.1, and allowing a greater reliance to be placed on commercial transmission investment rather than the existing, centralised and regulated processes.

Generators that do not hold firm rights would be exposed to more of the cost of congestion (because they have not contributed to alleviating the congestion through the purchase of transmission rights), while generators that hold transmission rights would be hedged against the cost of congestion. This provides an incentive for generators to underwrite the appropriate amount, location and timing of transmission investment, balancing the costs of transmission investment against the costs of congestion, as well as other locational decision factors such as fuel resources.

The approach should result in a closer alignment of generation and transmission investment and should have substantial benefits because:

- by better aligning the processes of generation and transmission investment it should reduce the prospect of poor coordination, reducing costs to consumers, and
- if, despite this better alignment, poor coordination does occur, it is generators, rather than consumers, that bear more of the risk and cost of this and so have the power to manage these issues.

As such, it has the potential to minimise prices for electricity consumers in the longer-term by minimising the total system cost of building and operating both generation and transmission over time.

This final phase is a significant reform to the NEM, but is necessary in the face of the rapid transformation of the electricity sector.

QUESTION 4: GENERATORS FUND TRANSMISSION INVESTMENT

1. What issues and considerations should the AEMC take into account when developing and assessing phase 3?

### 3.1.5 Access reform timeframes

The Commission intends to make recommendations to the COAG Energy Council by the end of 2019 with regard to the phased access reforms with the intention that the COAG Energy Council submit rule change requests to the AEMC in January 2020. As highlighted above, the AEMC proposes that:

- dynamic regional pricing and incorporating the information from this into the transmission framework be in place by July 2022
- generators funding transmission infrastructure to be in place by July 2023.

QUESTION 5: ACCESS REFORM TIMEFRAMES

1. Are the timeframes suggested for the access reforms appropriate?
2. Is the timing of the phases appropriate?

## 3.2 Charging reform

Given the need for greater interconnection identified in the ISP, concerns have been raised about whether the current inter-regional transmission charging regime adequately attributes the cost of interconnectors to those who benefit from them.

Transmission pricing is always complicated and contentious, because it involves multiple objectives which are almost certain to conflict with each other. Developing a pricing method involves understanding the relative priorities of these objectives and finding suitable trade-offs between them. The current inter-regional transmission charging arrangements provide a mechanism for TNSPs to recover some costs associated with interconnector investments from TNSPs in other regions. However, these arrangements can be considered to be crude and improvements may be warranted.

In addition, part of the access reforms involve generators paying for transmission. This raises broader questions about the rest of the TUOS framework.

### 3.2.1 Inter-regional TUOS arrangements

In the CoGaTI final report, the Commission concluded that the existing inter-regional TUOS (IR-TUOS) arrangements should, over time, adequately ensure that those who benefit from an interconnector pay for that interconnector. However, given the large amount of interconnectors currently being considered for construction, the Commission considers that it is timely to review the IR-TUOS arrangements.

The Commission considers that there are a number of aspects of the existing IR-TUOS arrangements that could potentially be refined. For example, the Commission considers the following aspects should be considered further:

- **Should the pricing methodology be modified to allocate costs based on average load, as opposed to peak load?** Transmission locational costs are currently allocated to load points based on their non-coincident peak demand. However, as noted in the CoGaTI final report it is clear that benefits vary depending on a number of factors. While generally a region is more likely to be importing when its demand level is high, there can be other factors that affect this. For example, the proposed SA-NSW interconnector is likely to be flowing towards NSW when it is windy in SA; and towards SA when it is calm, regardless of the underlying demand levels. It may be worth the IR-TUOS arrangements reflecting this. One way to do this could be to consider whether costs should be allocated based on average load, rather than non-coincident peak load. Another way would be to consider the allocation of net benefits that would be an output from any RIT-T assessment.
- **Should the non-locational components of the inter-regional investment be included in the inter-regional transmission charge, rather than smearing it across the customers in the region?** The locational component of TUOS only allocates 50 per cent or so of the value of each asset. The remaining value is recovered through a non-locational "postage-stamp" charge where there is a single $/MW or $/MWh price applied to every load in the region. For the inter-regional charging arrangements, the locational 50 per cent of asset value is added to the charges. However, the non locational charge is not added. Therefore, the costs and benefits of a new interconnector are to be aligned then whether the non-locational charges should also be included needs to be considered.
- **Should a TNSP be able to discount the non-locational elements of the interregional transmission charge?** There are prudent discounting arrangements that a TNSP can apply to intra-regional transmission charges. Under these arrangements, a TNSP is permitted to discount the non-locational charges - possibly down to zero - applying to a particular customer if it considers that this is in the interest of consumers as a whole. This benefit could arise because of the price sensitivity of the customer, in which the full non-locational charge would cause it to close or relocate its business or find a means to bypass the transmission system. Prudent discounting arrangements allow a TNSP to take some factors into account, i.e. the customers willingness or ability to pay – which could not feasibly be incorporated into the transmission pricing method. This additional flexibility could lead to better outcomes for consumers as a whole. This flexibility may be useful in the inter-regional context.

