Australian Energy Market Commission

REVIEW

FINAL REPORT - VOLUME 2

Optional Firm Access, Design and Testing

9 July 2015

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About the AEMC

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

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Executive summary

The Council of Australian Governments Energy Council (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]

This volume of the Final Report provides an overview of the optional firm access model that the Commission has designed with extensive input from a range of stakeholders. The model set out in this volume forms the basis for the assessment work undertaken in Volume 1. The Commission has not undertaken further work on the model since the time of the Draft Report, aside from responding to stakeholder submissions.

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 risks associated with some transmission investment. It would do this by allowing generators to choose to pay for a specified level of access to the transmission network in order to manage the financial impacts of network congestion.

There are a number of elements of optional firm access. These arrangements represent an internally consistent and highly interlinked set of proposals. These elements are discussed further in this report and include:

- **Access products** - Each Transmission Network Services Provider (TNSP) would be required to offer a firm access service to generators in its region. Generators could purchase:
    - intra-regional access, which provides the firm generator with access to the regional reference price, either by being dispatched or by earning compensation; or
    - inter-regional access, which would provide firm access from one regional reference node to the regional reference node in an adjacent region, and would entitle the purchaser to the price difference between two regions.
- **Access settlement** - This is the process through which financial compensation would be provided to firm generators that are constrained off and so not dispatched. These payments would usually come from non-firm generators. Access settlement would occur automatically through the market operator's processes. The current processes for dispatch and the setting of the regional reference price would not be changed.
- **Firm access standard** - This defines the service to which a firm generator is entitled. It translates the firm access that generators purchase into the level of transmission capacity that TNSPs would be obliged to provide. It therefore

1 The Terms of Reference for this review can be found on the AEMC's website: www.aemc.gov.au

drives TNSP network planning and operation. It would be specified through two components:

- firm access planning standard - TNSPs would be required to plan their networks to provide the level of capacity necessary to be able to simultaneously provide access to all firm generators, under a set of specified network conditions; and
- firm access operating standard - TNSPs would be encouraged through an incentive scheme to operate their network efficiently to provide firm access under all conditions.

- **Access procurement** - The process for procuring firm access would differ depending on the firm access product to be purchased:
  - Generators would be able to purchase long-term intra-regional firm access directly from a TNSP after paying a price determined by the long run incremental cost (LRIC) model.
  - Market participants and traders would be able to purchase long-term inter-regional access through an auction process, which would be run by the market operator.
  - Generators would be able to purchase both intra-regional and inter-regional short-term firm access through a regular auction, which would be run by the market operator.
- **Access pricing -** Generators would pay TNSPs to obtain firm access. Access pricing would be based on the LRIC of the TNSP providing the access over the access term.
- **Transitional access** - At the time of implementation of optional firm access, existing generators would receive a level of transitional access. Transitional access would function identically to purchased firm access except that access would not be procured from a TNSP through the usual processes set out above.

These elements are discussed in more detail in this report, which sets out the Commission's detailed design of the model as at June 2015. Further detail on the model can be found in the accompanying AEMC Technical Report, which also includes a tabulated summary of the model's design.

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. The purpose of this project is to confirm (and potentially modify) the design of the optional firm access model, assess whether implementation would contribute to the achievement of the National Electricity Objective, and if so, determine how the model could be implemented.[2]

1.1 Structure of the Final Report

The Commission's Final Report presents its assessment and conclusions on whether the introduction of the optional firm access model would contribute to the achievement of the National Electricity Objective. It also presents a description of the developed optional firm access model.

This Final Report comprises two volumes:

- Volume 1 (assessment and recommendation) sets out the Commission’s final assessment of whether optional firm access would contribute to the National Electricity Objective, and the Commission's final recommendation on whether optional firm access should be implemented. It also sets out the Commission’s recommendations relating to a reporting regime and measures to increase transparency.
- Volume 2 (optional firm access model) provides an overview of the optional firm access model that has been designed in consultation with key stakeholders.

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

Volume 1 should be read in conjunction with Volume 2. The model set out in Volume 2 forms the basis for the assessment and recommendations made in Volume 1.

Consistent with its draft recommendations, the Commission has not undertaken any further work on the optional firm access model itself since the time of the Draft Report (aside from responding to stakeholders' submissions). Were optional firm access to be implemented in the future, the model would have to be considered in light of conditions at the time.

1.2 Background to this review

In April 2013, the AEMC completed a comprehensive review of the transmission arrangements that underpin the National Electricity Market (NEM), known as the Transmission Frameworks Review. Amongst other things, that review developed an

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

integrated package of market arrangements for the provision and utilisation of the transmission system, known as optional firm access.

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.[3] For further background on the Commission's current work, please refer to Volume 1 of the Final Report.

1.3 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, rather than regulated transmission businesses, would drive part of the decision-making about future transmission development or retirement.[4]
- Generators would bear the indicative costs of transmission development undertaken to support their access decisions. This should improve the management of the risks associated with transmission investment, given that generators have a greater ability, stronger incentives and better information to manage those risks than transmission businesses do.
- 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.

3 SCER, Transmission Frameworks - Detailed Design and Testing of an Optional Firm Access Framework, 25 February 2014.

4 TNSPs would still be required to meet their jurisdictional reliability standards for consumers.

1.4 Consultation on the model to date

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

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

Given the sources and amount of stakeholder participation and feedback received it is impractical to individually document and set out how this feedback has influenced the development of the final recommendations in this report. Therefore, this volume sets out the specification of optional firm access, reflecting feedback obtained from stakeholders through the various means described above. This specification would be reflected in any implementation of optional firm access going forward.

A summary on stakeholders' submissions on the technical aspects of the optional firm access model, and the Commission's responses to the issues raised, is contained in appendix E.

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

1.5 Content of this report

This report contains the following chapters:

- chapter 2 provides a summary of the optional firm access model;
- chapter 3 provides an overview of the governance aspects of the optional firm access model;
- chapter 4 discusses access settlement, which would be the process through which financial compensation would be provided to firm generators from (typically) non-firm generators;
- chapter 5 discusses the firm access planning and operating standard, which defines the minimum level of firm access service quality to which a firm generator would be entitled;

- chapter 6 discusses access pricing, including discussion of some indicative access prices obtained from using the prototype access pricing tool;
- chapter 7 discusses the various means by which firm access would be procured;
- chapter 8 discusses how existing regulation processes would be modified under optional firm access;
- chapter 9 discusses the transitional processes that would apply in the early years of the optional firm access model;
- appendix A discusses access settlement specification issues;
- appendix B discusses incentive scheme issues;
- appendix C discusses pricing issues;
- appendix D discusses input assumptions for the pricing prototype model;
- appendix E provides a summary on stakeholders' submissions on the technical aspects of the optional firm access model, and the Commission's responses to the issues raised; and
- appendix F contains a glossary of commonly used terms. For ease of reference, the first time each of these words is used in this report they are **bolded** in the text.

The prototype pricing model and accompanying user guide are available separately on the AEMC's website. They are unchanged from the March 2015 release. These items supplement this report and provide further detail and practical evidence on the access pricing method that is discussed in chapter 6.

2 Summary of optional firm access

2.1 Introduction

In the Transmission Frameworks Review the AEMC developed an alternative transmission model for the NEM, called **optional firm access**, which would provide generators with the option of obtaining financially firm access to their **regional reference price**. The Final Report and the accompanying Technical Report of that review laid out the design of the optional firm access model.

The purpose of this review was to develop further detail of the model as well as assess its potential benefits and costs. The following chapters set out the current specification of the various elements of the optional firm access model, following the detailed design work through this project. It details the AEMC's recommended design for optional firm access, given the current environment. Were optional firm access to be implemented in the future, aspects of the model would have to be considered in light of the circumstances of the time.

In order to provide background to the remainder of this report, this chapter provides an overview of the main components of the optional firm access model.

2.2 Objectives of optional firm access

Optional firm access would change the way in which transmission and generation investment decisions are made. It would mean generators would bear more of the risks associated with some transmission investment – the investment relating to providing their level of firm access. It would do this by allowing generators to choose to pay for a specified level of access to the transmission network in order to manage the financial impacts of network **congestion**.

The Transmission Frameworks Review set out that the optional firm access model aims to address the most significant concerns with the interface between transmission and generation:

- the lack of clear and cost-reflective locational signals for generators, such that locational decisions do not take into account the resulting transmission costs;
- 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 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;

- 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 development of the transmission network; and

- the resulting incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion.

Volume 1 of this Final Report discusses the Commission's final assessment on whether or not the problems reflected in the objectives are still problems, and so whether these would be resolved through the implementation of optional firm access.

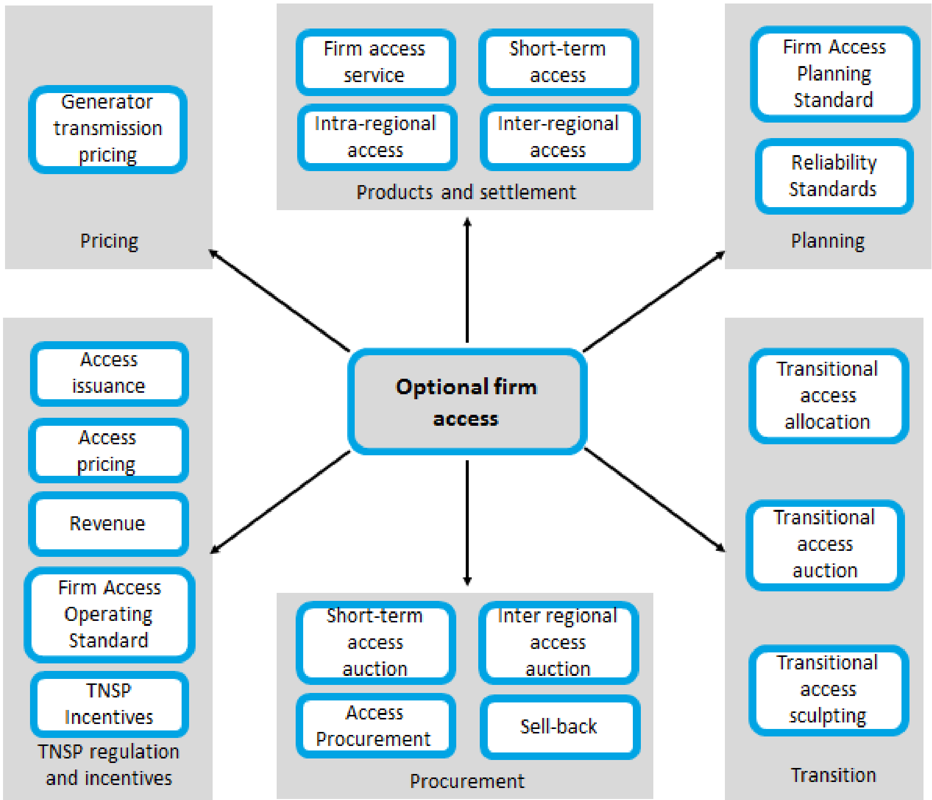
2.3 Overview of optional firm access design features

Under the current arrangements for transmission, generators may face a lack of certainty of access to the regional reference price. The present NEM design provides access to generators by allowing them to be dispatched and so sell their output at the regional reference price. During periods of intra-regional congestion, a generator's level of access to the regional reference price is dependent on the level of congestion and the dispatch offers of other nearby generators. It may be **constrained off** – unable to obtain the access it desires.

The optional firm access model gives generators the option of obtaining **firm access** to the regional reference price. Even when they were not dispatched because of congestion, **firm generators** would still be paid.

Figure 2.1 shows the main elements of the optional firm access model. Each element is interconnected to the other elements of the model. These are discussed further in sections 2.4 to 2.11.

Figure 2.1 Key features of optional firm access



2.4 Access products

Each TNSP would be required to offer the firm access service to generators in its region.[5]

2.4.1 Intra-regional

The intra-regional firm access product provides the firm generator (that is, a generator with **registered access**) with the right to sell its output up to its access amount at the **regional reference price**, either by being dispatched or by earning compensation. This compensation would be at least equal to the difference between the generator's offer and the regional price if congestion prevented it from being dispatched.[6] This compensation would be provided through **access settlement**.

Generators would have the option of purchasing a quantity of long-term intra-regional firm access from their **local TNSP**, which could be for all or part of their output. The generator would seek the combination of firm access amount, location and duration that best met its needs and for which it was prepared to pay the associated **access charge**.

5 The firm access service is a transmission service provided by TNSPs to generators and directed interconnectors. The firm access service comprises a number of different firm access products, which are discussed in section 2.4.

6 Other than in circumstances when access is scaled, as discussed below.

Generators that did not procure firm access would receive non-firm access. **Non-firm generators** would have access to the network, although they may receive a price less than the regional reference price (but no less than their offer price) for any generation that is dispatched. When dispatch of non-firm generators contributed to congestion they would compensate firm generators for any loss of dispatch.[7] The aim would be for firm generators to be in the financial position they would have been in had they not been **constrained off**. Therefore, financial certainty would be enhanced.

2.4.2 Inter-regional

TNSPs would also be required to offer inter-regional access. The inter-regional firm access product would be available to all market participants and traders.[8] These parties would be able to purchase **firm interconnector rights** that provide firm access from one **regional reference node** to the regional reference node in an adjacent region.

These firm interconnector rights would entitle the purchaser to the price difference between two regions on their access amount. This product would be firmer than the current **settlement residue auction** units that are available for purchase, since it would not depend on flows across the interconnector.

