AEMC

REVIEW

Australian Energy Market Commission

DRAFT REPORT - VOLUME 1

Optional Firm Access, Design and Testing

12 March 2015

Submissions due 30 April 2015. Reference: EPR0039
Draft Report - Volume 1
EMBARGO until 12 March 2015

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Reference: EPR0039

Citation

AEMC 2015, Optional Firm Access, Design and Testing, Draft Report - Volume 1, 12 March 2015, Sydney.

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

A foundation principle of the National Electricity Market (NEM) is that decisions to invest in generation capacity are made by businesses operating in a competitive environment, rather than by regional centralised utilities. The result is that risks associated with generation investment rest with those businesses.

Transmission investment decisions remain the province of regional, centralised transmission network operators.[1] Transmission businesses are subject to regulation of their revenues for the provision of transmission services, as well as through various other obligations relating to reliability and investment decision making processes.

The way these two investment decision making processes interact and, in particular, their operational consequences, have been a consistent instigator of reports and reviews throughout the life of the NEM. Since 1997 there have been no fewer than eleven major reports and reviews dealing with various aspects of congestion management and generator access. Given the extensive work undertaken on the design and testing of optional firm access, the intent of the Australian Energy Market Commission (AEMC or Commission) is that this will be the last such report for many years to come.

In the Commission's previous review of the transmission arrangements that underpin the NEM, known as the Transmission Frameworks Review, it was noted that the existing arrangements had, from an overall perspective, performed reasonably well. In a future where patterns of generation and transmission investment were much more uncertain, however, a mechanism whereby more transmission investment was driven by commercial negotiations between generation and transmission investment decision makers may be warranted. These broad conclusions have been reinforced by the detailed design and testing of optional firm access.

Draft assessment of optional firm access

The Commission's draft assessment of the benefits and costs of optional firm access is that, in the current environment, absent some major shift in market conditions and government policy settings, its implementation would not contribute to achievement of the National Electricity Objective.

If drivers emerge of a major transformation of the generation and transmission capital stock, where the outcomes are highly uncertain, the existing mechanisms for co-ordinating generation and transmission operations and investment may prove inadequate. In these conditions, the balance of expected benefits and costs of optional firm access would shift in favour of implementation.

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

In the absence of these conditions there is no doubt that, from time to time, bidding behaviour or system operation issues will arise in particular locations due to transmission constraints.[2] Where the materiality of these issues on market outcomes is small and duration likely to be temporary, regulatory interventions are unlikely to be warranted. Where the impact is material, specific and targeted measures can be considered through the rule change process, rather than by changing the foundations of the NEM through optional firm access or market based congestion management systems.

In the event that the conditions for proceeding with optional firm access emerge, considerable resources and lead times would be required for implementation. In this regard, the Commission makes a further draft recommendation that market conditions be monitored for indicators of these emerging drivers. This should be undertaken as an adjunct to the Commission's existing annual Last Resort Planning Power functions.

The review

This draft report is published in response to a review instigated by the COAG Energy Council (formerly the Standing Council on Energy and Resources) in February 2014. The Commission was asked to undertake a detailed design and testing of the optional firm access model and recommend to the COAG Energy Council whether it should be implemented in the National Electricity Market (NEM).

The review follows on from the Transmission Frameworks Review. That review looked at whether the current transmission frameworks are likely to lead to efficient outcomes. In that project, the AEMC identified a number of issues with the efficiency of the co-ordination between transmission and generation in the National Electricity Market. The concept of optional firm access was developed as part of that review.

What is optional firm access?

Optional firm access would change the way in which transmission and generation investment decisions are made, and would mean generators would bear more of the risk associated with some transmission investment. Generators could choose to pay for a specified level of access to the transmission network in order to manage the financial impacts of network congestion. Specifically:

- Generators would fund and guide the development of new transmission, which would underpin their access rights, both within regions and between regions.
- Generators would bear the indicative costs of transmission development undertaken to support their access decisions.
- Generators would have the option of purchasing a level of firm access rights to manage congestion risk, which might be for all or part of their generating

2 It is noted that transmission constraints may, at times, provide opportunities to bid spot prices either higher or lower than they would otherwise be.

capacity. These financial rights would entitle the holders to receive compensation payments when congestion occurs. The payments would be funded by those generators who were dispatched in excess of the level of firm access rights, if any, that they have purchased.

- Generators would have the option of not holding firm access rights for any generating capacity. Such generators would not bear any indicative costs of transmission developments.

Some stakeholders have expressed the view that optional firm access is not really optional because commercial considerations would drive them to purchase access rights. However, the point is that there would be no regulatory obligation on generators to purchase access (as compared to the requirement to have a connection agreement). Generators could choose the level of access they wish to purchase relative to their generating capacity.

Functional assessment of the optional firm access model

The Commission has developed, refined and enhanced the optional firm access model. Elements of the model, particularly the pricing element, would require further work during a detailed implementation phase. However, the Commission is of the view that, from a functional perspective, the optional firm access model could be implemented in the NEM, and, as outlined above, in a changing and uncertain investment environment would contribute to the National Electricity Objective, provided implementation risks could be managed.

Overall assessment of optional firm access against the National Electricity Objective

Optional firm access would impact the National Electricity Market in an investment sense, as well as an operational sense. Specifically:

- it would have an impact on what would be the level of generation and transmission investment. This can be seen through the assessed impact categories of risk allocation and generation and network investment; and

- it would have an impact on operational outcomes for TNSPs and generators, given an existing level of generation and transmission capital stock. This can be seen through the assessed impact categories of inter-regional hedging, financial certainty for generators, incentives on Transmission Network Service Providers (TNSPs) to operate the network efficiently, and efficient dispatch of generation.

The Commission considers that optional firm access could help the market adapt in an environment of major changes in the capital stock requiring significant investment and characterised by high levels of uncertainty with respect to relative costs, technologies and hence location decisions, in the following ways:

- *Risk allocation:* The risks associated with transmission investment include the risk associated with demand projections resulting in a different level of investment than is required, and the risk of supply-side changes resulting in higher costs of some generation types and obsolete investments. Optional firm access would change the allocation of these risks in the transmission and wholesale markets. Some of the risk would be shifted from consumers, who currently directly bear most of the costs associated with transmission, to generators who would bear costs related to their need for access.

- *Generation and network investment:* Under optional firm access, there would be better signals between generators and transmission businesses relating to the impacts of investment. Generators, rather than transmission network planners, would drive part of the decision-making about future transmission development. These better signals from generators to transmission network planners would also be beneficial when the network is shrinking and transmission businesses are deciding whether or not to replace assets. Optional firm access would promote a diversity of views about the future of both generation and transmission, by placing more of the responsibility for the development of the network with generators. This would help improve the co-ordination between transmission and generation investment in the NEM so that total system costs would likely be minimised for consumers.

  — Ernst & Young (EY) have estimated that the benefits of improved co-ordination, measured as the difference in total system costs (ie, generation and transmission) between the current planning arrangements and optional firm access, range from $51 million (with a reduced Renewable Energy Target (RET) and no carbon price) to $86 million in the base case (weak demand growth, the RET in its current form and no carbon price) to $670 million with an emissions reductions scenario that targets a 40 per cent reduction on 2000 levels by 2025 and an 80 per cent reduction by 2040.

- *Inter-regional hedging:* Optional firm access could improve the firmness of inter-regional hedging. This could facilitate more generators and retailers to contract with each other across regions in the NEM.

Regarding other criteria, which are all operational outcomes, against which optional firm access has been assessed:

- *Financial certainty for generators:* Optional firm access should improve financial certainty for generators who purchase optional firm access. However, most generators have said that they would not value such a product. Financial transmission rights in energy markets elsewhere are valued, and have been purchased, by generators. It is possible that if congestion levels were to increase in the NEM, more generators may value access more highly. Indeed, some generators have expressed different views in the past, when congestion levels were higher.

- *Incentives on Transmission Network Service Providers (TNSPs) to operate the network efficiently:* TNSP incentives would be better linked to the value to the wholesale market of any shortfalls in capacity.

- *Efficient dispatch of generation:* Based on the information available, the value of dispatch inefficiencies would appear to be small. Therefore, while optional firm access would remove some of these dispatch inefficiencies, the benefits across the NEM would be small.

The level of costs associated with implementing optional firm access was also considered as part of this assessment. The estimated transaction costs (for the first five years) are approximately $90 million.

As discussed above, given the current market conditions, the investment-related benefits that the Commission has been able to quantify are similar to the level of costs. There has been a reduction in demand for electricity and there is an excess of generation supply, causing fewer significant impacts from congestion, and little projected transmission and generation investment for the foreseeable future.

Based on its assessment of all of the categories, including the implementation costs, the Commission is of the view that optional firm access would contribute to the National Electricity Objective in an uncertain and changing investment environment (for transmission, generation or both).

When should optional firm access be implemented?

The Commission recommends that optional firm access could be considered for implementation when there are signs that the investment environment is beginning to change and become more uncertain. Both these conditions are required for consideration of implementation.

Accordingly there should be regular monitoring of conditions in the NEM. If there are signs that conditions are beginning to change in a way that the benefits from optional firm access could be greater, a process to implement optional firm access could be considered, taking into account the implementation risks involved. Conditions that could justify the implementation of optional firm access will be considered further in the final report. As stated above this should be undertaken as an adjunct to the Commission's existing annual Last Resort Planning Power functions.

A lead time would be required to implement optional firm access. This links to the monitoring process that will be developed, and will also be considered further for the final report.

Tasmania

If optional firm access was implemented, Tasmania should be excluded from the optional firm access model in the first instance, assuming elements of the Tasmanian market remain as they are currently. Relative to other regions, the technical challenges for optional firm access are greater and the benefits are lower in Tasmania. The nature of interconnection between Tasmania and the mainland also makes it easier to separate than all other regions.

Previous reviews on similar issues

The Commission notes that the issues that have been contemplated in this review have been considered, in at least eleven reviews including the *Transmission and distribution pricing review* in 1999 by NECA, the *Parer review* in 2002, the *Regulatory and Institutional Framework for Transmission review* by Firecone in 2003, the *Energy Reform Implementation Group (ERIG) review* in 2007, and the AEMC's *Transmission Frameworks Review* in 2013. Many of those have examined issues about congestion, and generator access to the transmission network. These reviews have shown:

- solving these issues is technically complex;
- stakeholders have different views about the importance of these issues, and their solutions; and
- the importance of these issues to stakeholders changes as market conditions change.

The Commission considers that optional firm access is an appropriate solution to address these issues in the right circumstances, but that current market conditions do not justify its implementation. By monitoring the investment environment to determine if conditions are right for optional firm access, the optional firm access model developed as part of this review can be applied when it is of benefit, and further reviews can be avoided.

Alternatives to optional firm access

A number of stakeholders have also proposed either simplified versions of optional firm access, or alternatives, as part of submissions to the Commission's request for comment. The Commission will further consider such options that have been raised, and the effectiveness of them, prior to producing the Final Report.

Responding to this draft report and next steps

Submissions on this Draft Report are requested by no later than **30 April 2015**. Stakeholders are encouraged to include any relevant information and comments in their submissions.

As required by the terms of reference for this review, a Final Report setting out the Commission’s final recommendations will be published in mid-2015.

Contents

1 Introduction

The COAG Energy Council (formerly called the Standing Council on Energy) has asked the Australian Energy Market Commission (AEMC or Commission) to develop, test and assess the optional firm access model.

1.1 Transmission Frameworks Review

This project follows on from an earlier AEMC project, the Transmission Frameworks Review, which was completed in April 2013. This was a comprehensive review of the transmission arrangements that underpin the NEM.

In the Transmission Frameworks Review, the AEMC identified a number of concerns with the efficiency of the co-ordination between transmission and generation in the National Electricity Market. They were:

- The lack of clear and cost-reflective locational signals for generators, such that locational decisions do not take into account the resulting transmission costs.
- Transmission network service providers (TNSPs) estimating the benefits of transmission development, where those benefits are better known to generators, and the risk of inefficient decisions being borne by consumers rather than the decision-maker.
- The resultant planning of transmission networks not being co-optimised to minimise the combined costs of generation and transmission.
- The importance of TNSP's operating their networks to maximise availability when it is most valuable, and the challenge they face in doing so given the lack of exposure to the financial costs of reductions in capacity.
- The difficulty that market participants have in managing the risk of price differences between different regions of the NEM, with a resulting negative impact on the level of contracting between generators and retailers in different regions.
- The lack of certainty of dispatch faced by generators when there is congestion, compounded by the inability of generators to obtain firm access, even where they fund augmentations of the transmission network.
- The resulting incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion.

Amongst other things, that review developed an integrated package of market arrangements for the provision and utilisation of the transmission system, known as optional firm access. This was designed to be an all-encompassing solution to the above concerns.

On 25 February 2014 the AEMC received Terms of Reference from the COAG Energy Council to develop, test and assess the optional firm access model that was initially proposed as part of the Transmission Frameworks Review.[3]

1.2 Optional Firm Access, Design and Testing review

The objectives of the Terms of Reference are:

- confirm or modify the design of the optional firm access model as a result of testing and evaluation;
- assess whether implementing optional firm access is likely to contribute to the National Electricity Objective (NEO);
- engage with industry participants and governments to build understanding of the model and the potential impacts of its implementation; and
- recommend to the COAG Energy Council whether to implement optional firm access, and if so, how it could be implemented.

The terms of reference for the design, testing and assessment of optional firm access has not required the AEMC to reconsider the issues and problems identified as part of the Transmission Frameworks Review.

However, in undertaking work on optional firm access, the AEMC has become aware that some stakeholders do not think optional firm access should be implemented. A number of stakeholders have questioned whether the issues identified as part of the Transmission Frameworks Review, that optional firm access is intended to address, are still relevant. Stakeholder views regarding the issues optional firm access was designed to address are important factors for the Commission to consider.

Further, given the magnitude of the reform, and the effort required to implement optional firm access, an important element to consider in terms of implementation risk is the degree of commitment parties have to the reform. Therefore, the Commission has also taken these factors into account as part of its draft recommendation.

1.3 Objectives of optional firm access

Optional firm access would change the way in which transmission and generation investment decisions are made, and would mean generators would bear more of the risk associated with some transmission investment. Generators could choose to pay for a specified level of access to the transmission network in order to manage the financial impacts of network congestion. Specifically:

3 Standing Council on Energy and Resources, Transmission Frameworks - Detailed Design and Testing of an Optional Firm Access Framework, 25 February 2014.

- Generators would fund and guide the development of new transmission, which would underpin their access rights, both within regions and between regions. Generators, rather than regulated transmission businesses, would drive part of the decision-making about future transmission development.
- Generators would bear the indicative costs of transmission development undertaken to support their access decisions. This would create improved incentives for risk management, given that generators have the ability, incentives and information to better manage risk.
- Generators would have the option of purchasing a level of firm access rights to manage congestion risk, which might be for all or part of their generating capacity. These financial rights would entitle the holders to receive compensation payments when congestion occurs. The payments would be funded by those generators who were dispatched in excess of the level of firm access rights, if any, that they have purchased.
- Generators would have the option of not holding firm access rights for any generating capacity. Such generators would not bear any indicative costs of transmission developments.

The optional firm access model is intended to help the market adapt to changing and uncertain conditions, particularly demand and generation patterns, to deliver better outcomes for consumers.

1.4 Our process

The Commission has published a series of reports as part of this project, to update progress of the work being carried out and to seek stakeholders' views on analysis and conclusions. This is the third such report to be published. The timing of key publications is set out below.

Table 1.1 Review process

Document	Purpose	Date
First Interim Report	To present the assessment framework, and provide a progress update on the work.	Published 24 July 2014
Supplementary Report: Pricing	To provide a progress update on the work done to date on pricing[4] since the Transmission Frameworks Review. A pricing model prototype for participants to consider was also published.	Published 31 October 2014

4 Under optional firm access, access prices would be calculated using a long-run incremental costing method.

Document	Purpose	Date
Note - Request for Comment	To acknowledge a number of comments made by stakeholders about optional firm access, and clarify how these comments will be addressed as part of the work that the Commission is currently carrying out. It also invited stakeholders to confirm their views on some matters.	Published 5 December 2014
Draft Report	To set out: • a draft recommendation as to whether or not optional firm access should be implemented; • a draft assessment of the benefits and costs of optional firm access; and • a detailed design of the optional firm access model.	Published 13 March 2015
Final Report	To set out: • a final recommendation as to whether or not optional firm access should be implemented, and if so, in what form; • a final assessment of the benefits and costs of optional firm access; • a detailed design of the optional firm access model; • more detailed consideration for how monitoring of conditions should take place if optional firm access is not implemented immediately; and • draft implementation plans (if required) for how optional firm access should be introduced.	By Mid-2015

1.5 Working with AEMO

The Australian Energy Market Operator (AEMO) and the AEMC are working collaboratively on this project. Technical matters have been progressed jointly.

However, the Terms of Reference establish separate governance and reporting structure for each institution. Therefore, separate reports are being prepared. To date, AEMO has produced a First Interim Report and Draft Report that respond to AEMO's Terms of Reference.

AEMO developed a detailed model of access settlement. This revealed a number of design issues that have subsequently been jointly resolved through discussions between AEMO and the AEMC. The access settlement element of optional firm access has been demonstrated to be functional and operates generally as intended.

AEMO was also asked to prepare a detailed design and implementation plan for “stage one”, where access settlement is introduced ahead of other parts of the optional firm access reform in order to improve the efficiency of generator dispatch. As AEMO found that recent inefficient dispatch episodes have been dominated by issues that are beyond the scope of access settlement to address, AEMO has not recommended implementing the access settlement element of optional firm access on its own. The Commission supports this conclusion. AEMO will therefore bring its formal work to a close.

However, AEMO will continue to assist in providing the Commission with technical support for the remainder of the optional firm access review.

1.6 Consultation

The Commission has taken a consultative approach in conducting this review, having undertaken three rounds of formal public consultation. In addition, one public forum and three public workshops have been held. Further, the review's advisory panel has met on four occasions and the review's technical working group has met on six occasions. Also, numerous informal meetings with stakeholders have been held. Industry secondees have provided additional input.

Stakeholder participation has been valuable, with the divergent and detailed views presented being very useful to the development of the draft assessment and recommendations set out in this draft report. The Commission appreciates and thanks stakeholders for the advice and evidence provided, and the time and resources committed to the review.

Appendix E of this Volume summarises stakeholders' submissions on our assessment work, and the Commission's responses to the issues raised. Submissions are also discussed in the chapters throughout this report.

The Commission notes Frontier Economics has published a report on the optional firm access proposal, which was prepared for a coalition of generators.[5] The Commission will consider this report prior to publishing its final report.

If any stakeholders are interested in understanding further detail on the draft recommendations AEMC staff can provide more information. Please contact Victoria Mollard to arrange a discussion on (02) 8296 7800 or at victoria.mollard@aemc.gov.au.

5 See: Frontier Economics, OFA design and testing - response to AEMC First Interim Report, A report prepared for AGL, Origin, Snowy Hydro, Hydro Tasmania and Stanwell, February 2015.

1.7 Submissions

Written submissions from interested stakeholders in response to this First Interim Report must be lodged with the AEMC by no later than 5pm, **Thursday 30 April 2015.**

Submissions should refer to AEMC project number "EPR0039" and be sent electronically through the AEMC's online lodgement facility at www.aemc.gov.au.

All submissions received during the course of this review will be published on the AEMC's website, subject to any claims for confidentiality.

1.8 Structure of Volume 1 of the draft report

This draft report comprises two volumes:

- Volume 1 (impact assessment and recommendation) sets out the Commission's assessment of whether optional firm access would contribute to the National Electricity Objective, and the Commission's draft recommendation on whether optional firm access should be implemented.
- Volume 2 (optional firm access model) provides an overview of the optional firm access model that has been designed and developed during this review.

These reports build on the description of the model that was set out in two progress reports by the AEMC – the First Interim Report and Supplementary Report on Pricing. In these reports, the AEMC informed stakeholders of the work undertaken on the elements of optional firm access since the conclusion of the Transmission Frameworks Review.

Volume 1 should be read in conjunction with Volume 2. The model set out in Volume 2 forms the basis for the assessment work undertaken in Volume 1.

There is also an accompanying AEMC staff report, which provides a detailed technical description of the optional firm access model.

The Commission has also published a series of consultant reports, which are referred to throughout this draft report.

1.9 Content of this report

This report contains the following chapters:

- chapter 2 - the development of the Commission's assessment framework;
- chapter 3 provides a summary comparing the current arrangements for transmission frameworks to those under optional firm access;
- chapter 4 - the impact category of risk allocation;

- chapter 5 - the impact category of efficient investment and disinvestment in network capacity and generation;
- chapter 6 - the impact category of financial certainty for generation;
- chapter 7 - the impact category of effective inter-regional hedging;
- chapter 8 - the impact category of incentives on transmission operators to operate the network;
- chapter 9 - the impact category of efficient dispatch of generation;
- chapter 10 - the level of transaction costs and complexity;
- chapter 11 - the Commission's overall draft assessment;
- chapter 12 - specific jurisdictional arrangements;
- appendix A provides further detail on the assessment of historical congestion;
- appendix B sets out a history of NEM reviews on congestion;
- appendix C provides further detail on inter-regional hedging, both without, and with optional firm access;
- appendix D sets out a detailed analysis on the incentive scheme; and
- appendix E summarises stakeholders' submissions to the First Interim Report and Note for Comment relating to the assessment of the optional firm access model, and the Commission's responses to the issues raised (a similar summary will be published alongside this Draft Report in respect of submissions on the model itself).

2 Development of the assessment framework

As set out in the terms of reference, one of the key components of this review is to determine whether the implementation of optional firm access would contribute to the achievement of the National Electricity Objective. Answering this question involves:

- assessing potential areas of impact (for example, improving efficiency in the longer term driven by the signals on generation and transmission investment); as well as
- identifying any one-off, and ongoing costs and risks.

2.1 National Electricity Objective

The overarching objective guiding the Commission's approach is the National Electricity Objective. The National Electricity Objective is set out in section 7 of the National Electricity Law, 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"

By way of background, the three fundamental limbs of efficiency are:

- allocative efficiency (efficient use of);[6]
- productive efficiency (efficient operation);[7]
- dynamic efficiency (efficient investment and innovation).[8]

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6 Allocative efficiency is achieved when resources that are used to produce goods and services are allocated to their highest value uses. This requires that goods and services are provided, and that consumption decisions are made, on the basis of prices that reflect as closely as possible the opportunity (or marginal) cost of supplying those goods and services.

7 Productive efficiency is achieved when only the minimum resource inputs are used to produce a given set of goods and services. Achieving productive efficiency is important because it avoids wasting resources which could have been used for producing something else.

8 Dynamic efficiency is concerned with ensuring allocative and productive efficiencies are sustained over time. This requires markets and supporting regulatory arrangements to provide incentives for firms to innovate and invest at efficient levels over time. It also relates to the discovery and use of new, economically valuable information ("value discovery"), which is of particular importance in relation to innovation and investment.

2.2 Assessment process

The AEMC's assessment process for this project is set out below. The draft recommendation is based on this assessment.

2.2.1 Step 1: Identify categories of impact

The Commission has identified the potential categories of impact that optional firm access would likely have on investment in, and operation and use of, transmission and generation. These are discussed in more detail below, and in chapters 4 through 10.

Some stakeholders proposed additional categories of impact that the Commission should consider. This is discussed further in section 2.3 below.

2.2.2 Step 2: Assess magnitude of impact

In conducting the assessment the Commission has sought to assess the impacts - both positive and negative - within these categories. The assessment of the optional firm access model has been conducted against the counterfactual of the current arrangements for transmission and generation continuing. A summary of the current arrangements, compared to those under optional firm access, is contained in chapter 3.

Stakeholders have expressed differing views as to whether the assessment should be more qualitative or quantitative. For example, Trustpower considers that a qualitative analysis is not enough to assess the model.[9] However, the South Australian Department of State Development (South Australia DSD) notes that many of the benefits associated with the model would be significantly more difficult to model and quantify than the associated costs. It considers that the Commission should consider the quantitative results of the modelling as only one input into a wider qualitative assessment of the proposal.[10]

The Commission has attempted to quantify such impacts where possible - but in some cases this has not been possible, and so the Commission has undertaken a more qualitative assessment. Further, while for some impacts quantification is possible, such quantification may exhibit a large range of uncertainty. Also, in some instances the qualitative issues are more important than the quantitative issues. For example, having an efficient allocation of risk is an important element; however, the impact is difficult to quantify.

2.2.3 Step 3: Assess impacts across a range of scenarios

The Commission has also sought to assess the impacts across a range of scenarios, which include considering different future views of the NEM (for example, different levels of congestion in the network, different types of generation that connect to the

9 See: Trustpower, First Interim Report submission, p. 1.

10 See: South Australian Department of State Development, First Interim Report submission, p. 1.

network, or, indeed, whether generation connects more to the distribution network). Particularly in the case of a proposed reform of this magnitude, it is critical to assess the proposal against a number of possible developments in the market. This is so that any reforms implemented would be robust, and less likely to require further adjustment as circumstances change.

In general, the impacts of optional firm access would depend on the extent to which wider changes in the market eventuate. It is difficult to predict what the likely future change in the market could be. Accordingly, the Commission has assessed the optional firm access model across a number of different futures.

2.3 Categories of impact for assessing the optional firm access model

2.3.1 Stakeholder submissions

The First Interim Report set out the following categories of impact for assessing the efficiency of the optional firm access model:

- allocation of risk;
- efficient investment in network capacity;
- efficient investment in generation capacity, including locational signals on where to build plants;
- financial certainty for generation;
- effective inter-regional hedging;
- incentives on TNSPs to operate the network more efficiently;
- efficient dispatch of generation;
- efficient incentives on TNSPs to manage trade-offs between operation and investment; and
- the level of transaction costs.

Some stakeholders commented that the Commission should consider additional categories to those set out above:

- The Victorian Department of State Development and Business Innovation (Victorian DSDBI) proposed three more categories: "wholesale and retail market competition", "security of supply" and "market transparency". These have not been considered as separate categories of impact for the following reasons:
  - Wholesale and retail market competition are encapsulated in other categories - efficient investment in generation capacity (chapter 5), financial certainty for generation (discussed in chapter 6), and effective

inter-regional hedging (chapter 7). For example, improved generator financial certainty has the potential to lead to improvements in the wholesale and retail markets, including in respect of retail competition.

  - Security of supply is a measure of the power system's capacity to continue operating within defined technical limits even in the event of a disconnection of a major power system element such as an interconnector or large generator. Such elements are maintained through reliability standards, which would be unchanged by optional firm access and so this has not required a specific category. Further, efficient investment in network and generation capacity can only help maintain security of supply.

  - Market transparency is an outcome from effective provision of all of the above categories, and so we do not consider it should be set out as it is own category. It would also be complex to separate out the effects of this from the other categories.

- Snowy Hydro proposed a separate category solely focussed on "effective intra-regional hedging." This is encapsulated in financial certainty for generation (discussed in chapter 6).

- The Clean Energy Council proposed a category relating to "interaction with other legislative instruments", that is, the application of other legislation such as the Renewable Energy Target. As set out in the National Electricity Law, and reflected in the terms of reference for this review, the AEMC's role is guided by the National Electricity Objective.[11]

- Grid Australia considered that the Commission should consider "efficient disinvestment". Networks and generation can be retired as well as invested in. Such considerations become more important in scenarios where there is declining demand. Disinvestment is the flipside of investment, and so the Commission has clarified that those categories that relate to investment in generation and transmission also include disinvestment.

2.3.2 Final categories of impact

The finalised categories of impact, which incorporate stakeholder feedback, are set out below. In addition, the category "efficient incentives on TNSPs to manage trade-offs between operation and investment" has been merged into "efficient investment in network capacity". This is discussed further in chapter 5.

11 National Electricity Law, Part 4, Division 1, section 32.

Table 2.1 Categories of impact

	Category of impact
1	Risk allocation
2	Efficient investment and disinvestment in network capacity
3	Efficient investment and disinvestment in generation capacity
4	Financial certainty for generation
5	Effective inter-regional hedging
6	Incentives on TNSPs to operate the network efficiently
7	Efficient dispatch of generation
8	Level of transaction costs and complexity

There are significant linkages between these different categories. For example, the incentives that govern transmission investment and operation will impact on the costs of generation investment; if generators face the full costs of transmission, they will factor these costs into their decision on where to locate. Similarly, generation investment decisions will impact on the costs of operating the transmission system. Generation location decisions influence the amount of congestion in the network which, in turn, influences how the TNSP may operate the network.

An extension of this is that the overall impact of optional firm access (which is achieved by bringing together the impacts across all of the above identified categories of impact) may be greater than the sum of these individual impacts. While it may be possible to address some of the individual categories using alternative approaches, the optional firm access model may deal with them in a more integrated fashion. This would provide a greater overall benefit by providing a more integrated and stable market design, than a more piecemeal design.

2.3.3 Mapping to problems articulated in the Transmission Frameworks Review

The Transmission Frameworks Review identified a number of concerns with the efficiency of the co-ordination between transmission and generation in the NEM. The concerns identified map the impact categories set out above (excluding the level of transaction costs).

Table 2.2 Mapping of problems articulated in Transmission Frameworks Review to assessment framework for optional firm access

Problem articulated	Category of impact
The lack of clear and cost-reflective locational signals for generators, such that locational decisions do not take into account the resulting transmission costs	3
TNSPs estimating the benefits of transmission development, where those benefits are better known to generators, and the risk of inefficient decisions being borne by consumers rather than the decision-maker	1 and 2
The resulting planning of transmission networks not being co-optimised to minimise the combined costs of generation and transmission	2 and 3
The importance of TNSPs operating their networks to maximise availability when it is most valuable, and the challenge they face in doing so given the lack of exposure to the financial costs of reductions in capacity	6
The difficulty that market participants have in managing the risk of price differences between different regions of the NEM, with a resulting negative impact on the level of contracting between generators and retailers in different regions	4 and 5
The lack of certainty faced by generators when there is congestion, compounded by the inability of generators to obtain firm access, even where they fund augmentations of the transmission network	4
The resulting incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion	7

Therefore, the Commission has been able to assess whether optional firm access addresses the concerns raised in the Transmission Frameworks Review.