The Commission is considering these questions in more depth through re-examining the IR-TUOS arrangements. This would allow these changes to be implemented alongside dynamic regional pricing, and will assist in providing information about costs of congestion.

> QUESTION 6: IR-TUOS
>
> 1. How should IR-TUOS be refined?
> 2. What are the answers to the specific questions raised above, or how might the AEMC go about answering these questions?
> 3. What other considerations should the AEMC take into account when refining IR-TUOS?

### 3.2.2 TUOS framework

As discussed in section 3.1.4, the final stage of the access reforms involve generators having the option to pay for transmission in return for firm access rights. This raises broader questions about the rest of the TUOS framework.

AEMO also considers that there is a broader issue with the pricing arrangements for distribution and transmission networks that is needed and a holistic review of how network costs are recovered, and from whom.[13]

In order to allow a broad consideration of TUOS issues, alongside the implementation of access reform, we are considering components of TUOS that need to be revisited, including:

- identifying pricing principles for TUOS and testing and agreeing on these with stakeholders, e.g. some principles may include **transparency** around the pricing methodology
- considering the **impact of recent trends and market outcomes** and how these may change the dynamics and use of the principles, e.g. entry of variable renewable generation, which has a variable output that depends upon local weather conditions, may create more variability about how the transmission network is used, which could impact on how it is priced
- considering the **impact of market design changes** and how this could impact on transmission pricing - this could include the introduction of five minute settlement, as well as the proposed access reforms
- developing sequencing for TUOS reform, by categorising:
    - discrete elements of the TUOS pricing method that can be tackled separately
    - the types of interdependence between the market issues and these discrete elements
    - the predictability of the various market changes.

13 AEMO, stakeholder paper, E*merging generation and energy storage in the NEM*, November 2018.

**QUESTION 7: TUOS FRAMEWORK**

1. What insights do you have with regard to the above components of TUOS which you consider the AEMC should take into account when assessing TUOS reform?
2. What other components of TUOS should be considered?

### 3.2.3 TUOS reform timeframes

The Commission intends to make recommendations to the COAG Energy Council by the end of 2019 with regard to both IR-TUOS and the TUOS framework more generally with the intention that the COAG Energy Council submit rule change requests to the AEMC in January 2020. The AEMC proposes that:

- IR-TUOS reforms be in place in July 2022
- TUOS reforms are implemented in July 2023, to coincide with the phase 3 of the access reforms.

**QUESTION 8: TUOS REFORM TIMEFRAMES**

1. Are the timeframes suggested for the TUOS reforms appropriate?

# 4 LODGING A SUBMISSION

Written submissions on this consultation paper must be lodged with Commission by 29 March 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 Elizabeth Bowron on (02) 8296 0619 or elizabeth.bowron@aemc.gov.au.