2.4.3 Short-term

Finally, TNSPs would be required to offer intra-regional and inter-regional short-term access. Short-term access would provide the same firmness of access as long-term access. Short-term access would be backed by any spare capacity (that is, spare after accounting for the existing firm access) on the network. Short-term access could also be supplied by generators engaging in secondary trading.

2.5 Access settlement

Access settlement is the process through which financial compensation would be provided to firm generators that are constrained off and so not dispatched. These payments would usually come from non-firm generators.

Access settlement would occur automatically through the market's settlement process. The current processes for dispatch and setting of the regional reference prices would not be changed.

Access settlement would occur around congested **flowgates**: bottlenecks in the transmission network which are represented by binding **transmission constraints** in the National Electricity Market Dispatch Engine (**NEMDE**).

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7 Although generators would have the option of being firm or non-firm, participation in the model would be mandatory.

8 Consistent with those parties that can currently participate in the Settlement Residue Auctions (SRA) auctions.

Two factors would need to be calculated in order to determine settlement payments: a generator's usage of a flowgate and its **entitlement** to that flowgate. Its usage would depend on its output and how much it contributed to the constraint. Its entitlement would be based on the lesser of its purchased access level and its capacity, and would also depend upon the prevailing network conditions.

A generator may require entitlements on several flowgates in order to achieve its agreed level of access. Access settlement would automatically translate the generator's purchased access amount into an entitlement on each relevant flowgate, which would depend on how electricity flows on the network.

The generator would not be required to determine its entitlement or **participation** at each flowgate. The generator would purchase an amount of access (in MW) that would be specified at the location of its power station.

The allocation of entitlements would aim to give firm generators a target entitlement corresponding to their agreed access amount on each flowgate. However, where the **flowgate capacity** was less than required to meet the aggregate agreed access levels, this may not be possible. Consequently, entitlements could be scaled back, resulting in a **shortfall** in access settlement payments. TNSPs would be incentivised to avoid shortfalls occurring.

In summary, access settlement undertakes two main tasks. First, it allocates access to **congested flowgates**, giving preferential financial access to firm generators. Second, it provides some financial compensation to generators dispatched below their (scaled) entitlement levels and recovers the cost of this from generators dispatched above their (scaled) entitlement levels.

Access settlement would be undertaken by Australian Energy Market Operator (AEMO) through its role as the market operator.

2.6 Firm access standard and planning

The **firm access standard** defines the minimum level of firm access service quality to which a firm generator is entitled. It translates the level of access that generators would be entitled to (that is, their registered access) into the level of transmission capacity that TNSPs would be obliged to provide. It would therefore drive TNSP network planning and operation decisions.

The firm access standard would be specified through two components: a **firm access planning standard** and a **firm access operating standard**. It therefore recognises that the actual network capacity reflects both TNSP planning (what capacity it has built) and operational decisions (how much of that capacity is delivered at any time).

2.6.1 Firm access planning standard

Under optional firm access, the TNSPs would not be required to plan or operate their networks to provide **non-firm access** (and would receive no financial compensation for doing so). However, they would still be required to meet their jurisdictional **reliability standards** for consumers. Thus TNSPs would be required to plan their networks to meet both the reliability and firm access planning standards simultaneously.

Under the firm access planning standard, TNSPs would be required to plan their networks to provide the level of capacity necessary to be able to simultaneously provide access to firm generators, under a set of specified network conditions. The TNSP could provide this capacity in a number of ways: by developing its network, undertaking operational actions, or entering into network support agreements to enable more capacity.

TNSPs would be responsible for specifying the network conditions that would be used in the firm access planning standard. These specified conditions would be approved by the Australian Energy Regulator (AER). These conditions are intended to represent an extreme set of conditions, such that system operation would typically be inside the limits.

Key aspects of the planning process would be the same as currently, with TNSPs being required to both produce an Annual Planning Report and undertake a Regulatory Investment Tests for Transmission (RIT-T) for qualifying investments. However, there would be changes to the RIT-T analysis resulting from the implementation of optional firm access – the market benefits to non-firm generators would no longer be estimated as part of the process. This is because generators would be able to signal the value placed in transmission development through purchasing firm access. Benefits that accrued to parties other than non-firm generators (such as to consumers) would still be taken into account.

2.6.2 Firm access operating standard

Under the firm access operating standard, TNSPs would be required to operate their network efficiently to provide firm access under all conditions. This would be underpinned by an incentive scheme, which is discussed further below.

2.7 Network operation and TNSP incentive scheme

As noted above, TNSPs would be required to operate their networks to meet the firm access operating standard. This would be underpinned by an incentive scheme to encourage the efficient operation of their networks.

The scheme would specify an annual dollar benchmark of **shortfall costs** for the TNSP to meet. This benchmark would be based on the amount of shortfall costs that an efficient TNSP would be expected to incur. Shortfall costs arise when the actual network capacity is less than the network capacity under the **firm access planning standard conditions**, and are the cost to firm generators of receiving reduced access.

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

It would be impossible for the TNSP to supply all firm access at all times, as events can happen outside the TNSP's control. Supplying access at all times also would be inefficient, since it would require the TNSP to build out all constraints in the network, even at times when generators do not value access. Therefore, caps would apply, limiting a TNSP's exposure to extreme shortfall costs in "abnormal" operating conditions.

The incentive scheme would be low-powered – TNSPs would be exposed to a small amount of their maximum allowed revenue under the scheme.

TNSP incentive payments would be paid to, or collected from, firm generators.

The details of the incentive scheme, such as what the shortfall benchmark is, would be set by the AER.

This incentive scheme would replace the existing market impact component of the service target performance incentive scheme.

2.8 Access procurement

The process for procuring firm access would differ depending on the firm access product to be purchased. The firm access products can be either:

- long-term or short-term;[9] and
- intra-regional or inter-regional.[10]

2.8.1 Long-term intra-regional access

Generators would be able to purchase long-term intra-regional firm access directly from a TNSP after paying a price determined by the pricing model (as discussed in section 2.9).

The procurement process would typically be iterative, with the generator submitting a request, the request being priced and the generator then amending its request in response. Procurement requests would be ordered in a first-come-first-served basis.

Generators would also be able to sell back any firm access they hold to the TNSP at a regulated price that represents the saving to the network of not supporting the firm generator. TNSPs would be required to buy any firm access that a generator wished to sell back.

9 Long-term access is that bought from the expansion lead time (for example, 3 years) out, while short-term access is that bought within the expansion lead time (for example, 3 years).

10 **Intra-regional access** is that from the generator's node to the regional reference node, and **inter-regional access** is that from one regional reference node to another.

2.8.2 Long-term inter-regional access

Generators would be able to purchase long-term inter-regional firm access through an auction process, which would be run by AEMO, the market operator. The auction would drive the expansion for future inter-regional capacity. Market participants and traders would bid for this future capacity, based on the benefits that would accrue to them.

2.8.3 Short-term access

Generators would be able to purchase both intra-regional and inter-regional short-term firm access through a regular auction, which would be run by the market operator.

In this auction, TNSPs would be required to offer all spare capacity on their networks to be sold as firm access. Short-term access sales would not provide any obligation on TNSPs to expand transmission capacity. It would just be a mechanism for allocating access on existing capacity.

Generators could also offer existing access holdings into the auction to be sold, so the auction would facilitate a secondary market.[11]

2.9 Access pricing

Generators would pay TNSPs to obtain firm access. There would be no charge for **non-firm access**, although non-firm generators would be required to compensate firm generators they constrained off through access settlement (as described in section 2.5).[12]

A request for additional long-term firm access by a generator would increase the network capacity that the TNSP would be required to provide over time, imposing new costs on the TNSP. The firm generator would pay an amount to the TNSP that covered an estimate of these incremental costs. Access pricing would estimate what these costs would be, based on the **long run incremental cost** (LRIC) of the TNSP providing the access over the access term.

The long run incremental cost is the difference between two costs:

- the **baseline cost**, which is the net present value of a baseline network development scenario (including investment, operating and maintenance) that is in place before the **access request** is received; and

- the higher **adjusted cost**, which is the net present value of the adjusted network development scenario – that is, an amendment to the **baseline expansion plan** to accommodate the new access request.

11 If the transfer of access was between two generators at the same node, they could engage in a bilateral exchange.

12 Non-firm generators would still receive the **local price**, even if they must pay compensation.

The long run incremental cost would be determined at the time a generator makes an access request and would specify the amount that the generator must pay for access over the access term.

The price paid by generators for firm access would be produced through a regulated, stylised pricing model, developed and maintained by the AER (with input from TNSPs and the National Transmission Planner, amongst others).

The **stylised expansion** plans on which **access prices** would be predicated are not the actual plans that the TNSP would follow to develop the network (that is, access prices are different to project costs). There would not be a one-to-one mapping between an access request and a transmission expansion project.

Short-term access would be sold in an auction that would have a reserve price of zero. This represents the zero long run incremental cost of transmission during the short-term horizon since any firm access issued in the short-term must be backed by existing spare transmission capacity.

2.10 TNSP regulation

Since TNSPs would be monopoly providers of the firm access service, the service would be treated as a prescribed service under the Rules. The general structure of the revenue regulation process would not be changed under optional firm access. The AER would still set the total revenue that TNSPs receive at the start of a regulatory period and the TNSP would still have an incentive to incur less costs. But it would be modified slightly: revenue regulation would allow the TNSP to earn a combined revenue that reasonably reflects the efficient costs of delivering both services to consumers (that is, reliability) and firm access services. A TNSP's revenue allowance would therefore reflect its projected expenditure to meet both standards.

There would also need to be some modifications as to how revenue is recovered. In order to calculate transmission use of system (TUOS) charges under optional firm access, each TNSP would estimate the amount of revenue expected to be received from providing firm access. By subtracting this revenue from the allowed annual revenue requirement determined by the AER, the TUOS revenue to recover from consumers would be derived.

2.11 Transitional access

At the time of implementing optional firm access, existing generators would receive a level of **transitional access**. Transitional access would act identically to the firm access service except that access would not be procured from a TNSP through the usual processes described above.

The allocation of transitional access is intended to allow participants to adjust to a significant regulatory change in the market. However, so that generators would be required to purchase any access that they value, this transitional access would be sculpted back over time.

Transitional access would be allocated for free to generators pro rata to their capacity, with the remainder auctioned to generators (or, in the case of firm interconnector rights, market participants) for intra-regional or inter-regional access. The transitional access would be allocated so that the network would be compliant with the firm access planning standard at the start of optional firm access, that is, no new network build would be required to provide transitional access.

The allocated and the auctioned transitional access would be sculpted, at the same rate. That is, whether 1 MW of transitional access was allocated to Generator X, or purchased in the auction by Generator X, the 1 MW would be "sculpted" back over time in the same way.

Sculpting would occur in the following manner:

- there would be an initial five year period where transitional access would be held at a constant level; then
- the transitional access would begin to be sculpted back. The period of sculpting of transitional firm access would be over ten years.

Therefore, fifteen years after the implementation of optional firm access, there would be no transitional access retained by any generator.

3 Governance

3.1 Introduction

Governance refers to the institutional arrangements for the administration of the optional firm access model. This chapter considers the various elements of the optional firm access model and allocates the responsibility for administering and overseeing those elements to different bodies.

This chapter sets out the Commission's high-level approach to governance, including the:

- principles for allocation of responsibilities to bodies (section 3.2);
- interaction with the drafting of Rules (section 3.3); and
- allocations for governance that the Commission has recommended (section 3.4).

These allocations are described more fully in the chapters that discuss each element of the optional firm access model.

3.2 Principles for allocation of responsibilities to bodies

The following principles represent the most important considerations when allocating responsibilities for parts of the optional firm access model to different bodies. As principles they have been applied flexibly, and at times there is the need to trade one principle off against another.

Principle 1: Promotes best natural fit

This principle focuses on the way the responsibility fits with the existing processes and accountability of the particular body. It is less about the skills and expertise of the body, since these can be acquired or learned. It also reflects the desire for consistency with the national framework for energy.

Principle 2: Achieves a balance between national (strategic) and local perspectives to achieve appropriate checks and balances

At times it can be beneficial to have a national perspective on a particular responsibility, and at other times there could be a benefit in decisions being made at a more local level to achieve a local perspective.

Principle 3: Minimises conflicts of interest

To the extent a body has existing roles or responsibilities, these may overlap with responsibilities under the optional firm access model. This principle reflects that, to preserve independence, conflicts of interest between these existing responsibilities and any allocation under optional firm access should be minimised. Conflicts of interest can be both real and perceived.

Principle 4: Allows for proportionate regulation

In allocating responsibilities for elements of the optional firm access model, any administrative and regulatory burden should be no greater than necessary.

3.3 Interaction of governance with the Rules

Governance is also driven by how much prescription is included in the Rules. The greater the detail prescription in the Rules, for example, the less discretion the responsible body would have when it comes to making decisions.

In many cases the Rules would contain a high level framework. This allows the Rules to be flexible to respond to changing conditions in the energy sector. For example, in respect of any optional firm access incentive scheme the Rules would be likely to contain a high level framework, which another body (such as the AER) would consider when designing the incentive scheme. This also reflects the current level of detail in the Rules with respect to other incentive schemes, such as the STPIS, where more detail is included in the scheme document developed by the AER.

In other cases more prescription may be required. For example, more prescription in the Rules could be expected in respect of access settlement, and other technical areas. This also reflects the current Rules around settlement.

In addition, the allocation of responsibilities to bodies should itself be set out in the Rules. Some National Electricity Law (NEL) changes may also be required for this. The Rules should also set out if there is a process a particular body should follow in adopting new functions, and what the checks and balances are on the exercise of power by that body.