The terms of reference asks the Commission to assess the optional firm access model against the status quo. Stakeholders have been asked to comment on whether or not the problems identified as part of the Transmission Frameworks Review are still relevant. Consideration of whether or not these problems still remain has also been factored into the assessment and conclusions on optional firm access.

2.4 Structure of remainder of the report

Each of the categories of impact is discussed in further detail in chapters 4 to 10. Each chapter is structured as follows:

- the desired characteristic of each category.
- whether or not there is a problem with the current arrangements with respect to this impact category.
- whether optional firm access would improve this impact category (or have negative impacts).

3 Summary of current arrangements as compared to optional firm access

Table 3.1 provides a summary of the current arrangements for the transmission framework, focussing on the interrelationship between transmission and generation investment, and operational decisions under the current market frameworks, compared to the arrangements under optional firm access. For a more comprehensive description of the optional firm access model, refer to chapter 2 of Volume 2 of this draft report. This table can be used to frame the discussion of impacts throughout the rest of this report.

Table 3.1 Current arrangements for the transmission framework versus optional firm access transmission framework arrangements

Element	Current arrangements	Arrangements under optional firm access
Access	Open access regime in which generators have a right to connect to the transmission network, but no right to the regional reference price. Limited options for generators to seek firmer transmission access rights and such current options (for example, clause 5.4A[12]) are unused. Generators earn revenue by being dispatched. Physical dispatch of electricity determined by dispatch offers of generators and level of network congestion.	Optional firm access regime, giving generators the ability to purchase access rights to the regional reference price. Generators would choose to have firm access rights that are for all or part of their generating capacity or have no access rights for any of their generating capacity. Generators would pay TNSPs to obtain firm access rights (see "pricing" below) There would be no charge for non-firm access. Although, in the event of network congestion affecting dispatch, generators with firm access rights would be financially compensated by those generators who would be dispatched in excess of their purchased firm access amounts (including those generators who were entirely non-firm). Physical dispatch of electricity unaffected by optional firm access - generators would still earn revenue by being dispatched.

12 This clause of the Rules appears to contemplate generators negotiating firm transmission network user access with TNSPs. The Rules provide for generators to negotiate compensation from a TNSP in the event that they are constrained off or on the network, in return for an access charge. However, this provision cannot work in practice because the scheme is not mandatory and all generators have open access to the network. In addition to compensation arrangements, clause 5.4A contains a number of other provisions regarding access and connections. This includes use of system services charges to be paid by a connection application where network augmentation or extensions are required to facilitate a connection. This was discussed in more detail in the Final Report of the Transmission Frameworks Review at page 98.

Element	Current arrangements	Arrangements under optional firm access
Planning	AEMO as National Transmission Planner undertakes long-term strategic planning. It produces a National Transmission Network Development Plan (NTNDP), in consultation with TNSPs. This considers a planning horizon of at least twenty years. TNSPs are required to plan to meet reliability standards. Jurisdictional planning bodies (TNSPs) undertake planning more focussed on the near-term and driven by specific investment needs. They produce an Annual Planning Report (APRs), which must take into account the most recent NTNDP, and considers a planning horizon of at least ten years. This must set out what the TNSP is doing to meet reliability standards. Jurisdictional planning bodies also undertake project specific planning through the (Regulatory Investment Test for Transmission (RIT-T). RIT-Ts consider the benefits to generators, consumers and network businesses of a particular investment. The AEMC has the Last Resort Planning Power (LRPP), which allows the Commission to direct registered participants to apply the RIT-T to potential transmission projects if they are likely to relieve projected constraints in respect of national transmission flowpaths connecting NEM regions.	AEMO would still produce the NTNDP, as it does now. TNSPs would be required to plan to meet both reliability, and the firm access planning standards. These standards would work together, rather than being additional to each other. TNSPs would still focus on near-term planning, and produce APRs. These would need to describe activities they were doing to meet the firm access planning standard (as well as to meet the reliability standard). TNSPs would also still undertake project specific planning through the RIT-T, where investments to meet either the firm access planning standard or reliability standard required augmenting the network. There would be no need for the Last Resort Planning Power.
Investment decision making	TNSPs are responsible for making investment decisions, in accordance with their planning activities are set out above. TNSPs must make investments in order to meet the jurisdictional reliability standard. They can also undertake other investments if the benefits are deemed to outweigh the costs (determined through the RIT-T).	Unlike in the current arrangements, generators would make decisions to drive some transmission investment by purchasing firm access. The firm access planning standard would be determined by the amount of firm access purchased by generators.

Element	Current arrangements	Arrangements under optional firm access
	Any investments are funded from revenue received from consumers.	However, the RIT-T for investments to meet these standards could be on a least cost basis (ie, provided it is to meet one of the standards, the benefits do not need to outweigh the costs). Further, the RIT-T would no longer require the TNSP to consider the benefits that would accrue to non-firm generators.[13] TNSPs would still need to make investments in order to meet the jurisdictional reliability standard.
Economic regulation of transmission services	TNSPs are subject to economic regulatory oversight by the Australian Energy Regulator (AER) in relation to their augmentation, replacement, operating and maintenance costs for the provision of prescribed services.[14] TNSPs must apply to the AER, for the AER to assess its revenue requirements. The AER sets a maximum allowed revenue that a network can recover from consumers during a regulatory period (see "pricing for transmission" below). The AER sets a TNSP's revenue allowance on an ex ante basis (that is, ex ante incentive framework for setting network revenues).	Many aspects of revenue regulation would remain unchanged. The AER would continue to set an annual aggregate revenue requirement, but, under optional firm access, this would also take account of the cost of providing firm access. However, there would continue to be a maximum allowed revenue from TUOS charges. Under optional firm access, this would be equal to the annual aggregate revenue requirement less the projected firm access revenue, to avoid this revenue being recovered twice. Optional firm access would only apply in respect of prescribed services.

13 Although, TNSPs would still need to consider the benefits to firm generators, consumers and network businesses.

14 Aside from in Victoria, where AEMO procures augmentation investments through contracts. The costs associated with these are recovered on a cost-pass through basis from Victorian consumers, and are not subject to economic regulatory oversight. Network owners (AusNet Services and Murraylink) have the costs of replacement, operating and maintenance determined by the AER, and so are subject to economic regulation in this respect.

Element	Current arrangements	Arrangements under optional firm access
	In determining the revenue allowance, the AER projects the revenue requirement of a business to: • cover its efficient costs of reliably supplying customers (including operating and maintenance expenditure, capital expenditure, asset depreciation costs and tax liabilities); and • provide a commercial return on capital.	
Pricing for transmission	The TNSP's maximum allowed revenue is recovered through transmission use of system (TUOS) charges to consumers. No generator charges are imposed for using the shared transmission network.	The TNSP's revenue requirement would be recovered through: • Firm access charges (based on LRIC) paid by firm generators. LRIC captures the incremental transmission costs that are created by a generator's decision to locate in a particular part of the network; and • TUOS charges paid by consumers. TUOS charges would not recover costs paid for by generators for firm access.
Connections	TNSPs are responsible for assessing all new generator and load connections against the Rules requirements, and providing the assets that are necessary to connect these parties.[15]	There would be no changes to the connection arrangements. The procurement process for firm access would be separate to the connections process. However, where new generators were procuring access, the connections and procurement processes may occur at the same time.

15 Aside from in Victoria, where AEMO is responsible for assessing all new generator and load connections against the Rules requirements, but is not responsible for providing the assets associated with connection. The assets associated with connection are provided by a supplier of the asset owners' choice.

4 Risk allocation

4.1 Description

One of the main elements in choosing a market design or form of regulation is deciding who takes responsibility for the various risks that are present. In the context of optional firm access, the Commission is concerned with how the risks relating to transmission and generation investment are shared between generators, TNSPs and consumers. For electricity transmission and generation investment, the most relevant risks are:

- demand for electricity and/or prices being more or less than anticipated;
- supply-side costs changing (for example, changes in relative fuel costs), rendering generating plants economically obsolete, or at least uncompetitive; and
- project costs being higher than anticipated at the planning stage.

As a starting point, the Commission has developed some principles for the efficient allocation of risk. The placement of risk should lead to:

- **Mitigation of risk:** the consequences of that risk should it materialise (that is, the potential for loss - either in a financial or a physical sense) being avoided or lessened.
- **Incentives to improve risk management:** incentives being created for the risk management to improve over time. That involves allocating risk to a party who can, relative to others, better manage the consequences of that risk.

This can occur if the party holding the risk has:

- **Incentives** to manage the risk, because it stands to gain or lose from doing so, and there is a clear link between its actions and the outcomes of the risk.
- More **information** than other parties to manage the risk. It can use this information to better mitigate the impact of the associated loss.
- The **ability** to **better manage risk** than other parties, and so it can take actions to avoid or reduce the impact of the associated loss.
- The **ability to improve risk management over time**, through experience. The party can learn and become more adept at risk management, meaning that it might make fewer errors in the future, or the likelihood of errors would become lower over time.

An efficient allocation of risk should result in better operational and investment decisions being made in transmission and generation investment.

Set out below is an assessment of how the incidence of risk changes under optional firm access compared to the current arrangements, and the incentives that this would create. Note that under optional firm access, TNSPs would still be required to meet reliability standards and so there would still be risk left with consumers, in respect of investments undertaken to meet those standards.

4.2 The risk associated with demand projections

One potential risk is associated with demand projections. That is, the future is not known, and any projections about what demand will be in the future, and where it will be located, may be wrong, as viewed in hindsight.

4.2.1 Under current arrangements

Currently, if TNSPs make investment decisions that build the network to the wrong size, or in the wrong location, due to errors in demand projections, consumers will largely bear the **volume risk** associated with this. Volume risk refers to there being too much, or too little, transmission network capacity.

For example, during the Transmission Frameworks Review, the AEMC engaged ROAM to apply a theoretical model that rebuilds the NEM over time to meet actual demand, with perfect hindsight. ROAM's modelling found a substantial amount of transmission overcapacity in most parts of the NEM.[16] One such example of this was in the case of South East Queensland - Central Queensland. The development of demand in central Queensland has meant lines between South East Queensland and Central Queensland are used less frequently. They were built assuming that more power would need to flow south than is currently the case.

Table 4.1 below sets out how any projection errors in demand impact parties under the current arrangements.

Table 4.1 Risks associated with demand projections under current arrangements

Risks associated with demand projections	Impact
Projection error: overestimate or underestimate of demand	TNPSs would make an investment decision that would size the network (in hindsight) differently from what it should have been sized. Consumers will bear most of the volume risk through either: • paying higher than network charges than necessary, if the network is oversized; or • reliability issues, or higher electricity prices if congestion occurs where the network is undersized.

16 See: ROAM Consulting, Modelling Transmission Frameworks Review, 28 February 2013.

Risks associated with demand projections	Impact
	TNSPs may bear some of the risk: • depending on the extent to which the projection error is reflected in the AER's projections that it bases the TNSP's revenue allowance on; and • if it suffers any reputational risk through building the network differently to what should have been built. Generators may also face some risks, depending on where they are located, and the level of congestion that results.

Currently, TNSPs have some incentive to revise plans to develop their networks if projection errors become apparent within the regulatory period:

- If the overestimate became apparent, then the TNSP would face a trade-off between retaining its current expenditure allowance (that is, not making the investment but keeping allowance today) versus having a larger future Regulated Asset Base (RAB) (that is, making the investment, and associated expenditure today, but having a higher asset base in the future).

- If the underestimate became apparent, then the TNSP would be incentivised to invest by its performance incentives, the requirement to meet reliability standards and reputation.

If the TNSP experiences some loss as a consequence of errors in demand projections, it will have some incentive to improve future RIT-T assumptions, and possibly to challenge the need for reliability investments.

Consumers and generators also currently have incentives and opportunities (for example, through consultation on RIT-Ts) to contest demand projections because of the effects on prices and consumption.

Further information on how investment in transmission occurs currently is set out in chapter 3.

4.2.2 Under optional firm access

These impacts and incentives would change under optional firm access.

Under optional firm access the projection error would express itself as a **pricing signal** through the long run incremental cost (LRIC) price charged to generators, not as a TNSP investment decision. In response to this price signal, generators would need to decide whether or not to purchase firm access.

Table 4.2 below sets out how any projection errors in demand would impact parties under optional firm access.

Table 4.2 Risks associated with demand projections under optional firm access

Risks associated with demand projections	Impact
Projection error: LRIC overestimates or underestimates demand	The error in demand projections would express itself as a pricing signal, which generators would respond to. Generators would face a price risk - that the price would be higher or lower than it should be - depending on whether they are locating in areas of the network with surplus or insufficient spare capacity. However, the price risk effects would be neither smooth, nor one-directional[17] due to the mixture of network elements that would be required to give firm access in most locations. That is, the LRIC price that the generator would pay would be the sum of LRIC across a number of different elements. Therefore, the price signals would still hold. Locations that impose more transmission costs from generators locating there would have a higher access price, than other locations.
Projection error: generator overestimates or underestimates demand	The generator may overestimate or underestimate future demand, and purchase too much or too little firm access. The consequences of holding too much or too little firm access would be borne in the first instance by the generators' shareholders: • if they have purchased too much firm access or invested in too much generation, they may not be able to recover the cost of their investment because volumes and prices of spot and contract sales could be lower than their business case required; or • if they have purchased too little firm access or invested in too little generation, they might have forgone the opportunity to earn revenue (either because their power station is smaller than it could have been, or they have been constrained off through insufficient access).

Optional firm access would change the impacts and incentives on parties.

Under optional firm access there would be locational signals relating to the expected spare capacity. These locational signals under optional firm access would still remain, even when there are errors in demand projections. They may, however, be dulled or sharpened, depending on the extent of the error.[18]

However, optional firm access would enable investors to make their own decisions in respect of the price signal, and make an investment in spite of it. Generators could choose to invest or not, based on their own analysis. Therefore, some of the risk would

17 See chapter 6, volume 2.

18 For further details see chapter 6 of Volume 2 on the locational signals under optional firm access.

be shifted from consumers, who currently directly bear most of the costs associated with transmission, to generators, who would bear costs related to their need for access.

The changed risk allocation under optional firm access would likely create stronger incentives on generators in respect of relevant investment, than currently apply to TNSPs. This is because generators have better ability, information and incentives to manage risks, than TNSPs currently do. Assigning some responsibility for transmission investment decision-making to generators may therefore be expected to lead to improved management of the associated risks.

Optional firm access also has the scope for creating better dynamic learning effects over time:

- If the price signal (through LRIC) over or underestimates demand, but the generator correctly estimates demand, the price signal should self-correct over time where there are errors in demand projections, since the inputs would be regularly reviewed and consulted on; while

- If the price signal is correct, but the generator is wrong, its investors stand to lose shareholder value as discussed above. The competitive discipline of capital markets means that underperforming firms have strong incentives to turn around any loss of shareholder value.

In other words, even without the ability to manage the risk of errors in the current period, the generator has a stronger incentive to improve performance over time than the TNSP.

Such impacts are discussed in further detail in chapter 5, which discusses efficient investment in generation and transmission. This effect becomes more important when there is greater uncertainty in relation to demand projections.

Where firm access is insufficient to provide reliability, the TNSP would undertake a reliability RIT-T. The impacts and incentives associated with the risk of demand projections would be the same as under current arrangements.

4.3 Risks associated with supply-side changes

A second potential set of risks is those associated with supply-side changes. These have the potential to change the relative costs of different power stations, with respect to fuel source, location and operating regime.[19]

4.3.1 Under current arrangements

In the context of supply-side changes, it becomes more difficult for TNSPs to predict the system development path that would reliably meet demand at least cost. Table 4.3

19 That is, baseload, mid-merit or peaking plant.

below sets out how any projection errors of supply-side changes impact parties under current arrangements.

Table 4.3 Risks associated with supply-side changes under current arrangements

Risks associated with supply-side changes	Impact
Error for the TNSP in relation to the supply-side (relative generation costs, location, operating type)	TNSPs build their networks to accommodate a higher-cost generation pattern than could have resulted. Consumers bear the higher production costs, which could be locked in for some time if generators locate according to the TNSP's plan. If a cheaper generation pattern emerges, including the cost of new transmission investment, then the original flowpaths could become redundant but would be still being paid for by consumers.
Errors for the generator in relation to supply-side (relative generation costs, location, operating type)	Generation is built in the "wrong" place or technology, resulting in obsolete generation infrastructure. Investors stand to lose shareholder value: as may not be able to recover the cost of their investment. Volumes and prices of spot and contract sales may be lower than their business case required.

If TNSPs make errors in projecting relative supply costs, a higher than necessary system cost can be incurred. Consumers would bear these higher costs, which could be locked in for some time. This could occur through two means:

- Generators' locational decisions are affected by the ability to locate near an uncongested flowpath. For example, by making a particular investment decision the TNSP could reduce congestion in a certain part of the network, and so encourage generation investment in that area. This may create a bias towards the generation and transmission development path that the TNSP predicts, even where a lower cost combination exists.

- If the regulated planning approach delivers a transmission path that is significantly different from that required by competitive investment in generation, then a different generation pattern could emerge, despite the TNSP's investment. There is a risk that the transmission assets that the TNSP has invested in would be underutilised, and that alternative transmission assets would need to be built.

There is not necessarily a strong incentive to improve management of this risk currently. Consumers, who bear most of the risk of the higher system cost, have only limited ability to influence future decisions, and not much information or expertise regarding relative costs of different combinations of generation and transmission. TNSPs rely on the transparent nature of the RIT-T process to manage this risk.

Generators also have shareholder equity invested in their locational decisions currently. If they make the wrong generation investment decision (either by investing in the wrong location or generation type) they stand to lose shareholder value.

4.3.2 Under optional firm access

These impacts and incentives would change under optional firm access. Table 4.4 below sets out how any projection errors of supply-side change impact parties under optional firm access.

Table 4.4 Risks related to supply-side changes under optional firm access

Risks related to supply-side changes	Impact
Error for the TNSP in relation to the supply-side (relative generation costs, location, operating type)	Generators would bear the risk of both the power station and the transmission investment, if the generator chooses to be firm. If the generator chooses to be non-firm, then TNSPs through reliability RIT-Ts would need to estimate the least-cost transmission/generation development path. The RIT-T would no longer include benefits to non-firm generators. Therefore, non-firm generators may bear some of the risk associated with not being able to be dispatched.

Under optional firm access, if the generator chose to be firm, it would take on the risk of both its power station and its transmission investment being rendered uncompetitive if it backs the wrong technology or location or operating regime. The generator would therefore have a strong incentive to make the correct decision.

The generator would also have an information advantage over the TNSP. It would know its own costs at least - although it would still have to rely on estimates of rival technologies. The TNSP's information with regard to relative transmission costs would be represented in the LRIC model. These information advantages would have the potential to result in improvements over the current arrangements.

Therefore, there is reason to expect that generators would make better decisions than TNSPs regarding the likely technology and location of power stations that would prove competitive. In the case where the generator makes the wrong decision, the incentives for future improvement would be stronger than when the TNSP does so. This would be due to the dynamic learning effects over time that are expected under optional firm access. This was discussed above in relation to demand projections.

Such impacts are discussed in further detail in chapter 5, which discusses efficient investment in generation and transmission. These effects become more important in an uncertain and changing investment environment, particularly in relation to relative costs, generation location and operating regime.

4.4 Risks associated with planning costs being different from project-specific costs

Another potential risk, which stakeholders have raised, is the risk of the project specific planning costs being different from the actual project-specific costs. Put another way, the risk is the difference between how much an investment is expected to cost at the planning stage compared with the costs once it has been built, that is, what the actual construction and operating costs are. Under optional firm access, the access prices would not be the same as the project cost that the TNSP would incur, just as there is not a one-for-one match between actual costs and planning costs currently.

However, this risk is the same under the current arrangements and optional firm access. The regulatory framework provides an allowance for a prudent operator to efficiently plan, augment, operate and maintain the network:

- under current arrangements, the allowance is to meet reliability standards;[20] while
- under optional firm access the allowance would be to meet both reliability and firm access standards.

TNSPs have incentives through ex ante regulation (both now, and under optional firm access) to minimise costs:

- to the extent that the costs are greater than those planned, then the TNSP bears a risk in the current period. The risks of overspend going forward depends on what the AER rolls into the asset base; while
- to the extent that the costs are lower than those planned, then the TNSP gets a benefit in the current period. The benefits of underspend going forward depends on what the AER rolls into the asset base.

This is discussed in more detail in Table 4.5.[21]

20 Although TNSPs can make investments that maximise net market benefits as well; the obligation relates to meeting reliability standards.

21 Under optional firm access there is the additional complexity that the TNSP revenue comes from two different sources (transmission use of system (TUOS) charges and firm access revenue). However, this does not materially change the impacts of this risk, or the incentives (see chapter 8 of Volume 2 of this Draft Report for further information).

Table 4.5 Risks associated with planning costs being different from project-specific costs under both current arrangements and optional firm access

Risks associated with planning costs being different from project-specific costs	Impact
Planning costs are different from project-specific costs	TNSP bears the cost of spending more than a prudent operator would have spent. In effect, this reduces shareholder returns in the current regulatory period. If the overall revenue allowance is exceeded, the TNSP also risks having inefficient expenditure excluded from the RAB through ex-post review. Depending on what the AER rolls forward, consumers may bear some costs in the form of a higher future RAB. This would be appropriate because of the regulatory obligation to meet reliability standards and because the expenditure was efficient in light of the information that was observed. If the TNSP underspends, it gains the benefits of this in the current regulatory period. However, in the long term consumers may benefit through having a lower future RAB.

4.5 Commission's conclusions

The risks associated with transmission investment include the risk associated with demand projections resulting in a different level of investment than is required, and the risk of supply-side changes resulting in higher costs of some generation types and obsolete investments.

Optional firm access would change the allocation of these risks in the transmission and wholesale markets. Some of the risk would be shifted from consumers, who currently directly bear most of the costs associated with transmission, to generators who would bear costs related to their need for access.

This re-allocation of risk becomes more important in an uncertain and changing investment environment (for transmission, generation or both), as the risks associated with transmission investment may increase. The Commission considers that it is appropriate to shift some of the risk to generators, given that they have the incentives, ability and information to improve risk management.

5 Efficient investment in network capacity and generation

5.1 Description

This chapter considers efficient investment in both network capacity and generation (categories of impact 2 and 3) together, since optional firm access would contribute to the ability of transmission and generation investment to be coordinated.

The economic regulation and planning arrangements for transmission need to allow for efficient outcomes to be achieved under a broad range of scenarios. This is most likely to occur when:

- the combined costs of generation and transmission are taken into account in investment and operational decisions by generators and TNSPs, leading to lower costs overall; and
- parties that make investment decisions have a direct financial stake in the efficiency of outcomes resulting from these decisions (see section 4.1).

Below the Commission discusses the meaning of: efficient co-ordination of transmission and generation investment; efficient investment in networks; and efficient investment in generation.

5.1.1 Efficient co-ordination

Efficient co-ordination of transmission and generation investment requires:

- information being exchanged between the generation and transmission sectors;
- that information being accurate and meaningful to the recipients; and
- investment decisions by each generator and TNSP incorporating this information and being efficient in light of that information.

Efficient co-ordination between these sectors contributes to efficient investment in both networks and generation, which is discussed further below.

5.1.2 Efficient investment in networks

Transmission investment involves both augmentation and replacement decisions. These decisions determine the location and the capacity of the network. Efficient investment creates a network development path that seeks to maximise value for consumers. It allows the demand for electricity to be met by the least-cost combination of transmission and generation, so consumers do not pay more than they need to.

The most efficient development occurs when the TNSP develops projects that maximise net benefits, being the value of higher reliability and lower congestion less the cost of the project. The value of lower congestion is generally represented by the difference in generation costs that can be achieved when easing constraints allows more or cheaper power stations to deliver their generation. In order for this to occur, the TNSPs should have the information and incentives to effectively trade-off the cost of augmenting and replacing the network, with the value to generators and consumers of relieving congestion and maintaining reliability.

Augmentation/replacement decisions and operational solutions should also be able to be traded-off.

An efficient level of congestion occurs when the cost of undertaking any more investment would be greater than the benefit provided, in terms of reducing the productive cost of reliably servicing demand. This means that:

- building out all constraints on the network is unlikely to be efficient, with overinvestment ultimately imposing costs on consumers; and
- underinvestment in the network could prevent generators accessing the spot market, and lead to a more expensive mix of generation being dispatched to meet demand than would have occurred with more investment.

Further, for more efficient and timely investment TNSPs should also have:

- appropriate regulatory incentives and obligations; and
- signals, and access to information, for them to invest in their networks to meet the needs of generation and consumers.

Further, TNSPs should have signals, and access to information, for them to invest in their networks to meet the needs of generation and consumers. Such signals would create the best chance for the network to be maintained or expanded in an efficient and timely manner.

Currently, TNSPs have statutory obligations to maintain reliability of supply to end-users. They are subject to ex ante incentive-based regulation and undertake an economic cost-benefit test (the RIT-T, see Box 5.1:) in deciding what investments to make. These measures encourage the TNSPs to plan and operate their networks to meet their reliability obligations at least cost. TNSPs are also permitted, but not obliged, to undertake capital expenditure to reduce congestion - within their own region or between two regions - when this passes the RIT-T.

Box 5.1: Regulatory Investment Test for Transmission

The Regulatory Investment Test for Transmission (RIT-T) is a process for individual investment decisions, which examines the costs and benefits of various project options and establishes the one that maximises net market benefits. The RIT-T is undertaken by the entity with responsibility for transmission planning in each jurisdiction. Importantly, the RIT-T serves as a transparent guide to efficient investment, and no obligations or other consequences flow from its results.

The focus of the RIT-T is on the "net market benefits" to those who produce, consume and transport electricity. The RIT-T is prescriptive about what market benefits must be estimated.

For investments to meet the relevant jurisdictional network reliability standard, such net benefits may be negative, that is, at least cost where benefits are lower than the cost incurred. However, TNSPs are also permitted, but not obliged, to undertake investments for "market benefits". Such investments pass the test only when they have a positive cost-benefit ratio (that is, maximise net market benefits).

The RIT-T must be applied to all augmentation investments with a value over five million dollars. The RIT-T is not required if a transmission asset is being replaced, rather than augmented. There is also a specified process surrounding the RIT-T, which is set out in the Rules. This includes public consultation on the options under consideration in the RIT-T, as well as the associated input assumptions.

However, the RIT-T itself does not determine the revenue allocated for a particular project. It is part of a broader economic regulation process, in which ex ante incentive based regulation promotes efficient investment decisions by TNSPs. It may considered by the AER when the AER is determining revenue allowances for TNSPs.

There is some limited oversight of the RIT-T provided by the AER; however, this focuses only on matters of process rather than assessing (or approving) the TNSP's analysis.

The Last Resort Planning Power is currently held by the AEMC, and allows the Commission to direct registered participants to apply the RIT-T to potential transmission projects if they are likely to cost effectively relieve projected constraints in respect of national transmission flow paths connecting NEM regions. The Commission reports annually on the LRPP. To date, it has not identified any gaps in relation to inter-regional transmission planning that would require a direction to a TNSP to undertake a RIT-T.

5.1.3 Efficient investment in generation

Generators should have incentives to invest in new plant where and when it is efficient to do so. Information and price signals from the wholesale and contract markets, as well as from TNSPs, should provide financial incentives for generators and demand to make efficient location decisions by trading off the costs they impose on the shared network with other relevant decision factors such as proximity to fuel source.

Therefore, in addition to other locational signals from the market,[22] generators should also be aware of:

- signals from TNSPs for new generators that reflect the combined cost of generation and transmission, and rely on the generator's own valuation of the likelihood of congestion and the value of avoiding congestion;
- signals for new generators that encourage generators to invest in the appropriate fuel type and technology; and
- signals from TNSPs for incumbent generators regarding the value of replacement of transmission, taking into account costs imposed or avoided on the transmission network when making closure decisions.

5.2 Is there a problem with the current arrangements?

5.2.1 Stakeholder submissions

Regulatory Investment Test for Transmission

Some stakeholders commented on the current RIT-T framework (a description of the RIT-T process is contained in Box 5.1: above):

- AGL considers that the RIT-T framework has appeared to do a reasonable job so that transmission investment keeps pace with generation developments where this maximises net economic (consumer and producer) benefit.[23]
- The Clean Energy Council considers that the recent RIT-T decision to invest in upgrading the Heywood Interconnector is evidence that the principles behind the RIT-T are working and have the capacity to deliver efficient outcomes for consumers in the long term.[24]

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22 Locational signals can be considered to mean prices and/or costs that generators face, and which vary by location.

23 See: AGL, Request for comment submission, p. 3.

24 See: Clean Energy Council, Request for comment submission, p. 1.

- Stanwell considers that the current RIT-T arrangements provide a clear locational signal since the TNSP must consider the full market benefits of an augmentation option and its alternatives.[25]

- In contrast, SACOSS comments that the end result of the Heywood RIT-T has been approval of expenditure over $100m – much more than SACOSS believes was necessary.[26] SACOSS argued that a staged approach to investment potentially provided a better cost benefit ratio.