# ABBREVIATIONS

| | |
|---|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| CoGaTI | Coordination of generation and transmission investment |
| Commission | See AEMC |
| DNSP | Distribution network service provider |
| IR-TUOS | Inter-regional transmission use of system |
| ISP | Integrated System Plan |
| NEL | National Electricity Law |
| NEM | National electricity market |
| NEO | National electricity objective |
| REZ | Renewable energy zone |
| RIT-T | Regulatory investment test for transmission |
| TNSP | Transmission network service provider |
| TUOS | Transmission use of system |

# A RECOMMENDATIONS IN THE *COORDINATION OF GENERATION AND TRANSMISSION INVESTMENT* FINAL REPORT

## A.1 Better coordinating investment in new generation and transmission infrastructure

In the final report published as part of the CoGaTI review on 21 December 2018, the Commission made a series of recommendations for how investment in generation and transmission should be better coordinated into the future. The outcomes that would be achieved through the actioning of the recommendations formed part of a cohesive package to transform the way generation and transmission would be planned, invested in and operated in the NEM. The process for coordinating transmission and generation investment must be rigorous and transparent, in order to maximise the long-term interests of consumers. Our recommendations create a phased reform work program to transform the coordination of generation and transmission investment, and the recommendations complement each other.

The final report published in December 2018 explained the reforms in five stages.

**Stage 1: Implement reforms that are necessary to advance ISP group 1 projects**

*Build ISP group 1 projects*

- In order to address the ISP group 1 projects, Dr Kerry Schott AO will submit a rule change request to the Commission to allow the three post-regulatory investment test for transmission (RIT-T) processes completed by the Australian Energy Regulator (AER) to be undertaken concurrently for the group 1 projects only.
- The AEMC will progress this rule change request on an expedited basis, with the rule change process completed by the end of quarter 1, 2019. This would save six to eight months off the regulatory process, while ensuring that the checks and balances for a robust process, and assessment that the investments are efficient, remain. This will provide sufficient time for the group 1 projects to be operational to meet the needs identified by AEMO in the ISP.[14]

**Stage 2: Embed an actioned ISP in the regulatory framework to progress projects going forward, and integrate large-scale energy storage systems into the NEM**

*An actioned ISP*

- Actioning the ISP is required to allow the progression of the ISP group 2 projects in a timely manner. An actioned ISP requires clear links between the ISP and network

14 The rule change request was submitted by Dr Schott on 21 December 2018, and the AEMC initiated the rule change on 24 January 2019. On 14 February 2019, Dr Schott submitted an additional rule change request that seeks to apply some of the regulatory streamlining recommended by the Commission for priority group 1 projects to the new South Australia-New South Wales interconnector, known as Project EnergyConnect. Given that these two rule change requests are closely related, the AEMC consolidated them into a single rule change request, which was initiated on 21 February 2019.

investment decisions, and the ability for generation and network investment decisions to be coordinated by those best placed to implement them.

- Embedding the actioned ISP streamlines, removes duplication and de-risks the transmission planning and investment decision-making process to help TNSPs make the decisions that they need to be making to assist the transition of the power system. By removing duplication and streamlining the regulatory process, actioning the ISP would reduce the time it currently takes for the RIT-T and post RIT-T processes to be completed by an estimated 18 months.

*An improved RIT-T*

The regulatory process for non-ISP projects can also be improved, to complement an actioned ISP. Reducing the time frame associated with completing the project assessment draft report of the RIT-T from 12 months to nine months will reduce the time it takes to complete transmission planning and investment decision-making processes. Additionally, removing the preferred option assessment that the AER undertakes after the completion of a RIT-T will streamline and remove duplication from the regulatory process.

*Integrating large-scale storage systems*

As part of the transformation of the generation fleet in the NEM, large-scale energy storage systems are increasingly seeking to connect to the grid. This has raised some questions about the applicability and appropriateness of the existing regulatory framework for large scale energy storage technologies. The Commission recommends that AEMO submit a rule change request to create a new NEM registration category to accommodate energy storage systems. This is a pressing issue that needs to be addressed to remove barriers to entry for the connection of storage to the system.

**Stage 3: Dynamic regional pricing to provide congestion signals to connecting parties, as well as implementing reforms to inter-regional transmission use of system pricing to ensure that the costs of interconnectors are aligned to those who benefit**

*Access reform - dynamic regions for pricing generation*

- Actioning the ISP needs to be paired with the mechanisms necessary to allow generation to contribute to the enhancement of the networks and the management of congestion along it. We need a phased reform to address generator connection and access to the transmission network, and to make congestion management fit for purpose for the energy transformation - reform is needed now in order to be put in place for the future.
- First, dynamic regional pricing will be implemented, which will put a price on network congestion. Where congestion arises, and transmission constraints occur, pricing regions will be dynamically created through existing dispatch processes which will reflect transmission constraints that are actually occurring at that particular time.
- This will introduce a signal to generators that reflects the short-run costs of using the network, providing better information to generators.