The Commission has not included any draft specifications for Rule changes with this Final Report.

3.4 Allocations of responsibilities to bodies

A high level overview of the recommended allocation of responsibilities to bodies is set out below. These are discussed more fully in the chapters dealing with the respective elements.

These allocations consider existing energy industry bodies only: AEMC, AER, AEMO (as market operator), AEMO (as National Transmission Planner) and TNSPs. The Commission has avoided creating new bodies were optional firm access to be implemented, since this would create unnecessary administrative challenges and additional burdens.

Table 3.1 Allocation of responsibilities

Role	Recommended allocation	Level of detail in Rules	Comments
Access settlement	AEMO as market operator	High	Similar to existing Rules regarding settlement, Rules likely to be prescriptive as to how access settlement should be undertaken by AEMO (as market operator).
Firm access planning standard	AER/TNSPs	Low	AER to develop guidelines, TNSPs to prepare firm access planning standard conditions for approval by AER. The AER should consult with the NTP. Possible oversight of AER by Reliability Panel.
Pricing model	AER	Low	AER to perform many of the functions, but AEMO (as NTP) likely to be consulted and provide data. TNSPs would also provide data. Independent audit also possible. TNSP "turns the handle" on the model.
Registry of access certificates	AEMO as market operator	High	Detailed Rules to describe mechanism, registry architecture. AEMO (as market operator) to maintain registry and manage access settlement payments (that is, compensation). Generator obligations (including payment of the access price) to be set out in a payment deed to the TNSP.
Running the short-term firm access auction	AEMO as market operator	Medium	Similar arrangements to SRA auctions, with some detail in Rules and some in AEMO procedures.
Creation of stylised network constraints for the purposes of the transitional access and short-term firm access	TNSPs	Low	TNSPs to prepare the constraints that feed into the model, based on the firm access planning standard.
Inter-regional access (auction element only)	AEMO as market operator	Medium	Likely to be similar arrangements to the current SRA auctions, with some detail in Rules and some in AEMO procedures.
Inter-regional pricing (reserve price in auction)	AER and TNSPs	Low	This will follow the intra-regional pricing approach for thermal constraints. For stability constraints, TNSPs would be responsible for developing costs, subject to AER oversight.

Role	Recommended allocation	Level of detail in Rules	Comments
Revenue regulation	AER	High	AER to have responsibility for revenue regulation aspects, to link current AER responsibilities under chapter 6A. Decisions to be made at time of revenue reset.
Incentives	AER	Low	AER to develop incentive scheme in accordance with principles in Rules. Likely to reflect existing STPIS governance arrangements.
Transitional access	Rules	High	For the initial allocation of access the AEMC would make a determination on the allocation through a rule change process. The Rules would contain a list with the numerical transitional allocation. For the auction of transitional access, AEMO (as market operator) would run auction in accordance with principles in Rules and AEMO procedures.

4 Access Settlement

Summary of this chapter

The firm access service gives generators the option of obtaining firm access to the regional reference price. Even when they are not dispatched because of congestion, firm generators would still be paid an amount at least equal to the difference between their offer and the regional reference price.

These payments would occur through access settlement. Existing dispatch processes would be unchanged.

Generators that choose to be non-firm could face new costs: they could be liable to make payments to firm generators through access settlement in the event of congestion. However, even where they were liable to make such payments they would be assured of receiving at least their offer price.

4.1 Introduction

Access settlement is the process through which financial compensation would be provided to **firm generators** that are **constrained off** and so not dispatched.

This chapter discusses:

- the **firm access service** (section 4.2);
- the operation of **intra-regional access** settlement (section 4.3);
- an example of the operation of intra-regional access settlement (section 4.4);
- the operation of **inter-regional access** settlement (section 4.5);
- practical implementation issues created by the introduction of access settlement (section 4.6);
- issues relating to the metering of generators (section 4.7); and
- governance arrangements of access settlement within optional firm access (section 4.8).

4.2 What is the firm access service?

4.2.1 Access under current arrangements

The Commission understands that a generator's primary concern is gaining profit through earning revenue. This is currently achieved by being dispatched, subject to constraints and the offers of other generators, and receiving the **regional reference**

price in return. This provides backing for forward (derivative) contracts that are sold to retailers.

During periods of **congestion**, a generator's level of access may be uncertain, dependent on the level of congestion and the dispatch offers of other nearby generators. The generator may be **constrained off** – unable to obtain the access it would like in order to be dispatched. When generators raise concerns that they are not getting "access" to the market, their fundamental concern is that they are not earning revenue.

Consequently, access for a generator can be thought of as being paid at the regional reference price.[13]

4.2.2 Access under optional firm access

The introduction of a firm access service would give generators more certain access to the regional reference price. Even if a generator was not dispatched because of congestion, under optional firm access, firm generators would still be paid.

A firm generator would generally be paid an amount at least equal to the difference between its offer and the **regional reference price** if it is not dispatched because of network congestion. This is referred to as “financial access” and separates (financial) access from (physical) dispatch. However, even financial access must be underpinned by physical network capability to provide sufficient revenue from **non-firm generators** to compensate firm generators when they would be constrained off. Therefore, sufficient network capability must be provided to meet aggregate demand for all firm access.

By separating access from physical dispatch, financial access can be reallocated on a different basis, with priority given to firm generators – those generators who pay for a firm access service from their local TNSP. Firm generators would enjoy greater financial certainty than they do now; non-firm generators would receive less certainty. However, existing dispatch processes (and so physical access) would remain unchanged.

Although network capability would be planned to meet aggregate demand for firm access under a set of **firm access planning standard conditions**, there would be some operating conditions under which the capacity of the transmission network would be reduced and access for firm generators might also correspondingly reduce.[14] Consequently, even firm generators would only ever achieve *firm* financial, and not *fixed* financial or physical access.

There would be no obligation on generators to procure firm access. Generators who did not would receive, instead, **non-firm access** for which they would not pay the

13 Ignoring losses.

14 TNSPs might contribute to part of the shortfall cost though an incentive scheme, discussed in section 5.3.

TNSP. **Non-firm generators** would have access to the network but they may, however, earn a lower price during times of congestion, in effect providing compensation to firm generators through access settlement. TNSPs would be required under the firm access planning standard to plan the network to provide the agreed access levels under a set of specified conditions (this is explained in more detail in chapter 5).

4.3 Intra-regional access settlement

Access settlement would provide compensation to firm generators when their dispatch would be reduced during times of network congestion. The cost of providing the compensation would be typically recovered from non-firm generators whose dispatch contributed to the congestion. Access settlement would occur around congested **flowgates**: bottlenecks in the transmission network which are currently represented by binding transmission constraints in the NEM dispatch engine (NEMDE).

The effect of access settlement – in conjunction with the existing settlement framework – would be to create a **local price** for each generator, reflecting the regional reference price and any congestion. Non-firm generators would be paid the local price on their output; while firm, constrained off generators would be compensated based on the difference between the regional reference price and their local price.

Two factors would need to be calculated in order to determine settlement payments: a generator's **flowgate usage** and its **entitlement** to that flowgate. Its usage would depend on its output and how much it contributed to the constraint. Its entitlement would be based on the lesser of its **agreed access** level and its rated generating capacity,[15] and would also depend upon the prevailing network conditions.

A generator that chooses to purchase a level of access below its capacity would be **part-firm**. A part-firm generator would receive firm access up to its agreed firm access level and the remainder of its generation would be treated as non-firm.

A generator may require entitlements on several flowgates in order to achieve its agreed level of access. Access settlement would automatically translate the generator's agreed access amount at its location in the network into an entitlement on each relevant flowgate. This translation would depend on how energy flows on the network.[16]

All intra-regional access would operate equivalently, no matter how the firm access was procured. See chapter 7 for an outline of the different methods by which generators would be able to procure firm access.

15 Availability in the case of non-firm scheduled generators and the unconstrained intermittent generation projections for non-firm semi-scheduled generators. See section 4.4 on how the entitlement of a firm generator would be determined.

16 These would not be fixed entitlements to each flowgate, but would vary dynamically with the capacity of the network. The sum of entitlements on each **congested flowgate** would always be set equal to that flowgate's capacity.

The allocation of entitlements would aim to give firm generators a target entitlement corresponding to their agreed access amount on each flowgate. However, should **flowgate capacity** be less than required to meet aggregate agreed access levels (for example, during transmission outages), this may not be possible. Consequently, entitlements may be scaled back, resulting in a **shortfall** in access settlements payments.[17]

Figure 4.1 illustrates the scaling of entitlements under decreasing levels of flowgate capacity for the three generator access categories set out in Table 4.1. For simplicity, the generators are assumed to have the same capacity, **availability** and **participation** in the flowgate.

Figure 4.1 Entitlement scaling for different access categories

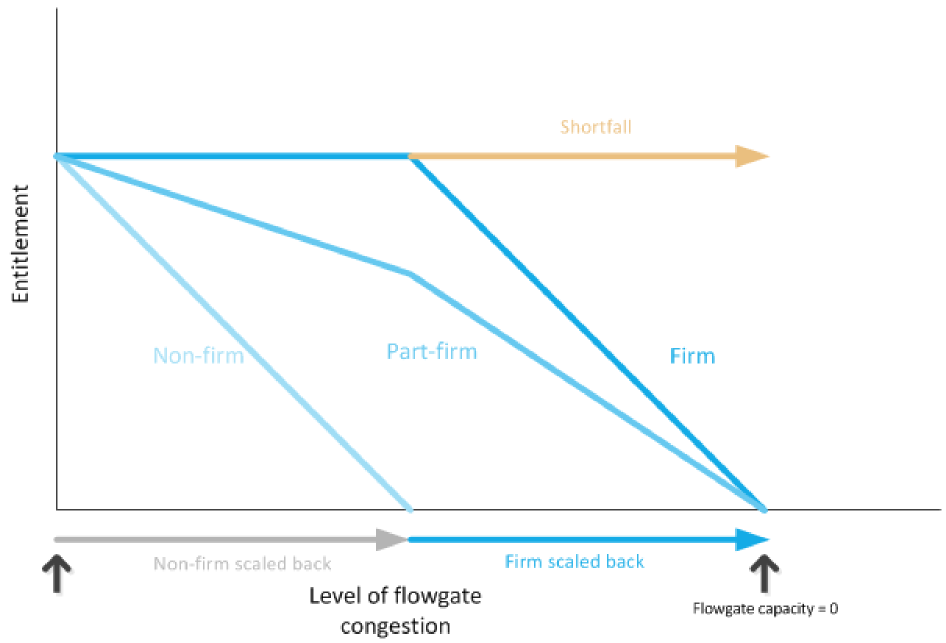


Table 4.1 Generator access categories

Generator type	Description
Firm (that is, firm for all of its capacity)	agreed access = capacity
Part-firm (that is, firm for part of its capacity, but non-firm for part of its capacity)	agreed access < capacity
Non-firm (that is, non-firm for all of its capacity)	agreed access = 0

It can be seen from the figure above that the scaling of firm entitlements only occurs once non-firm entitlements have been scaled to zero and there is a shortfall across the flowgate. On the other hand, when flowgate capacity is high, it might be possible to

17 Although TNSPs might contribute to part of the shortfall payments though an incentive scheme – see section 5.3.

give full entitlements to firm generators and also give some entitlements to non-firm or part-firm generators in excess of their agreed access amount.

Where a generator's actual usage exceeded its entitlement it would be required to pay compensation. Conversely, where a generator's entitlement exceeded its usage it would receive compensation. Typically, dispatched non-firm generators would compensate constrained off firm generators. Aggregate compensation paid out must always equal aggregate compensation received each trading interval. Access settlement must always balance.

A flowgate's capacity would be represented by the sum of the left hand side of the relevant binding **constraint equation**, while the generator's usage would be defined by the participation factor and its output. Some generators have negative participation factors, and thus by generating would increase the flowgate capacity. These are **flowgate support generators**, and their treatment is described in more detail in section 4.6. Were optional firm access to be introduced, then as part of its implementation, possible changes could be considered to the process by which AEMO consults stakeholders on constraint equation formulations, given constraint equations' materiality in access settlement.

The flowgate capacity, summed with the contribution of flowgate support generators is the **effective flowgate capacity**. The sum of the usage of all (positive participation factor) generators in a flowgate would need to equal the effective flowgate capacity. A flowgate would be any **transmission constraint**.[18]

The amount of compensation paid or received would be the difference between a generator's usage and its entitlements, multiplied by the **flowgate price**.[19] The flowgate price is a measure of the value that is gained by relaxing the underlying constraint by a small amount. It is measured by the reduction in the total cost of generation dispatch when 1MW additional energy is able to pass through the flowgate. Where a constraint prevents cheaper generation from being dispatched, such that demand must be met by more expensive generation from elsewhere in the region, then the flowgate price would be high.

Generators that were required to pay compensation would earn at least their offer price on each unit of energy for which they were dispatched. Therefore, a generator should not regret being dispatched.