Locational signals

Numerous stakeholders have commented that it is not clear when new generation would be required in the future.[27] Some refer to AEMO's Electricity Statement of Opportunities, which sets out that no new generation capacity is required in any NEM region to maintain supply-adequacy over the next ten years. By implication, if no new generation is being built, there is no need for locational signals.

Generators have commented that there are other factors that are more important in sending locational signals. For example, AGL comments that fuel availability is generally the most important factor in any generator locational decision, but is arguably even more important to renewable plant. Proponents of new generation also consider water and labour availability, access to transmission infrastructure, local network constraints and applicable loss factors in deciding where to locate.[28]

Origin goes further to say that the current locational signals in the NEM are sufficient.[29]

5.2.2 Analysis

Co-ordination of transmission and generation

Currently, generation and transmission investment decisions occur separately:

- Investment in generation assets is market-driven, amongst other things, takes into account expectations of future demand, the location of the energy source, access to land and water and proximity to transmission; while

- Transmission businesses have statutory obligations to maintain reliability of supply to end-users. They are subject to ex ante incentive-based regulation and undertake an economic cost-benefit test to help decide what investments to make. These measures encourage the TNSPs to plan and operate their networks

25 See: Stanwell, Request for comment submission, p. 6.

26 SACOSS, First Interim Report submission, p. 2.

27 See: AGL, Request for comment submission, p. 2; Origin, Request for comment submission, p. 1.

28 See: AGL, Request for comment submission, p. 2.

29 See: Origin, Request for comment submission, p. 2.

to meet their reliability obligations at least cost. Transmission businesses are also permitted, but not obliged, to undertake capital expenditure to reduce congestion - within their own region or between two regions - when this passes a cost-benefit test.

The differences in generation and transmission investment and separate processes have the potential to result in a development path that does not minimise the total system costs faced by consumers.

Currently, TNSPs have to assess the proposed investment options through the RIT-T by estimating the benefits that would result for market participants and consumers, and comparing these to the associated costs. The RIT-T depends on assumptions and modelling provided by the TNSP. TNSPs do consult publicly under the RIT-T process, partly in order to test their identification of the likely costs and benefits. However, the consultation typically reveals - as it did in the case of the Heywood RIT-T - that the assumptions and scenarios that are used by TNSPs to estimate the benefits are subject to different views amongst participants.[30]

In the future, TNSPs may have to assess much greater changes in the pattern of generation in the NEM. This assessment will become more difficult. For example, ElectraNet has recently attempted to quantify the effects of additional wind generation on the Eyre Peninsula in South Australia, displacing investment in wind generation that would have otherwise occurred in areas with lower quality wind resources (principally in New South Wales). Such RIT-T assessments, which require assumptions about relative generation costs, become harder as the amount of technologies multiply.[31] These assessments also become harder as changes in demand (both growth and location) become less predictable.

In the Transmission Frameworks Review, ROAM's modelling found a substantial amount of transmission overcapacity in 2012 in most parts of the NEM, compared to what hindsight showed was efficient.[32] Decisions that were appropriate at the time, may appear inefficient in retrospect with different information available, for example, if projected and actual patterns of demand differed. At best, this illustrates the difficulties associated with long-term decision making. At worst, it suggests that the current arrangements do not promote efficient decision making.

Locational signals

The Commission considers that there are few locational signals relating to the costs that generators impose on the transmission network in the medium- to long-term:

30 See: http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Heywood-Interconnector-RIT-T.

31 This could occur through factors outside of energy, or might occur due to environmental or other policies.

32 ROAM Consulting, Modelling Transmission Frameworks Review, 28 February 2013.

- Marginal loss factors are not a good locational signal - they may indicate present flows on the network, but they are not a good indicator of future flows. Further, they do not signal current or future congestion or the likely cost of transmission expansion to relieve this congestion. The Commission understands that marginal loss factors can change substantially year to year, with consequent impacts on generator revenues; so the present loss factor is not necessarily a good indicator of future losses.

- Current congestion costs are not necessarily a meaningful indicator of future congestion costs. A generator may not be able to predict TNSP behaviour or the behaviour of other generators, and therefore congestion costs, over the life of its investment.

Case study of generation and transmission investment co-ordination

The Commission engaged Houston Kemp to develop a case study looking at the historical co-ordination of transmission and generation investment in South Australia, paying particular attention to the locational decisions of generators in that state. South Australia was chosen due to the numerous new generators that have been constructed in the region for over more than a decade.

After consulting with stakeholders about the issue Houston Kemp found:

- The new generators that have located in the South East South Australia region of South Australia do affect interconnector flows. In particular, some generators have had a multiplicative effect on the limit of the interconnector. That is, they offset the interconnector by a ratio of greater than one - one unit of output leads to the interconnector capacity being reduced by more than one unit.[33] This is suggestive of a sub-optimal outcome.

- None of the parties Houston Kemp consulted with was of the view that the choice of these generators to locate in the mid-north region of South Australia was inefficient, or that the access degradation of Northern and Playford B power stations contributed to the mothballing/retiring of these plants.

- The Eyre Peninsula provides a good example of a locational decision made by generators that has ultimately caused additional transmission costs. This is because ElectraNet has had to pay more for network support at Port Lincoln.

Some stakeholders[34] have suggested that S5.2.5.12 of the Rules could be relied on to either prevent a connection to a network if its effect would be to downgrade the capacity of a relevant interconnector, or to require the connecting party to pay costs so

33 Houston Kemp also noted that stakeholders raised a number of examples of other generator locational decisions in the NEM that had a greater than 1:1 impact on interconnector flows: Uranquinty, Kogan Creek, Basslink, Mortlake, Lower Tumut and Bogong. See: HoustonKemp, A South Australian case study for the Australian Energy Market Commission, 2 February 2015, p. 10.

34 These stakeholders were interviewed by HoustonKemp. See: HoustonKemp, A South Australian case study for the Australian Energy Market Commission, 2 February 2015, p. 10.

that the capacity of the interconnector was not downgraded. The Commission considers that this clause may not to be able to be applied in this way.

S5.2.5.12 is a technical requirement that prescribes the automatic, minimum and negotiated access standards representing the performance bounds relevant to impact on network capacity. Connections can be (and usually are) sought at levels below the automatic access standards, provided they do not adversely affect power system security and the quality of supply to other network users. The automatic access standard provides the upper bound, the minimum access standard the lower bound, and the Rules outline the content of a negotiated access standard. A generator is able to negotiate its performance standards with a TNSP within this framework and most generators usually negotiate a standard somewhere between the minimum and automatic access standards. Once negotiated, AEMO is advised of the standard agreed upon and generators are required to implement a compliance programme to ensure ongoing compliance with such standards, which compliance programme is integral to maintaining power system security. It is doubtful that this section in the Rules places an outright obligation on a TNSP to ensure that interconnector capacity is not degraded.

Power system security and quality of supply are usually independent of interconnector congestion or capacity. The mandatory requirements for the negotiated access standard (outlined in S5.2.5.12 (c)-(e)) illustrate that it is the impact on security and quality of supply that is addressed by this technical standard.

The Houston Kemp study shows that generator locational decisions do impact on the transmission network, and impose costs. Further, it shows that the effect of some of these locational decisions may have been inefficient. To demonstrate whether this is actually the case, it would be necessary to consider what the counterfactual outcome would be, that is, what would occur if these generators had been charged costs associated with transmission infrastructure.

5.2.3 Commission's conclusions

The Commission considers that there may be scope to improve the efficiency of network and generation investment and how they are coordinated. Currently, inefficiencies may occur due to the fact that generation and transmission investment occur through two separate processes.

While TNSPs predict, and estimate, the development of demand and supply, together with generation costs, through the RIT-T and related processes, generators should typically know their own costs better and have strong financial incentives to have an accurate view on demand and supply.

The absence of a price signal for generators related to transmission may result in locational decisions that increase the overall costs of transmission and generation. For example, proximity to a gas pipeline is likely to be important to a gas-fired generator, but currently that generator would not be exposed to the full cost of electricity transmission investment that may be required to support its locational decision. This could mean that generation and transmission is not coordinated as well as it could be.

This has particularly impacted interconnectors in the NEM. Investment in interconnectors has occurred, with this expected to result in net market benefits associated with the increased capacity and flows between regions. For example it was expected that the investment would allow cheaper cost generation in one region to displace higher cost generation in another region. However, generators have located along interconnector flowpaths, in some cases degrading the capacity, and so reducing the inter-regional benefits that were expected for the interconnectors.

Transmission and generation investment in the future may look quite different from the past. Therefore, improvements to current arrangements become more critical in the future if:

- the diversity of location and operating type of generators change. For example, this could occur if there are more types of renewable generation, entering the NEM or more generation is integrated with storage or other new technologies;
- demand patterns change, or change in a way that is not easy to predict; or
- relative network costs become less predictable, for example, as the cost of gas changes, what the relative cost of gas transmission is compared to electricity.

The potential for such changes would make it harder for the TNSP to make assumptions that underpin a RIT-T assessment. The increased potential for the TNSP to invest in a development path that does not enable the least-cost combination of generation and transmission, could result in inefficiencies both within and between regions.

Given that this assessment would become more difficult for the TNSP, it would be preferable to have commercial entities making decisions on the best combination of generation and transmission to meet demand, especially given their own knowledge of their own costs, and the incentives. This is discussed in chapter 4.

5.3 Impacts of optional firm access

5.3.1 Stakeholder submissions

By relying so heavily on AEMO and TNSP projections of the likely volume and location of generation growth on different parts of the network AGL considers that the optional firm access appears to further embed centralised transmission planning and the inherent risks of projection errors.[35] Further, it states that optional firm access may require TNSPs to inefficiently over-build the network where the reliability standard

35 See: AGL, Request for comment submission, p. 2.

and firm access standard are treated "additionally", rather than as complementary and overlapping standards, under the optional firm access regime.[36]

Some other participants have also noted concerns about optional firm access leading to uneconomic overbuild of network capacity.[37]

Origin notes that, conceptually, greater co-optimisation of transmission and generation is a desirable outcome. However, it questions the extent to which this is achievable given that the majority of transmission build has been, and will continue to be, driven by the need to meet reliability standards. Further, Origin considers that an increase in network expenditure would ultimately impact the retail market.[38]

Stanwell considers it is highly questionable whether a generator would be better able to determine the benefit of transmission investment over the long term than a TNSP, especially without detailed knowledge of other network and generation developments.[39]

5.3.2 Analysis

Long run incremental cost and locational signals

Optional firm access would provide more signals for generators about where to locate. Compared to the status quo, generators would be faced with prices which reflect matters such as the level of spare capacity at a location, and the distance from the regional reference node. 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 locational decisions being made.

As a consequence of the generator purchasing access at a particular location, having made the trade-offs just discussed, it would fund and guide the development of new transmission to underpin its access rights, both within regions and between regions. Generators, rather than regulated transmission businesses, would drive some part of the decision-making about future transmission development.

In order to have effective locational signals, it is also important that the LRIC pricing model produces prices that are reasonably cost reflective. This is discussed further in chapter 6 of Volume 2. Work on the prototype shows that the model produces locational signals reflecting both distance and spare capacity on the network.

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36 See: AGL, Request for comment submission, p. 2; Stanwell, First Interim Report submission, p. 14.

37 See: AGL, First Interim Report submission, p. 2; PIAC, First Interim Report submission, p. 4; Ethnic Communities Council of NSW, First Interim Report submission, p. 2.

38 See: Origin, Request for comment submission, p. 2.

39 See: Stanwell, Request for comment submission, p. 9.

The Commission does not consider that TNSPs would treat the firm access standard and the reliability standard as mutually exclusive. Optional firm access does not alter the physically meshed nature of transmission networks. The TNSP would still be providing services to consumers (including large users), firm generators and non-firm generators. It would be virtually impossible to separate out those assets used to meet the different standards. Further, as discussed above in chapter 4, transferring some of the risk to generators would be expected to decrease total system costs over time. Finally, it would be possible that some investment undertaken in response to a request for optional firm access could substitute investment that would have been undertaken for reliability purposes alone in the absence of optional firm access.

Improved co-ordination

The Commission engaged Ernst & Young (EY) to refresh and expand the work conducted by ROAM Consulting (acquired by EY) during the Transmission Frameworks Review. This assessed the potential economic benefits delivered by the impact of optional firm access on generation and transmission development in the NEM. EY's modelling finds that the improved co-optimisation of generation and transmission investment under optional firm access has the potential to deliver substantial economic benefits over the period 2014 to 2040 in net present value terms, when compared to the modelled outcomes under the current RIT-T process.

The base case scenario (weak demand growth and no carbon price) has relatively muted development in generation and transmission, and consequently, the impact of different transmission planning methods is minor. EY found that improved co-ordination under optional firm access (in the base case) would save $86.6 million over the period 2014 to 2040 in net present value terms. In undiscounted terms, improved co-ordination would save $361 million over the same period. The modelled benefits become more significant in the longer term, where existing spare transmission capacity is projected to be insufficient to meet emerging demand.

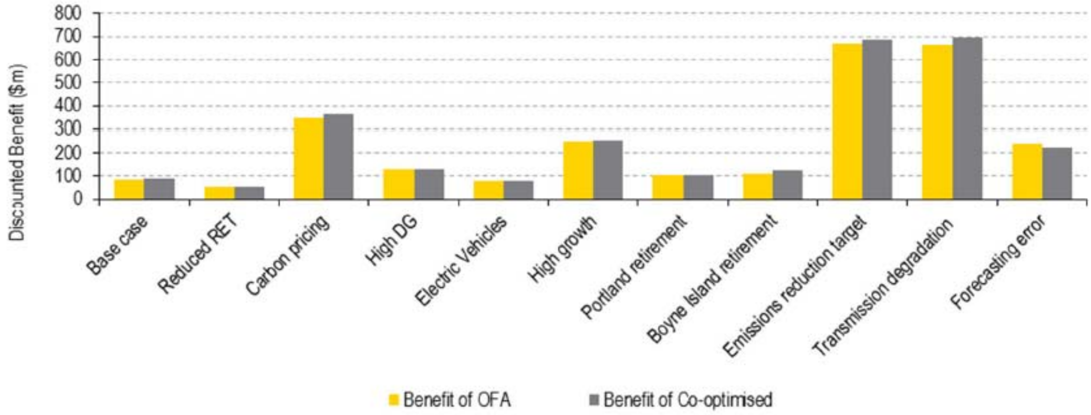
However, the benefits vary widely depending on the scenario chosen. The benefits range from $51 million (with a reduced RET and no carbon price) to $670 million with an emissions reduction scenario (all from 2014 to 2040 in net present value terms). The benefits of optional firm access are larger in scenarios that encourage significant transmission augmentation or transformation of the generation sector. In particular, the pursuit of emissions abatement can be achieved at a substantially lower cost under optional firm access by effectively exposing generation developments to both resources and transmission considerations. High demand growth, or the expectation of growth, even if it does not eventuate, can also result in optional firm access benefits.

These benefits are set out below in Figure 5.1. This shows the discounted benefit of:

- optional firm access - the model assessed in this report, where transmission development is required to meet the firm access planning standard given projected generation development; and

- co-optimised planning - a theoretically optimal approach where generation and transmission is fully co-optimised for each scenario considered; compared with
- the RIT-T planning methodology - reflective of the current arrangements where transmission follows generation.

Figure 5.1 Discounted benefit of optional firm access and co-optimised planning



EY also concludes that exposing generation to replacement decisions for the existing transmission network could be a source of savings. For example, EY has have modelled the retirement of some large industrial consumption loads in the NEM (Portland and Boyne Island retirement).

The benefits of optional firm access in the retirement scenarios can be considered as an incremental benefit from the base case. This would be the difference between the base case benefits from optional firm access and the benefits under these retirement scenarios. While these benefits may be considered to be small, they are benefits nonetheless. These scenarios demonstrate the potential for optional firm access to impact on market development in response to major changes in consumption.

The Commission notes that EY also modelled a general transmission degradation scenario where the transmission network was assumed to be reducing in size by approximately two per cent per year. While this scenario seems to show large benefits from optional firm access, the Commission considers that in such a scenario, the associated assumptions and so benefits, are likely to be somewhat overstated.

The Commission notes that the modelling results should be treated as one consideration to be taken into account, rather than determinative of the conclusion to be drawn. Modelling of dynamic benefits is very challenging, and requires a number of simplifying assumptions about the future. Moreover, the EY modelling inherently favours central planning. Perfect co-optimisation is achieved where the model decides the location of both transmission and generation with perfect knowledge of the future. In the context of an uncertain future, decentralised planning (that is, changing the allocation of risk) also offers benefits that are not captured by the modelling. This is discussed above in chapter 4.

Oakley Greenwood

The Commission engaged Oakley Greenwood to assess the impacts of optional firm access on generators and their behaviour in the wholesale, contract and retail markets.

In Oakley Greenwood's view optional firm access would link directly with transmission investment, and this would be beneficial. To the TNSP, optional firm access would be a direct input to the firm access planning standard, and it would avoid the need for a TNSP to make assumptions about benefits of transmission investment that accrue to generators, as is currently the case under RIT-T assessments.

As discussed above in Box 5.1:, TNSPs can undertake market benefit investments where such investments have a positive net market benefit test. Under optional firm access, generators would be able to signal what transmission investment they value, and TNSPs would no longer have to make such assessments. A key role of optional firm access would be to replace TNSP decision making about network investment (or retirement) over and above the network needed to meet reliability standards, with generators driving such decision making.

Case study of generation and transmission investment co-ordination

Drawing on the case study examples that Houston Kemp set out, optional firm access should provide more locational signals than the status quo. An example of this is where a generator locates on the interconnector flowpath and degrades the value and capacity of the interconnector. Under optional firm access, the generator that chose to locate there would either:

- be non-firm, and so absorb the cost of constraining of the interconnector by receiving its local price when it did so; or
- be firm, and purchase access, paying the cost of upgrading the interconnector so both the interconnector and generator could be accommodated.

While a generator might have chosen to locate in the same area of the network, due to the transfer capacity of locating near a major flowpath for example, that generator would be exposed to the cost of doing so under optional firm access. Optional firm access would present generators with additional options (that is, whether to be firm or non-firm). Generators would face the full cost of transmission and generation, and so would select the efficient location option, compared to the current arrangements where that may not be the case.

Houston Kemp also noted that generators have been proponents of a particular option in the Heywood RIT-T. The Commission considers that optional firm access would provide a clearer way for generators to signal the benefits of transmission infrastructure, rather than relying on public consultation under the RIT-T.

5.3.3 Commission's conclusions

Transmission and generation investment in the future may look quite different from the past. Under optional firm access, generators, rather than transmission network planners, would drive part of the decision-making about future transmission development. In choosing to acquire firm access, generators would fund and provide signals that guide the development of new transmission investment to underpin their access rights. The development of interconnectors between different regions would be driven by generators', retailers' and traders' purchases of inter-regional access.

Therefore, optional firm access would result in more co-ordination of transmission and generation investment, since it would result in:

- information being exchanged between the generation and transmission sectors;
- that information being accurate and meaningful to the recipients; and
- investment decisions incorporating that information and being efficient in light of it.

Optional firm access would promote a diversity of views in terms of the future of both generation and transmission, by placing more of the responsibility for the development of the network with investors in generation. Such diversity should promote efficient outcomes. In particular, generators are in a good position to consider how the transmission network should develop, especially in respect of efficiently providing generators with access to network.

The information and signals for investment that would be provided under optional firm access become more important in a future that is characterised by changing and uncertain transmission and generation development where:

- relative costs are harder to estimate (because of the entry of new technologies with uncertainty trajectories); and
- where demand (and so the value of transmission/generation development) is less certain and/or harder to predict.

These conclusions are supported by the EY modelling.

Further, under optional firm access, generators would face prices reflecting the costs of transmission development undertaken to support their access decision. This should result in more-informed locational decisions by generators. Competition would likely limit a generator's ability to pass through the costs of inefficient decisions to consumers.

Similarly, the Commission also considers that optional firm access could provide some benefits in an environment where there is declining demand and the network shrinks. This means some ageing assets may not be replaced on a like for like basis (or at all). Here, generators could signal through their access decision which parts of the network are valued and should be replaced. This could result in more efficient co-ordination in relation to retirement of generation plant where closure decisions would take into account the costs of both generation and transmission, as well as replacement decisions by TNSPs.

6 Financial certainty for generation

6.1 Description

Financial certainty relates to generators being able to *manage* the trading risks they face in the wholesale market, including the risk of congestion restricting a generator's access to the regional reference price.[40] Other risks include plant reliability risk, fuel risk and risk related to the market price.

The decision to invest in generation is influenced by, amongst other things, the ability of generators to manage the trading risks they face. A generator can manage such risks in a number of ways, including:

- entering into contracts for some or part of its generating capacity. Where generators rely on contracting to manage trading risk, a deep and liquid contract market is required;
- vertically integrating with a retailer to manage trading risks, securing an agreed price for some or all of its generating capacity; and
- diversifying its portfolio (either in respect of location, generation type, or both) in order to manage trading risks.

Generators can manage (or partially manage) trading risks through contracts. Selling forward (derivative) contracts against their output allows generators to manage (or hedge against) the risk of spot price volatility. In the example of a basic swap, where a generator sells a volume of forward contracts, and is dispatched for an equal quantity, it receives the contract price on that volume through the receipt (or payment) of contract for difference payments where the spot price is lower (or higher) than the contract price.[41]

Dispatch risk may affect the ability of generators to sell forward contracts against their output.[42] Risks posed by congestion may result in generators selling a lower amount of output than they would otherwise have sold. Whenever a generator has contracted for a higher amount than it is dispatched for, it is not perfectly hedged: it is exposed to the cost of making contract for difference payments but does not earn revenue by selling into the spot market to back those contracts.[43]

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40 As discussed in section 6.2 one way generators can currently manage this risk is through "race to the floor" behaviour. This category focuses on managing this risk. Inefficiencies associated with "race to the floor" behaviour are discussed in chapter 9.

41 More complex derivative products also exist in the wholesale electricity market.

42 Other risks, such as outages of power station generating units, may also deter generators from contracting for all of their output.

43 Generators might deliberately sell a higher volume of contracts than their expected level of dispatch in the expectation of the contract price exceeding the spot price. Their motivation in this case is speculative - deliberately taking a risk, rather than the offsetting of risk which is achieved by hedging, that is, contracting up to expected dispatch volume.

The ability of generators to hedge against price volatility, through contracts, is important. It provides greater financial certainty to investors as they can be more assured of receiving a future stream of predictable and stable revenue. The presence of dispatch risk may affect liquidity in the contract market and potentially result in fewer contracts available for retailers.

Improved financial certainty for generators through a well-functioning contract market should also lead to improvements in the wholesale and retail markets such as:

- helping to establish a lower risk-adjusted cost of capital, that is, in lower financing costs for investors. This may result in lower prices for consumers, with generators able to offer electricity (both spot and contract) at lower prices than they otherwise would;
- making investment in the electricity sector more attractive than it otherwise would be, and so improve competition amongst generators in the wholesale market; and
- helping to improve retail competition.[44] For a new entrant retailer without generation assets, the most common strategy to manage wholesale price volatility is to enter financial contracts with generators that lock in the future price of electricity. The effectiveness of this strategy depends upon retailers being able to purchase these products at competitive prices, when required. Improved financial certainty, where it leads to increased contract market liquidity, can increase the ability of retailers to enter into such contracts, and so, accordingly, increase retail competition. The ability of non-vertically integrated retailers to compete against vertically integrated participants that are able to match generation to their retail portfolio in order to hedge against wholesale price risk may also improve.

6.2 Is there a problem with the current arrangements?

6.2.1 Management of congestion risk under the current arrangements

Currently, congestion may prevent generators from selling the desired amount of their offered output at the regional reference price. Generators face the risk of intra-regional congestion and the risk that it will increase if a new generator locates nearby.

Generators sometimes manage their congestion risk, and so their access to the network, by "race to the floor" bidding behaviour. Generators bid to the floor price, with the result being that access is "shared" amongst them. This is discussed in Box 6.1.

44 Indeed, the AEMC's annual reviews of competition considers "contract market liquidity" as one element of the market indicator "barriers to entry, exit or expansion". See: AEMC, 2015 Retail Competition Review, Approach Paper, 18 December 2014, p. 10.

Box 6.1: What is meant by "race to the floor" bidding behaviour?

Here, generators behind a binding constraint bid towards the market floor price (-$1,000) in order to gain a share of volume access. NEMDE applies “tied-bid” rules, resulting in the following dispatch outcomes:

- In radial constraints (where all generators share the same coefficient in the binding constraint), (volume) access is allocated in proportion to generator offered availability. In practice, this is frequently observed in some Latrobe Valley-Melbourne constraints.[45]
- In loop-flow constraints (where generators do not share the same coefficient in the binding constraint), most (~70 per cent of constraints) involve an interconnector term where dispatch of the interconnector can be varied. As the interconnector cannot rebid to -$1,000, it will be dispatched down towards zero. Often this provides enough volume for the participating generators to be dispatched for their offered availability.
- The interconnector can even be dispatched below zero, implying a counter price flow on the interconnector. AEMO is required to “clamp” the interconnector and limits exports from the higher priced region when the accumulation of negative IRSR 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. So the sharing of volume access is to small coefficient generators first, then large coefficient generators if sufficient access is available, with interconnectors suffering a complete loss of access, regardless of their coefficient.

6.2.2 Stakeholder submissions

Generators have commented that congestion risk is currently a relatively small issue for them.[46] Generators have also commented that their hedging decisions are predominantly based on *other* factors, such as plant and market risk, rather than the risk of being constrained off and not accessing the network.[47]

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45 Typically, when the Latrobe Valley-Melbourne lines are constrained, the Victorian regional price is high. Gas turbines in the Latrobe Valley might start up to get a share of the high price. Hydro Tasmania could potentially be able to undercut the Latrobe Valley generators due to the pricing of Basslink. The available Latrobe Valley generators would then share the remaining volume access.

46 See: Stanwell, First Interim Report submission, p. 7; Energy Australia, First Interim Report submission, p. 3.

47 See: InterGen, First Interim Report submission, p. 2; Hydro Tasmania, First Interim Report submission, p. 1; CS Energy, First Interim Report submission, p. 4; InterGen, Request for comment submission, p. 3.

Moreover, a number of generators (including AGL, CS Energy and Hydro Tasmania) have commented that congestion has typically been short-term and transient.[48] That is, it affects one or other part of the network from time to time, rather than presenting as a systemic network access issue. Further, they state that the current declining demand and oversupply in the NEM have also contributed to the reduced significance of congestion.[49]

However, AGL notes that it is unable to predict whether such an issue would re-emerge or become more material at some time in the future.[50]

In contrast to the views of most generators:

- GDFSAE recognises that the level of concern surrounding transmission congestion has lost prominence in recent years, primarily due to the decline in electricity demand and the resultant over-supply of generation capacity in the NEM. But, it considers that the current circumstances provide a good opportunity to consider and implement new access arrangements, and for participants to become familiar with those arrangements before the need to use the arrangements occurs.[51]

- Alinta considers that the current market arrangements for generator access to transmission assets tend to favour large participants over smaller participants. Some larger participants have the ability to create an internal hedge, which ensures delivery of revenue during times of constraints both intra-regionally and inter-regionally. The size and location of Alinta's portfolio means that it does not gain the advantage of a natural hedge against constraints and so has a limited ability to respond when these arise. In particular, Alinta mentions its remote position in the South Australian Flinders region, which, in the absence of optional firm access, means that there is a risk that these assets could face additional congestion constraints and potentially become stranded if more wind generation locates in this region.[52]

Westpac also comments that, while congestion issues have improved in recent times, some market participants can still influence interconnector flows, and so congestion can reoccur with little or no notice. It considers that it is entirely possible that significant congestion will re-emerge over investment length timeframes.[53]

48 See: CS Energy, First Interim Report submission, p. 4; AGL, Request for comment submission, p. 2; Hydro Tasmania, Request for comment submission, p. 1.

49 See: Hydro Tasmania, Request for comment submission, p. 1.

50 See: AGL, Request for comment submission, p. 2.

51 See: GDFSAE, Request for comment submission, p. 2.

52 See: Alinta, Request for comment submission, p. 1.

53 See: Westpac, Request for comment submission, p. 2.

6.2.3 Analysis

Oakley Greenwood

Oakley Greenwood made some conclusions regarding whether congestion risk is a problem for generators, including:

- Generators face different levels of congestion risk. For example, for generators that are located on interconnectors, congestion has a more material impact.
- While currently the overall risk of congestion is low, in the longer term, the incidence of congestion may increase again. For example, the existing transmission network ageing and requiring replacement or retirement may lead to changed patterns of local congestion.

Historical analysis

The Commission has considered historical patterns of congestion. The charts in appendix A illustrate the extent of congestion within zones in the NEM between 2010 and 2014. The dataset is limited to reporting on congestion where binding constraints would have a marginal value of greater than $10/MW, and where the frequency of binding was above some 40 dispatch intervals.

These charts represent the count of how often constraints have bound in a region, or on an interconnector. They do not take into account a representation of "value". Therefore, while constraints may have bound few times, the constraints could have been when spot prices were high, and may have significantly impacted market participants.

Notwithstanding these information limitations, it is worth noting that:

- the level and location of constraints has varied from 2010 to 2014; and
- interconnectors typically have a much larger level of constraints occurring on their flowpaths than constraints occurring on intra-regional flowpaths.

Further these results differ from those developed when the prototype LRIC model is applied. This is since these two approaches are not comparing the same thing. The pricing model graphs are a measure of the projected level of spare capacity in the network (and so is influenced by the level of future constraints), as well as distance from the regional reference node. It is also a measure of the *incremental* cost of providing access. So, if there is little spare capacity in the base case, it is not going to have a high incremental cost. In contrast, appendix A shows the historical patterns of congestion and demonstrates the actual instances of material constraints.