*Charging for use of the transmission system*

- An actioned ISP focusses attention on the development of interconnectors. Given this, concerns have been raised about whether the current inter-regional transmission charging regime adequately attributes the cost of interconnectors to their beneficiaries.
- The Commission considers that there may be some elements of the existing inter-regional transmission charging arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment. The inter-regional TUOS arrangements should be re-examined in March 2019, and changes implemented alongside dynamic pricing.

**Stage 4: Information from dynamic pricing reveals congestion costs, with this being used as an input into the ISP's transmission planning**

*Access reform - better information*

The information on patterns and costs of congestion and the dynamic location of regions that is revealed through dynamic regional pricing will be used by the market. This information will be available to AEMO and the wider market, enabling AEMO to develop future ISPs with increased accuracy, TNSPs to make efficient transmission investments informed by an enhanced ISP, and the AER to assess the efficiency of transmission investments.

**Stage 5: Generators given a new option to fund transmission infrastructure, providing them with choice and control about how they access the wholesale market, as well as broader TUOS reform**

*Access reform - generators contribute towards transmission*

- Generators will use the ISP, along with other sources of information, as an important guide to their generation and transmission investment decision-making and have the choice to compel TNSPs to provide transmission services consistent with the level of firm access (that is, guaranteed access to the wholesale market) paid for by generators. This final stage is a significant reform to the NEM, but is necessary in the face of the rapid transformation of the electricity sector.
- The market driven approach of phased access reform aligns the disaggregated, commercial decisions of the generation sector with those of the transmission sector. It provides the necessary tools for those who are best placed to bear the risk of resource investment to do so, facilitating the coordination of generation and transmission investment and avoiding unnecessary risks being placed on consumers.

*Charging for use of the transmission system*

Part of the access reforms involve generators paying for transmission. This raises broader questions about the rest of the TUOS charging framework. In order to allow a holistic consideration of TUOS issues, alongside the implementation of access reform, the AEMC will scope components of TUOS arrangements that need to be revisited, with the intention for necessary rule changes to be submitted by the COAG Energy Council by the end of 2019.

**Renewable energy zones**

Actioning the ISP and its complementary changes to access will facilitate renewable energy zones (REZs) through introducing more commercial drivers into transmission development.

The changes to the access regime would enable better trade-offs to be made between the cost of transmission and the cost of generation in the development of REZs, and would align more of the risk of investment decisions with those who make them, and away from consumers. REZs forming through generators making a decision about the most efficient way to coordinate their investment in both generation and transmission infrastructure is likely to minimise total system costs since generators will be given more options and opportunities to fund transmission infrastructure, influencing transmission planning decisions. Under these changes, REZs will emerge as a consequence of generators' and prospective generators' commercial locational investment decisions.

The final report included an implementation work plan for the comprehensive package of recommendations made by the Commission to improve the coordination of generation and transmission investment. The implementation work plan is provided in Table A.1.

Table A.1: **CoGaTI final report recommendations - Implementation work plan**

| TIMING | PLANNING | ACCESS AND CONGESTION | CHARGING | CONNECTION (AND STORAGE) | ECONOMIC REGULATION |
|---|---|---|---|---|---|
| December 2018 | Dr Kerry Schott AO submits rule change request to the AEMC to allow concurrent AER assessment of post RIT-T process for group 1 projects - **SUBMITTED 21 DECEMBER 2018; INITIATED 24 JANUARY 2019** | | | | |
| March 2019 | AEMC final determination on rule change request to allow concurrent AER assessment of post RIT-T processes for group 1 projects.<br>AER to submit a rule change request to the AEMC to reduce the time frame associated with completing the | | | AEMO to submit rule change request to the AEMC to create a new NEM registration category to accommodate large-scale energy storage systems. | AER to submit a rule change request to the AEMC to remove clause 5.16.6 (where the AER makes a determination as to whether the preferred option satisfies the regulatory investment test) from the NER to streamline and reduce duplication. |