4.4 Access settlement example

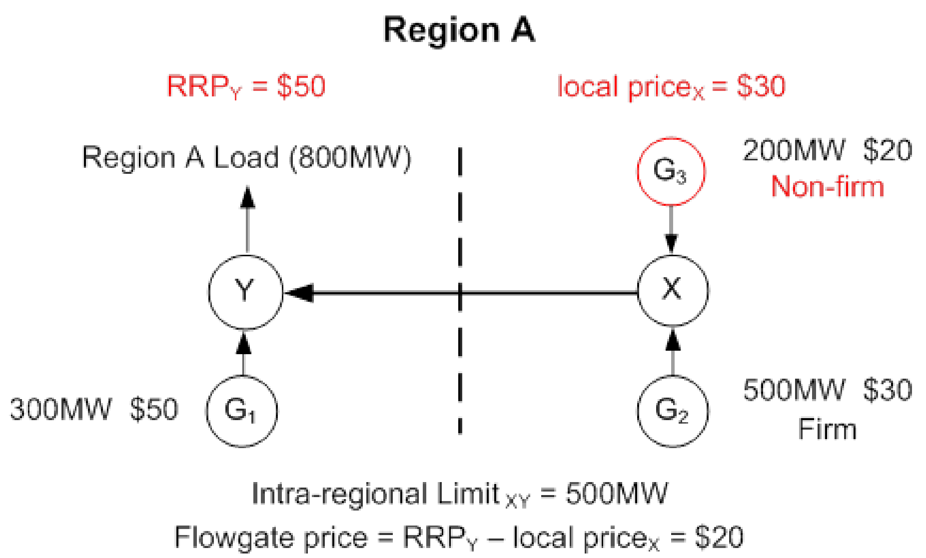
This section lays out a simple example of how access settlement would operate under optional firm access. Figure 4.2 illustrates a region with two nodes: X and Y. The

18 This includes any constraints on any elements that operate as transmission, for example, dual function assets, which are distribution assets that form part of the transmission network.

19 In addition, generators may receive payments from TNSPs whose actions were responsible for the network flow to be diminished (in accordance with the **firm access operating standard** as discussed in section 5.3).

regional demand of 800MW is located at node Y. The network limit between X and Y is 500MW. The dashed line indicates a flowgate.

Figure 4.2 Two-node network example



There are three generators: G_1 is located at node Y while G_2 and G_3 are located at node X. G_2 has 500MW firm access. G_3 is non-firm. G_1 does not participate in the flowgate: it has no need for access to the flowgate capacity. Node Y is the **regional reference node**. The regional reference price is the local price at the regional reference node.

G_2 offers 500MW at $30/MWh. G_3 offers 200MW at $20/MWh. The combined dispatch of the two generators cannot be greater than 500MW. With offers totalling 700MW, the network would be constrained and access to the flowgate would be rationed. G_3, with the cheaper offer, would be dispatched for 200MW causing G_2 to be constrained off by this amount. G_3, however, would make payments to G_2 through access settlement. Settlement outcomes are illustrated in Table 4.2.

Table 4.2 Access settlement outcomes

Generator	Dispatch (MW)	Energy settlement	Flowgate entitlement (MW)	Flowgate usage (MW)	Entitlement - usage (MW)	Access settlement	Total revenue
G_1	300	$15,000	N/A	N/A	N/A	N/A	$15,000
G_2	300	$15,000	500	300	200	$4,000	$19,000
G_3	200	$10,000	0	200	-200	-$4,000	$6,000
Total	**800**	**$40,000**	**500**	**500**	**0**	**$0**	**$40,000**

Through energy settlement, G_2 would receive the regional reference price of $50 for each unit for which it is dispatched. The payment G_2 receives through access settlement would be equal to the difference between its entitlement to the flowgate and its usage of the flowgate, multiplied by the flowgate price of $20. Assuming that G_2 were willing to be dispatched at its offer of $30, it would earn $20 per unit above its offer on the 300MW for which it was dispatched. Through access settlement, G_2 would also receive $20 for the 200MW by which it would be constrained off (for which it would incur no operating costs).

The compensation is funded by G_3, as a non-firm generator contributing to congestion. G_3 would receive the regional reference price of $50 on its dispatch, but after paying compensation through access settlement, would receive net revenue equal to the local price of $30. Table 4.3 shows the resulting operating margin for each of the generators, assuming that the generators' offers represent the amount at which they would be willing to be dispatched.

Table 4.3 Operating margin with congestion

Generator	Total revenue	Generating costs	Operating margin	Margin/MW
G_1	$15,000	-$15,000	-	-
G_2	$19,000	-$9,000	$10,000	$20
G_3	$6,000	-$4,000	$2,000	$10
Total	**$40,000**	**-$28,000**	**$12,000**	

For comparison, Table 4.4 repeats the above margin analysis as if there were no congestion, that is, as if the flowgate capacity were increased to 700MW so both G_2 and G_3 could be fully dispatched (with dispatch of G_1 decreasing to 100MW). In this case, no access settlement would apply, and each generator would simply earn the regional price on its dispatch quantity.

Table 4.4 Operating margin without congestion

Generator	Total revenue	Generating costs	Operating margin	Margin/MW
G_1	$5,000	-$5,000	-	-
G_2	$25,000	-$15,000	$10,000	$20
G_3	$10,000	-$4,000	$6,000	$30
Total	**$40,000**	**-$24,000**	**$16,000**	

By comparing the outcomes in Table 4.3 and Table 4.4 it can be seen that:

1. Access settlement puts G_2 in the same financial position it would have been in if it had been fully dispatched for 500MW: in both scenarios it earns $10,000 margin, or $20/MW.

2. G_3 earns a lower margin when there is congestion than when there is not. Even with access settlement G_3 still earns a positive margin - its net revenue of \$30/MW is higher than its offer of \$20/MW - so it should not regret being dispatched.

4.5 Inter-regional access settlement

Inter-regional access settlement would work in a similar manner as described above for intra-regional access settlement.

Inter-regional access settlement would work by allocating a pool of funds to holders of **firm interconnector rights** (the concept of firm interconnector rights is discussed further in chapter 7). The pool of funds available would be equal to:

- the price difference between two regions, multiplied by the interconnector flow; plus
- payments from generators whose dispatch caused the interconnector flow to be diminished.[20]

A mathematical representation of how inter-regional access settlement would work is contained in appendix B of the Technical Report.

Counterprice flows on interconnectors could still arise where generators in the **exporting region** were in merit relative to the importing regional reference price, despite the exporting region having a higher regional reference price. Through the access settlement process, the holders of firm interconnector rights would be compensated for any counterprice flows, preventing any negative settlements residue from arising. The inter-regional access right would therefore be firmer than the existing settlement residue auction units.

There could potentially be a shortfall when there is negative effective flowgate capacity on a flowgate, which would cause an interconnector to be constrained-on. This shortfall would be paid by the TNSP in the **importing region**.[21]

The model used for inter-regional access settlement would be the same as that used for intra-regional settlement, as discussed above. This would be easily facilitated since intra-regional settlement needs to recognise inter-regional entitlements on flowgates where the underlying constraint has an interconnector term.

20 In addition, firm interconnector right holders may receive payments from TNSPs whose actions were responsible for the interconnector flow to be diminished (in accordance with the firm access operating standard as discussed in section 5.3).

21 This can be considered analogous to the current arrangements for the treatment of counterprice flows on interconnectors.

4.6 Specification of access settlement

While working to develop the optional firm access model, a number of design decisions have had to be clarified in a number of areas of access settlement. These designs have fed into the access settlement work that AEMO undertook. These specification decisions include:

- Flowgate support generators would not receive payments through access settlement for increasing effective flowgate capacity.
- Access settlement would be undertaken on a trading interval basis.
- Scheduled and semi-scheduled market generators would be subject to optional firm access.
- Non-scheduled generators would not be subject to optional firm access – a non-scheduled generator would continue to receive the regional reference price for all of its generation, regardless of the constraints in the network.
- **Embedded generators** (those connected to a distribution network) that were scheduled or semi-scheduled would be part of the optional firm access regime, and so could procure firm access on the transmission network.[22]
- If a local price was below the market floor price,[23] then a method would be used so that generators would not face large negative local prices.
- Local prices generated by access settlement and entitlements would be loss-adjusted.
- A generator's entitlement under firm access would have a cap, with this cap being based on the capacity of the generator.

These design specifications are discussed in more detail in appendix A. Further detail on other access settlement specifications can be found in the accompanying Technical Report.

4.7 Metering arrangements

Currently, the market operator (AEMO) dispatches generating units and determines revenues in settlement using different metering systems. However, under optional firm access it would be necessary to integrate the dispatch and revenue metering systems

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22 As noted above, any dual function assets (that is, parts of the distribution network that form part of the transmission network) would also be included in optional firm access.

23 This situation could arise where the marginal generator on a congested flowgate had a low participation factor. This is because the flowgate price is the difference between the regional reference price and the marginal generator's offer *divided* by this generator's participation factor in the flowgate. A high flowgate price could lead to other generators with large participation factors in the same flowgate facing an extremely low local price, possibly below the market floor price.

for access settlement to function. Such a change would also require alterations to how generators' ancillary loads are treated:

- Optional firm access would introduce a new concept of an access unit identifier.[24] This would be created by allocating each generating station's **auxiliary load** across associated **dispatchable units**.[25] The access unit identifier would be used in access settlement, and would measure the output of one or many dispatchable units net of one or more auxiliary loads.[26]

- Under optional firm access, there may be stronger incentives for load to be classified as auxiliary load for the purposes of access settlement, since auxiliary load would be charged the local price rather than the regional reference price in the presence of congested flowgates. To minimise this occurrence, guidelines for what could be new auxiliary load would be created: load could only be classed as auxiliary load if it was operationally, commercially and temporally associated with, and electrically close to, the dispatchable unit associated with an access unit identifier.

- However, some existing generators have metering and auxiliary load arrangements that would not comply with the above principle. Therefore, grandfathering arrangements would need to be developed for existing generators.

These metering arrangements are discussed in more detail in appendix A.

4.8 Governance

Access settlement would require a body to be responsible for:

- determining flowgate capacities in the presence of binding constraints;

- specifying the participating generators in a flowgate;

- calculating the flowgate usage of each generator;

- determining the access settlement payment each generator must make or receive; and

- collecting and distributing settlement payments.

Many of the above functions rely on data that AEMO creates in real time in its role as market operator. For example, the presence of flowgates and generators' participation

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24 In the First Interim Report this concept was referred to as a revenue meter identifier (RMID).

25 These are dispatch units, which the AEMO dispatch process determines targets for. Typically, these are individual physical generating units. However, in some cases they are logical "aggregated" units, which represent the aggregate output of a number of specified physical units.

26 Flowgate usage would be floored at zero when an access unit identifier has a net import into the generator.

in those can be considered to be directly transferable from the processes AEMO currently uses for dispatch. Furthermore, the determination of the size of access settlement payments, and their distribution, is analogous to the current activities undertaken by AEMO in the settlement of dispatched energy.

Consequently, AEMO in its role as market operator would be the appropriate organisation to undertake these tasks. This fits with governance principle 1: promotes best natural fit. Access settlement fits with the existing processes and accountability of AEMO, given its analogies with energy settlement. Governance principles 2-4 would also be accommodated.

Reasonably detailed Rules outlining the operation and calculation of access settlement, similar to the current Rules on energy settlement, would be necessary as part of the implementation of the access settlement regime.

A party would also need to be responsible for undertaking the case-by-case assessment of what load could be classed as auxiliary load. This body would also have responsibility of mapping dispatchable units and auxiliary loads to access unit identifiers.

This would be best undertaken as part of the connection process between the TNSP and the generator. This process would be subject to a series of criteria that would be defined in the Rules and undertaken by the TNSP. This fits with the governance principles, most notably, principle 1: promotes best natural fit, as the TNSPs would be examining the security and expected network impact of any connection at the same time.

The mapping of existing auxiliary loads as part of the grandfathering arrangements would be determined as part of the implementation project if optional firm access were to be introduced. AEMO, as the market operator, would be the best body for this role since it already has all of the relevant information relating to the dispatch and connection arrangements of current generators.

5 Firm Access Standard

Summary of this chapter

Under optional firm access, TNSPs would be required to meet the firm access standard, which would have two components:

- the firm access planning standard; and
- the firm access operating standard.

The firm access planning standard would represent a requirement for TNSPs to plan their network to provide the agreed access levels under a set of specified conditions. The firm access planning standard conditions would be designed so that network capacity would be provided when generators value it the most.

The firm access operating standard would encourage TNSPs to operate their network efficiently to provide firm access *under all conditions*. This would occur through an incentive scheme, which would incentivise TNSPs to efficiently manage their network with regard to congestion at all times.

TNSPs would not have any requirements to provide access to non-firm generators. But, the firm access standard would not affect a TNSP's obligation to meet jurisdictional reliability standards.

5.1 Introduction

The **firm access standard** would define the minimum level of service quality to which a firm generator would be entitled. A firm generator's entitlements would be translated (through its access arrangement) into the level of transmission capacity that the TNSP would be obliged to provide. The specification of the firm access standard is an integral part of the optional firm access model since it provides generators with confidence in the effective provision of the firm access service, as well as driving efficient network planning and operation by the TNSPs.

The firm access standard would have two components, the firm access planning standard and the firm access operating standard.

The firm access planning standard would comprise a set of market and network conditions. These are the conditions for which the TNSP would be required to plan to provide access to firm generators. These are described as the firm access planning standard conditions throughout the remainder of this chapter. By implication, the TNSP would not have to plan to provide firm access for firm generators under other conditions.

The firm access operating standard would encourage the TNSP to operate their network efficiently to provide firm access to firm generators *under all conditions*. This would occur through an incentive scheme.

The firm access standard would not affect a TNSP's obligation to meet jurisdictional **reliability standards**.

This chapter sets out the:

- design of the firm access planning standard (section 5.2);
- design of the firm access operating standard, including the incentive scheme for TNSPs (section 5.3);
- interaction between the different components of the firm access standard (section 5.4); and
- governance arrangements for the firm access standard (section 5.5).