Future projections

There is very little information on future projections of congestion.

The NTNDP includes an assessment of the adequacy of the national transmission grid to reliably support major power transfers between NEM generation and demand centres. In the 2014 NTNDP, AEMO states that reduced maximum demand for electricity means there will be less network congestion in all regions over the next twenty years compared to the 2013 NTNDP.[54]

However, AEMO does identify locations where potential network congestion may arise if new generation development occurs in line with least-cost modelling over the next five years. This includes areas in Central Victoria, Northern Central NSW, and Northern South Australia. All of these examples are related to connecting wind generation to the power system. This is expected to contribute to network congestion, particularly at times of high wind generation output.[55]

Other products to manage congestion risk

In theory, a generator's uncertainty as to whether it would be able to generate and receive the regional reference price - at exactly those times when prices are likely to be particularly high - could decrease its willingness to contract with retailers, or increase the price at which it is willing to do so if it cannot otherwise manage the risk. If this congestion tended to be volatile and unpredictable, the willingness of a generator to contract at a given price may be corresponding lower.

If this risk did exist, then in theory, an insurance product could be offered to generators to protect them against this risk. A party could guarantee to pay a generator for a fixed volume of output, at a fixed price, even if congestion occurred. However, as far as the Commission is aware, there are no such insurance products currently available. This suggests that could be due to one or both of the following:

- There is no supply of such a product because creating such a product is problematic. There may be difficulties in specifying the detail of the insurance arrangements, for example, how congestion would be described so as to define those times when the generator would receive a payout. There may also be little incentive to guard against risk where one is protected from its consequences. We understand from stakeholders, that this has been the case.[56]
- There is no demand for such a product.

54 AEMO, 2014 National Transmission Network Development Plan, 2014, p. 19.

55 AEMO, 2014 National Transmission Network Development Plan, 2014, p. 19.

56 For example, Stanwell notes that in relation to insurance products, some non-firm products have been offered and transacted throughout the history of the NEM, although in many instances the discount expected from the buyer for taking on this risk has made transactions prohibitive. See: Stanwell, First Interim Report submission, p. 7.

International experience

In some respects, optional firm access can be viewed as similar to Financial Transmission Rights (FTRs), which are used in overseas markets. While optional firm access would give generators the option of acquiring long term access rights, and FTRs are more commonly of shorter duration, FTRs aim to provide financial certainty for generators.[57] Under a FTR arrangement, generators without FTRs receive the nodal price. FTRs are typically paid out in full to the holders.

FTRs have been implemented in a range of markets (mainly in the US, and recently New Zealand). The experience in these markets has found that FTRs have worked effectively as a hedging mechanism for congestion risk, which has facilitated bilateral contracting among market participants.[58]

The demand for FTRs in other markets demonstrates that generators in those markets value a product which can help them manage congestion risk.

6.2.4 Commission's views

Nearly all generators have stated that congestion risk is not a material problem *at the moment.* However, two generators (with less diversified portfolios) consider congestion risk is a problem.

While congestion may not be a significant problem currently, this may not always be the case. Patterns of congestion change over time (see above).

So, while congestion risk may be low at the moment, this may not be the case in the future. It is conceivable that the risk could change over time. There are various scenarios under which congestion patterns and levels on the network could increase or decrease:

- changes to environmental policy leading to changes in the generation mix technology, and so changed patterns of congestion;
- increased levels of distributed generation leading to decreased transmission congestion;
- continued high gas prices, creating a shift in consumption away from gas back to electricity, increasing demand on the network and so congestion;

57 For further detail on the difference between FTRs and optional firm access see section 8.6.4 of the Transmission Frameworks Review Final Report.

58 See: NERA, Review of Financial Transmission Rights and Comparison with the Proposed OFA Model in Australia, 12 March 2013.

- changes to the network over time. For example, if ageing assets are not replaced because they are no longer required to support the reduced demand, congestion could change;[59] and
- closure of large industrial plants (for example, a smelter), creating changes to local load and so changed patterns of congestion.

6.3 Impacts of optional firm access

6.3.1 How much access would be purchased

Before considering the impacts of optional firm access on financial certainty, it is first necessary to consider whether or not generators would purchase firm access, and, if so, how much firm access would be purchased.

Stakeholder submissions

Stakeholders have different views about how much firm access would be purchased.

Stanwell considers that since optional firm access would not provide fully firm access, and that the NEM is currently experiencing low congestion, generators would be unlikely to buy firm access.[60]

Others consider that optional firm access would not be optional, and generators would be forced into purchasing access (but from a competitive disadvantage point of view, rather than needing to manage congestion). For example, InterGen considers that baseload plant would most likely be compelled to seek firm access due to the significant risk of financial loss during an "access" event and an inflexibility of some plant to respond quickly to these signals without risking a plant trip.[61]

GDFSAE considers that one of the strengths of the proposed optional firm access mechanism is that it would be optional, allowing individual businesses to make their own decisions on the extent to which they wish to purchase firm access based on their risk adjusted outlooks and projections.[62]

Analysis

Oakley Greenwood concludes that the majority of generators would hold relatively high levels of firm access. This is because the allocation of transitional access would set

59 Also, the Commission's recommendation for a new framework for transmission reliability standards may mean that congestion will not be as quickly built out in the future. This is because more transmission investment would need to be justified on the basis of the value to consumers and their reliability.

60 See: Stanwell, First Interim Report submission, p. 7.

61 See: InterGen, Request for comment submission, p. 2.

62 See: GDFSAE, Request for comment submission, p. 2.

a commercial precedent for participants - such a view or mindset may be difficult to change. Generators would likely see risks in being non-firm while neighbouring generators are firm. Generators might hold a level of firm access that was equivalent to their existing contracting position.

Further, Oakley Greenwood states that optional firm access could be compared to insurance. Generators would assess the merits of holding optional firm access in a similar fashion to their current assessments of energy hedging and business continuance insurance. This assessment would see generators compare the cost of buying the insurance to the probability weighted risk and resultant cost of an insurable event occurring in the absence of insurance. If the access price was less than the cost they would face, then generators would purchase.

The Commission also has undertaken some analysis on how much firm access would be purchased by generators. The Commission concludes that all network capacity would be sold as long-term firm access or short-term firm access. This is due to the requirement on TNSPs to offer all spare network capacity into the short-term firm access auction. This auction would have no reserve price. In a competitive auction, generators would bid for (or offer) short-term firm access at its perceived value, with this value reflecting:

- a simple monetary "fair value" based on the congestion price;
- hedging value for backing new forward sales; and
- hedging value for backing existing commitments, for example, forward contracts or debt.

In a less-than-competitive auction, generators may strategically bid lower than the value of the access, in order to purchase access cheaply. For example, in the extreme, a monopoly generator could buy zero long-term firm access, and bid zero for short-term firm access. Therefore, prices of firm access would better approximate incremental transmission costs where there is a competitive generation sector.

Since generators could sell long-term firm access into the short-term firm access auction, effectively it would be a short-term firm access forward product. The price generators would be prepared to pay for long-term firm access would reflect the expectation of the future auction clearing prices for short-term firm access. If risk-averse, a generator might pay more for long-term firm access in order to gain price certainty.

Commission's conclusions

The Commission considers that, in deciding whether or not to purchase firm access, generators would trade off the cost of firm access against the risk of congestion including the risk of making payments to any generators with firm access. They would consider the direct cost of congestion, the associated financial risks, the opportunity cost of limiting contract sales, as well as potentially whether or not the neighbouring generators may purchase firm access. Generators would then choose whether to purchase access on that basis.

Generators would be given an allocation of some transitional access for free at the commencement of optional firm access. Generators' experiences with such a product would inform their decision on whether or not to purchase firm access.

However, while generators may make these trade-offs, given the reasons set out above (including the likelihood of access prices, at least through the short-term auction being low) it is quite likely that generators would hold a large amount of firm access. However, generators would choose the level of access they wish to purchase relative to their generating capacity.

It is also relevant to consider the *price* at which this firm access would be purchased. If generators consider that congestion risks are low, it would be expected that the price paid in the short-term auction would be low. Therefore, generators may be able to hedge a risk that they consider immaterial (at the moment), for a price that is likely to be low.

Regarding stakeholders' views that optional firm access is not really optional, the point to be made is that there would be no regulatory obligations on generators to purchase access, as compared to the requirement to have a connection agreement.

6.3.2 Firm access to improve financial certainty

Stakeholder submissions

Some stakeholders consider that the introduction of optional firm access may actually decrease financial certainty. Stakeholders have cited a variety of reasons for this:

- AGL and Snowy Hydro consider that participants would have to hedge load in the presence of both a local price and regional reference price. Non-firm generators would face basis risk that they may receive the local price.[63]
- AGL considers that "fracturing the [regional reference price]-index into a complex nodal pricing system (with overlapping paths to market via various meshed flow-gates)" seems likely to make contracting and hedging considerably more complicated than it is today.[64]
- Snowy Hydro considers that under the current market arrangements there is a well-defined method of allocating transmission capacity (a summary of this method can be found above in Box 6.1:). There is no basis risk as the generator receives the regional reference price when it is dispatched. In contrast, under optional firm access, Snowy Hydro considers that volume risk would still exist as

63 See: AGL, First Interim Report submission, p. 3; Snowy Hydro, First Interim Report submission, p. 3;

64 See: AGL, Request for comment submission, p. 3.

dispatch would not be not guaranteed. Additionally there would be basis risk if a proportion of a generator's output is priced at its local price. In Snowy Hydro's view, this additional basis risk would adversely impact the functionality and liquidity of the contract markets.[65]

- CS Energy considers that since generators would not be fully compensated under optional firm access, there would not be much certainty from the access product.[66]

In contrast, GDFSAE considers that the optional firm access model would enhance risk management options for generators. Faced with increasing uncertainty, GDFSAE believes it is better to have more risk management options and therefore believes that introducing network access risk management is likely to be beneficial in the longer term.[67]

In a submission to the AEMC reflecting its role in transmission in Victoria and as National Transmission Planner, AEMO considers that optional firm access may not provide a material increment in financial certainty to the generator, due to a variety of other market design issues, which AEMO considers could also result in market price volatility (for example, late strategic rebidding).[68] This conclusion is discussed further below in the context of AEMO's work on the access settlement component of optional firm access.

Analysis

Oakley Greenwood concludes that, on balance, optional firm access would increase the assurance generators have about energy contracting and so allow for higher levels of contracting. Initially, the change in the overall level of energy contracting may be marginal. However, the materiality of the increase in contracting would be dependent on the circumstances of each generator, future network configuration, and on the geographic distribution of future generation plant.

Such an outcome should reduce the volatility in spot prices and the cost of contracts. Given this, optional firm access may become more valuable to generators over time.

Further, Oakley Greenwood comments that the introduction of optional firm access would mean that non-portfolio and less diversified generators would have a better means of managing congestion risk. This is compared to more diversified portfolio generators who have a natural hedge against congestion.

Through its terms of reference, AEMO assessed the practicality of the access settlement element of optional firm access, using historical events as a basis for understanding the concept. AEMO reviewed historical events to identify cases that would demonstrate

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65 See: Snowy Hydro, Request for comment submission, p. 7.

66 See: CS Energy, First Interim Report submission, p. 4.

67 See: GDFSAE, Request for comment submission, p. 2.

68 See: AEMO, First Interim Report submission, pp.4-5.

the workings of access settlement. In order to minimise the impact of other issues (such as late strategic rebidding), AEMO filtered the events down to those that were reasonably stable across a half-hour. These were only found to occur in relatively low regional price conditions, below $100 per megawatt hour.

AEMO found that access settlement provides gains in terms of financial certainty when multiple generating units and interconnectors are constrained off from a regional price. It has also found that access settlement provides gains when power stations respond individually to the settlement prices faced, that is, when power stations are not operating as part of a generator's broader portfolio. The Commission notes that AEMO has not been able to assess the effects of access settlement in the presence of portfolio bidding.

Such analysis is consistent with the qualitative assessment undertaken by Oakley Greenwood above. In summary, AEMO found that the events that it reviewed showed that access settlement does function as intended, and appears to create the expected improved incentives towards improving financial certainty.

Optional firm access would only address and mitigate the financial uncertainty that is caused by congestion that affects scheduled and semi-scheduled generators and/or interconnectors. AEMO noted that uncertainty can be caused by factors other than congestion, such as, late strategic rebidding.[69] The Commission notes that optional firm access has not been designed to improve financial certainty caused by these other factors.[70]

Commission's conclusions

Under the optional firm access model, by decoupling financial access from dispatch, generators would be able to "insure" (or hedge) against congestion risk. A constrained-off firm generator would earn the difference between its local price and the regional reference price on its access amount, which should at least equal the margin it would have earned by being dispatched. Under the status quo a generator's ability to earn the regional reference price is dependent on it being dispatched. Therefore, in theory under optional firm access, financial certainty should be increased (particularly if the access price is less than the financial benefit to the generator).

This should increase confidence for investors in the electricity sector, which could be translated into lower financing costs.

Given that generators have different views as to whether or not they would purchase firm access, it is difficult for the Commission to make conclusions in this regard. Most generators have said that they would not value such a product. However, financial transmission rights in energy markets elsewhere are valued, and have been purchased,

69 See: AEMO, Optional Firm Access AEMO Draft Report, December 2014.

70 The Commission notes that issues associated with late strategic rebidding are currently being considered under a separate rule change proposal. See: http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith.

by generators. It is possible that if congestion levels were to increase in the NEM, more generators may value access more highly. Indeed, some generators have expressed different views in the past, when congestion levels were higher.

The Commission notes that there may be possible improvements in terms of wholesale market competition. Generators that have less diversified portfolios would be better equipped to compete with more diversified portfolio generators, since they could purchase firm access to manage congestion risk.

7 Effective inter-regional hedging

7.1 Description

The NEM is an interconnected system, which provides for inter-regional trade. Inter-regional trade generally refers to:

- a generator in one region selling forward contracts to a retailer in another region of the NEM (or, conversely, a retailer hedging its retail risk in one region through purchased contracts with a generator located in another region); or

- a vertically integrated participant that is attempting to serve its retail customers in one region with generation assets that are located in another region.

In both cases, the generator or retailer must sell its power at the spot price in one region, and - in effect - buy it back at the spot price in another region, exposing it to possible price differences between the regions.

An inter-regional product hedges the risk from volatile inter-regional price differences. Such products are usually in the form of contracts. The availability of inter-regional products should give generators and retailers greater confidence to supply retail load which is supported by remotely-located generation. This should enable generators in lower priced regions to contract with retailers in higher priced regions, with resulting benefits to those consumers in higher priced regions. Examples of how inter-regional products work are included in appendix C.

An inter-regional hedging product also facilitates retail competition. By hedging risks from inter-regional price differences, retailers in one region, who may have contracts with generators (or their own generation assets) in that region, may be encouraged to enter into other regional markets. Therefore, inter-regional hedging products allow the benefits of the existing interconnector capacity to be realised in promoting inter-regional trade – without any additional investment in capacity.

7.2 Is there a problem with the current arrangements?

Currently, generators that trade inter-regionally can partially hedge against inter-regional price risk, by purchasing the right to a share of the inter-regional settlements residue (IRSR) that accrues when prices between regions separate. The value of the IRSR is equal to the difference between the price paid by retailers in an importing region and the price received by generators in an exporting region, multiplied by the amount of flow across the relevant interconnector. Such rights are known as settlements residue auction (SRA) units, after the auction that AEMO holds every quarter.

SRA units provide an effective inter-regional hedge only when the interconnector is able to flow at capacity and in the direction equal to the volume of SRA units sold. The two main instances where interconnector flows are reduced are:

- As discussed in Box 6.1, if generators who compete with the interconnector in dispatch bid -$1,000 they will be dispatched ahead of the interconnector - since the interconnector cannot rebid in this fashion. Such behaviour can create counterprice flows, which mean that the interconnector flow, and so the payout under the SRA, is zero.
- If the interconnector's available capacity is reduced (for example, due to outages on the network) then flows, and therefore residues, will be reduced.

Both of these instances have the effect of reducing interconnector flows, and so residues paid out on SRA units.

7.2.1 Stakeholder submissions

Stakeholders have mixed views about the effectiveness of inter-regional hedging in the NEM today.

Snowy Hydro comments that firm inter-regional hedges are already available and achievable now with plain vanilla financial instruments. In Snowy Hydro's view, contract traders already use these liquid financial instruments, which are traded on a daily basis to achieve 100 per cent firm hedges across different pricing regions. Therefore, it considers that there is no evidence to suggest that the issuance of long-term inter-regional access is required or that it would improve the availability of an already liquid and competitive market for inter-regional hedges.[71]

Snowy Hydro goes on to note that inter-regional products are only used at the margin to help mitigate the risk of sold forward hedges, referring to the ACCC's analysis for the Australian Competition Tribunal.[72] This is discussed further below.

Stanwell also consider that this concern is greatly overstated. Stanwell notes that it conducts both wholesale and retail activities in regions where it does not own or operate generation, and it considers the options for management of basis risk in the current market design are sufficient. Further, financial markets provide participants with a greater range of product specification compared to SRAs.[73]

In contrast, the South Australian DSD notes that it is concerned about constraints on the interconnector during periods of high demand in South Australia as this reduces competition by limiting the availability to import Victorian electricity during these periods.[74]

Similar to this view, the AER considers that network congestion periodically inhibits efficient trade by constraining electricity flows from low to high price regions. At times, counter-price flows occur, with electricity being exported from high to low price

71 See: Snowy Hydro, Request for comment submission, p. 6.

72 See: Snowy Hydro, Request for comment submission, p. 6.

73 See: Stanwell, Request for comment submission, p. 14.

74 See: South Australian DSD, First Interim Report submission, p. 2.

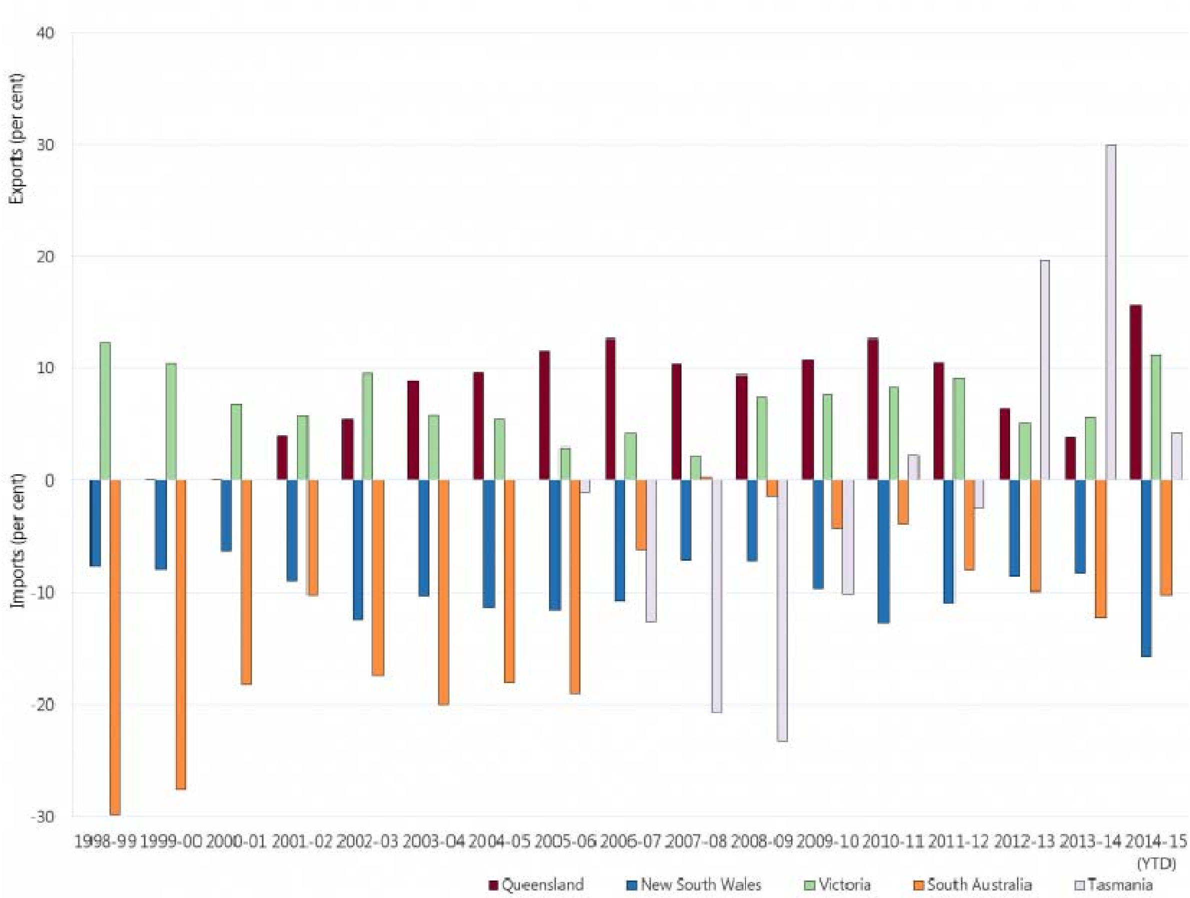
regions. Counter-price flows create market distortions that damage interregional trade and impose costs on consumers.[75]

7.2.2 Analysis

Flows across the interconnector

Annual flows across the interconnectors, as a percentage of regional energy consumption has not changed substantially since NEM start. While this measures energy flows across the interconnectors, this does not necessarily indicate the level of inter-regional trade. That is, physical flows do not in and of itself mean trade.

Figure 7.1 Annual flows across the interconnectors as a percentage of regional energy consumption



Further, there has been an increase in the total hours of binding constraint on interconnectors since NEM start.[76]

The Commission engaged Houston Kemp to examine a case study looking at historical co-ordination of transmission and generation investment in South Australia.

75 See: AER, State of the Energy Market 2014, p. 41.

76 Based on data provided to the AEMC from AEMO.

One of Houston Kemp's findings is that a number of generators in South East South Australia have located near the Heywood interconnector. These generators have had a multiplicative effect on the limit of the Heywood interconnector (that is, 1 MW output from these generators has reduced interconnector flows by more than 1 MW).

An inter-regional trader faces the risk of inter-regional congestion, which would impact on the payout of its SRA units. But, if a new generator locates on the interconnector, it gets priority access during congestion (through generators bidding to the floor). If generators who compete with the interconnector bid -$1,000 they will be dispatched ahead of the interconnector - since the interconnector cannot rebid. This has the effect of reducing the flows on the interconnector, and so the payout under the SRAs. The Commission considers that this has a significant effect on inter-regional trade, which can make long-term inter-regional trading unviable.

SRA effectiveness

There is also evidence indicating that SRA units are not an effective inter-regional hedge:

- From 1 July 2010 until December 2014, there was approximately $45 million of negative IRSRs accrued across all three interconnectors.[77] During times of negative IRSRs, the payout under the SRA is scaled back towards zero. This would have had an impact on the ability of participants to trade inter-regionally, and also the value of the inter-regional product. Importantly, the total value of the negative IRSR is not that informative in and of itself. What is important is the counterfactual: the amount that an inter-regional hedge would have paid out during these counterprice flow periods.

- From 1 January 2013 until December 2014, approximately 16 per cent of all trading intervals have been counterprice flow periods (that is, there has been a counterprice flow on at least one interconnector, in one direction). This is significant. Further, these results incorporate the fact that AEMO intervenes in the market to limit negative inter-regional residues accumulating beyond $100,000. That is, the total amount of counterprice flow periods may have been higher if AEMO had not intervened.

- During the Transmission Frameworks Review, AEMO undertook some indicative analysis of the inter-regional effects of interconnectors being constrained off following the NSW 70/71 constraint binding.[78] The effect of this constraint was to "bind" the Vic-NSW and QNI interconnectors. AEMO performed a hypothetical recreation of the event, and found that in the absence of disorderly bidding there would be a $300 million savings on NSW pool

77 Source: AEMC calculations based on data provided by AEMO.

78 Which bound as a result of "race to the floor" bidding behaviour.

settlements through greater imports.[79] Inter-regional traders lose access when the interconnector is congested.

- Instances of interconnector flows being less than the nominal capacity during periods of price separation have impacted on the value of the SRA product. In many instances, the total residue paid out from the product is less than what participants have paid for the product - the long-term cost:payout ratio has remained roughly stable at approximately 135 per cent over ten years from 2004 to 2014.[80] If the SRA price is less than its fair value (the expected amount of payouts), it implies that the SRA is not being bought in order to provide protection from inter-regional price differences. Further evidence on this is discussed below.

If the SRAs represented an effective method of inter-regional hedging, they would have a value above or equal to the expected quarterly average price difference between regions. (A risk averse participant may wish to pay more than the average expected price difference, so as to protect against volatility). Table 7.1 shows the 2016 Q1 difference between forward contract prices of two adjacent regions, and the SRA price in the last auction for interconnectors (in the direction from least to most expensive, and converted to a $/MWh value).

Table 7.1 Future prices for 2016 Quarter 1[81]

		Queensland - NSW	NSW - Victoria
1	Inter-regional price difference[82]	$23.65/MWh	$4.30/MWh
2	SRA price in latest auction[83]	$3.58/MWh	$1.84/MWh
(1/2)-1	Percentage difference between SRA price & inter-regional price difference	561%	134%

As can be seen, the value of the SRA is lower than the expected difference in prices shown in forward contracts. The final row shows the size of the differences, expressed as a percentage difference in forward contract prices. For example, the Queensland Q1 2016 futures price is $24/MWh higher than the NSW Q1 2016 futures price. If the SRA

79 The bids that were used were the ones that were in place in the pre-dispatch timeframe for that afternoon, but were entered before the congestion was expected.

80 Source: AEMC calculations based on data available here: http://www.aer.gov.au/node/9771.

81 South Australia - Victoria has not been included due to lack of futures prices for 2016 Q1 in South Australia.

82 The difference between contract bid price in two adjacent regions. The more expensive region listed first. Contract prices were sourced from https://asxenergy.com.au/futures , accessed 20 February 2015.

83 SRA prices are the clearing prices for the most recent tranche divided by the number of hours in a quarter. Prices were sourced from http://www.aemo.com.au/Electricity/Market-Operations/Settlement-Residue-Auction/Reports.

was a perfect hedge, then the corresponding SRA unit for this period should be approximately $24/MWh. However, in the latest AEMO SRA auction, this was sold at $3.58/MWh.

Other hedging products

The Commission understands that some generators trade swaps inter-regionally. For example, if a generator in Victoria wanted to supply a customer in NSW, it could buy a Victorian swap, and sell a NSW swap to hedge that risk. Alternatively, if a generator in Victoria wanted to supply a customer in NSW, it could buy a Victorian swap, and combine this with a cap contract referencing the NSW spot price.

The Commission also understands that there is some secondary trading of SRAs - however, this is relatively limited in terms of quantity. Further it appears that stakeholders consider the SRA products to have different firmness, depending on what interconnector they are over. The firmness is influenced by perceptions about the length and number of outages across the network, strategic bidding behaviour by generators, and by the physical limits of the interconnector itself.

Therefore, while there may be some products available that may assist in managing inter-regional risks, none of these products results in a firm hedge for participants trying to manage inter-regional price differences.

AEMC's retail competition review

As part of its annual retail competition reviews, the AEMC considers a number of market indicators. One of these is the indicator of "barriers to entry, exit or expansion". This analysis in the 2014 review drew on information provided in retailer interviews and surveys and included consideration of (amongst other things) a retailer's ability to manage spot price risk, either physically (through vertical integration with a generator) or financially (through contracting with a generator or via financial markets).

Of interest to this impact category, the review found that there are five vertically integrated retailers that are located and competing in South Australia. Some retailers considered it difficult to expand in the electricity market in South Australia without having interests in generation assets.

One of the reasons retailers cited as a potential impediment to entry and/or expansion in the South Australian retail electricity was the inability for retailers that do not have generation interests in the state to access competitively priced hedging instruments. This was considered to be the most significant impediment by retailers. By extension, this can also be considered to imply a lack of effective inter-regional hedging instruments. If such instruments were available, then the retailers with only Victorian generation interests could retail in South Australia.

It should be noted, however, that the Commission concluded that these market conditions did not appear to be an insurmountable barrier to entry for the purposes of its assessment of the effectiveness of retail competition.

Australian Competition Tribunal

Such issues were also recently considered by the Australian Competition Tribunal in its assessment of AGL's takeover bid of Macquarie Generation.[84] However, these issues were considered in the context of defining the market in which to consider the merger.

Originally, the Australian Competition and Consumer Commission (ACCC) rejected AGL's bid for Macquarie Generation, saying it was likely to reduce competition in the NSW retail electricity market. Amongst other things, the ACCC concluded that a retailer seeking to manage price risk associated with its customer load in one region of the NEM would very rarely (if ever) enter into a hedge contract under which payments are calculated by reference to the spot price in a different region of the NEM, since this is not an effective way to manage the risk of price divergences between regions of the NEM. Purchasing inter-regional settlement residues is not typically viewed as an effective tool to facilitate inter-regional hedging given that flows on interconnectors can be limited. The ACCC noted that this is especially the view of market participants with operations on only one side of adjoining regions of the NEM.[85]

However, AGL appealed the ACCC's decision. The appeal was considered by the Australian Competition Tribunal. In relation to inter-regional hedging, the Tribunal noted that:

- "inter-regional hedge contracts are actively traded, albeit perhaps with a higher degree of risk and at a greater cost if this risk is to be curtailed";[86] and
- "a retailer to whom AGL were to refuse to supply a hedge contract could easily turn to another supplier, including generators in NSW or interstate or financial intermediaries".[87] However, the Tribunal recognised that IRSR units do not always provide a reliable or "firm" hedge against inter-regional price divergences.[88]

The Tribunal noted it was also aware that interconnector capacity and reliability has increased, and market participants are now more familiar with IRSRs.