| TIMING | PLANNING | ACCESS AND CON-GESTION | CHARGING | CONNECTION (AND STORAGE) | ECONOMIC REGULA-TION |
|---|---|---|---|---|---|
| | project assessment draft report of the RIT-T from 12 months to nine months. | | | | |
| January - June 2019 | AEMC, Energy Securtiy Board and the COAG Energy Council Senior Committee of Officials to work together to develop the necessary NEL and NER changes required to implement the ISP. | AEMC through CoGaTI 2019 to develop rule changes to progress the phased network congestion and access reforms. | | | |
| August 2019 | NEL and NER changes implementing the ISP to be in place.<br><br>AEMO starts consultation on the 2020 ISP, under the new framework. | | | | |
| June - December 2019 | | AEMC through CoGaTI 2019 to develop rule changes to progress the phased network congestion and access | AEMC to review IR-TUOS & TUOS arrangements and develop rule change requests on any | | |

| TIMING | PLANNING | ACCESS AND CONGESTION | CHARGING | CONNECTION (AND STORAGE) | ECONOMIC REGULATION |
|---|---|---|---|---|---|
| | | reforms. | changes. | | |
| January 2019 | | COAG Energy Council to submit rule change requests on network congestion and access reforms to the AEMC. | COAG Energy Council to submit rule change requests on TUOS changes to the AEMC. | AEMC final determination on AEMO rule change request on new registration category for large-scale energy storage systems. | |
| July 2022 | Information from dynamic regional pricing is being used to inform the ISP's transmission planning. | Dynamic regional pricing is implemented. | IR-TUOS reforms are implemented. | | |
| July 2023 | Generators are allowed to fund transmission infrastructure, influencing transmission planning decisions. | Generators are allowed to fund transmission infrastructure, and receive access rights in return, implementing firm transmission rights. | TUOS reforms are implemented. | REZs are enabled through funding transmission infrastructure. | Corresponding changes to the economic regulatory framework, reflecting that generators are funding transmission infrastructure are in place. |

Source: AEMC, *Coordination of generation and transmission investment review*, final report, pp.x-xii

# B DYNAMIC REGIONS FOR PRICING GENERATION

As discussed in Chapter 3, 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.

Under dynamic regional pricing, in any individual dispatch interval, dispatched generators will be paid the new, dynamic regional price that applies where they are connected, rather than the existing regional reference price. Where there are no constraints on the transmission network, the new, dynamic region will include the regional reference node, and so the price generators receive will be the existing regional reference price.

Creating dynamic regions has the effect of putting a price on congestion and hence addresses a number of the concerns raised in Chapter 2. Dynamic regions introduce a signal to generators that reflects the short-run costs of using the network. This will provide better information to generators about where congestion occurs, which they can consider when making their locational decisions, as well as removing the current incentives for disorderly bidding by generators when there is congestion.

Market customers (e.g. retailers) would continue to be settled at the regional reference price.

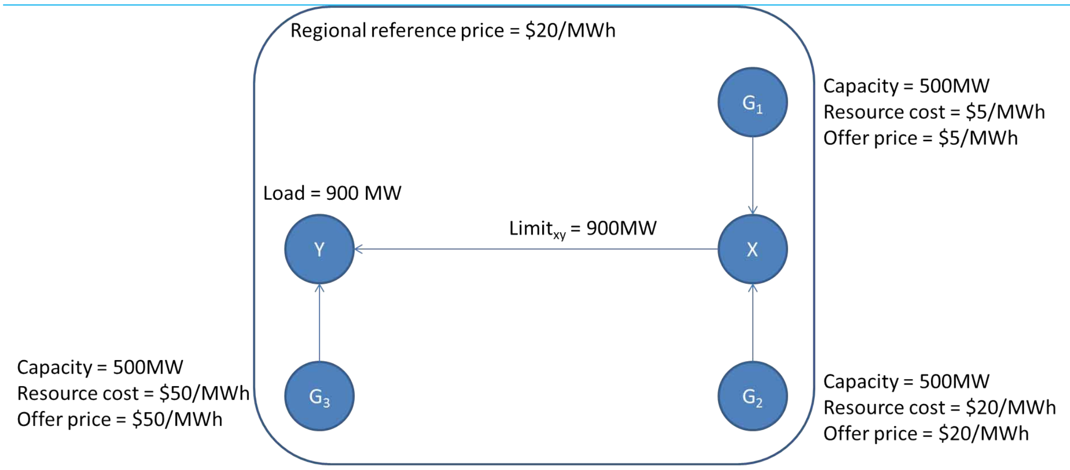
A consequence of this change is to introduce a new risk to generators arising from generators not being settled at the regional reference price. This risk is addressed, in part, by providing financial compensation to generators on the difference between the regional reference price and the dynamic regional price of the generator. The money to back this compensation arises from the difference between the price market customers are being settled at (the existing regional reference price) and the price some generators are being settled at (the new, dynamically determined regional price of the generator). This is analogous to inter-regional settlement residue in the current NEM, but would occur intra-regionally under the method described above.