5.2 Firm access planning standard

5.2.1 Defining the firm access planning standard

The firm access planning standard would be defined as a mandatory standard. It would require a TNSP to plan its network so as to be able to provide the sum of the agreed access levels for all firm generators under a set of specified conditions.[27]

The firm access planning standard would take into account the generator's economic assessment of the value of access. In deciding how much firm access to procure, a generator would undertake its *own* economic assessment of the value of that firmness. The firm access planning standard – by incorporating the procurement decision of each generator – would therefore be established as an inherently economic standard.

However, in order to allow TNSPs to plan to this level, the firm access planning standard would be expressed in a way that specifies the requirements on the TNSP, that is, how much capacity needs to be provided. The TNSP must plan to meet all of purchased firm access under the firm access planning standard conditions. Indeed, expressing the firm access planning standard in a way other than in this manner would mean the TNSP would second-guess a generator's assessment.

The firm access planning standard would be defined by the capacity that would be needed in order for all firm generators in the network to receive their full access amount during a set of conditions.[28] These conditions would be equivalent for all generators within a region that have purchased firm access.

27 Meeting the standard would involve the TNSP planning to evaluate the outcomes of a predetermined set of contingencies, without reference to the probability of the contingencies occurring.

28 Stakeholders have raised concerns that the TNSP would be required to plan, and develop, the network to meet the firm access planning standard which could lead to inefficient build. We consider that the provision of the **sell-back** option for firm access (as discussed in chapter 7) minimises the probability of inefficient network expansion occurring.

The TNSP would have no firm access planning standard obligation in relation to non-firm generators. The TNSP would retain the responsibility to meet the jurisdictional reliability standards for consumers in that region. Thus, the TNSP would be required to plan and operate its network to meet both the reliability and firm access standards.

5.2.2 Principles and methodology for setting the firm access planning standard conditions

The firm access planning standard conditions would be designed so that network capacity would be provided when generators would value access most highly. Further, defining these conditions would also provide guidance to TNSPs for their planning arrangements.

The Rules would set out the principles for how the firm access planning standard conditions could be determined. With reference to the above considerations, the principles could include that the conditions:

- be nationally consistent;
- be set transparently;
- coincide with instances where potential constraints would either occur frequently or lead to high flowgate prices, that is, where congestion is material in the market;
- be able to be reflected in the inputs to other elements of the optional firm access model, for example, the pricing model;
- take into account market factors that could materially affect transmission capacity such as the influence of local load; and
- take into account ambient environmental factors that could materially affect transmission capacity, for example, temperature.

Drawing on these principles, the AER would develop a guideline with further detail describing the firm access planning standard conditions.[29] This would contain a methodology around how the following factors should be specified:

- scheduled and semi-scheduled generation – for example, assumptions about the expected availability of scheduled and semi-scheduled generation, including those operating as flowgate support;
- non-scheduled generation – for example, assumptions about the expected availability of non-scheduled generation;

29 Further detail on the governance of the firm access planning standard is set out in section 5.5.1.

- transmission – for example, assumptions about what assets are in service, and the ratings of these assets; and
- demand – for example, assumptions about how much demand response may be present, and whether this would be used.

On the basis of the guideline, TNSPs would develop the firm access planning standard conditions which would specify the above factors. To meet the firm access planning standard, the TNSP would need to plan its network to deliver firm access during these conditions.[30]

During the course of this review the Commission has assumed a firm access planning standard condition of summer peak demand. This assumption has been used in the assessment work as set out in Volume 1, the pricing prototype model and **transitional access** modelling. In general, peak demand would be a consideration for the firm access planning standard conditions.

5.2.3 Planning for the firm access planning standard

A TNSP would be required to meet both the firm access planning and reliability standards concurrently. Under the Rules, the TNSP's planning processes would be required to identify impending breaches of these standards and identify appropriate options to remedy these (as they are currently required to do in relation to reliability standards).

In order to plan its network, the TNSP would first consider what capacity is necessary to meet both standards. To do this the TNSP would need to consider every flowgate on its network, and the way each flowgate could impact different uses of the network.

The TNSP would then consider the limitations on its network in providing this capacity (that is, the current condition of the network). This would include assessing factors such as demand (for example, the distribution of local load), capacity of lines (for example, line rating assumptions) and areas of congestion. It would then be required to plan its network to overcome these limitations so that it remains compliant with its obligations under both standards.

The results of this planning would be set out in each TNSP's Annual Planning Report, which is a detailed short-term plan for the network. Each TNSP is currently obliged to produce an Annual Planning Report.[31] It sets out the current capacity and emerging limitations of the network under a range of different scenarios. Currently, the reports cover potential upcoming issues and future projects the TNSP may need to undertake to meet the jurisdictional reliability standards.

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30 The TNSP may develop stylised constraint equations to feed into a network model that is required for other elements of the optional firm access model, as described in section 7.4.3.

31 National Electricity Rules (NER) clause 5.12.2.

With the introduction of optional firm access, each TNSP would be required to evaluate its firm access planning standard obligations in these Annual Planning Reports. This may include setting out:

- a quantification of the firm access planning standard requirement the TNSP has in relation to total purchased firm access;
- a description of the current and potential flowgates that may impact on the provision of firm access to generators during the conditions in the firm access planning standard; and
- an outline of the planning actions that would be undertaken so that the TNSP would continue to meet its firm access planning standard obligations.

The firm access planning standard must be met in an ongoing sense over the whole network.

Generators would not be required to specify or monitor individual potential flowgate developments, since this would be the TNSP's responsibility under the firm access planning standard. A generator would only be required to specify and purchase a level of access at a particular point for a particular time period. The TNSP would be responsible for determining where constraints on the network may bind under the firm access planning standard conditions, and so allow the firm access planning standard to be met.

Following this planning, the TNSP may need to undertake developments to meet its firm access requirements. As currently, where relevant, the TNSP would then be required to apply a RIT-T to identify and select a development option with the highest net benefit to resolve any potential firm access planning standard breaches.[32] The RIT-T process under optional firm access is described in chapter 8.

5.3 Firm access operating standard

The objective of the firm access operating standard would be for TNSPs to operate the network efficiently.[33] The firm access operating standard would be underpinned by an incentive scheme, which would incentivise TNSPs to efficiently manage their network with regard to congestion.

It would be inefficient for a TNSP to operate and plan its network so as to provide full capacity at all times. There may be circumstances that affect capacity on the network that are caused by events outside the TNSP's control, such as bushfires. Further, TNSPs need to reduce capacity at times where it is not valued (for example, during off-peak

32 Consistent with NER clause 5.16.3(d), for those developments to meet the firm access planning standard that are estimated to cost less than $5 million, these would also have to be planned, and built, at least cost.

33 Taking into account the relevant jurisdictional and environmental obligations it must comply with.

times) for actions such as maintenance. It would not be efficient to require full capacity under these conditions.

The AER would be ultimately responsible for the development of the incentive scheme. The AER would be required to follow high-level principles and objectives which would be set out in the Rules, as is currently the case for other TNSP incentive schemes, such as the service target performance incentive scheme (STPIS).

The incentive scheme would replace (and would represent an evolution of) the market impact component of the STPIS as it applies to TNSPs.

Given that the AER would design the incentive scheme in accordance with Rules-based principles, the detail of the scheme described in this section is therefore one possible design option that the AER could implement.

The TNSP incentive scheme would:[34]

- include rewards and penalties based on **shortfall costs** (section 5.3.1);
- apply at all times (section 5.3.2);
- use an annual shortfall costs benchmark to measure the TNSP's performance, based on the shortfall costs of an efficient TNSP (section 5.3.3);
- use nested caps to limit TNSP risk (section 5.3.4);
- have parameters (the annual shortfall cost benchmark for the TNSP, and nested caps) set by the AER (section 5.3.5); and
- require that payments under the scheme be recovered at the end of the year (section 5.3.6).

5.3.1 Shortfall costs as the basis for TNSP rewards and penalties

TNSP rewards and penalties under the incentive scheme would be based on shortfall costs. As discussed in chapter 4, shortfall costs are the cost to firm generators of shortfalls of transmission capacity that result in firm access entitlements, and so compensation for firm generators, being scaled back.[35]

The shortfall cost can be defined as the flowgate price multiplied by the difference between the target flowgate capacity (that which is required to provide the target firm

34 The First Interim Report discussed two options for an incentive scheme. The Commission, as set out in the First Interim Report, considers that Option 2 is preferable. Therefore, the incentive scheme described here can be considered to be analogous to Option 2 as discussed in the First Interim Report.

35 For the purpose of simplicity, this chapter discusses the incentive scheme in the context of firm generators who have purchased intra-regional firm access. As discussed in section 7.3, parties other than generators would be able to purchase inter-regional access. The incentive scheme would apply in an identical manner for these other parties.

entitlements to all firm generators participating in the flowgate) and the effective flowgate capacity (the actual flowgate capacity plus any flowgate support). By incorporating the flowgate price, the value of the shortfall to generators would be reflected.

Through the incentive scheme, the TNSP would be incentivised to manage the level of shortfall costs, and so the costs to firm generators, of network constraints.

5.3.2 Incentive scheme applies at all times

The TNSPs would have an obligation to provide firm access under the firm access planning standard conditions. The incentive scheme would complement the firm access planning standard by providing TNSPs with an *incentive* to operate efficiently at all times.

It is acknowledged that there would always be the possibility of shortfall costs; the level of access provided to a firm generator could fall below the agreed amount from time to time as operational conditions vary (for example, planned or unplanned outages on the network, or due to off-peak variances in network capacity). Indeed, it would be inefficient for there to be no shortfalls of capacity on the network – this would require an unconstrained approach to planning, which would likely lead to inefficient over-investment in the transmission network.

This would create some uncertainty for firm generators about the quality of service that they would receive. The firm access operating standard and incentive scheme are intended to reduce this uncertainty.

The TNSP should be provided with a *continual* incentive to efficiently provide levels of access to firm generators. Therefore, the incentive scheme would apply at all times. A TNSP would make efficient decisions to operate its network based on trading off the cost of the penalty (or benefits of reward) versus the cost of operational actions to avoid the penalty.

The incentive scheme would apply equally for intra-, inter-, long-term and short-term firm access, in order to avoid any difference in firmness or treatment of these types of access.

5.3.3 Annual shortfall cost benchmark

At the start of each year, the AER would set an annual shortfall cost benchmark for the TNSP, based on the AER's estimation of the shortfall costs[36] of an efficient TNSP.[37]

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36 As detailed in the technical report, the annual shortfall cost benchmark would also be set with regard to efficient operating costs.

37 As discussed in section B.1, the benchmark might be set with regard to the TNSP's own historic performance.

For example, the AER may set the annual shortfall cost benchmark for a particular TNSP at $10 million. Because this is set in dollar terms, it directly relates to the *value* of shortfall costs experienced by generators.

The shortfall costs that would be calculated through access settlement would always be penalties (or zero), in the sense that in each trading interval they are "using up" the benchmark set by the AER at the start of the year. Importantly, TNSPs would not be rewarded for providing, at any time, more flowgate capacity than the target flowgate capacity (that which is required to provide the target firm entitlements to all firm generators participating in the flowgate, and so there be no shortfall).

In any particular trading interval, performance at (or better than) the target flowgate capacity would result in none of the annual benchmark set by the AER being “used up”. This is because there would be no shortfall. However, the running total of shortfall costs for the year would not *decrease* if capacity were to be provided in excess of the target flowgate capacity. This would be appropriate as firm generators would not have signalled that they value capacity above the target flowgate capacity.[38]

At the end of the year, the TNSP would pay penalties if the actual shortfall costs over the year are higher (worse) than the benchmark set by the AER at the start of the year. Conversely, it would receive a reward if the actual shortfall costs over the year are lower (better) than the benchmark set by the AER. Any difference between the benchmark specified by the AER at the start of the year and annual actual aggregate shortfall costs would be payable by/to the TNSP.[39]

For example, if the AER set the annual shortfall cost benchmark at $10 million for a particular TNSP, and the actual aggregate shortfall costs were $8 million, the TNSP would receive from firm generators $2 million. Conversely, were the actual aggregate shortfall to be $12 million, the TNSP would pay $2 million. How this allocation would occur is discussed below in section 5.3.6.

It is appropriate that a TNSP would be rewarded for beating the annual shortfall cost benchmark set by the AER, even if some shortfall costs would have occurred. This is because the benchmark set by the AER would represent the efficient level of shortfall costs. As a result, the scheme would provide a continuous incentive (subject to the caps, as described below) to improve efficiency.

While a firm generator would be making payments to a TNSP were it to beat the annual shortfall cost benchmark set by the AER, these payments would be as a result

38 For the purpose of clarity, note that the *target* flowgate capacity is equal to the capacity required to provide the target firm entitlements to all firm generators participating in the flowgate – that is, the flowgate capacity required for no shortfall costs to arise. This is a different concept to the annual shortfall cost *benchmark* set by the AER – that is, the efficient amount of shortfall that occurs during a year.

39 Although the shortfall costs calculated through access settlement would always be penalties (or zero), the TNSP would receive a penalty *or* reward (that is, the incentive scheme would be symmetrical) depending on whether the aggregate shortfall costs is higher or lower than the benchmark.

of, and offset by, improvements in settlement outcomes for the firm generator as a result of reduced shortfall costs. Therefore, firm generators would be better off than if there had been no incentive scheme, since the reduction in shortfall costs as a result of the TNSP responding to the scheme incentives would be larger than the generator contributions to the TNSP rewards.

5.3.4 Caps

There would be caps on payments under the incentive scheme, to limit the risk that TNSPs are exposed to under the scheme.