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84 See: Application for Authorisation of Acquisition of Macquarie Generation by AGL Energy Limited [2014] ACompT.

85 See: ACCC, Statement of Issues, AGL Energy Limited - proposed acquisition of the business and assets of Macquarie Generation, 6 February 2014.

86 Application for Authorisation of Acquisition of Macquarie Generation by AGL Energy Limited [2014] ACompT, para 355.

87 Application for Authorisation of Acquisition of Macquarie Generation by AGL Energy Limited [2014] ACompT, para 356.

88 Application for Authorisation of Acquisition of Macquarie Generation by AGL Energy Limited [2014] ACompT, para 94.

7.2.3 Commission's conclusions

At the moment, generators locating on interconnector flowpaths are given priority - this means that they constrain off the interconnector (in some instances at a large ratio). The effect of this is to reduce flows across the interconnector, in turn, reducing the value and effectiveness of the existing SRA units.

Stakeholder views vary on the effectiveness of the current inter-regional hedging arrangements.

The AEMC considers that the effectiveness of inter-regional trading products could be improved. This is because the payout on the SRA product is highly dependent on flow, and the current market arrangements mean that flows on the interconnector are reduced frequently.

Interconnectors are the first to suffer the impact of "race to the floor" bidding behaviour in a mixed constraint. This decreases the firmness of the SRA units at the time when they would be most valuable, and therefore diminishes the ability of participants to hedge inter-regional trade. It is likely that, since the SRA is not totally effective, a small retailer cannot risk being exposed to very high inter-regional price differences even for a small amount of time. This is likely to lessen competitive pressure on generators and retailers within a given region. Further, other products do not appear to be readily available for those who want to trade inter-regionally.

Therefore, the Commission considers that the current inter-regional products could be improved. Such improvements could also improve wholesale and retail competition in a national sense. The Commission considers that improvements could be made by making the available inter-regional products firmer.

7.3 Impacts of optional firm access

7.3.1 Stakeholder submissions

Snowy Hydro considers that the inter-regional product under optional firm access may be slightly firmer. However, this may not mean that there is more contracted volume available to the market, since trading across regions is inherently riskier and costlier than trading within a single pricing region.[89]

The South Australian DSD see this as being one of the key benefits of optional firm access. It considers that giving generators and retailers the opportunity to procure inter-regional access rights on interconnectors would provide benefits to the market as it should encourage the market-led development of interconnector expansion. It would also be beneficial for generators who operate across regions since it provides a firmer mechanism for hedging the price difference between regions.[90]

89 See: Snowy Hydro, Request for comment submission, p. 6.

90 See: South Australian DSD, First Interim Report submission, p. 2.

Further, Westpac, who is a liquidity provider for market participants, considers that firm interconnector rights would be a superior hedging product to SRAs. The offering of this product would allow Westpac to more competitively price various inter-regional risk products for its customer base.[91]

7.3.2 Analysis

Optional firm access separates access to the regional reference price from dispatch. A firm interconnector right (FIR) would replace the existing SRA product. Optional firm access would enable market participants to obtain inter-regional access that is not dependent on dispatch. An inter-regional trader holding a FIR under optional firm access would no longer be concerned about interconnector *flows,* but rather interconnector *capacity* since a capacity shortfall would lead to its access being scaled back. The effect of this would be to make the FIR holder largely indifferent as to what factors reduce flows across the interconnector. While counter-price flows may still arise, access settlement would mean that the holders of the product were not affected.

Although access settlement payments would be scaled back if transmission capacity was reduced, then the responsible TNSP(s) would be liable to pay a proportion of the shortfall in funds. Such incentives would be expected to give confidence that TNSPs would decrease the frequency and impact of outages on reducing interconnector flows, and so improve payouts under the FIRs.

As noted above, reduced flows across the interconnector (which have the effect of reducing the payout under the SRA) are predominantly caused by two factors:

- race to the floor bidding behaviour by generators, which has the effect of constraining off the interconnector (see Box 6.1); or
- network outages across the interconnector flowpath.

The incentives for both of these outcomes could be reduced under optional firm access:

- As Oakley Greenwood stated in its report, its view is that the introduction of optional firm access would change incentives on generators to “bid to the floor”, and so should provide for a firm inter-regional hedge.
- Further, to the extent that reduced flow across interconnectors is due to poor network performance, the introduction of the optional firm access TNSP incentive scheme would create incentives to address this problem.

7.3.3 Commission's conclusions

The Commission considers that the introduction of optional firm access, and of firm interconnector rights, would create a firmer inter-regional hedging product. This would be an improvement on the current inter-regional hedging products available.

91 See: Westpac, Request for comment submission, p. 1.

To the extent that traders cannot manage the spot price differences, the optional firm access inter-regional product would:

- give generators and retailers greater confidence to trade across regional boundaries;
- give vertically integrated participants greater confidence to meet their retail load using remotely located generation; and
- better enable generators in lower priced regions to contract with retailers in higher priced regions, with resulting benefits to consumers in higher priced regions.

It may also help maintain or improve retail competition levels. A firm interconnector right would have similar firmness to that enjoyed by intra-regional generators currently, and similar firmness to intra-regional firm access. So, from the point of view of congestion risk, intra-regional and inter-regional trading would become equivalent. By decreasing the risk of inter-regional price differences, firm inter-regional access would help retailers in one region, who have contracts with generators (or their own generation assets) in that region, to enter into other regional markets.

For example, this would most likely be observed in South Australia. As noted above, as part of its review into the effectiveness of retail competition in South Australia, some retailers noted that it is difficult to expand in the electricity market without having interests in generation assets. A firm inter-regional hedge would provide an alternative.

The introduction of the firm interconnector rights may therefore allow the benefits of the existing interconnector capacity - without any additional investment in capacity - to be better realised in promoting inter-regional trade. This could facilitate more generators and retailers to contract with each other across regions in the NEM.

8 Incentives on TNSPs to operate the network

8.1 Description

TNSPs should provide an efficient level of network capacity: that is, invest to increase the availability of network capacity to the extent that this capacity is valued by the market. This value varies with time, so the TNSP should aim to maximise availability when the value of network capacity is at its highest (at times of high spot prices). TNSPs should take into account the value of the transmission capacity, as it could be used by generators and consumers.

Achieving an efficient level of network capacity involves the TNSP making trade-offs between the cost of providing capacity, and the value of this to consumers.

A financial incentive is likely to provide the most robust and transparent driver for efficient decision making. This view, that financial incentives are likely to lead to more efficient outcomes is widely held (and practised) by regulators internationally, as well as in Australia. No incentive would mean that TNSPs would provide network capacity in the way that minimises its own costs, rather than taking into account the market value.

For example, TNSPs should be encouraged to schedule planned outages at times when the market does not value the capacity of the network highly because wholesale prices are low (for example, such times may occur when congestion is not expected). Conversely, TNSPs should not schedule planned outages at times when the market values the capacity of the network highly (for example, when congestion is expected or during periods of high demand when wholesale prices are high and so the value to generators of not being able to access the market is high).

In order to achieve such incentives on TNSPs to operate their network efficiently, TNSPs need to have clear responsibility and accountability for the operation and performance of the transmission network.

8.2 Is there a problem with the current arrangements?

8.2.1 Current incentives on TNSPs

Currently, TNSPs have a number of incentives placed on them to efficiently operate the network.

One of these is the market impact component of the STPIS. This is designed to provide an incentive to transmission businesses to reduce the impact of planned and unplanned outages on wholesale market outcomes. TNSPs do so by reducing 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.

This is a low-powered incentive to minimise outages when constraints are binding and the estimated market impact is above a defined threshold. A TNSP can earn up to 2 per cent of its regulated revenue if it eliminates all relevant outage events with a market impact of over $10 per megawatt hour. The AER sets separate targets reflecting the circumstances of each network based on its past performance.

The market impact component has been progressively applied to TNSPs since 2009.

The value of network capacity under this scheme is measured as the difference between the:

- total cost of producing sufficient electricity to meet demand if all limitations due to network outages on the transmission network were removed; and
- total cost of producing sufficient electricity to meet demand if no limitations due to network outages on the transmission network were removed.

8.2.2 Stakeholder submissions

Hydro Tasmania notes that since the introduction of the market impact component it has observed a change of behaviour from TNSPs in terms of planning, rescheduling and management of transmission outages that have resulted in a significant reduction in market impact.[92] For example, Hydro Tasmania notes that it has observed occasions where the value of the market impact component to the TNSP has been several multiples of the impact on resource costs from an outage resulting in a disproportionate response by the TNSP. It considers that it would be worthwhile investigating changes to this scheme to make it symmetrical, and to incorporate scaling based on the marginal value of binding outage constraints.[93]

8.2.3 Analysis

Historical performance of the STPIS

Typically, TNSP performance under the market impact component has improved over time. As shown in Table 8.1 incentives to TNSPs under the scheme have typically increased over time. These incentives are proportional to how well TNSPs have performed in minimising outages.

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92 See: Hydro Tasmania, Request for comment submission, p. 1.

93 See: Hydro Tasmania, Request for comment submission, p. 1.

Table 8.1 Incentive received under the market impact component of the STPIS (percentage of incentive received)

TNSP	2009	2010	2011	2012	2013
Powerlink		1.97	1.95	1.98 | 2.00[94]	1.86
TransGrid	0.39	1.45	1.39	1.48	1.58
AusNet Services			0.0	0.8	1.31
ElectraNet			0.52	0.00	1.90 | 0.00[95]

However, the Commission understands that the scheme has been less effective in South Australia due to the fact that at times there is considerable wind or solar PV generation online. Wind and PV generators, by themselves, are not able to provide the required controls to ensure system security. Reducing conventional generation increases the complexity of managing the power system, and so, by implication the ability to manage outages.

Historical constraint performance

The Commission has obtained data from AEMO on every binding constraint, in every trading interval, for the period November 2013 to October 2014. This has allowed an examination of this historical congestion to identify the frequency and extent of shortfalls that occur in the network.

This analysis is contained in appendix D.

While the past is not necessarily a guide to the future, this historical constraint performance has been informative in considering which constraints are driven by network outages, and which are driven by other influences (for example, system normal constraints). In summary:

- Constraints occur for a number of reasons including:
  - variations in local demand;
  - changes to flowgate support generators;
  - changes to the output of the largest generator in a region;
  - changes to non-scheduled generation; and
  - network outages.

94 Powerlink reported separately for the first and second halves of 2012.

95 ElectraNet reported separately for the first and second halves of 2013.

- There is a substantial impact from system normal constraints, with outage constraints having a limited impact, that is, low shortfall costs (the top six constraints were all system normal).

These observations appear consistent across both intra-regional and inter-regionally congestion.

8.2.4 Commission's conclusions

It appears to be the case that the market impact component of STPIS has prompted changes in TNSP operations that have led to a reduction in the number of periods that are congested, according to the STPIS criterion. Such a view is also generally supported by stakeholders.

However, the current incentive scheme has a limited scope. It only applies at times of network outages. Further, while there is some value indication in the scheme (the $10/MWh threshold), this can be seen as a rather blunt measure of the value of transmission capacity. The Commission considers that while the scheme has incentivised TNSPs to improve performance, it would be better to have an incentive scheme that covers all periods, not just outage periods, and is better tied to measures of value.

8.3 Impacts of optional firm access

8.3.1 Stakeholder submissions

A number of stakeholders (Hydro Tasmania, Snowy Hydro) are of the view that it would be preferable to make incremental improvements to the existing incentive scheme, rather than implementing optional firm access.[96]

However, South Australian DSD and Victorian DSDBI consider the optional firm access incentive scheme is an important component of the model.[97]

8.3.2 Analysis

The optional firm access model would introduce a new incentive scheme on TNSPs. This would measure the value of network capacity based on the shortfall cost (that is, the difference between the regional reference price and the local price) of the congestion. This reflects a marginal price and can be contrasted with the average value, which is considered under the current STPIS).

96 See: Hydro Tasmania, Request for comment submission, p. 1; Snowy Hydro, Request for comment submission, p. 6.

97 See: South Australian DSD, First Interim Report submission, p. 2; Victorian DSDBI, First Interim Report submission, p. 6.

As discussed above, the Commission has obtained from AEMO data on every congested flowgate in every trading interval in the period November 2013 to October 2014. The Commission has used this data to simulate the effects of the optional firm access incentive scheme.

The results of this analysis are contained in appendix D. This analysis suggests that:

- The structure of the optional firm access incentive scheme is largely "right" - the various caps are rarely hit, but do serve to substantially reduce TNSP risk. Therefore, the incentive scheme should be relatively low-powered in magnitude. That is, a relatively modest amount of the TNSP's revenue should be exposed under the incentive scheme.

- The firm access planning standard conditions do not always result in the highest levels of network congestion - so a continuous incentive that encourages TNSPs to maximise capacity at times outside of these conditions becomes important.

- The outage-related congestion represents a small proportion of congestion costs. This could be because the current market impact component scheme is effective in reducing these, or it could also suggest that the scope of the incentive scheme should be increased to cover system normal conditions.

8.3.3 Commission's conclusions

The optional firm access incentive scheme has two major benefits over the existing market impact component scheme:

- it applies at all times (not just at outages); and

- it exposes the TNSP to a better approximation of the market value of the congestion that is created (compared to the current tariffed market impact component penalty).

Further, under optional firm access, the incentive scheme would only cover firm access. A TNSP would not be incentivised to provide non-firm access. So, a TNSP would be guided towards providing network capacity that generators have indicated they value. Therefore, optional firm access would result in more efficient incentives on TNSPs.

If optional firm access was not implemented, incremental improvements to the existing STPIS regime may capture some of these benefits. This could include expansion of the market impact component by the AER so that it covered all conditions, and exposed the TNSP to a better approximation of the market value.

The transmission planning arrangements in Victoria have some implications on how the optional firm access incentive scheme could be implemented in this jurisdiction. This is discussed further in chapter 12.

9 Efficient dispatch of generation

9.1 Description

In a competitive energy market environment, price signals provide the incentives to guide participants' actions. Those actions include how they should run their plant, when maintenance should be carried out, and when and what type of technology to invest in. Profit and capital market disciplines provide incentives to manage risk (see chapter 4).

As an energy-only market, the NEM is designed so that generators earn revenue for the energy they produce. Short-term dispatch and long-term investment in generation decisions are driven primarily by wholesale market prices and expectations of those prices. As such, the efficacy of the price signal is critical to the efficient operation of the market. The ability of the spot price to vary in response to changes in supply and demand promotes dynamic efficiency by providing a price signal that encourages the least-cost mix of new entrant generation.

For short-term efficiency in energy-only markets to be achieved, prices must reflect marginal economic costs, not marginal incurred costs.[98] Incurred costs encompass the actual expenditure made or directly incurred in that period as a result of increased output, such as fuel costs. Economic costs include fuel costs but also encompass returns to the business owners. Short-term economic costs should compensate generators for fixed costs and costs attributable to start-up, shut-down and changes input, which require remuneration.

For a price to be efficient in any particular market period, it must provide returns to the marginal generator and therefore must be in excess of incurred costs. Generators have an incentive to bid to a price that is higher than their incurred costs but below the costs of their competitors. In this manner, generators aim to be dispatched in preference to their competitors and at the same time receive a price for their output which is in excess of their incurred costs and provides profits.

For an electricity market design such as the NEM with a uniform clearing price, the extent to which there is a competitive bidding process tends to lead towards a least cost generating mix for any given level of required output. This is a tendency, rather than a rule. Price discovery has more to do with discovering the efficient levels of returns to the business owners as opposed to achieving efficient dispatch in the very short term.

However, the ability of the market to arrive at an efficient outcome may be compromised by a number of behaviours, including:

- managing network congestion (exhibited by "race to the floor" bidding behaviour);

98 Professor George Yarrow and Dr Chris Decker (Regulatory Policy Institute), Bidding in energy-only wholesale electricity markets, December 2014, p. 4.

- late strategic rebidding; and
- 5/30 behaviours, for example, generators respond to low prices in the five minute dispatch interval at the start of the 30 minute trading interval with a high price and attempt to spike prices in the five minute dispatch interval at the end of trading intervals.

The Commission notes that the floor price currently exists in order to mitigate risk for generators. It enables generators with minimum operating levels or contract commitments to bid into the market and still be dispatched. Therefore, there may be some times where it is appropriate for generators to bid at the floor price. In other instances, however, generators may be seeking to manage network congestion by bidding at the floor price. Where generators engage in non-cost reflective bidding behind a binding constraint in order to gain a share of volume access, this can be considered to be inefficient.

9.2 Is there a problem with the current arrangements?

9.2.1 Stakeholder submissions

Stanwell notes that short-term inefficiencies do not mean that the market is not operating efficiently.[99]

Further, Stanwell comments that the estimated costs of "race to the floor" bidding behaviour in terms of productive efficiency has not been material.[100]

9.2.2 Analysis

Quantifying the economic impacts of congestion is not a straightforward task. The focus to date has been on assessing the impacts of race to the floor bidding behaviour in relation to the productive inefficiencies that have resulted from altered dispatch patterns.

There have been several studies that estimate the productive efficiency of “race to the floor”. This is calculated as the difference in the cost of generation permitted by the constraint if generators did not alter their bids in response to the constraint, compared to the cost of generation permitted by the constraint when generators behind the constraint rebid -$1,000. Using this kind of analysis:

- In 2013, ROAM found that the cost of "race to the floor" bidding behaviour from 2010 to 2012, ranged from $3 million to $15 million per annum.[101]

99 See: Stanwell, First Interim Report submission, p. 9.

100 See: Stanwell, Request for comment submission, p. 17.

101 See: ROAM Consulting, Modelling Transmission Frameworks Review, 28 February 2013.

- In 2008, Frontier Economics found that the cost of "race to the floor" bidding behaviour in 2007/08 was approximately $8 million per annum.[102]

There is some evidence that race to the floor bidding behaviour has not been as prevalent over the past few years. For example, a recent analysis undertaken by ROAM Consulting for the AEMC as part of the Bidding in Good Faith rule change showed that over the past two years there have been higher levels of price volatility in Queensland.[103] However, in contrast to previous forms of price volatility that were due to congestion, this volatility tends to be short in duration and occurs mostly in 5-minute dispatch intervals towards the end of 30-minute trading intervals. ROAM considers that this is because there has been a reduction in congestion, and so in the more recent instances, the high prices are typically driven by generators undertaking last minute rebids to shift capacity to high market prices, knowing that other generators would have insufficient time to respond before dispatch.

9.2.3 Commission's conclusions

The Commission considers that the ability of generators to adjust bids (including bidding to the "floor") provides generators with necessary flexibility to adjust their position to accommodate changes in market conditions and to respond to the offers of other participants. The resulting dynamic process of participants learning and reacting to the actions of their competitors is an important part of an efficient functioning market.

However, bidding to the floor can also mean the market arrives an inefficient outcome, with generators seeking to "game" congestion that is present.

Therefore, the Commission considers that there can sometimes be productive inefficiencies associated with "race to the floor" bidding behaviour. However, the available evidence suggests that these inefficiencies are small in magnitude. Indeed, the few quantitative estimates of these inefficiencies have grown smaller over the past few years.

9.3 Impacts of optional firm access

9.3.1 Stakeholder submissions

Several generators (including Snowy Hydro, CS Energy and Stanwell) are concerned that AEMO, in its role of modelling access settlement outcomes, was unable to clearly demonstrate the efficiency in dispatch benefits of optional firm access.[104]

102 See: AEMC, Congestion Management Review, Final Report, June 2008, p. 33.

103 See: ROAM Consulting, Analysis of rebidding activity in the NEM, 17 October 2014.

104 See: CS Energy, First Interim Report submission, p. 6; Snowy Hydro, First Interim Report submission, p. 3; Stanwell, First Interim Report submission, p. 10.

Snowy Hydro notes that AEMO's modelling on access settlement has shown that at least five other major factors influence dispatch and access settlement has no ability to alter those influences. It is therefore questionable in its view, as to whether there would be any improvement in efficient dispatch. Further, it considers that the introduction of the optional firm access model may increase incentives to offer electricity in a non-cost reflective manner.[105]

However, the Commission considers that, as described below, AEMO has demonstrated that access settlement does operate as intended in respect of congestion.

9.3.2 Analysis

As discussed in chapter 6, AEMO has shown that access settlement does provide dispatch efficiency gains. Access settlement leads to improved incentives and more efficient dispatch outcomes associated with a reduction in "race to the floor" bidding behaviour. However, AEMO has been unable to assess the effect of access settlement where there is portfolio bidding. This is because, under portfolio conditions, other bidding behaviours are also typically present when congestion occurs. This masks the impact of any "race to the floor" bidding.

Where generators and interconnectors are located around loops, potential efficiency gains are larger due to different coefficients in a constraint equation. For example, it is possible for a generator to constrain off a competing interconnector by a factor of fifteen to one by increasing its own dispatch. This underutilises the network's capacity, paradoxically increasing the regional spot price.

However, AEMO goes on to observe that the access settlement element neither addresses, nor is intended to address, all of the drivers for dispatch inefficiency that are commonly observed.

AEMO's work was supported by Oakley Greenwood who concluded that optional firm access would strengthen incentives for generator bids to be cost reflective. Specifically, it would disincentivise "bidding to the floor" when congestion does occur, which could lead (as explained above) to inefficient dispatch. However, Oakley Greenwood places a caveat around this analysis about large, diversified portfolios operating in the NEM. The portfolio impact is dependent on geographic distribution, as well as network configuration, and so is variable and hard to predict.

Finally, ROAM's work for the AEMC as part of the Transmission Frameworks Review also supported this view. ROAM found that removing "race to the floor" bidding behaviour following the introduction of optional firm access was predicted to save $8.8 million, in net present value terms, over the period 2013-30.

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105 See: Snowy Hydro, Request for comment submission, p. 7.

9.3.3 Commission's conclusion

The access settlement element of optional firm access is likely to change incentives on generators with the effect that "race to the floor" bidding under congestion conditions would be reduced. However, optional firm access does not (and was not designed to) change other "disorderly bidding" behaviours, such as, late strategic rebidding or 5/30 bidding.

While optional firm access would remove some of these dispatch inefficiencies, the benefits across the NEM would be small.

10 Level of transaction costs and complexity

10.1 Description

Under the terms of reference the AEMC is required to consider the costs that are imposed on parties if the optional firm access model is to be implemented. These include both:

- the one-off costs of implementing such a model; and
- the incremental on-going costs of operating, and investing, under such a model.

These are called "transaction costs" for the remainder of this chapter.

These costs do not include any indirect costs (for example, the cost of purchasing access) associated with the introduction of the optional firm access model.

10.2 Stakeholder submissions

Stakeholders have commented on the costs associated with introducing optional firm access:

- Hydro Tasmania considers that optional firm access would result in high implementation and on-going costs.[106]
- Both Stanwell and CS Energy consider the transaction costs associated with optional firm access to be high, due to the complexity of the model.[107]
- The Clean Energy Council notes that Commission should undertake extensive research to develop estimated costs for the implementation of optional firm access.[108]

Numerous stakeholders (including Origin, Stanwell, Alinta, Snowy Hydro) have also commented on the level of complexity associated with the optional firm access model.[109]

106 See: Hydro Tasmania, First Interim Report submission, p. 1.

107 See: Stanwell, First Interim Report submission, p. 12; CS Energy, First Interim Report submission, p. 9.

108 See: Clean Energy Council, First Interim Report submission, p. 7.

109 See: Origin, Request for comment submission, p. 1; Stanwell, Request for comment submission, p. 1; Alinta, Request for comment submission, p. 2; Snowy Hydro, Request for comment submission, p. 8.

10.3 Analysis

The Commission engaged consultants to estimate the transaction costs for transmission and generation businesses. These estimates do not include:

- the cost of purchasing access;
- the cost of any investment in the network that may result from the purchase of firm access by market participants;
- any resultant effects on revenues received from the wholesale spot market;
- any costs incurred by organisations prior to the final determination on the optional firm access rule change; or
- any other indirect costs that may result from the introduction of optional firm access.

10.3.1 Transaction costs for TNSPs

EMCa assessed the one-off and incremental on-going costs of optional firm access to TNSPs in the NEM.[110] The analysis of transaction costs includes both new costs as a result of optional firm access implementation and transactional savings to the business that may result from investment being more market driven and which may offset other transaction costs.

Costs associated with the four mainland TNSPs, including AEMO in respect of its TNSP role in Victoria, were assessed.

EMCa undertook the following approach to this task:

- EMCa held interviews with key TNSP personnel (regulatory, planning, network operations & systems/IT) in each region.
- EMCa used these interviews to assess impacts on resources following the introduction of optional firm access.
- EMCa then used this resource impact approach and its own experience with transmission businesses to determine the transaction costs associated with optional firm access.

EMCa estimates that the optional firm access transaction costs for TNSPs (excluding TasNetworks) would be **$8.1 million** ($2014).[111] This figure is based on the EMCa base estimate, as contained in its report. This reflects the total implementation costs ($4.1 million), plus five years of on-going costs ($4 million).

110 EMCa, The transaction cost associated with the implementation of the firm access model, January 2015.

111 A discount factor of one was assumed.

10.3.2 Transaction costs for generators

Market Reform assessed the one-off and incremental on-going costs of optional firm access to generators in the NEM.[112]

Market Reform undertook two approaches to estimating the cost of optional firm access to generators:

- A survey of NEM generators was conducted to obtain their estimates of the costs within scope. The survey identified low, best and high cost estimates for both the implementation cost and on-going annual operational cost of optional firm access. Affiliated entities (for example, if parent companies trade on behalf of multiple NEM participants) were asked to provide a consolidated response. Fourteen companies completed and returned the survey.

- Market Reform developed a cost model based on its experience in planning and managing Energy Trade and Risk Management projects. Costs that could not be estimated using this approach– such as legal costs – were taken from survey results.

Each participant (that is, each generator in the NEM) was assigned a nominal complexity, based on the perceived scale and sophistication of its operations. Within each complexity grouping, estimates were derived for those participants who did not respond to the survey based on the statistics for those who did. In this way, a survey-based estimate of the total cost of optional firm access was formed. Similarly, the number of organisations within each complexity level was multiplied by the cost model results for that complexity, in order to provide a cost-model-based estimate of the total cost of optional firm access.

Market Reform estimate that the optional firm access transaction costs for generators would be **$80 million** ($2014).[113] This figure is based on the "best cost" estimate, derived through Market Reform's cost model approach. This reflects the total implementation costs (approximately 50 per cent), plus five years of on-going costs (approximately 50 per cent).

The cost estimates produced through the survey method are more variable than the cost model estimates. The survey method estimated transaction costs of optional firm access would be $121 million. However, Market Reform notes that surveys of participant costs can be informative but should not be viewed as definitive. Respondents will have different levels of understanding of the proposed market design changes, and their potential impact on the respondent organisation. There is also potential for responses to be influenced by whether or not the respondent is in favour of the market design proposition. Finally, not all participants responded to the survey meaning that a component of the overall cost estimate had to be interpolated based on others' responses.

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112 Market Reform, Transaction costs of OFA for generators in the NEM, January 2015.

113 A discount factor of one was assumed.

Given this, the Commission has chosen to use Market Reform's cost model estimates when considering transaction costs for generators.

10.3.3 Transaction costs for AEMO in relation to access settlement

AEMO has estimated the costs of changes relating to access settlement that may be required for AEMO if optional firm access was to be implemented. This includes costing the following:[114]

- maintenance of a list of firm access quantities and access settled meters as advised by TNSPs other processes;
- changes to the settlements processes to operate access settlement, covering both generator firm access and firm interconnector access;
- changes to constraint formulation or tagging processes necessary to support the access settlement concept;
- testing of new systems; and
- provision of additional market information to assist participant engagement with optional firm access settlements.

AEMO have estimated that it would cost **$1.8 million** (2014$) to implement the access settlement component of optional firm access.[115] This is just the one-off implementation costs. The Commission understands that AEMO has also formed the view that it does not consider there would be any additional ongoing costs of operating access settlement.

10.3.4 Transaction costs for AEMO and AER

The Commission has not estimated transaction costs associated with the changes to the following market institutions following the introduction of optional firm access:

- AEMO, in respect of functions outside of access settlement (most notably undertaking procurement auctions); and
- AER.

AEMO operates on a cost recovery basis as a corporate entity. AEMO fully recovers its operating costs through fees paid by participants. Therefore, it would be expected that

114 AEMO did not assess the costs of implementing either the inter-regional or the short-term firm access auction. We note that AEMO did estimate that by retiring the SRA auctions as part of the introduction of optional firm access, it would save AEMO between $865,000 and $1,057,000. These savings are not included in the estimates since these costs would be more than offset by AEMO introducing two new auctions.

115 AEMO estimated the project costs to be between $990,000 and $2,650,000. The Commission has averaged these costs to arrive at $1.7 million.

an increase to AEMO's function, as a result of optional firm access, would likely increase (but not substantially) fees paid by participants in the market.

The AER sits within the Commonwealth Government, along with the ACCC. The AER therefore receives its funding through the Commonwealth Government. Any increase to its functions following the introduction of optional firm access would likely affect the level of AER funding required, but would not have a direct cost impact on market participants.

10.3.5 Complexity

Numerous stakeholders have commented that the optional firm access model is complex. The Commission agrees. However, the NEM is a complex market. In designing optional firm access, the Commission is conscious that this would be an evolution of the existing design of the market.

Optional firm access is an all-encompassing solution that addresses a number of problems as detailed in chapters 4 through 9. It aims to be implemented across different regions of the NEM, across both the generation and transmission sectors, to accommodate a range of businesses, types of generation, and network characteristics. Therefore, it needs to accommodate all of these characteristics and that necessarily involves some complexity.