This financial compensation could be dynamically allocated to generators on the basis of their capacity. As a result, generators will not always be fully compensated on the price difference between the dynamic region they are in and the existing regional reference price. While this risk is not fully addressed here, the Commission notes that the risk may not be any greater than the risk that generators currently face. Currently, generators face the risk that they are not dispatched as a result of a transmission constraint and hence receive zero revenue regardless of the market price. Following these changes, generators will instead be exposed to a different risk: that despite being dispatched, they receive the dynamic regional price rather than the region-wide price, and are not fully compensated the difference between these prices.

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



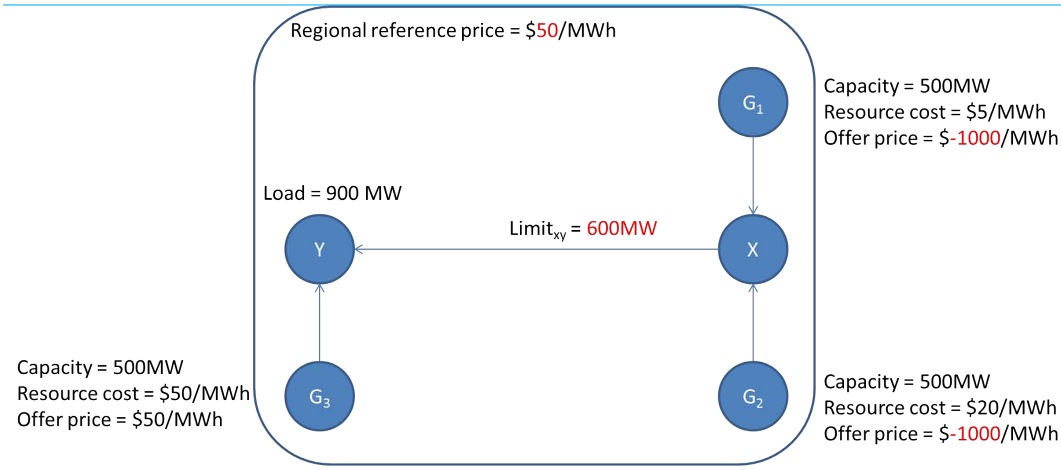

| Generator | Capacity (MW) | Congestion hedge ($) | Offer ($/MW) | Dispatch (MW) | Dispatch revenue ($) | Resource cost ($) | Margin ($) |
|---|---|---|---|---|---|---|---|
| G1 | 500 | 0 | 5 | 500 | 10,000 | 2,500 | 7,500 |
| G2 | 500 | 0 | 20 | 400 | 8,000 | 8,000 | 0 |
| G3 | 500 | 0 | 50 | 0 | 0 | 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** |