Caps have the effect of lowering the power of the incentive scheme. However, low-powered schemes can be successful. The current market impact component of the STPIS has been observed to work well at incentivising TNSPs to reduce the market impact (that is, impact on generators) of constraints in the capacity of their network. This is despite it being low-powered (that is, TNSPs being exposed to a small amount of their maximum allowed revenue under the scheme).

Given that a TNSP would be exposed to shortfall costs during all trading intervals, there is potential for extreme shortfall costs to arise under “abnormal” operating conditions, because NEM spot prices (and so shortfall costs) can be very high. Therefore, any single cap that may be applied to limit a TNSP’s aggregate exposure could be reached very quickly. If this were to occur, then the TNSP would have no further exposure to the scheme – and so no further incentive to manage access shortfalls – for the remainder of the year. Indeed, a TNSP may have an incentive to bring forward scheduled outages from future years, given that it cannot be penalised under the scheme for any shortfall costs that arise from them.

Therefore, “nested” caps would be included in the incentive scheme. “Nested” refers to the caps effectively being placed inside one another. So, within the annual cap, there may be monthly caps, and then daily caps within the monthly caps, and so on.

The nested caps would be designed (and so set at a level) to limit TNSP exposure to unmanageable risks (for example, the timing of forced outages), while leaving a TNSP fully exposed to manageable risks (for example, the timing of planned outages, or the resolution of unplanned outages). The caps effectively share the risks between the TNSP and the firm generators. They limit the share that is borne by the TNSP, but in doing so increase the share that is borne by generators.

For example, a possible scheme may include the following nested caps:

- no more than $10 million exposure in a year;
- no more than $200,000 exposure in a day (one 50th of the annual cap); and
- no more than $20,000 exposure in a trading interval (one 10th of the daily cap) on any flowgate.

Once a TNSP hits one nested cap for a time period, it would no longer continue to accrue shortfalls during that time period against the next cap. For example, if the trading interval cap was $20,000, once the TNSP hit $20,000, only the $20,000 would contribute to the daily cap, even if more than $20,000 of shortfall was accrued in the trading interval. This stops the TNSP exhausting a number of caps in one short period.

5.3.5 Setting the incentive scheme parameters

The parameters of the incentive scheme (the annual shortfall cost benchmark for the TNSP, and the nested caps) would be set by the AER. These parameters would determine the strength of the incentive scheme and influence the size of payments to and from firm generators as a result of the scheme.

In general, the parameters should drive TNSPs towards efficient behaviour and also reflect the concerns of generators, such as certainty around access firmness. Possible factors that the AER might consider in setting the incentive scheme parameters are discussed in appendix B.

5.3.6 Recovery and allocation of incentive scheme payments

At the end of the year, the shortfall costs would be calculated by the AER for each trading interval in the year for each flowgate and for each generator, subject to the nested caps.[40]

The total annual shortfall cost benchmark would be allocated by the AER between the firm generators at the start of the year (in effect, each generator would have its own benchmark of shortfall costs).

The rewards or penalties would be calculated at the end of the year. They would then be paid to/from the TNSP from/to each individual firm generator, as the difference between the TNSP's actual shortfall costs (subject to the nested caps) and the annual shortfall cost benchmark set at the start of the year for that generator. Payments to/from each generator must aggregate to equal the payment from/to the TNSP. How these payments and allocations would be given effect would be determined at the implementation stage.

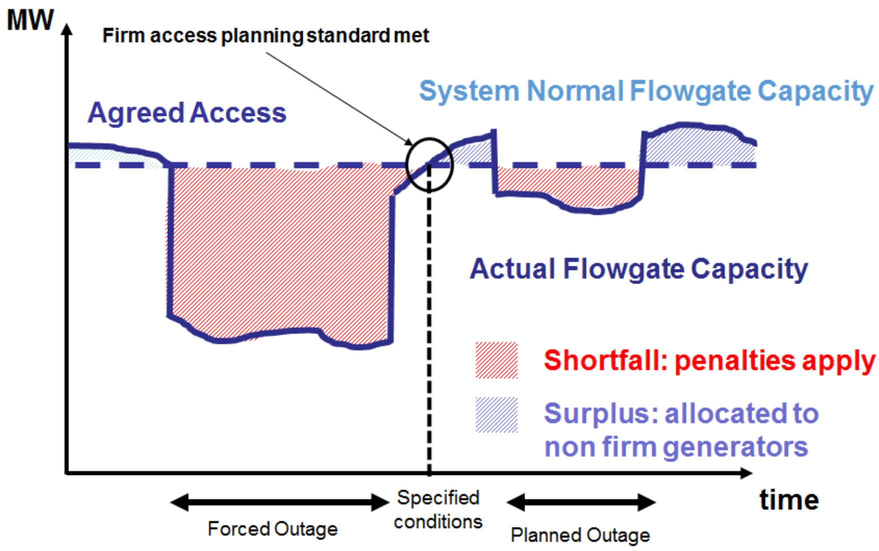
To avoid cashflow issues, the annual settlement could be spread over the following year, as determined by the AER. For example, one twelfth of the annual settlement amounts could be paid to or from the generator/TNSP in each month.

40 This calculation would be separate from the process by which access settlement payments to firm generators would be scaled back in real time, as discussed in chapter 4.

5.4 Combined operation of the firm access planning standard and the firm access operating standard

The firm access planning and firm access operating standards are designed to work together to encourage a TNSP to plan and operate its network efficiently so as to provide the firm access service. Figure 5.1 shows a simplified example of how the firm access planning and operating standards would interact. This diagram shows the flowgate capacity that would be available for the generator over the course of time as the blue solid line. The horizontal dotted blue line represents the purchased level of firm access, while the vertical dotted line represents the flowgate capacity provided during the firm access planning standard conditions.

Figure 5.1 Operation of the Firm Access Standard



In this example, the TNSP meets the firm access planning standard as the level of access matches the purchased level of access at the specified conditions. Additionally, the TNSP has dropped below the firm access level agreed at two points, once because of a planned outage and the other due to a forced outage. In both of these periods, due to the firm access operating standard, the TNSP would face penalties as part of the incentive scheme. Consequently, the TNSP would have an incentive to minimise the market impacts (and so duration) of these outages.

A forced outage may occur during the firm access planning standard conditions, depending on how they are specified. Typically, TNSPs should factor in the probability of forced outages occurring at such times when they plan the network to meet the firm access planning standard. If an extremely large outage on the network occurred, it could be the case that the capacity on the network during the specified conditions may be lower than that required under the firm access planning standard. However, this should be rare. Regardless, the firm access operating standard would continue to apply and so would incentivise the TNSP to restore the outage as quickly as possible.

Another issue is the treatment of known flowgates that repeatedly become congested outside of the firm access planning standard conditions, causing firm generators to be scaled back. TNSPs would not be required to develop the network to remove these flowgates to comply with the firm access planning standard. However, the TNSP would accumulate losses under the incentive scheme in the situations where there were flowgate shortfalls. As discussed in section 5.5.1, with the AER's approval, the TNSP may alter the methodology of determining the firm access planning standard conditions so they encompass this flowgate congestion. This would then require the TNSP to plan for solutions to resolve the congestion of these flowgates.

5.5 Governance

This section sets out:

- how the firm access planning standard conditions would be set (section 5.5.1);
- how the firm access planning standard would be enforced (section 5.5.2); and
- the development and regulation of the incentive scheme for the firm access operating standard (section 5.5.3).

5.5.1 Setting the firm access planning standard conditions

As described in section 5.2.1, there would be principles for setting the conditions of the firm access planning standard. These principles would be written into the Rules as part of the implementation of optional firm access.

From the principles, the AER would produce a guideline including a methodology with further detail on how the firm access planning standard conditions should be set. Given the technical expertise the National Transmission Planner is likely to have in this area, it would be prudent for the AER to consult with the National Transmission Planner as part of developing guidelines.

Each TNSP would have responsibility for developing the firm access planning standard conditions for its own network, on the basis of the methodology set out in the AER guideline. Given regional variances, some of the detail around these conditions may be different in each region. A TNSP has the most knowledge of when its network is at its most constrained, and by allocating this decision to the TNSP a local perspective is introduced, which is consistent with governance principle 2.

The AER would then review the conditions proposed by the TNSP, and if satisfied, approve them. The AER has experience with processes for engaging with TNSPs in this way, so the AER having this role fits with governance principle 1: promotes best natural fit.[41] The AER would consult with the National Transmission Planner when reviewing the TNSP proposed conditions.

41 There could be oversight of the AER through either the Reliability Panel or a judicial review process.

5.5.2 Monitoring compliance with the firm access planning standard

Given that the firm access planning standard is a network-wide planning standard, the AER would be the entity best placed to assess the TNSP's compliance with its planning obligations across the network as a whole. If the obligation to plan the network is set out in the Rules, this would automatically form part of the AER's monitoring and enforcement role supported by its information gathering powers. In order to monitor compliance with the firm access planning standard, the AER would need access to a large amount of planning information.

It is important to bear in mind that the occurrence of an outage is unlikely to be an indication that the TNSP has failed to meet its obligations to plan its network to meet the firm access planning standard. While outages can be an indication of a failure to plan properly, outages are expected even where the TNSP has planned properly.

In addition, Rules requiring compliance with the firm access planning standard could be a conduct provision.[42] A conduct provision allows a "person other than the AER" to seek action against another party based on a breach of the provisions. It also allows the person to recover the amount of loss or damage that was suffered as a result of any breach of that conduct provision. Through this, generators would have the ability to take action for failure of a TNSP to meet its obligation to plan its network in accordance with the firm access planning standard.

5.5.3 Incentive scheme

The AER would be ultimately responsible for the development of the incentive scheme, in accordance with high-level principles as set out in the Rules. This is appropriate, given the AER's experience in developing other network service provider incentive schemes, and in keeping with the governance principle 1: promotes best natural fit.

The AER currently regulates and sets incentive schemes for TNSP monopolies to protect customer interests. Under optional firm access, generators would have a strong incentive to help design the incentive scheme, because the objective of the incentive scheme would be to encourage a TNSP to provide an efficient level of access firmness. Therefore, while retaining ultimate responsibility, the AER would be required to seek input from generators into the scheme's design (along with other relevant stakeholders), through the usual consultation processes under the Rules.

42 In order for a Rule to be made a conduct provision, there would need to be a recommendation made to the COAG Energy Council to give effect to this.

6 Pricing

Summary of this chapter

Cost-reflective pricing signals are required for firm access, to help to co-optimise generation and transmission investment.

The Commission favours a long run incremental cost (LRIC) based, stylised model for pricing. The LRIC method is better able to provide cost-reflective price signals to generators than other methods because of the manner in which it values spare capacity in the network, and so captures both present and future incremental costs. The stylised approach is able to quickly and transparently produce access prices.

The Commission has developed a prototype of the pricing model based on the design features for the stylised LRIC pricing model. This is available for stakeholders to use. While the pricing prototype is producing prices for which the relativities are as expected, the Commission has been unable to determine whether the quantum of the prices reasonably reflects the incremental TNSP costs of providing access.

The reason that prices from the prototype pricing model may not reasonably reflect the incremental TNSP costs of providing access is in part due to the limitations of the prototype pricing model itself. These limitations would be expected to be overcome with more time, resources and data availability, although some technical challenges may still remain.

At the same time, it is important to bear in mind that prices fixed at the time of the access request would always be based on projections of TNSP incremental costs. As a result they can never fully reflect the TNSP's ultimate incremental costs.

The Commission also acknowledges the concern that the access pricing method would be dependent on centrally-developed forecasts. Although this is intrinsic to the LRIC pricing method, this concern can be mitigated through appropriate governance. For example, one option could be for some prices produced by the model to be tested on a case-by-case basis before being applied. This would need to be developed as part of the implementation process, should a decision be made to introduce optional firm access.

6.1 Introduction

Providing new or additional firm access increases the network capacity that a TNSP would be required to provide, thus imposing new costs on a TNSP.

An access charge would be paid by firm generators to TNSPs. It would reflect the incremental transmission costs that are created by the generator's decision to locate in a particular part of the network.

This charge would cover the incremental costs imposed on the TNSP for providing the firm access, while providing a locational signal to generators that is not part of the current arrangements. By exposing generators to the long-term transmission costs associated with their locational decision, this would help to co-optimise generation and transmission investment.[43]

As non-firm generators would not impose incremental costs on the transmission network (because the TNSP would have no obligations towards them under the firm access standard), non-firm generators would not be charged for access.

This chapter discusses:

- an overview of the access pricing methodology (section 6.2);
- details of the pricing methodology (sections 6.3 to 6.8);
- the governance of access pricing (section 6.9);
- the prototype pricing model developed by the Commission (section 6.10); and
- conclusions drawn from the prototype pricing model (section 6.11).

Appendix C discusses these matters in greater detail.

6.2 Overview of access pricing methodology

The access pricing methodology would have the following design features:

- **access prices** would be set by a regulated process overseen by the AER (section 6.3);
- the price paid by firm generators for access would be fixed at the start of the life of the registered access (section 6.4);
- for long-term intra-regional access, prices would be derived used a stylised model to calculate projected transmission costs, based on the **long run incremental costing (LRIC)** method (sections 6.5 and 6.6);
- for long-term inter-regional access (section 6.7), the auction reserve price (discussed in chapter 7) would be the sum of:
  - the stylised LRIC for costs associated with **thermal flowgates**; and

43 For further discussion, please see volume 1 of this report.

- — manually estimated (by TNSPs, subject to AER oversight) **deep connection costs** for costs associated with **stability flowgates**; and

- **access charges** would be payable annually over the term of the registered access based on a default **payment profile** (section 6.8).