Further, the optional firm access makes explicit complexity that is currently implicit in the NEM, allowing it to be managed by participants. For example, it involves pricing an individual's incremental cost to the network.

10.4 Commission's conclusions

Taking into account the transaction costs that the Commission has estimated, it can be seen that the approximate transaction costs of optional firm access are **$90 million** ($2014).

The Commission recognises that these transaction costs do not take into account the level of complexity that is associated with the optional firm access model. The optional firm access model involves a degree of complexity that is commensurate with the design and operation of the NEM. Indeed its complexity is, in part, driven by the complexity of the NEM.

11 Overall draft assessment and recommendation

11.1 Overall assessment against the National Electricity Objective

The Commission has assessed what the impacts on the market would be if the optional firm access model as developed in this project was to be implemented. This assessment has been carried out using both quantitative and qualitative approaches. This assessment was carried out against defined criteria, as set out in chapters 4 through 10 above.

Optional firm access would impact the NEM in both an investment sense, as well as an operational sense. Specifically:

- it would have an impact on what would be the level of generation and transmission investment. This can be seen through the assessed impact categories of risk allocation and generation and network investment; and
- it would have an impact on operational outcomes for TNSPs and generators, given an existing level of generation and transmission capital stock. This can be seen through the assessed impact categories of inter-regional hedging, financial certainty for generators, incentives on TNSPs to operate the network efficiently, and efficient dispatch of generation.

The Commission considers that optional firm access could help the market adapt in an environment of major changes in the capital stock requiring significant investment and characterised by high levels of uncertainty with respect to relative costs, technologies and hence locational decisions in the following ways:

- *Risk allocation:* The risks associated with transmission investment include the risk associated with demand projections resulting in a different level of investment than is required, and the risk of supply-side changes resulting in higher costs of some generation types and obsolete investments. Optional firm access would change the allocation of these risks in the transmission and wholesale markets. Some of the risk would be shifted from consumers, who currently directly bear most of the costs associated with transmission, to generators who would bear costs related to their need for access.
- *Generation and network investment:* Under optional firm access, there would be better signals between generators and transmission businesses relating to the impacts of investment. Generators, rather than transmission network planners, would drive part of the decision-making about future transmission development. These better signals from generators to transmission network planners would also be beneficial when the network is shrinking and transmission businesses are deciding whether or not to replace assets. Optional firm access would promote a diversity of views about the future of both generation and transmission, by placing more of the responsibility for the development of the network with generators. This would help improve the co-ordination between transmission

and generation investment in the NEM so that total system costs would likely be minimised for consumers.

 - Ernst & Young (EY) have estimated that the benefits of improved co-ordination, measured as the difference in total system costs (ie, generation and transmission) between the current planning arrangements and optional firm access, range from $51 million (with a reduced Renewable Energy Target (RET) and no carbon price) to $86 million in the base case (weak demand growth, the RET in its current form and no carbon price) to $670 million with an emissions reductions scenario that targets a 40 per cent reduction on 2000 levels by 2025 and an 80 per cent reduction by 2040.

- *Inter-regional hedging:* Optional firm access could improve the firmness of inter-regional hedging. This could facilitate more generators and retailers to contract with each other across regions in the NEM.

Regarding other criteria against which optional firm access has been assessed:

- *Financial certainty for generators:* Optional firm access should improve financial certainty for generators who purchase optional firm access. However, most generators have said that they would not value such a product. Financial transmission rights in energy markets elsewhere are valued, and have been purchased, by generators. It is possible that if congestion levels were to increase in the NEM, more generators may value access more highly. Indeed, some generators have expressed different views in the past, when congestion levels were higher.

- *Incentives on TNSPs to operate the network efficiently:* TNSP incentives would be better linked to the value to the wholesale market of any shortfalls in capacity.

- *Efficient dispatch of generation:* Based on the information available, the value of dispatch inefficiencies would appear to be small. Therefore, while optional firm access would remove some of these dispatch inefficiencies, the benefits across the NEM would be small.

The level of costs associated with implementing optional firm access was also considered as part of this assessment. The estimated transaction costs (for the first five years) are approximately $90 million.

As discussed above, given the current market conditions, the investment-related benefits that the Commission has been able to quantify are similar to the level of costs. There has been a reduction in demand for electricity and there is an excess of generation supply, causing fewer significant impacts from congestion, and little projected transmission and generation investment for the foreseeable future.

11.2 Draft recommendation

The Commission's draft assessment of the benefits and costs of optional firm access is that, in the current environment, absent some major shift in market conditions and government policy settings, its implementation would not contribute to the achievement of the National Electricity Objective.

Currently the market is experiencing historically low spot prices, fewer significant impacts from congestion and low levels of both generation and transmission investment. These subdued conditions have been driven principally by:

- a reduction in the demand for electricity, due to:
  - lower levels of industrial consumption (including large load shutting down);
  - improved energy efficiency in all sectors;
  - the increasing prevalence of solar rooftop installations; and
- an excess of generation supply.

Further, successful implementation of a reform of this nature, would require a substantial amount of effort and time from participants and market bodies in the NEM. At the moment, this commitment is not present. In part, this is due to participants' views regarding subdued market conditions.

The benefits of optional firm access would be greater in an environment where new investment (either transmission, generation or both) is more likely. The Commission recommends that optional firm access could be considered for implementation when there are signs that the investment environment is beginning to change and become more uncertain. Both these conditions are required for consideration of implementation.

Given the resources required for implementation and the lead times involved, the Commission makes a further draft recommendation that market conditions be monitored for indicators of these emerging drivers. This should be undertaken as an adjunct to the Commission's existing annual Last Resort Planning Power functions. If there are signs that conditions are beginning to change in a way that the benefits from optional firm access could be greater, a process to implement optional firm access could be considered for implementation, taking into account the implementation risks involved.

11.3 Functional assessment of the optional firm access model

The Commission has developed, refined and enhanced the optional firm access model. Each of the model elements, particularly the pricing element, would require further work during a detailed implementation phase. However, the Commission is of the view that, from a functional perspective, the optional firm access model could be implemented in the NEM, and, in a changing and uncertain investment environment would contribute to the National Electricity Objective, provided implementation risks could be managed.[116]

11.4 Further work to be done before the Final Report

The Commission welcomes responses on the draft assessment, and draft recommendation as set out in this Volume. The Commission will consider such submissions before making final recommendations to the COAG Energy Council.

Given the above recommendation, the AEMC does not propose to undertake further development work on the optional firm access model itself. Any remaining development work will be left until a later implementation stage.

For the Final Report, the Commission will consider the following, and welcomes stakeholder comments on this:

- **Monitoring of conditions in the NEM**. The Commission will consider the possibilities for how indicators that relate to the likely benefits of optional firm access in the NEM could be monitored. This monitoring would be undertaken as an adjunct to the Commission's existing annual Last Resort Planning Power functions.
  - Most signs or indicators that would increase investment can be linked with either changes to emissions costs; or changes to the costs of generation. There would also need to be indicators about the level of demand. The Commission will develop signals or indicators that could be considered in this monitoring, and how this monitoring would occur.
  - A lead time would be required to implement optional firm access. For the Final Report the Commission will also consider what this lead time to implement optional firm access would be, and how this lead time could be incorporated into the monitoring process.
- **Alternatives to optional firm access**. A number of stakeholders have proposed either simplified versions of optional firm access, or alternatives, as part of submissions to the Commission's request for comment. Such options may reduce the costs associated with optional firm access, and so make the case for change today stronger. The Commission will consider such options that have been raised, and the effectiveness of them, prior to producing the Final Report. The Commission notes that such alternatives are typically not that simple, and are likely to be nearly as complex as optional firm access.

116 Further, AEMO's work, on its terms of reference, has confirmed this for the access settlement element. Access settlement has been demonstrated to be functional and operates generally as intended. See: http://www.aemo.com.au/Electricity/Market-Operations/Optional-Firm-Access.

— A focus in this regard will be on the alternative solutions to address the use of interconnectors. More specifically, this is where new generators may seek to locate on interconnector flowpaths in order to take advantage of the large capacity available. The effects of such decisions may be to diminish flows across the interconnector, in which case fewer residues will accrue. Further, if generators who compete with the interconnector in dispatch, bid at the floor price, they would be dispatched ahead of the interconnector. The Commission will consider such alternatives to address these issues, including any Rule-changes that may be required.

12 Jurisdictional specific matters

The Terms of Reference refer to the possibility of implementing optional firm access in some jurisdictions first. In the work undertaken in this project, the Commission has considered whether there are any unique features of a jurisdiction that mean one jurisdiction should be treated differently to the others.

The two jurisdictions that the Commission has considered in detail are Victoria and Tasmania. This chapter explains why those jurisdictions may need to be treated separately for the purpose of optional firm access, and how that might affect the optional firm access model if it was implemented.

12.1 Victoria

12.1.1 Differences from other jurisdictions

The administrative and governance arrangements for transmission are different in Victoria from the other regions that make up the National Electricity Market. In particular, AEMO is the TNSP responsible for planning of the shared network, and procuring services from third party network service providers. Third party network service providers own, maintain and operate the shared network. In most cases the service provider which performs these roles is AusNet Services.

These differences affect how optional firm access could apply. In particular, in Victoria it would be necessary to allocate risk or responsibility for planning or operational failures between AEMO and the third party network services providers. For example, it may be unclear whether an outage has been caused by a failure to plan, or an operational issue. In other jurisdictions where one TNSP both plans the network and operates the network, this need to allocate responsibility would be unnecessary.

While probabilistic planning is used in Victoria, this would not affect the application of optional firm access.

12.1.2 Proposed approach

During this project, the Commission has consulted with Victorian bodies, including AEMO and AusNet Services, to clarify how optional firm access could be applied in that jurisdiction.

If optional firm access were implemented in Victoria, AEMO would be the appropriate body to engage with any generators seeking firm access as part of the procurement process. That is, AEMO would be the “counterparty” to the firm access arrangements.

Separately, AEMO could enter into an arrangement with third party network service providers such as AusNet Services to allocate responsibility for any access shortfalls that occur. In general, AEMO would take primary responsibility for planning failures and the network service providers for operational failures. The split of the firm access planning standard from the firm access operating standard that has been proposed as part of the recent work on optional firm access should make this allocation easier.

In respect of the optional firm access incentive scheme, one option would be for AEMO to be treated as the TNSP for the purposes of the incentive scheme. It could then pass on any penalties or rewards to the relevant third party network service providers through a contractual mechanism. However, it may be challenging to apply incentives to AEMO given it is a not-for-profit organisation. To the extent that this creates difficulties, this would need to be worked through if optional firm access came to be implemented.

In summary, in order to implement optional firm access in Victoria AEMO would need to put in place arrangements between it and third party network service providers. Work on Victorian issues so far indicates that it should be possible to overcome any challenges that arise.

12.2 Tasmania

12.2.1 Differences from other jurisdictions

It would be technically more challenging to implement optional firm access in Tasmania compared to other jurisdictions. In particular:

- *Classification of constraints.* Under optional firm access, transmission constraints would form the basis of the flowgates used in access settlement. Frequency Control Ancillary Services (FCAS) constraints would typically not be included in access settlement since these are not generally caused by limitations on TNSP networks, meaning that they are not considered flowgates. In Tasmania, FCAS constraints have a larger impact on generator trading than in other regions. Therefore, Tasmanian participants would gain less certainty from the purchase of firm access, and might so place a lower on the value of the product. While such constraints are present in other regions of the NEM, they are not present to the same extent, and so the Commission does not consider this is a problem in other regions.

- *Connection point complexity.* As noted in Volume 2, there would need to be specific requirements for the metering arrangements and auxiliary load, to enable access settlement. In a number of rare circumstances across the NEM, there are generators whose current metering configurations could not be grandfathered to meet these requirements. Some of the most complex examples of this are in Tasmania. While these could be integrated into the optional firm access arrangements, it may be difficult.

- *Location of the regional reference node.* The Tasmanian regional reference node, at George Town, is not located at the largest city in the region. In the mainland regions, the regional reference node is located near the largest city in the region.

> The location of the regional reference node factors into a number of elements of the optional firm access model, most notably the LRIC pricing model. Here, where the amount of registered access is greater than the demand, additional load is simulated at the regional reference node to balance total capacity and demand. Consequently, a number of constraints, that do not reflect physical realities, appear through such modelling.

At the same time, the structure of the market in Tasmania means that the benefits of implementing optional firm access appear fewer. Generation in Tasmania is dominated by HydroTasmania, meaning that it is immaterial whether it is firm or non-firm since there are limited other generators to manage congestion risk in respect of. In addition, HydroTasmania and TasNetworks are owned by the same entity (the Tasmanian Government). This should make for better co-ordination of investment between generation and transmission.

Finally, the unique way in which Tasmania is connected to the mainland; being a single link, controllable HVDC, unregulated MNSP, means that it is easy to separate. There are no cross-border issues - no Tasmanian generators have an effect on constraints in the Victorian region, and vice versa. Therefore, it would be easier to separate out Tasmania.

12.2.2 Proposed approach

If optional firm access was implemented, Tasmania would be excluded from the optional firm access model in the first instance, assuming elements of the Tasmanian market remain as they are currently. As set out above, the technical challenges for optional firm access are greater in Tasmania and the benefits are lower. In addition, it is easier to exclude Tasmania from the optional firm access model than it is for other jurisdictions.

Tasmania would be excluded from optional firm access from George Town south. This means it would not be possible for generators to purchase firm access for Tasmanian flowgates.

However, Basslink northwards flows would be included in optional firm access within the Victorian region. Basslink is an MNSP, and so would be treated like a generator in the optional firm access model. This is because Basslink southwards flows are treated as a demand-side user in Victoria, and so beyond the scope of the optional firm access model. In the region it delivers power into (the importing region), it is similar to a generator in the sense that it injects power into the shared network at a specific node. Basslink would also be allocated a level of Victorian transitional access.

Tasmania would only be excluded from optional firm access initially. There would be the possibility of Tasmania being brought into the optional firm access model in the future. This would be considered further during any implementation process for optional firm access. Work on implementation should also consider whether the elements of the Tasmanian market have changed since the time of this Draft Report such that there would be more benefits and fewer technical challenges from implementing optional firm access.

A Historical congestion patterns

The Commission has considered historical patterns of congestion. The charts below illustrate the extent of congestion within zones in the NEM between 2010 and 2014. The dataset is limited to reporting on congestion where binding constraints would have a marginal value of greater than $10/MW, and where the frequency of binding was above some 40 dispatch intervals. Such limitations are needed given that the mapping of constraints to locations is challenging, and requires manual consideration of the constraint formulation.

The level of congestion in a zone/interconnector is allocated to a category ranging from "mild" to "severe" congestion. The categories are defined by reference to the number of instances constraints bound in that zone/interconnnector for the given year. However, inter-regional and intra-regional congestion use different scales, and so cannot be compared. For example, in 2014 Murraylink had "mild" congestion compared to the other interconnectors; while North Queensland had "mild" congestion compared to the other zones. These numbers cannot be compared - North Queensland had zero instances of binding constraints; while Murraylink had 988 instances of binding constraints.

Inter- and intra-regional congestion cannot be placed on the same scales since the incidence of congestion on interconnectors is significantly greater than intra-regional congestion.