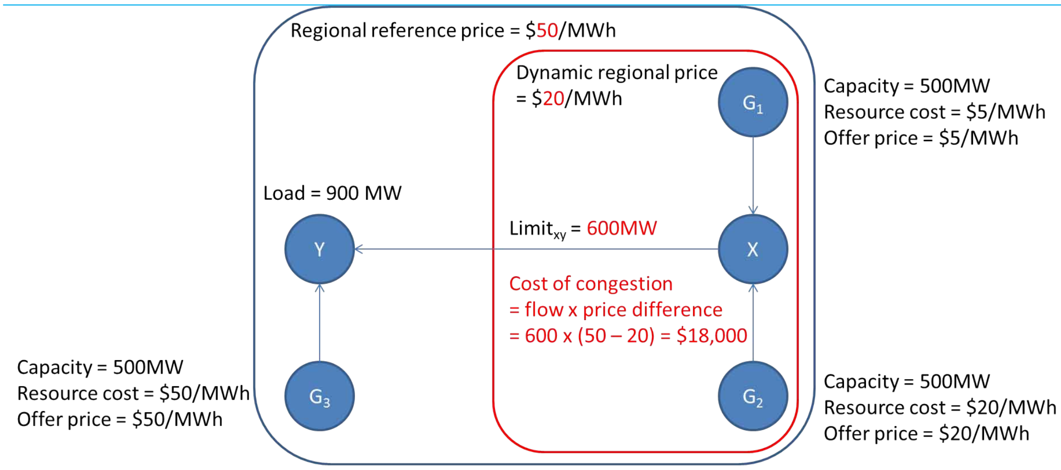
Source: AEMC analysis

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.[15] 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).

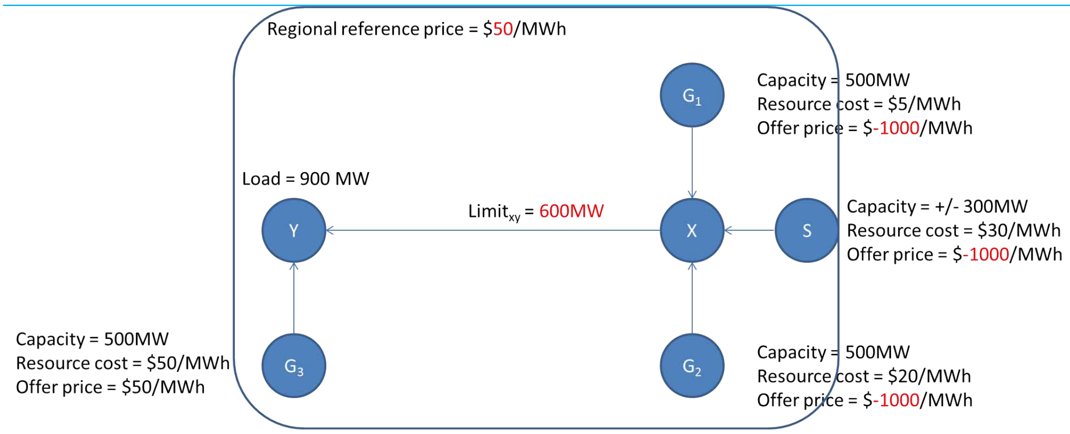
15 In this example, generator 2 would have an incentive to bid just above the bid of generator 1, in order to increase the compensation payment. This would allocate more of the margin to generator 2 and less to generator 1. However, physical dispatch outcomes are unaffected by this bidding behaviour 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** |

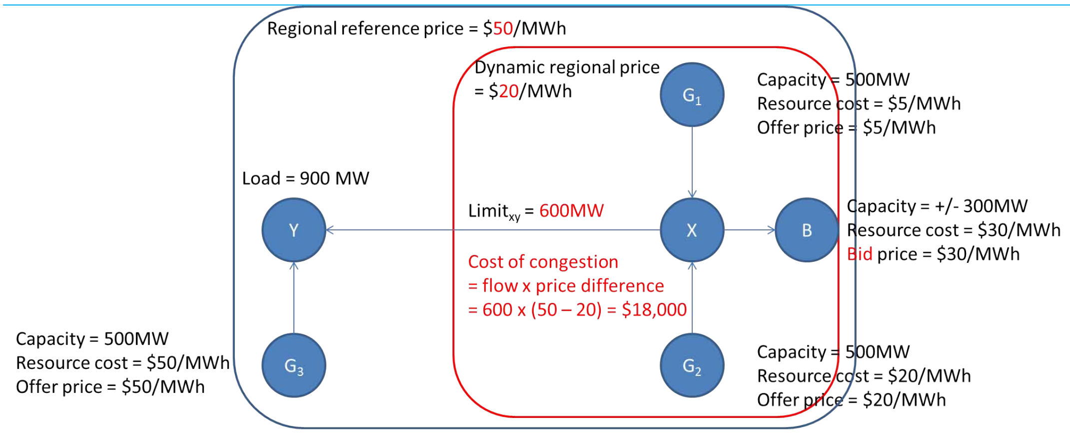
Source: AEMC analysis

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.