There has been stakeholder concern regarding a number of these design features, particularly the use of a stylised pricing model based on the LRIC method.

Some stakeholders have argued that a stylised model is not capable of deriving cost-reflective access prices. Further, a number have also argued that the deep connection charge (DCC) pricing methodology is simpler and less reliant on – potentially inaccurate – projections which would be used as inputs to the pricing model.

The Commission has considered these stakeholder concerns in making its recommendations, as discussed in each of the relevant sections below.

As discussed in chapter 7, short-term access would be procured via an auction, with no reserve price. Chapter 9 discusses how transitional access would be procured and priced. Therefore, the pricing methodologies discussed in this chapter do not apply to short-term access or transitional access (although the pricing for *renewing* transitional access is discussed in section 6.5.3).

6.3 Access prices set through regulated process

Access prices would be set by a regulated process overseen by the AER, as opposed to being negotiated between the TNSP and generator. Prices set though a regulated process are favoured over negotiated prices (that is, prices determined in agreement between the buyer and seller) because firm access is provided by the shared network and so is a monopoly service:

- Negotiating prices may be problematic for shared transmission services, as it may be difficult to determine the contribution of any individual party to the costs of the shared network, and may result in the shifting of costs between other network users (such as other firm generators or consumers). Under a regulated process, no such difficulties arise.

- As a monopoly service, the generator would be unable to shop around other providers to secure a better price. Through the negotiation process, a TNSP may be able to charge prices above the efficient cost of providing the firm access service.[44]

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44 A TNSP’s incentive to secure a high price is lessened by revenue regulation arrangements. Beyond the current regulatory period, consumers, rather than the TNSP, would be the *immediate* beneficiary of higher firm access prices, due to the regulatory reset process (discussed in chapter 8). In the long term, access prices which are not cost reflective could result in inefficient investment signals, to the long term detriment of consumers.

6.4 Access prices fixed at start of registered access

The charge to be paid by the firm generator would be calculated during the **access procurement** process, and fixed for the life of the registered access.[45]

Fixing prices at the start of the registered access term provides financial certainty to firm generators. Conversely, prices that could vary up or down over the course of the registered access (as, for instance, the projected cost of providing the access varied) would provide less financial certainty to generators. Generators may then choose not to purchase the firm access as a result, or to only purchase it for a short length of time to limit their exposure to the risk of price changes.

Less purchased firm access would mean that many of the benefits of the optional firm access model, as outlined in Volume 1 of this report, would be reduced. Indeed, one of the objectives of the optional firm access model is to provide financial certainty to firm generators, which requires a fixed access price at the start of the registered access.

6.5 Intra-regional access prices based on long run incremental costs

6.5.1 Long run incremental cost

Transmission planning is a long-term process and it would not be sufficient to simply calculate the *immediate* cost of the extra investment required prior to new access rights commencing. The new access may cause a *future*, already planned, investment to be brought forward. The capital cost would remain the same, but the advancement means that, after applying a discounting rate, there would be an incremental cost in net present value (NPV) terms.

A methodology in which *all* incremental costs are calculated – present *and* future – is referred to as the long run incremental cost (LRIC)[46] method. The LRIC method forms the basis for the access pricing approach for long-term, intra-regional access.

The LRIC is the difference between two costs:

- the **baseline cost**, which is the NPV of a baseline network development scenario which reflects the expected expenditure on the network absent of the requested access (including development, replacement, operating and maintenance expenditure); and
- the higher **adjusted cost**, which is the NPV of an adjusted network development scenario – that is, an amendment to the baseline network development scenario to accommodate the new **access request**.

45 Except for some defined indexation.

46 Forward-looking long run incremental cost (FL-LRIC) is a defined term used in telecommunications pricing and regulation. FL-LRIC is similar to the concept of **long run marginal cost (LRMC)** as discussed in section 6.5.2.

LRIC = cost of adjusted scenario – cost of baseline scenario

Other things being equal, the characteristics of the LRIC pricing methodology are that:

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

These signals should promote more efficient use of the existing network and, by exposing generators to the long-term transmission costs associated with their locational decision, help to co-optimise generation and transmission investment.

6.5.2 Rationale for the LRIC method versus alternative pricing methods

Two alternative pricing methodologies that could be used for access pricing are:

- The long run marginal cost (LRMC) method, where the access price is a constant unit cost equal to the average unit cost of capacity expansion. In effect, the LRMC assumes zero spare capacity currently exists or is created by an expansion, and so charges a constant unit cost (the average unit cost) regardless of incremental usage.
- Deep connection charging (DCC), which is the full cost of immediate expansions only. The access price is either zero (where incremental usage is less than initial spare capacity and so there is no immediate expansion), or the full expansion cost (where incremental usage exceeds initial spare capacity and so expansion is prompted), which decreases on a per unit basis as incremental usage increases.

The rationale for using LRIC as opposed to LRMC or DCC is discussed in more detail in appendix C. In summary, LRIC is preferred for access pricing because it provides price signals to generators that are more cost-reflective than the other two methodologies, in particular in how it values spare capacity in the network – and so captures both present and future incremental costs.

Appendix C also demonstrates that both the LRMC and DCC methods are special cases of the LRIC method:

- LRIC approaches LRMC in the special case of very high projected growth of electricity flow.

- LRIC approaches DCC in the special cases of zero growth of electricity flow.

The Commission considers that both LRMC and DCC make implicit assumptions about the future, but that these assumptions may not be robust under all scenarios. Therefore, the Commission considers that it is preferable to have a pricing method where forecasts are explicit, and so can be publicly consulted on and tested.

Some stakeholders have commented that DCC may be more appropriate in today's investment environment, given the current low demand growth projections, and the relative ease by which the immediate costs (as per the DCC approach) may be calculated compared to the incremental costs into the future (as per the LRIC approach). However, LRIC is a *generalised* approach which can accommodate different projections of electricity flow growth, and is therefore adaptable to an uncertain future for electricity demand. It is therefore more robust to changing demand patterns over time.

6.5.3 LRIC pricing method design specifications

Design specifications of the LRIC pricing method include:

- In relation to replacement expenditure, the LRIC would include projections of costs associated with maintaining and/or replacing existing assets in order to meet the firm access planning standard, so that the price is reflective of both expansion and replacement costs.

- New access in one region may create incremental usage – and so incremental cost – on some transmission elements in a neighbouring **remote region**. The access price would include incremental costs associated with these remote elements, to the extent they are material. Where this is the case, corresponding payments would be made to the remote TNSP.

- The long run *decremental* cost (LRDC) would be used for sell-back pricing. The LRDC is the *saving* to the TNSP – the costs *avoided* – should the sell-back proceed. The LRDC would be calculated using the same pricing model that is used for calculating LRIC. The LRDC is also the appropriate pricing methodology for renewing transitional access (the right to renew transitional access is discussed in chapter 9).[47]

[47] The LRDC method would be used to price the *renewal* of transitional access. The initial price of transitional access is set using a different method (partially free, partially at a price set at auction), as described in chapter 9.

6.6 Long term intra-regional access prices derived using stylised model

Long-term, intra-regional access prices would be derived using a stylised model based on the LRIC method discussed above. This means that prices would be unlikely to perfectly reflect underlying transmission costs.[48]

The stylised approach contrasts with an approach whereby access requests are priced "manually" (that is, with considerable human input) on a case-by-case basis, so that the inherent complexity in transmission planning is captured in the prices.

For the stylised model, the characteristics of an access request (access amount in MW, access term in years, and the node from which access is being provided) would be entered into a model. The model would then derive a price for access to the regional reference node in the local NEM region, based on methodological and input assumptions programmed into the model.

6.6.1 Rationale for stylised approach for pricing

The stylised method assumes away much of the complexity inherent in transmission planning. This has the advantage of producing smooth and stable price outcomes, and providing pricing transparency for generators.[49]

While there would be some cost in setting up the stylised model, and in keeping it up-to-date, a clear advantage of such an approach is that it would be able to quickly and transparently produce prices for numerous possible access requests. This would allow generators to quickly tailor their access request (given the price difference of different locations, access amounts and access terms) to best suit their needs.

A manual approach has the disadvantage that it could be extremely onerous, costly and time-consuming to derive prices, as demonstrated by the RIT-T process by which transmission investment options are considered.[50] For each individual firm access purchase, the adjusted projected investment would have to be calculated (into the future, in order to capture present and future incremental costs) for different combinations of firm access amount, timing and location, in order for a generator to make an informed decision on its preferred firm access purchase.

The Commission understands that a manual, bespoke approach is desired by some stakeholders because of its ability to produce prices which better reflect costs. While individually calculated prices might be more reflective of estimates of costs made at the time of access procurement, a stylised model should be capable of producing *reasonably*

48 Although, as noted in section 6.6.1, this is also the case for all other pricing methods where the price is fixed at the time of the access request.

49 The stylised expansion plans on which access prices are predicated are not the actual plans that the TNSP would follow in developing the network.

50 The level of assessment undertaken as part of a RIT-T is appropriately rigorous, given that it is only undertaken on a limited number of investment options.

cost-reflective prices to provide good locational signals. That is, prices would reflect the right *relativities* in costs between locations, and would be sufficiently cost-reflective in absolute terms so that generators do not buy too much or too little firm access overall because it is too cheap or expensive.

Further, achieving fully cost-reflective prices is something that may never be possible to achieve. As firm access can impose costs on the TNSP which are in the future, even manually calculated prices would be based on projections of costs (themselves based on projections of future market conditions such as demand and firm access growth). No method for pricing firm access (including prices estimated on a case-by-case basis) can be perfectly cost-reflective where the pricing is fixed at the time of the access request.

6.6.2 How the stylised LRIC model would work

An example of how the long run incremental cost would be calculated is provided in the following two figures, which model the incremental costs associated with a thermal flowgate.[51] Figure 6.1 represents the baseline development scenario for a single element of the shared transmission network, such as a transmission line or network transformer. Its development has three drivers:

- initial spare capacity – the amount of spare capacity on the element in the base year;
- annual flow growth – the amount by which maximum flows on the element increase each year; and
- lumpiness – the amount of capacity that would be added through the efficient expansion of that element.

The initial spare capacity would be eroded as the projected flow increased on the element, typically through an increase in the demand for electricity over time.[52] As soon as the spare capacity was projected to be exhausted, the element would be expanded in a scale efficient "lump". This would provide new spare capacity, which would be progressively eroded through subsequent flow growth until, eventually, a second expansion was required, and so on.

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51 Thermal flowgates and non-thermal flowgates (stability flowgates) are discussed in section 6.6.4.

52 For the purposes of illustrative simplicity, Figure 6.1 and Figure 6.2 assume that transmission elements are everlasting – the baseline and adjusted capacity of a network element always either stays the same (as the existing elements remains functional) or increases, as elements are expanded. Instead, the pricing model would take account of the finite life of elements, represented through a decrease in baseline capacity over time, as the elements reach the end of their life and are removed. If the capacity of an element is not immediately exceeded despite an asset not being replaced (for instance because demand, and so lineflow, has declined), the replacement is not required to meet the firm access standard, either immediately, or at all, impacting the incremental cost.

Figure 6.1 Baseline development scenario for a network element

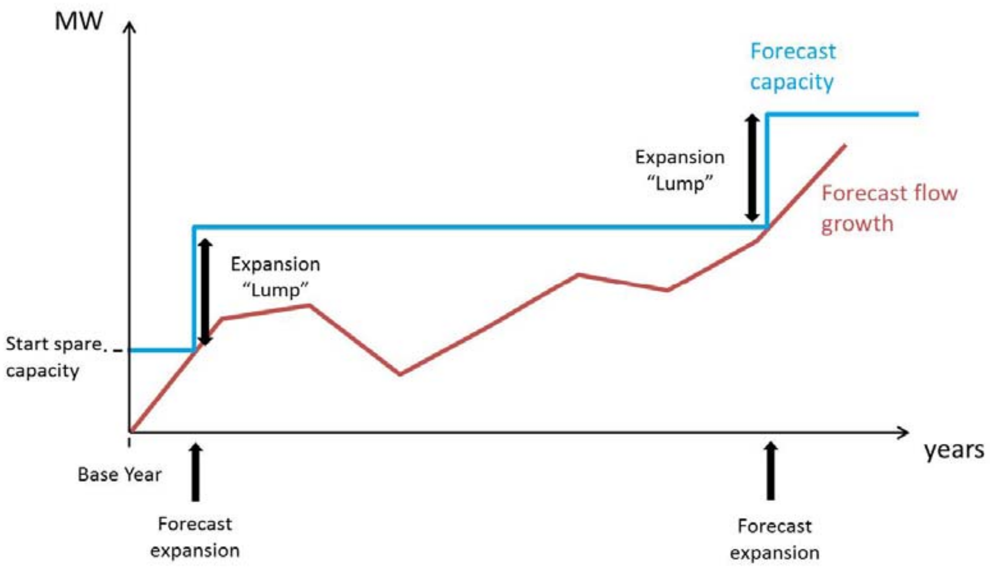
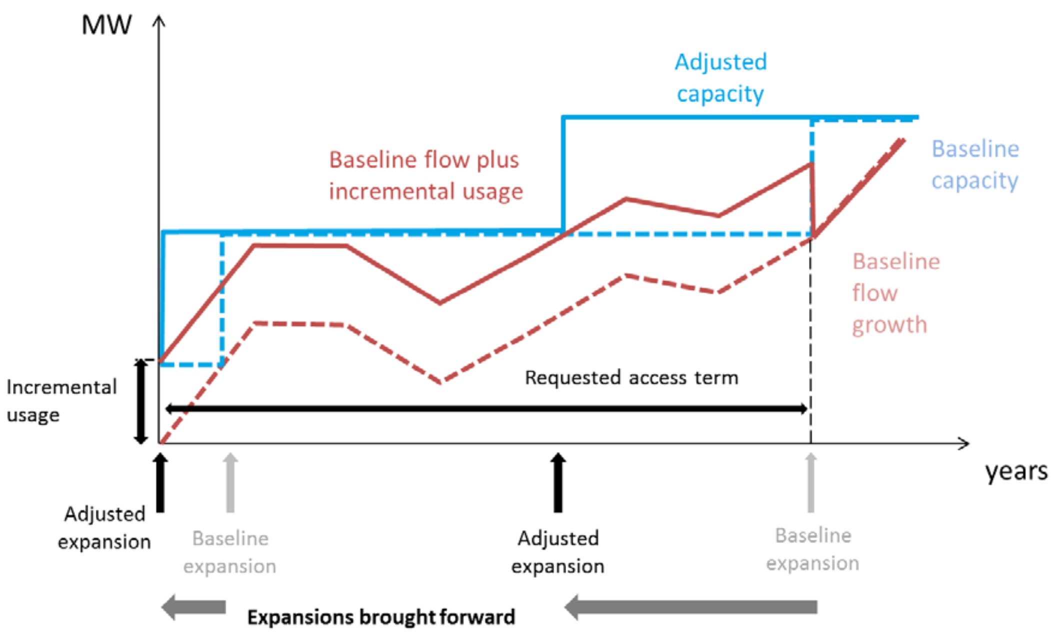


Figure 6.2 illustrates how the request for additional access would result in an adjusted development scenario for the network element. The effect of the access request is to increase the projected flow on the network element, and therefore to bring forward the already planned developments by varying amounts. To model the adjusted development scenario, two things need to be represented:

- incremental usage: the extra flow induced on the element by the access request; and
- access term: the period of the access request and so the period for which the extra flow occurs.