Figure A.1 Historical congestion - 2010

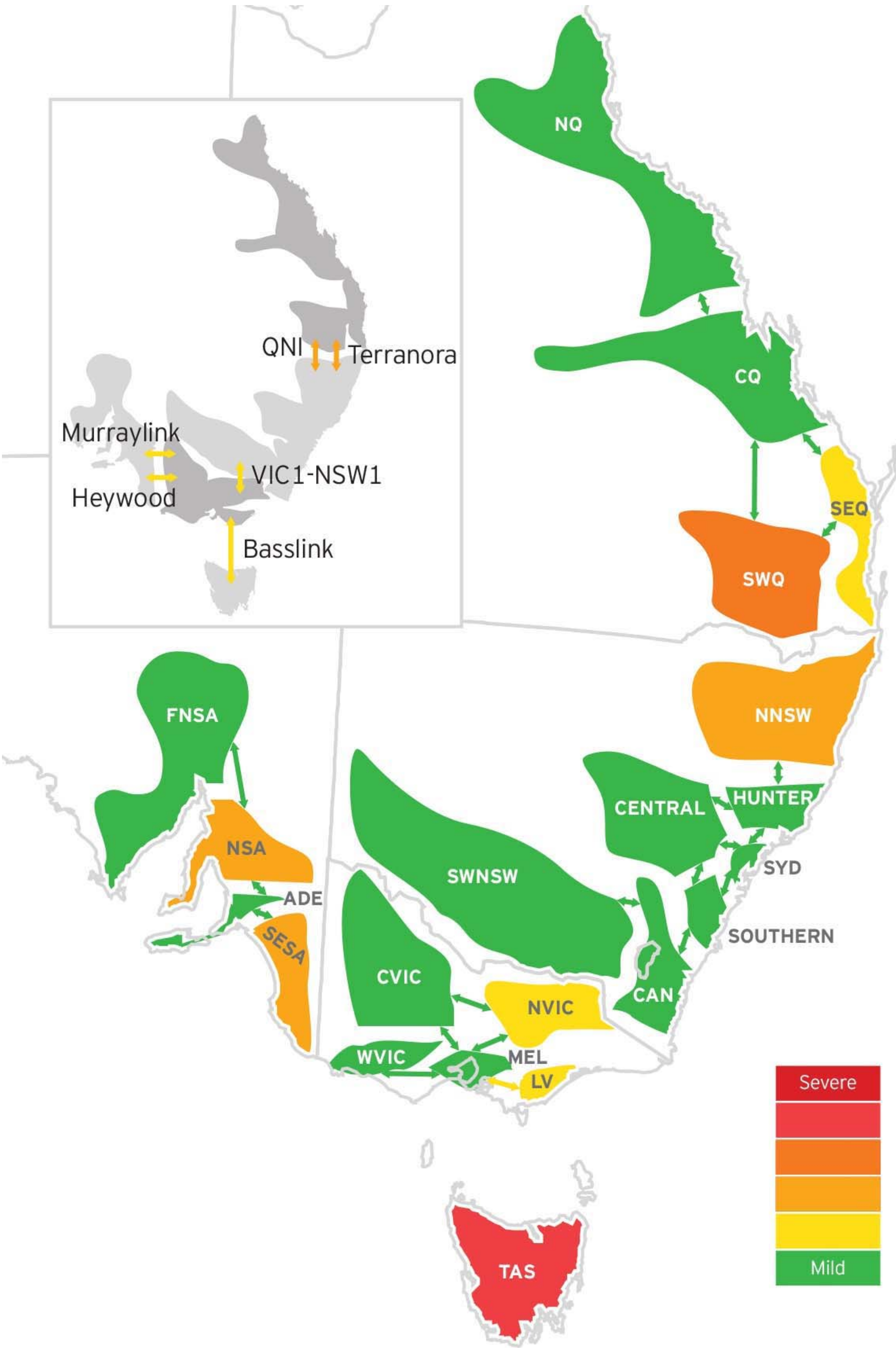


Figure A.2 Historical congestion - 2011

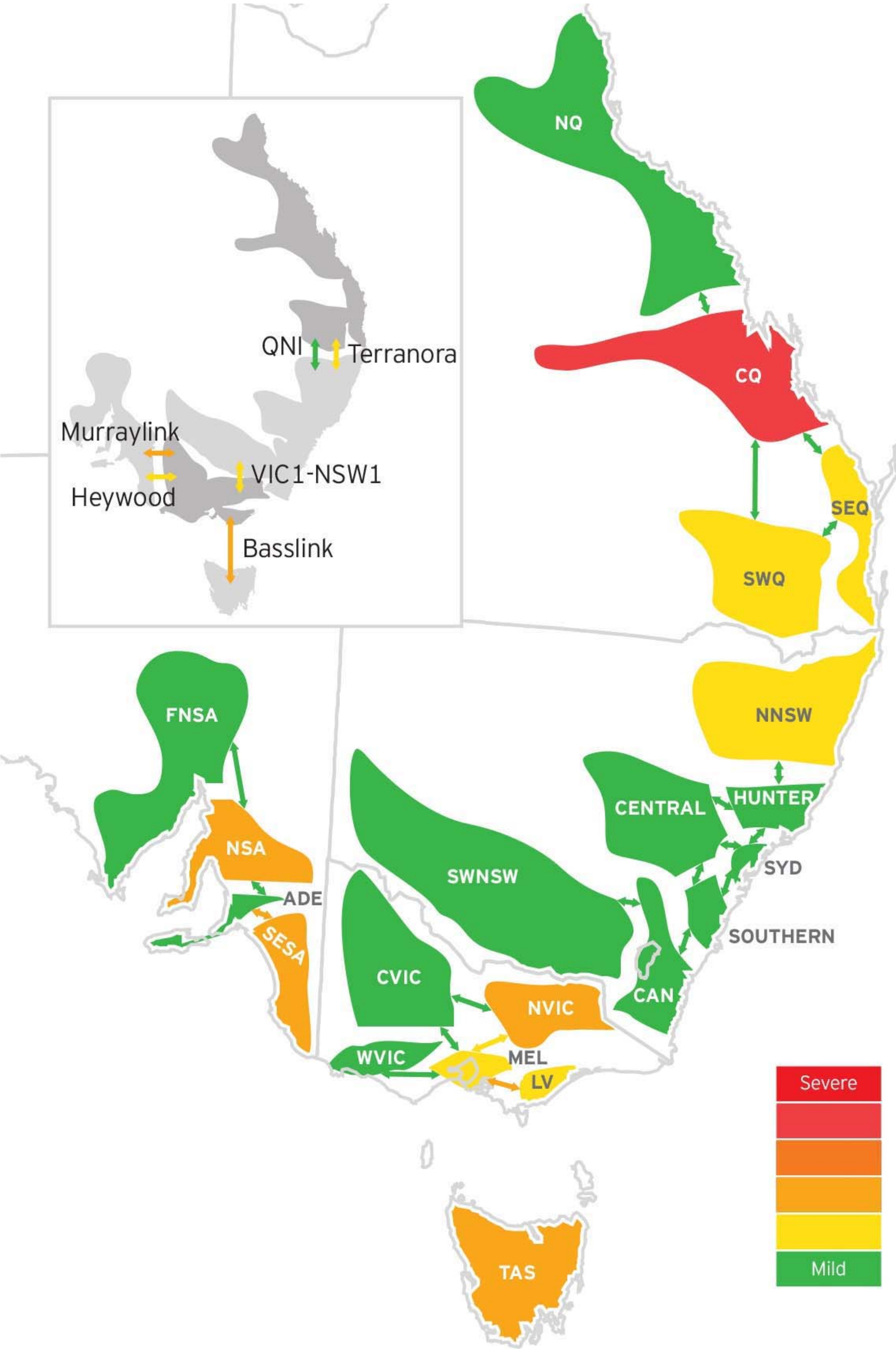


Figure A.3 Historical congestion - 2012

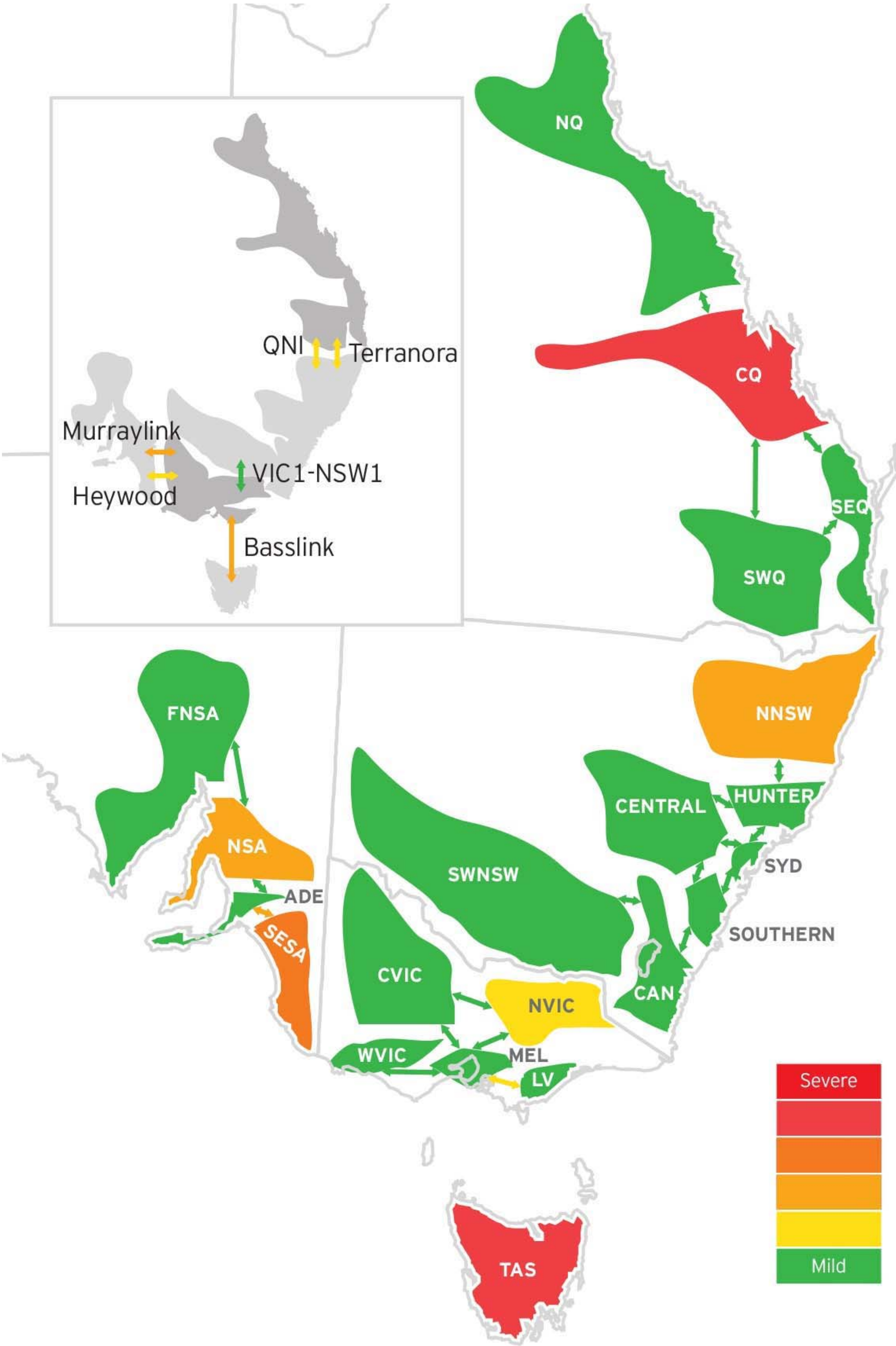


Figure A.4 Historical congestion - 2013

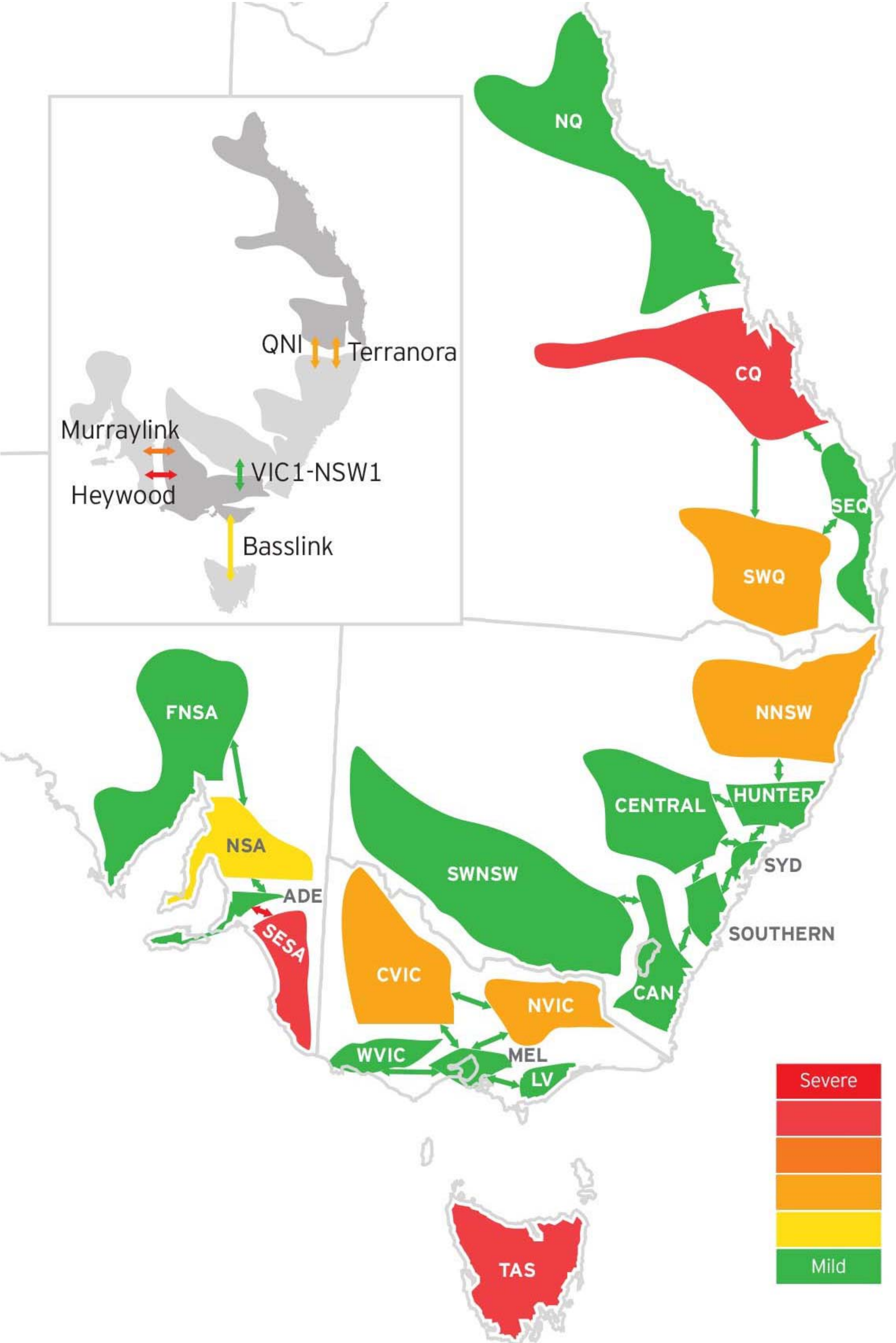
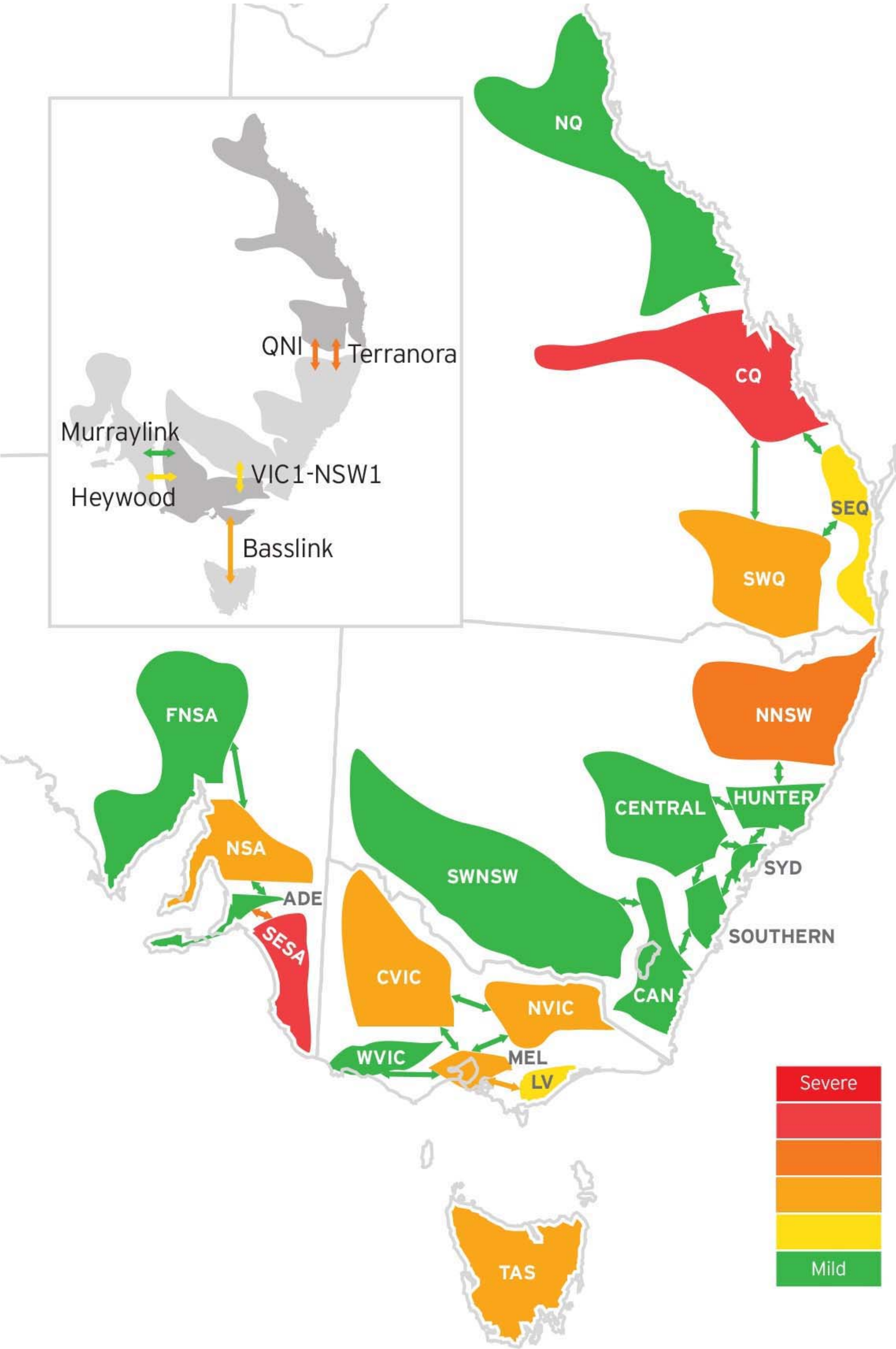


Figure A.5 Historical congestion - 2014



B History of reviews on congestion and access

In order to provide background and context to this project this appendix sets out a summary of historical reviews on congestion and access since the commencement of the NEM in 1998.

B.1 Transmission and distribution pricing review 1999

Table B.1 Summary of review[117]

Question	Answer
Who undertook the review?	NECA
When did the review take place?	December 1997 to June 1999
What were their findings in terms of whether access and/or congestion was a problem?	New transmission investment can benefit both generators and consumers. Currently, only consumers pay for new investments - this is a mismatch between who benefits, and a flaw in the current arrangements. It will lead to inefficient investment and inappropriate locational decisions. However, the current arrangements for recovering the cost of the existing network (that is, from customers) are appropriate. The recently introduced settlement residue auctions are welcome.
What were the recommendations?	Beneficiaries of new investment should pay in proportion to the estimated share of the benefit. These benefits are estimated as part of the TNSP's analysis of the project investment. The method for levying TUOS charges recommended is reasonably complex, but includes consideration of the utilisation of each transmission element (and hence indirectly factoring in the cost of future augmentation). The objective being to reflect the level of spare capacity on the system, and signal future investment costs. Once experience has been gained of the recently introduced settlement residue auctions, consideration should be given to firming-up the hedges provided under those auction arrangements. The transmission congestion contracts model (that is, FTRs) that are present in the US is a logical further development for the Australian market.

117 See: NECA, Transmission and distribution pricing review, final report, June 1999.

B.2 Review of Integrating the Energy Market and Network Services

Table B.2 Summary of review[118]

Question	Answer
Who undertook the review?	NECA
When did the review take place?	October 1999 to August 2001
What were their findings in terms of whether access and/or congestion was a problem?	SRAs are not a firm hedge due to (amongst other things) congestion. This has been a problem for those wishing to trade between South Australia and Victoria. For other directional interconnectors, this has not been a problem to date, because constraints have not resulted in reduced flow that has caused significant price separation and a lack of firmness. However, the risk that it may happen adds to the cost of inter-regional trade.
What were the recommendations?	Improved information flows, to inform SRA auction participants of likely interconnector capacity. Develop performance measures on the assets that affect interconnectors (based on the value of trade foregone as a result of network outages). Introduce contracts against those performance measures designed to encourage TNSP behaviour that maximises market benefit. In the future, requirements on TNSPs to deliver pre-determined interconnector transfer capabilities, with financial penalties/incentives on TNSPs to deliver at or above the contracted level of transfer capability. Separately, the introduction of firm access and payment of compensation by TNSPs in the event of an intra-regional network constraint was contemplated, but this suffers serious limitations on the grounds of complexity/practicability.

118 See: http://www.neca.com.au/Reviewscc3e.html?CategoryID=51&SubCategoryID=211

B.3 Parer review

Table B.3 Summary of review[119]

<table>
<tr><th>Question</th><th>Answer</th></tr>
<tr><td>Who undertook the review?</td><td>A 4 member panel, chaired by the Hon Warwick Parer, upon the request of the Ministerial Council on Energy.</td></tr>
<tr><td>When did the review take place?</td><td>2001 to December 2002</td></tr>
<tr><td>What were their findings in terms of whether access and/or congestion was a problem?</td><td>It is not possible to obtain firm financial transmission rights to underpin interstate contracting.

The process for determining transmission augmentations is flawed.

Regulated interconnectors do not face market incentives.

Lack of cost reflective network pricing for both load and generation.</td></tr>
<tr><td>What were the recommendations?</td><td>SRA auction to be replaced with a firm financial transmission right, auctioned by NEMMCO:

• which gives owners the right to the difference between pool prices between regions to the extent of the MW of capacity sold, as opposed to the extent of flow over the line;

• NEMMCO would protect itself from financial risk by selling less financial transmission rights than the full capacity of the interconnector, and using surplus residues to meet commitments.[120]

Inter-regional augmentation to be informed by the price of the auctioned financial transmission right (as an indicator of the value of firm inter-regional access). Intra-regional augmentation decisions to also take account of (inter-regional) price differentials caused by congestion.

TNSPs should be incentivised according to the value of congestion (for example, based on extent of price separation between regions). This arrangement should also be duplicated within regions.

Full nodal pricing as the long-term goal.</td></tr>
</table>

119 See: http://www.efa.com.au/Library?ParerFinRpt.pdf

120 This option was specifically rejected by NECA in the RIEMNS review, on the basis that participants concluded that this is a risk that is best managed by individual participants.

B.4 Regulatory and Institutional Framework for Transmission 2003

Table B.4 Summary of review[121]

Question	Answer
Who undertook the review?	Firecone, upon request of the NEM ministers
When did the review take place?	August 2003 to November 2003
What were their findings in terms of whether access and/or congestion was a problem?	The current regulatory framework has resulted in potential inefficiencies, partly as a result of transmission. These potential inefficiencies include: • potentially higher energy market spot prices as a result of congestion; • delayed inter-regional transmission investment; • locational signals for consumers which do not reflect the cost of supply; and • low inter-regional trade. However, these issues are best managed through improvements to existing frameworks.
What were the recommendations?	The focus should be on making the current arrangements more effective (as opposed to trying to replace the current model for transmission), for example: • improved criteria for changing regional boundaries, and adjustment of the boundaries if necessary against these new criteria (see below); • improvements to NEMMCO's (now AEMO) constraints formulation (see below); • introduce a TNSP incentive program, which reflects the marginal costs of constraints; • maintain the requirement for consultation on forward scheduling of outages; and • clarify that the regulatory test for augmentations includes market benefits.

121 Firecone, Regulatory and Institutional Framework for Transmission, Final Report, November 2003.

B.5 Energy Reform Implementation Group

Table B.5 Summary of review[122]

Question	Answer
Who undertook the review?	Energy Reform Implementation Group, following a request from the Council of Australian Governments
When did the review take place?	February 2006 to January 2007
What were their findings in terms of whether access and/or congestion was a problem?	Inadequate mechanism by which efficient transmission investments are determined, and to incentivise the efficient operation of existing assets. Inadequate commercial incentives for generators to locate efficiently. Inadequately coordinated investment on a national basis.
What were the recommendations?	That the AEMC's congestion management review (see section B.8) delivers a regime which will improve operations and dispatch in the short term and allocative efficiencies in the longer term (with appropriately modified terms of reference from MCE). MCE should adopt such a regime. Introduction of a comprehensive incentive regime from the AER.

B.6 Snowy Region abolition rule change

Table B.6 Summary of review[123]

Question	Answer
Who undertook the review?	AEMC undertook a series of rule changes, relating to the definition of the Snowy Region. This followed receiving various rule change requests from parties in the NEM: • Snowy Hydro - who sought to abolish the Snowy Region proposal; • Hydro Tasmania, International Power, LYMMCO, NRG Flinders, TRUenergy (together, known as the "Southern Generators") – "Congestion Pricing Proposal", who sought to effectively extend the interim arrangements and defer consideration of regional boundary change; and

122 See: http://www.industry.gov.au/Energy/EnergyMarkets/Pages/EnergyReformImplementationGroupReport.aspx

123 See: http://www.aemc.gov.au/Rule-Changes/Abolition-of-Snowy-Region

Question	Answer
	• Macquarie Generation – the "Split Snowy Region Proposal", who sought to split the Snowy Region into two regions, which would be known as the Murray Region (south of the new boundary) and the Tumut region (north of the new boundary).
When did the review take place?	January 2006 to August 2007
What were their findings in terms of whether access and/or congestion was a problem?	Price differences between regions provide locational signals for future investment in generation and transmission by signalling variations in the cost of supplying customers in different locations. Regional boundaries should be located at points of material and enduring network congestion. This is not the case in relation to the Snowy region. There are material and enduring network limitations between Murray and Tumut within the Snowy region, which are unlikely to be resolved through network investment (or otherwise) in the near future. The constraints provide Snowy Hydro incentives to behave in ways that can result in inefficient market outcomes.
What were the recommendations?	All three rule change proposals represent an improvement on the base case – there is a strong case to improve on this major congestion issue in the NEM. However, the Commission considered that abolishing the Snowy region was the preferred solution for addressing this congestion issue as the most proportionate and stable response. This Rule was made. In contrast, the split of the Snowy region was deemed to add complexity to the market arrangements without discernible benefits; while the congestion pricing proposal effectively deferred consideration of the regional boundary change, and so created unnecessary uncertainty.

B.7 Region boundary rule change

Table B.7 Summary of review[124]

Question	Answer
Who undertook the review?	AEMC, following a rule change request from the Ministerial Council on Energy.
When did the review take place?	January 2006 to December 2007.
What were their findings in terms of whether access and/or congestion was a problem?	Region boundaries are intended to transparently identify physical points of material and enduring congestion, so that market participants can more efficiently manage the risks associated with inter-regional trade. Ideally, regions should be areas within the power system that are free of material congestion. In practice, the trade-offs made between the granularity of the regional structure and transaction costs mean that some degree of congestion is likely to remain intra-regionally. Currently (at the time), regional boundaries could be changed with regard to primarily technical criteria.
What were the recommendations?	Changed the Rules from primarily technical criteria for changes to region boundaries to primarily economic criteria, as a means to manage congestion. The criteria include: • the region change solution will materially improve economic efficiency, which includes but is not limited to, improvements in productive efficiency, efficiency in relation to the management of risk and the facilitation of forward contracting, and long term dynamic efficiency; • the region change must be an appropriate and timely course of action in all the circumstances, having regard to the alternative congestion management options; and • the region change must be consistent with power system security and reliability. These criteria would also have the advantage of making the process for changing boundaries more predictable and stable.

124 See: http://www.aemc.gov.au/Rule-Changes/Process-for-Region-Change-(formerly-called-Region

B.8 Congestion Management Review

Table B.8 Summary of review[125]

Question	Answer
Who undertook the review?	AEMC, following a terms of reference from the Ministerial Council on Energy.
When did the review take place?	October 2005 to June 2008.
What were their findings in terms of whether access and/or congestion was a problem?	Congestion can create incentives to disorderly bid. Congestion can influence the location decision of investors. There is a lack of clarity on constraint formulations by AEMO, so market participants are unable to fully understand the commercial implications of constraints. Lack of firmness for IRSA units as hedging instruments, because no fixed manner in which AEMO intervenes in the market to manage Negative Inter-regional Settlements Residues. Lack of information on congestion (planned network events, and mis-pricing). Risk that a generator who funds a network augmentation does not realise the full benefits of the augmentation because another generator connects subsequently.
What were the recommendations?	Four rule changes to improve information available to market participants to help them understand the risks associated with congestion and improve risk management instruments (see section B.9 below): • Formalise NEMMCO’s use of fully co-optimised network constraints for the purposes of dispatching generation. • Amend Rules governing the funding of negative settlement residues to reduce uncertainty for inter-regional settlement residue unit holders. • Establish a new Congestion Information Resource, to improve information to congestion. • Strengthen Rules governing rights of generators who fund transmission augmentations, so that future connecting parties make a contribution. Not to introduce “locational-specific interim constraint management mechanism” as it fails to address the locational decision problem, and the disorderly bidding problem is not currently material.

125 http://www.aemc.gov.au/Markets-Reviews-Advice/Congestion-Management-Review

Question	Answer
	There may be future challenges to the NEM, primarily arising from climate change policy, potentially resulting in significant congestion and/or investment. This may warrant the re-examination of locational-specific interim constraint management mechanism, or introduce "generator nodal pricing". Generator nodal pricing could solve both the disorderly bidding problem and locational decision problem, but would be a complex and significant change. It is now timely to consider the case for such a fundamental change. These were considered in the Climate Change review (see section B.10).

B.9 Arrangements for managing risks associated with transmission network congestion

Table B.9 Summary of review[126]

Question	Answer
Who undertook the review?	AEMC, following a rule change request from the Ministerial Council on Energy.
When did the review take place?	February to August 2009
What were their findings in terms of whether access and/or congestion was a problem?	As per the Congestion Management Review, with regard to the first three Rules proposed, that is, information problems are a problem for access and congestion.
What were the recommendations?	Implement first of the three Rules to reduce the issues identified • Formalise NEMMCO's use of fully co-optimised network constraints for the purposes of dispatching generation. • Amend Rules governing the funding of negative settlement residues to reduce uncertainty for inter-regional settlement residue unit holders. • Establish a new Congestion Information Resource, to improve information to congestion. However, the fourth rule (network augmentations rule) was inappropriate for implementation now, given the issues being raised and considered in the Commission's Climate Change Review (see section B.10).

126 See: http://www.aemc.gov.au/Rule-Changes/Arrangements-for-Managing-Risks-Associated-with-Tr

B.10 Climate Change Review

Table B.10 Summary of review[127]

Question	Answer
Who undertook the review?	AEMC, following a request from the Ministerial Council on Energy.
When did the review take place?	September 2008 to September 2009
What were their findings in terms of whether access and/or congestion was a problem?	Climate change policies will significantly influence the utilisation of the network. In the context of changing utilisation of the network, inefficient operational and investment decision making on the part of transmission companies and generators may result from the current frameworks. These include: • poor locational and retirement decisions by generators; • disorderly bidding; and • over provision of transmission (as transmission follows generation).
What were the recommendations?	Charges to generators which vary by location to reflect network costs associated with their connection and use. In principle, generators should be able to negotiate and pay for enhanced levels of transmission service (further work required). Where practical and appropriate, pockets of material and transitory congestion within regions should be priced. The AEMC recommended that these should be considered further, which was undertaken in the Transmission Frameworks Review (section B.11).

127 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-Energy-Market-Frameworks-in-light-of-Cli

B.11 Transmission Frameworks Review

Table B.11 Summary of review[128]

Question	Answer
Who undertook the review?	AEMC, following a request from the Ministerial Council on Energy.
When did the review take place?	March 2010 to April 2013
What were their findings in terms of whether access and/or congestion was a problem?	There is a lack of clear and cost-reflective locational signals for generators, such that locational decisions do not take into account the resulting transmission costs. TNSPs estimate the benefits of transmission development, where those benefits are better known to generators, with the risk of inefficient decisions being borne by consumers rather than the decision-maker. The resultant planning of the transmission network is not co-optimised to minimise the combined costs of generation and transmission. It is important that TNSPs operate their network to maximise availability when it is most valuable, but currently they face challenges in doing this given the lack of exposure to the financial costs of reductions in capacity. Market participants have difficulties in managing the risk of price differences between different regions of the NEM, with a resulting negative impact on the level of contracting between generators and retailers in different regions. There is a lack of certainty of dispatch faced by generators when there is congestion, compounded by the inability of generators to obtain firm access, even where they fund augmentations of the transmission network. This creates incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion. The Commission developed the optional firm access model in response to these problems.
What were the recommendations?	That a detailed design and testing program for optional firm access should be initiated. This would allow for the better assessment of the costs and benefits associated with the model. (This is the current project).

128 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Transmission-Frameworks-Review

C Inter-regional trading products

This appendix sets out how inter-regional trading works under the current arrangements (that is, purchasing an SRA product) and then under optional firm access. To demonstrate this, it works it way through a series of progressively more complicated examples. All the examples in the below appendix use the following notation:

- G_N = Generator based in NSW
- RRP_N = Regional reference price in NSW
- RRP_V = Regional reference price in Victoria
- P = strike price
- Q = quantity
- IC(flow) = where IC is the NSW-Vic flow of the interconnector that is allocated to the SRA units held by the generator, which is set to zero when the interconnector flow is creating counterprice flows.
- A = generator purchases a quantity A of FIRs

C.1 Intra-regional swap

Assume a NSW generator enters into a basic swap with a NSW retailer. The generator sells a volume of forward contracts, and is dispatched for an equal quantity. It receives the contract price on that volume through the receipt (or payment) of contract for difference payments where the spot price is lower (or higher) than the contract price.

The generator's revenue is equal to:

$$G_N \text{ revenue} = [RRP_N - (RRP_N - P)] \times Q$$

Example 1: if RRP_N = \$100; P = \$50; Q = 100

$$G_N \text{ revenue} = [100 - (100\text{-}50)] \times 100 = \$5000$$

Example 2: if RRP_N = \$20; P = \$50; Q = 100

$$G_N \text{ revenue} = [20 - (20\text{-}50)] \times 100 = \$5000$$

Therefore, if a generator hedges with a retailer in its own region this leaves the generator indifferent to what the regional reference price is, that is, it should receive the same revenue regardless (provided it is dispatched for the same quantity).

C.2 Inter-regional swap, without an inter-regional hedging product

Assume a NSW generator enters into a basic swap with a Victorian retailer. However, the generator does not purchase an inter-regional hedging product.

The generator's revenue is equal to:.

$$G_N \text{ revenue} = [RRP_N - (RRP_V - P)] \times Q$$

Example 1: if RRP_N = \$100; RRP_V = \$80; P = \$50; Q = 100

$$G_N \text{ revenue} = [100 - (80\text{-}50)] \times 100 = \$7000$$

Example 2: if RRP_N = \$100; RRP_V = \$120; P = \$50; Q = 100

$$G_N \text{ revenue} = [100 - (120\text{-}50)] \times 100 = \$3000$$

Therefore, hedging with a retailer in another region, without some form of inter-regional hedging product leaves the generator exposed to any inter-regional price differences that may occur.

C.3 Inter-regional swap, with an existing SRA hedge

Assume a NSW generator enters into a basic swap with a Victorian retailer. The NSW generator also purchases a SRA product as an additional hedge to protect it from any inter-regional price differences that may occur.

The generator's revenue is equal to:

$$G_N \text{ revenue} = \{[RRP_N - (RRP_V - P)] \times Q\} + [(RRP_V - RRP_N) \text{ x } IC(flow)$$

Example 1: if RRP_N = \$100; RRP_V = \$120; P = \$50; Q = 100; IC(flow) = 100

$$G_N \text{ revenue} = \{[100 - (120\text{-}50)] \times 100\} + [(120\text{-}100) \times 100] = \$5000$$

Example 2: if RRP_N = \$100; RRP_V = \$120; P = \$50; Q = 100; IC(flow) = 0

$$G_N \text{ revenue} = \{[100 - (120\text{-}50)] \times 100\} + [(120\text{-}100) \times 0] = \$3000$$

Therefore, hedging with a retailer in another region, and purchasing a SRA unit protects the generator from inter-regional price differences, provided the flows across the interconnector are not reduced. If the flows are reduced (in the extreme case to zero), then the payout to the holders of the SRA units would also be reduced, and so the generator would not be protected from inter-regional price differences.

C.4 Inter-regional swap, with a firm interconnector right under optional firm access

Assume a NSW generator enters into a basic swap with a Victorian retailer. The NSW generator also purchases a firm interconnector right as an additional hedge.

The generator's revenue is equal to:

$$G_N \text{ revenue} = \{[RRP_N - (RRP_V - P)] \times Q\} + [(RRP_V - RRP_N) \times A$$

Example 1: if RRP_N = \$100; RRP_V = \$120; P = \$50; Q = 100; A = 100

$$G_N \text{ revenue} = \{[100 - (120\text{-}50)] \times 100\} + [(120\text{-}100) \times 100] = \$5000$$

Therefore, hedging with a retailer in another region, and purchasing a FIR (optional firm access inter-regional access right) protects the generator from inter-regional price differences in all circumstances. The inter-regional access product under optional firm access is independent of interconnector flow.

D Incentive scheme analysis

This appendix sets out an analysis of what the outcome of the incentive scheme described in chapter 5 of Volume 2 may have been had it been applied historically. As set out in that chapter, that incentive scheme is just one way an incentive scheme could be designed if optional firm access were implemented, and any incentive scheme that is developed may operate differently from that.

The firm access planning standard conditions under optional firm access would, by design, reflect the conditions under which congestion (and so access) risks are likely to be highest. However, this analysis has made an assumption that every generator holds firm access in accordance with the transitional access allocation determined by AEMO for the First Interim Report.

In the First Interim Report, AEMO undertook a study to estimate a potential allocation of transitional access under optional firm access.

This allocation has been carried out under peak demand conditions, so it is implicitly assumed that congestion risks are highest under these conditions. This is on the basis that these times are most likely to have extreme regional reference prices. This empirical analysis has *not* tested this assumption.

This analysis looks at the level of shortfall costs that would have resulted on the basis of this allocation of firm access. These shortfall costs arise when congestion and shortfalls (shortages of capacity) coincide on a flowgate. However, because the transitional access allocation has been designed to be firm access planning standard compliant (that is, accommodated under peak demand conditions), shortfalls would only occur when the effective flowgate capacity falls below the level of capacity at the peak.

D.1 Data sources and assumptions

AEMO has provided information on every congested flowgate in every trading interval in the period November 2013 to October 2014.

The Commission has used this, plus, the transitional access allocation that was derived by AEMO for the First Interim Report to simulate an incentive scheme with nested caps, based on TNSP exposures under the current market impact component incentive schemes.

These caps are indicative only. The trading interval cap is based on the penalty per trading interval under the current market impact component of the STPIS. The annual cap is based on the maximum annual upside under the current market impact component scheme. The caps are set out in Table D.1.

Table D.1 Incentive scheme caps ($000s)

Capping period	NSW	Queensland	South Australia	Victoria
Trading interval	38	73	21	32
Day = 5 ×trading intervals	190	365	105	160
Week = 3 ×day	570	1,095	315	480
Month = 2 ×week	1,140	2,190	630	960
Year	17,970	17,170	3,200	10,900

Flowgates have been tagged to TNSPs using an AEMO look-up table. Tasmanian data has not been analysed, due to the absence of any transitional access allocation.

There are a number of caveats associated with this analysis:

- the past is not necessarily a guide to the future - and outcomes may change anyway when incentives change under optional firm access;
- the peak historical conditions, which were used by AEMO when modelling transitional access, are not necessarily the same as the firm access planning standard conditions under optional firm access;
- historical flowgate prices may have been affected by disorderly bidding - in order to mitigate this effect, we have capped the prices at the regional reference price in order to remove this impact; and
- the incentive scheme parameters used are indicative only - these have been calibrated against the existing market impact component scheme.

D.2 Results

First, the Commission has calculated what each TNSP would pay under the optional firm access incentive scheme (given the above caveats). It is worth noting that under the above formulation, the caps are only substantially hit in South Australia and Victoria.

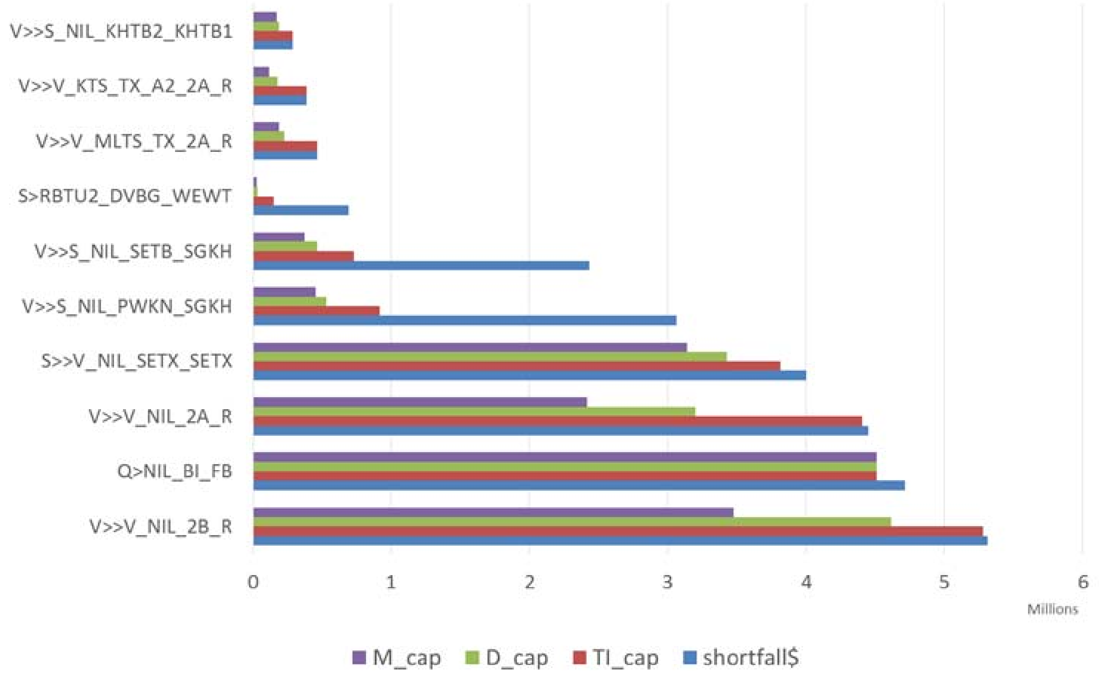
Table D.2 Scheme outcomes: annual payments ($000s)

Capping	NSW	Queensland	South Australia	Victoria
Uncapped payments	1,040	4,874	11,956	12,611
Payments applying the trading interval cap	1,040	4,668	7,308	12,503
Payments applying the daily cap	1,040	4,668	5,855	9,870
Payments applying the weekly cap	1,040	4,668	5,537	8,800
Payments applying the monthly cap	1,040	4,668	5,137	7,692
Payments applying the yearly cap	1,040	4,668	3,200	7,692

The annual cap limits overall TNSP risk and is likely to be set with regard to generic issues around TNSP risk and return, for example, what level of risk is consistent with the regulated WACC. The annual cap sets the "risk budget". The other, nested caps are then designed to allocate this risk budget across the year and aim to provide a strength of incentive commensurate with the ability of the TNSP to manage the shortfall. While it is difficult to make conclusions regarding the above simulated outcomes, the table appears to demonstrate that the structure is largely "right" - the various caps are rarely hit, but do serve to substantially reduce TNSP risk.

Figure D.1 sets out the ten most significant constraints by total shortfall costs, that is, the ten top ranked constraints where the capacity would fall below the firm access planning standard capacity.

Figure D.1 Most significant ten constraints by total shortfall cost



The Commission has explored these constraints in more detail, and discussed them with the Technical working group. Effective flowgate capacity depends upon many factors, such as:

- variations in local demand;
- changes to flowgate support generators;
- changes to the output of the largest generator in a region;
- changes to non-scheduled generators; and
- network outages.

Logically, those flowgates that exhibit the highest shortfall costs are those that:

- are commonly congested; and
- have effective flowgate capacity that is commonly below the peak level.

For example, the South East South Australia flowgates (for example, "V>>S_NIL_SETB_SGKH" constraint) are commonly congested because of a weak low voltage network, high interconnector flows and local wind generation. They commonly have shortfalls because non-scheduled wind output creates reduced effective flowgate capacity and because, presumably, this output can be higher outside of the peak demand conditions that AEMO used for the transitional access allocation than during them.

This analysis is informative since it shows that congestion does occur outside of the firm access planning standard conditions; and that effective flowgate capacity is not at a minimum under firm access planning standard conditions.

The empirical analysis also shows that system normal flowgates are responsible for the majority of shortfall costs over the historical period (six of the top ten constraints are system normal constraints, represented by the "NIL" component in the constraint name). This might be because TNSPs are currently incentivised to reduce congestion on outage flowgates but not on system normal flowgates. It is not clear, ex ante, whether TNSPs are also able to manage shortfall costs on system normal flowgates. But, shortfall costs being high at system normal times would validate including system normal flowgates within the scope of the incentive scheme

E Submissions - assessment of optional firm access

This appendix sets out a summary of submissions of the issues raised relating to the assessment of optional firm access in stakeholders' submissions to the First Interim Report, and Request for Comment. It also sets out the AEMC's response to the issues raised. Note that where stakeholder views relate to the same issue, they have been grouped together in the table and responded to by the AEMC collectively.

Table E.1 Summary of submissions

Issue raised	Stakeholder	AEMC response
General		
Optional firm access as a model is highly complex.	AGL, First Interim Report submission, p. 3; ERM Power, First Interim Report submission, p. 2; GDFSAE, First Interim Report submission, p. 2; InterGen, First Interim Report submission, p. 2; PIAC, First Interim Report submission . 4; Snowy Hydro, First Interim Report submission, p. 1; Origin, First Interim Report submission, p. 1; Infigen, First Interim Report submission, p. 2; Energy Australia, First Interim Report submission, p. 1; South Australian DSD, First Interim Report submission, p. 1; InterGen, Request for comment submission, p. 1.	Noted. See section 10.3.5.
The NEM is working and no further intervention is required.	InterGen, First Interim Report submission, p. 1.	Noted. See section 11.1.
Times have changed since the Transmission Frameworks Review - there is declining demand and over supply of generation.	Snowy Hydro, First Interim Report submission, p. 1; Origin, First Interim Report submission, p. 3; Energy Australia, First Interim Report submission, p. 2; AGL, Request for comment submission, p. 1; Hydro Tasmania, Request for comment submission, p. 1; GDFSAE, Request for comment submission, p. 1; InterGen, First Interim Report submission, p. 2.	Noted. See section 11.2.
Unlikely that the same set of market conditions experienced prior to the Transmission Frameworks Review would occur in the future	InterGen, Request for comment submission, p. 3.	

Issue raised	Stakeholder	AEMC response
Supports reforms to achieve long term market benefits that would arise from adoption of some form of financial access rights.	AEMO, First Interim Report submission, p. 1.	Agreed. See chapter 11.
Supports in principle a system of market based firm access rights.	Victorian DSDBI, First Interim Report submission, p. 2.	
Risks, uncertainties and costs presented by the proposed optional firm access reform are sufficient to prevent much of the proposed future large scale renewable energy investment from being advanced.	Clean Energy Council, First Interim Report submission, p. 1.	The Clean Energy Council has not quantified the effect on business cases, and therefore it is difficult to assess this claim. However, the AEMC's modelling of access prices indicates that under current conditions the cost of purchasing 100 per cent access for a new wind farm would be a small proportion of the total capital cost. Further feedback on the effect that purchasing access would have on the business cases of generators is welcome.
The project has the potential to significantly impact the profitability of investments, and reduce confidence to invest.	Trustpower, First Interim Report submission, p. 1; Goldwind Australia, First Interim Report submission, p. 1.	Noted. But, if a generator enters before optional firm access is implemented, it will be granted transitional access. The transitional arrangements have been designed to smooth the path from current to new arrangements, with a view to minimising balance sheet effects.
The review creates investment uncertainty.	InterGen, First Interim Report submission, p. 2; InterGen, Request for comment submission, p. 1.	
The problem that optional firm access is intended to address has not been clearly articulated or defined.	Clean Energy Council, First Interim Report submission, p. 5; ERM Power, First Interim Report submission, p. 2.	The Final Report for the Transmission Frameworks Review articulated the problems, and which are reproduced in section 2.3.3, that the optional firm access model aims to solve.
Supportive of the goal to guide more efficient investment in transmission infrastructure.	SACOSS, First Interim Report submission, p. 1.	Agreed. See chapter 5.

Issue raised	Stakeholder	AEMC response
Funded augmentations have been successful in alleviating constraints.	Clean Energy Council, First Interim Report submission, p. 16.	While there has been the ability for generators to fund investments in the transmission system, we understand that these arrangements have been little used. These arrangements also suffer from a free rider problem: other generators would benefit from the network capacity without having contributed to the costs of the network investment, and may even prevent the funding generator from using it.
ERM Power have a number of specific concerns about how the optional firm access model would impact on peaking generators, for example, that they may be potentially disadvantaged compared to baseload generators.	ERM Power, First Interim Report submission, pp. 3-5.	Noted. The Commission notes that optional firm access would affect generators with different operating types (that is, baseload, peaking) differently. However, the optional nature of firm access should allow these different types of generators to be accommodated.
There may be market power concerns regarding generators operating under an optional firm access regime.	MEU, First Interim Report submission, p. 7.	Noted. While optional firm access is not designed to address market power concerns, it is not expected that it would increase the ability to benefit from having market power.
Do not consider that there is an issue to consider. Would like to see more data on the problem.	PIAC, First Interim Report submission, pp. 2-3; Ethnic Communities Council, First Interim Report submission. p. 1.	Noted. As part of this work, the Commission has also considered whether or not problems identified as part of the Transmission Frameworks Review are still problems. This is discussed in chapters 4 through 10.
Do not consider the case for change has been made.	Hydro Tasmania, First Interim Report submission, p. 1; AGL, Request for comment submission, p. 3; Clean Energy Council, Request for comment submission, p. 1.	Noted. The Commission's draft assessment, including the consideration of whether optional firm access would contribute to the achievement of the National Electricity Objective or not is contained in this Draft Report.

Issue raised	Stakeholder	AEMC response
Full nodal pricing, combined with financial transmission rights, is the most efficient method for solving the problems identified by the AEMC.	Trustpower, First Interim Report submission, p. 1.	In some respects, optional firm access can be viewed as similar to nodal pricing with Financial Transmission Rights. However, it differs from the usual model in three respects, which the Commission considers makes optional firm access superior. Further information on this is provided on pages 117-118 of the Transmission Frameworks Review Final Report.
Do not support the implementation or continued development of optional firm access.	Goldwind Australia, First Interim Report submission, p. 2; Hydro Tasmania, First Interim Report submission, p. 3; Infigen, First Interim Report submission, p. 2; Origin, Request for comment submission, p. 1; InterGen, Request for comment submission, p. 4.	Noted. However, the Commission is required to fulfil its terms of reference that it received from the COAG Energy Council. See chapter 11.
In general, support the framework. Consider that optional firm access would increase market efficiency, both in the short term and over the investment planning horizon.	Westpac, Request for comment submission, p. 1.	Noted.See chapter 11.
Concerns about the risk of review events in long term power purchase agreements, and project finance arrangements; as well as a reduced ability to refinance existing projects.	Infigen, First Interim Report submission, p. 1.	While there would likely be a need to renegotiate long term power purchase agreements, the Commission understands that such agreements typically have such clauses in them to allow such renegotiation. Further, the allocation of transitional access is designed to appropriately transition investors in the sector to optional firm access.
Many generation projects are likely to be exposed to dramatic economic changes upon the introduction of optional firm access. Existing financing and power purchase agreement contracts are likely to require renegotiating to accommodate these changed circumstances.	Clean Energy Council, First Interim Report submission, pp. 11.	

Issue raised	Stakeholder	AEMC response
Optional firm access is a disproportionate solution to the problems it seeks to address.	Hydro Tasmania, Request for comment submission, p. 2.	Noted. See section 11.1.
Problems addressed by optional firm access are less significant in the short term. However, these issues could easily re-emerge by the time optional firm access is implemented. A time of slow change is a preferable time to consider long dated reforms.	Westpac, Request for comment submission, p. 2.	Agreed. Therefore, the Commission has made a draft recommendation that market conditions should be monitored for indicators that the investment environment is beginning to change in these ways. See chapter 11.
Assessment framework		
The categories of impact provide a sound basis for evaluating whether the introduction of optional firm access would benefit the National Electricity Objective	Stanwell, First Interim Report submission, p. 8	Agreed.
Support the proposed assessment framework.	Energy Australia, First Interim Report submission, p. 3; South Australian DSD, First Interim Report submission, p. 1; Victorian DSDBI, First Interim Report submission, p. 3.	
Consider three additional assessment categories could be included (wholesale and retail market competition, security of supply, market transparency).	Victorian DSDBI, First Interim Report submission, p. 3.	The Commission considers these factors are already included in the existing categories. See section 2.3.
The AEMC should consider retail and wholesale competition in the assessment framework.	CUAC, First Interim Report submission, p. 2.	
An explicit category for intra-regional hedging is required.	Snowy Hydro, First Interim Report submission, p. 8.	

Issue raised	Stakeholder	AEMC response
More weighting should be placed on financial certainty for generation; and the new criteria of effective intra-regional hedging.	Snowy Hydro, First Interim Report submission, p. 8.	The Commission has treated all impact categories equally.
Non-market costs of the NEM should be included in the assessment, for example, cost to consumers of energy grid pollution.	Australian Conservation Foundation, First Interim Report submission, p. 2.	The Commission has been asked to assess the optional firm access model, as to whether it promotes the National Electricity Objective. The National Electricity Objective does not take into account non-market costs.
AEMC should consider how optional firm access would work in a range of future scenarios.	AEMO, First Interim Report submission, p. 3; Clean Energy Council, First Interim Report submission, p. 7; Victorian DSDBI, First Interim Report submission, p. 4.	Agreed. See section 2.2.3.
The Commission should focus on demonstrating that optional firm access can and will provide a net benefit to consumers with rigorous and comprehensive economic and market analysis.	Clean Energy Council, First Interim Report submission, p. 5.	Agreed.
Assessment should be based on quantitative analysis.	Trustpower, First Interim Report submission, p. 1.	The Commission has attempted to quantify such impacts where possible - but in some cases this has not been possible, and a more qualitative assessment has been undertaken. See section 2.2.2.
The AEMC should not give disproportionate weight to transaction cost measurements versus longer term efficiency and competition benefits. But, economic modelling should be used where possible.	CUAC, First Inteirm Report submission, p. 2.	Agreed. See section 2.2.2.

Issue raised	Stakeholder	AEMC response
The Commission should consider the quantitative results of the modelling as only one input into a wider qualitative assessment of the proposal.	South Australian DSD, p. 2; Victorian DSDBI, p. 4.	
Efficient allocation of risk		
Risks and costs for consumers could be substantially increased with the implementation of optional firm access.	Clean Energy Council, First Interim Report submission, p. 19.	See chapter 4.
Consumers would have no ability to manage the risks inherent in the optional firm access process, yet are expected to underwrite the risks.	MEU, First Interim Report submission, p. 9.	Consumers would face less risks than under current arrangements. See chapter 4.
Currently, the risk that an optimal decision has not been made or that an investment fails to deliver its modelled benefits are disproportionately carried by electricity consumers.	SACOSS, First Interim Report submission, p. 1.	Agree. See chapter 4.
Support consumers facing less risks.	CUAC, First Interim Report submission, p. 1.	
Cost of transmission as an essential services is most efficiently recovered directly from end consumers.	Snowy Hydro, First Interim Report submission, p. 3.	It would be more efficient overall if generators bore some of the risks of transmission investment since they have the ability, information and incentives to better manage the risk. See chapter 4.
Rather than cultivating "market led" transmission investment, the model (by relying so heavily on AEMO and TNSP forecasts of the likely volume and location of generation growth on different parts of the network) appears to further embed	AGL, Request for comment submission, p. 2.	Generators would be required to make a decision as to whether they would purchase firm access. See chapter 4.

Issue raised	Stakeholder	AEMC response
centralised transmission planning and the inherent risks of forecast errors.		
Any firm access pricing errors will be borne by customers either through TUOS charges or passed on by the generator in wholesale prices.	Stanwell, Request for comment submission, p. 5.	Competitive discipline should prevent the extent to which generators can pass on these costs. See chapter 4. Compared to the current arrangements consumers would bear less risk of the cost of transmission investment.
Efficient investment in transmission and generator capacity		
Framework which provides an incentive for a generator to locate in uncongested parts of the network is a crucial issue.	South Australian DSD, Supplementary Report on Pricing submission, p. 1.	The absence of a price signal related to transmission in the NEM may result in locational decisions that increase the overall costs of transmission and generation. See chapter 5.
Benefits of a locational signal are questionable in a declining demand market - no new investment is required in the NEM for at least another decade.	AGL, First Interim Report submission, p. 1; InterGen, First Interim Report submission, p. 2.	
Locational decision making is affected by a range of factors, for example, fuel costs.	AGL, First Interim Report submission, p. 2.	The Commission considers that currently there are few locational signals relating to the costs that generators impose on the transmission network. See section 5.2.2.
The current locational signals are reasonable and sufficient to inform investments, such as marginal loss factors and expectations of network development under the RIT-T.	Clean Energy Council, First Interim Report submission, p. 15.	
There are already lots of locational signals for new entrants.	Snowy Hydro, First Interim Report submission, p. 3; Origin, Request for comment submission, p. 2.	

Issue raised	Stakeholder	AEMC response
Locational signals provided by optional firm access may not be material.	Origin, First Interim Report submission, p. 7; Stanwell, First Interim Report submission, p. 12; AGL, Request for comment submission, p. 2.	
Better locational signals for generators is important. The current weak signals have been a significant cause of the generator congestion that has occurred.	MEU, First Interim Report submission, p. 13.	
Firm access does not provide any changed locational signal.	Stanwell, Request for comment submission, p. 5.	Optional firm access would provide more signals for generators about where to locate. See section 5.3.2.
The Clean Energy Council set out a number of elements that should be considered in this impact category, for example, the relative benefits that optional firm access might provide when compared to the application of the RIT-T.	Clean Energy Council, First Interim Report submission, p. 8.	The Commission has taken such elements into account.
Conceptually, greater co-optimisation is a good thing. But, question the extent to which this is achievable given the majority of transmission build has, and will continue to be, driven by the need to meet the reliability standard.	Origin, Request for comment submission, p. 2.	Noted. The Commission considers one of the greatest benefits of optional firm access is its ability to lead to improved co-ordination of transmission and generation investment. See chapter 5. it is expected that under optional firm access a portion of transmission investment would be led by generators.
High level of co-ordination already exists with the application of the RIT-T.	Snowy Hydro, First Interim Report submission, p. 3; Clean Energy Council, Request for comment submission, p. 1; Snowy Hydro, Request for comment submission, p. 4.	
Do not consider the approach of encouraging market-led investment with a monopoly setting will produce better outcomes than the present approach.	Clean Energy Council, First Interim Report submission, p. 19.	

Issue raised	Stakeholder	AEMC response
The information and power asymmetry between generators and TNSPs from a commercial generator negotiating with a natural monopoly is likely to introduce significant risks and uncertainties into the transmission planning process leading to market inefficiencies.	Origin, First Interim Report submission, p. 5.	Under optional firm access, generators would drive some of the transmission investment decision making. The Commission considers that this would result in more efficient outcomes than currently occurred, through investment and generation investment being better co-optimised. See chapter 5.
Financial certainty		
The shift to nodal pricing - implicit in the optional firm access model - may create financial instability. Further, that the additional complexity manifests itself into high risk premiums sought in the contract market.	AGL, First Interim Report submission, p. 3; AGL, Request for comment submission, p. 3.	The Commission does not consider that any evidence has been provided by stakeholders that shows that the additional complexity would result in higher risk premiums in the contract market. The Commission welcomes further evidence in relation to this point.
Merit in examining in greater detail, the degree to which optional firm access would improve generators' ability to defend financial derivatives in the wholesale market.	AEMO, First Interim Report submission, p. 3.	The Commission engaged Oakley Greenwood to consider such matters. It also welcomes stakeholder feedback on this point.
The Clean Energy Council set out a number of elements that should be considered in this impact category, for example, the new risks that optional firm access creates in the project development process.	Clean Energy Council, First Interim Report submission, p. 7.	The Commission has considered these elements in its assessment of this impact category.
The provision of increased financial certainty must not be at the expense of consumers.	MEU, First Interim Report submission, p. 9.	Agreed.
Generators are more likely to be limited by physical risk and/or the relative value of market price to cost structures, than congestion risk.	InterGen, First Interim Report submission, p. 2; Hydro Tasmania, First Interim Report submission, p. 1; Stanwell, First Interim Report submission, p. 7;	The Commission recognises that for the majority of generators these other risks may be more significant than congestion risk.

Issue raised	Stakeholder	AEMC response
	InterGen, Request for comment submission, p .2.	However, for some generators, congestion risk is material. Further, congestion risk is unpredictable and so the significance of this may change in the future. See chapter 6.
Concerns regarding generator access to transmission and considers the risk of asset stranding and significant and unmanageable congestion pose a threat to investors.	Alinta, First Interim Report submission, p. 1; Alinta, Request for comment submission, p. 1; GDFSAE, Request for comment submission, p. 3.	
Second tier and new entrant competitors are likely to benefit from being able to better manage secure access to transmission. Current market arrangements favour large participants over smaller participants.	Alinta, First Interim Report submission, p. 1; Alinta, Request for comment submission, p. 1.	
Congestion is not a problem of sufficient materiality to warrant significant change to the market	Origin, Request for comment submission, p. 1.	
Optional firm access increases uncertainty for generators, by imposing basis risk on them.	Snowy Hydro, First Interim Report submission, p. 3; Origin, Request for comment submission, p. 2; Snowy Hydro, Request for comment submission, p. 7; Origin, First Interim Report submission, p. 3.	Basis risk is only imposed on generators to the extent that they are non-firm. Generators could purchase firm access if they considered this risk to be material. See section 6.3.2.
Optional firm access does not fully compensate generators, and so this impacts on the value.	CS Energy, First Interim Report submission, p. 4; InterGen, Request for comment submission, p. 2.	Agreed. It is firm access, and not fixed access. However, the specification of the product (that is, access under a set of specified conditions) should provide generators with the confidence to estimate what the impacts would be on its business.
Effective inter-regional hedging		
The current arrangements do not really permit contracting over interconnectors and so trading is almost non-existent.	MEU, First Interim Report submission, p. 10.	Agreed. See chapter 7.

Issue raised	Stakeholder	AEMC response
Retailers will not offer firm contracts between regions under the current arrangements.		
Inter-regional firmness is one of the optional firm access model's possible major benefits.	Alinta, First Interim Report submission, p. 3.	
Proposed inter-regional product would be firmer than the current SRA product, and would be a benefit of optional firm access.	GDFSAE, First Interim Report submission, p. 3; MEU, First Interim Report submission, p. 10; Lumo Energy, First Interim Report submission, p. 2.	
Firm interconnector rights would be a superior hedging product to SRAs. It would allow liquidity providers to more competitively price various inter-regional risk products for their customer base.	Westpac, Request for comment submission, p. 1.	
Firm inter-regional hedges are achievable now with plain vanilla financial instruments	Snowy Hydro, First Interim Report submission, p. 3; Snowy Hydro, Request for comment submission, p. 6	While there are some inter-regional hedges currently available, these are not as firm as the access rights under optional firm access. See section 7.2.2.
There are other existing products that can mitigate inter-regional exposures.	Stanwell, First Interim Report submission, p. 8.	
Current barriers to inter-regional trade are overstated.	Stanwell, First Interim Report submission, p. 5.	
The currently low value of SRAs is due to limited regional price separation between regions; the result of an over-supplied market.	Origin, First Interim Report submission, p. 8	Such information is helpful in informing the Commission's considerations of how effective an inter-regional product is. See chapter 7.
Optional firm access would result in reduced inter-regional trade across regulated interconnectors.	Hydro Tasmania, First Interim Report submission, pp. 1-2	The Commission considers the impact of optional firm access on the level of inter-regional trade is unclear.

Issue raised	Stakeholder	AEMC response
		Optional firm access does provide a much firmer hedge for inter-regional trade, which based on discussions with stakeholders should increase trade. Further, while there is not a specific transitional access allocation related to interconnectors, through the procurement processes, existing capacity should be allocated (inter- or intra-regionally) to the parties who value it the most, and new (inter- or intra-regional) capacity should be created if sufficiently valued by generators to exceed the costs.
Inter-regional benefits of optional firm access would be marginal, since it would reduce volume risk but increase basis risk.	EnergyAustralia, First Interim Report submission, p. 4.	Like intra-regional access, inter-regional access should only impose basis risk if the generator is non-firm. Otherwise, it should be protected from basis risk. The Commission acknowledges that the firm interconnector right is not 100 per cent firm; however, it is significantly more firm than the current SRA units, and so inter-regional basis risk should be reduced compared to current arrangements.
Efficient dispatch		
The possibility of delivering benefits in relation to congestion management and disorderly bidding have been brought into question by AEMO concluding that there were some generator behaviours that remain unchanged by access settlement.	AGL, First Interim Report submission, p. 2.	Optional firm access is only intended to address and mitigate the financial uncertainty that is caused by congestion that affects scheduled and semi-scheduled generators and/or interconnectors. See chapter 6.
AEMO's modelling has shown that other factors influence dispatch, aside from congestion.	Snowy Hydro, First Interim Report submission, p. 3; Snowy Hydro, Request for comment submission, p. 7.	

Issue raised	Stakeholder	AEMC response
Optional firm access may not result in efficient dispatch.	CS Energy, First Interim Report submission, p. 6; Stanwell, Request for comment submission, p. 5.	
Benefits from efficient dispatch are small.	Origin, First Interim Report submission, p. 4; Origin, Request for comment submission, p. 2.	Agreed. See section 9.3.3.
Short term inefficiencies do not mean the market is not operating efficiently.	Origin, First Interim Report submission, p. 8; Stanwell, First Interim Report submission, p. 9.	Agreed. See section 9.1.
Optional firm access can provide a benefit to consumers through generators taking actions to relieve congestion that is caused by insufficient transmission and causing harm to the generators involved.	MEU, First Interim Report submission, p. 6.	Agreed. The introduction of optional firm access would change generators' incentives in relation to bidding to the floor.
A highly attractive feature of optional firm access is the removal of incentives for a generator to bid out of merit order in the presence of local transmission constraints.	Westpac, Request for comment submission, p. 1.	
Consumers should also have the ability to invest in transmission infrastructure in order to obtain benefits from reduced congestion.	MEU, First Interim Report submission, p. 12.	Consumers can already invest in transmission infrastructure, through a funded augmentation, if they consider that this would be beneficial to them.
Consideration should be given to the likelihood that optional firm access should create new incentives for "disorderly bidding".	Clean Energy Council, First Interim Report submission, p. 8; AGL, Request for comment submission, p. 2.	Agreed. The Commission has considered such issues, with these considered in the Technical Report.
Efficient incentives on the TNSP to operate the network		
Supports providing incentives to TNSPs to provide a better service, but only if the resulting benefit exceeds the reward provided.	MEU, First Interim Report submission, p. 11.	The Commission considers that the current market impact component scheme has been successful, but the current scheme could be improved.

Issue raised	Stakeholder	AEMC response
The current incentive scheme has been effective.	Origin, First Interim Report submission, p. 5; Stanwell, First Interim Report submission, p. 9; Origin, Request for comment submission, p. 3; Snowy Hydro, Request for comment submission, p. 6	See chapter 8.
Transaction costs		
The Clean Energy Council set out a number of elements that should be considered in this impact category.	Clean Energy Council, First Interim Report submission, p. 8.	The Commission has considered these elements.
Invariable implementation costs are much higher than anticipated.	Clean Energy Council, First Interim Report submission, p. 6.	The Commission has engaged consultants to estimate the transaction costs (including implementation costs) associated with the introduction of optional firm access. See chapter 10.
Implementation costs would be high.	PIAC, First Interim Report submission, p. 5; Snowy Hydro, First Interim Report submission, p. 2.	
Does not believe the transaction costs are particularly onerous for optional firm access	CS Energy, First Interim Report submission, p. 9	
Other		
Optional firm access increases uncertainty in the connections process.	Clean Energy Council, First Interim Report submission, p. 12.	The Commission considers that the procurement of long-term intra-regional access would typically occur at the same time as the connections process. During any implementation stage of optional firm access, the interactions between the two processes would need to be considered.

Issue raised	Stakeholder	AEMC response
Implementation		
AEMO does not foreseen any specific issues arising as a result of the different transmission framework that applies in Victoria.	AEMO, First Interim Report submission, p. 3.	Agreed. See section 12.1.
An environment of low demand provides the ideal opportunity to introduce new access arrangements, so that participants can become familiar with the new measures.	GDFSAE, First Interim Report submission, p. 1; GDFSAE, Request for comment submission, p. 2.	Noted. The Commission will consider such implementation issues between the Draft and Final Report. See section 11.4.
Supports temporal staging.	GDFSAE, First Interim Report submission, p. 4; MEU, First Interim Report submission, p. 17.	
Supports a simplified model of optional firm access, facilitating possible staged introduction.	Alinta, First Interim Report submission, p. 1.	
Consider simultaneous implementation as the preferred option; but temporal staging could be a reasonable compromise.	South Australian DSD, First Interim Report, p. 5.	
Geographic staging should not be considered, it is counter to the notion of a national electricity market.	GDFSAE, First Interim Report submission, p. 4; MEU, First Interim Report submission, p. 17; PIAC, First Interim Report submission, p. 5; Snowy Hydro, First Interim Report submission, p. 12; Energy Australia, First Interim Report submission, p. 4.	Agreed. However, the Commission has set out that there may be some merit in excluding Tasmania from the optional firm access model, at least in the first instance. This would be considered further at implementation. See section 12.2.
In its current form, optional firm access is not practically workable for Tasmania (including because of issues with the pricing model specific to Tasmania).	TasNetworks, Supplementary Report on Pricing submission, pp. 1, 3.	Agreed. See section 12.2.

Issue raised	Stakeholder	AEMC response
Alternatives models to optional firm access		
Consider the Commission should consider implementing aspects of the model, rather than recommending doing nothing.	South Australian DSD, p. 5.	A number of stakeholders have proposed simplified versions of optional firm access, or alternatives. The Commission will consider such options, and the effectiveness of them, prior to producing the Final Report. See section 11.4.
Supports an abridged optional firm access method being developed, that would facilitate potential staging over the longer term and enable core aspects of the method that were supported to be implemented in a timely manner	Alinta, Request for comment submission, p. 2.	
AEMC should consider whether some elements of optimal firm access could be removed in the interests of a more pragmatic, simplified approach	GDFSAE, Request for comment submission, p. 3.	
The firm access operating standard (and TNSP incentive scheme) could be introduced separately, after the firm access planning standard and access settlement components of the optional firm access model. This may be preferable, given the complexity of the incentive scheme.	GDFSAE, First Interim Report, pp. 2-3.	
In preference to the optional firm access model, a specific review on improving existing SRAs should be undertaken.	EnergyAustralia, First Interim Report, p. 4.	
AEMC should consider whether access settlement could be progressed in a form for the purpose of firming inter-regional settlement residues only.	Alinta, First Interim Report, p. 6.	

Issue raised	Stakeholder	AEMC response
Initially, the optional firm access model should proceed without short-term inter-regional access, which should be considered at a later time.	GDFSAE, First Interim Report, p. 3.	
Given complexity, and possibly low value, short-term firm access should not be included in the initial optional firm access model design.	GDFSAE, First Interim Report, p. 3.	
A simpler solution (whether a more targeted version of optional firm access, or alternatives) may be more effective.	ERM Power, First Interim Report submission, p. 3; GDFSAE, First Interim Report submission, p. 2.	
Might be worth investigating changes to the MIC to make it symmetrical and to incorporate scaling based on the marginal value of binding outage constraints.	Hydro Tasmania, Request for comment submission, p. 2.	
The existing incentive scheme could be improved	Origin, Request for comment submission, p. 3.	
There is scope to better incentivise TNSPs, using an incentive scheme, without implemented the access settlement component of the optional firm access model, potentially through improvements to STPIS.	Alinta, First Interim Report, p. 3.	
Some incremental changes that could be considered include: RIT-T applied by an independent party and not by TNSPs; and STPIS continuous improvement program.	Snowy Hydro, Request for comment submission, p. 8.	