Figure 6.2 Adjusted development scenario for a network element



The baseline cost and adjusted cost would then be calculated by applying a discount rate to the capital costs (equal to the TNSP's regulated cost of capital, as set by the AER at the most recent regulatory reset) of the two development scenarios. The access price is the difference between these two costs, summed over all transmission elements in the network.

In order that the calculated incremental cost is as reflective as possible of actual costs, critical features that determine cost characteristics would be reflected in the methodology. These features include: the measurement of existing spare capacity; the lumpiness of transmission investment; the topology of the existing transmission system; and the background projected growth of demand and firm generation.

6.6.3 Updating the stylised pricing model

The LRIC pricing method would establish the *additional* cost imposed on the TNSP as a result of that specific access request.

An individual access request could impact on the additional cost of another access request – as access requests can use up spare capacity or prompt expansions or replacement. Prior and projected access requests would need to be included in the baseline modelled network development, so that the incremental cost of subsequent access requests could be calculated.

6.6.4 Stability flowgates

The approach outlined in section 6.6.2 relates specifically to estimating the LRIC caused by thermal flowgates, which are caused by thermal constraints.[53]

As demonstrated above, the costs associated with alleviating thermal flowgates can be readily modelled. This is because:

- there is a simple correspondence between assets and the thermal flowgates which they alleviate;
- there are simple relationships between thermal flowgate capacity and characteristics of transmission, generation and demand (for example, thermal flowgate capacity is not impacted by inertia); and
- expansions to alleviate thermal flowgates tend to be generic in nature.

However, not all costs associated with an access request would involve thermal flowgates. Stability flowgates, which are caused by stability constraints,[54] can also result in costs for the TNSP in order for them to provide access to firm generators.

53 Thermal constraints are caused by the heating of transmission assets as more power is sent across them. This can impact on the proper functioning of the asset, with implications for power system security and safety.

Unlike for thermal flowgates, using a stylised approach to model stability flowgates is difficult because:

- individual assets may contribute to alleviating stability constraints at multiple flowgates;
- stability flowgate capacity depends on highly complex interactions with generation (for example, inertia), transmission (for example, capacitors) and demand; and
- investments to alleviate stability flowgates are typically highly customised.

In the case of intra-regional access, thermal flowgates are expected to typically contribute to a large proportion of total costs. Stability flowgates are expected to only contribute a small proportion because the participation in stability flowgates is typically only significant on interconnectors and for generators on major flowpaths.

One approach to addressing stability constraints for intra-regional access would be to manually project the cost associated with such constraints for each access request, and include this in the access price. For the reasons discussed in section 6.6.1, this approach could be onerous.

Instead, given that costs associated with stability flowgates are likely to be low in the case of intra-regional access, the cost associated with stability flowgates would be estimated using a rule-of-thumb approach, incorporated into the pricing model. For example, a fixed (and relatively low) per MW price for stability constraints could be added to the LRIC price for thermal constraints, to give a total price.

The rule-of-thumb could differ for access requests in different regions, and even within regions. For example, the per MW price added for access requests from nodes in the La Trobe Valley could be higher than for nodes in Northern Victoria, based on the relative expected costs of alleviating stability constraints in order to provide access from those two areas. The price to be added could be updated each time the pricing model is refreshed.

Inter-regional pricing of stability constraints has a different approach, as discussed below.

6.7 Long term inter-regional access pricing

As discussed in chapter 7, long term inter-regional access would be procured through an auction, with the price paid by bidders being determined by the outcome of the auction.

54 Stability constraints refer to the need to keep the transmission system operating within design tolerances for voltage, with the ability to recover from disturbances, taking into account interaction control systems and other technical characteristics that are important to keep the power system intact. Stability limits tend to vary with the location and quantity of generation and demand, as well as with other factors.

The auction would have a reserve price representing the estimated cost of providing access. The estimated cost of providing access, and hence the reserve price, would be determined by adding the following:

- for thermal flowgates, access charges determined by the same LRIC model as discussed in section 6.6.2; and
- for stability flowgates, immediate costs (deep connection charges), as estimated by the TNSP, with AER oversight.

Note that there are two changes for the pricing of stability constraints as compared to intra-regional access – the use of deep connection charges (as opposed to using a rule-of-thumb approach), and the manual estimation of costs (as opposed to using a stylised model). The reasons for these two changes are given below.

6.7.1 Manual estimation of costs

For inter-regional firm access, stability constraints are likely to contribute to a larger proportion of total costs. If the rule-of-thumb approach for intra-regional access, described in section 6.6.4, were to be used in the case of inter-regional access, the potential for prices to diverge from underlying costs would be greater.

Further, there are only a limited number of directional interconnectors in the NEM, across which participants can buy inter-regional access. Stability costs would only have to be estimated for this limited number of directional interconnectors, in advance of the inter-regional access auctions, rather than for the numerous possible locations from which intra-regional access could be requested by generators, at any time. This means the administrative cost of undertaking manual cost estimates would be considerably less (in total) for inter-regional access, and the timing for undertaking these manual estimates would be less critical. It would only need to be calculated each time the auction is held, as opposed to every time a generator sought access.

The Commission also understands that TNSPs currently undertake frequent studies on interconnectors, including the cost of upgrades. Therefore, this would not be a substantial requirement on them in terms of additional resources.

6.7.2 Use of deep connection charges

For stability flowgates, the access price would be determined on a deep connection charge basis.

As discussed in section 6.5.2, deep connection charges are inefficient in the case of lumpy investments such as those to address thermal constraints, because they do not appropriately value spare capacity. This issue would be less pronounced for less lumpy expansions, as is typically the case for investments to alleviate stability constraints. For less lumpy expansions, the access request that prompts an expansion would typically be less costly, and less spare capacity (to be subsequently sold for free under the deep connection charges approach) would be created.

For example, if an access request prompts a large immediate investment which creates substantial spare capacity, the entire investment would be paid in full by the generator which prompted the access request. Subsequent access requests at that location would be free, providing the capacity created by the original access request was not exhausted. In contrast, for a less lumpy investment, while the generator which prompts the expansion would pay the entire cost of the investment, typically that investment would be smaller, and there would be little spare capacity to be sold at that location for free for subsequent generators.

Also, the process for purchasing inter-regional firm access means that multiple parties would typically contribute to an investment – the (relatively low) lumpiness of investment for stability constraints would be shared in order for the investment to proceed.

In determining the deep connection charge associated with stability flowgates, care would need to be taken to ensure that any investment that alleviates both thermal and stability constraints are not double counted, and erroneously charged twice.

6.8 Payment profiling

The methods for deriving firm access prices for both long-term intra- and inter-regional access would result in an *overall* price payable by the generator.

This price would be paid over the course of the access request term, in annualised instalments.

The profile of these instalments would be based on a specified default payment profile (for example, straight-line amortisation) as determined by the AER. A generator and TNSP could negotiate this payment profile, if approved by the AER, providing the total payments in NPV terms[55] summed to the price produced by the relevant pricing methodology. AER approval would be required, since a change in the payment profile may have an inter-generational impact on consumers (with present consumers paying more or less than future consumers), even though the total amount paid by consumers as a whole would be unchanged in NPV terms.

As discussed in chapter 8, if the cashflow implications for TNSPs of payment profiling were considered material, the AER could implement mechanisms to resolve this issue.

6.9 Governance of pricing

The governance arrangements for pricing would be set out in high-level detail in the Rules.

Access charges would be paid directly by generators to TNSPs, under terms set out in a payment deed.

55 Discounted at the TNSP's regulated cost of capital.

The AER would create and administer the stylised LRIC pricing model, and would have ultimate responsibility for it. This would include developing the model in keeping with the design stated in this chapter, determining categories of inputs to the model, providing oversight of TNSP inputs, and updating the model to reflect firm access purchases and sales.

Some stakeholders have had concerns with the allocation of this role to the AER. However, this allocation would be appropriate because it is in keeping with governance principle 1: promotes best natural fit:

- The AER has experience of considering consumer interests in applying regulatory functions. This is important because the price for firm access would impact directly on TUOS charges.
- The AER has experience with network pricing (through revenue regulation) as well as decision-making processes in which it considers a range of inputs from network businesses.
- The AER has experience with developing other models, such as the post-tax revenue model and its replacement expenditure model for network regulation. It could also use regulatory information notices and regulatory information orders to collect information.
- The AER would be able to apply consistency between prices for firm access and network costs that have been allowed in revenue determinations.
- The AER's role of approving the firm access planning standard conditions would also be relevant since the firm access planning standard is a driver of the inputs to the pricing model.

Both AEMO (as National Transmission Planner) and the TNSPs would be required to provide data as necessary, in keeping with governance principle 2. While both these bodies may also have a good natural fit for primary responsibility for the stylised pricing model, both AEMO and TNSPs could have a perceived conflict of interest (for AEMO, as the Victorian TNSP), which is not in keeping with governance principle 3.

The pricing model would be available for generators to use independently, albeit informally, to help in deciding on their location, access level and access term (noting that these prices could change as other access requests are registered).[56] This could also be a mechanism for generators and other parties to scrutinise the inputs in the model, and suggest changes to the AER.

The AER could be required to have the model independently audited.

TNSPs would be responsible for calculating access prices for prospective firm generators, using the latest version of the model produced by the AER.

56 Subject to any confidentiality concerns regarding the model and/or the data used in the model.

The AER would be responsible for determining the rules-of-thumb to estimate the costs associated with stability flowgates for intra-region access (described in section 6.6.4). The AER would seek information from relevant stakeholders as required (particularly the TNSPs), in order to make these determinations.

The estimation of deep connection charges for the purpose of determining the stability constraint component of the inter-regional access auction reserve price (as described in section 6.7.2) would be undertaken jointly by the two relevant TNSPs. This would be undertaken in a transparent manner (so that interested parties, such as prospective bidders) could scrutinise the TNSPs' approach and assumptions. The AER would provide oversight to this process, and resolve any disputes. AEMO (as National Transmission Planner) would be required to provide information to this process as necessary.

As discussed in chapter 7, access details, including prices, would be recorded on a certificate, registered with AEMO.

AEMO would be responsible for running the intra-regional access auction, also discussed in chapter 7.

6.10 The pricing prototype model

The Commission has developed a prototype of the pricing model based on the design features for the stylised LRIC pricing model.

As a prototype, the model does not yet implement all of the design features discussed in this chapter. The intention of the development of the pricing model is to help the Commission and stakeholders to understand:

- how the LRIC pricing method may be implemented in practice;
- the strengths and weaknesses, and practicalities, of using the LRIC method to calculate access prices; and
- potential access prices, and the extent to which those calculated access prices are sensitive to input data and other assumptions.

The model was first made available for stakeholders in October 2014.[57] The Commission published an updated version in March 2015.[58] The March 2015 version is now available alongside the Final Report on the AEMC's website. No further changes have been made to the prototype pricing model since March 2015.

57 This was version number ending "76ee".

58 This was version number ending "7234".

6.10.1 How the prototype pricing model works

In accordance with the LRIC method, the prototype pricing model calculates the difference in cost, in NPV terms, between two stylised network development scenarios:

- a baseline modelled network development scenario; and
- an adjusted modelled network development scenario.

Both the baseline and adjusted network development scenarios are calculated in the same way:

- Peak flows are calculated for transmission assets in a stylised representation of the NEM, in each year going forwards, based on network characteristics, and demand for electricity and amount of firm access at each node.
- Expansions, of a size and nature determined by the model, are prompted on a transmission asset when peak flows exceed the capacity of the asset.[59]
- The cost of the expansion of a transmission asset is calculated, given stylised costing assumptions.
- The capacity of the asset is increased in the model to reflect the expansion – a further expansion is not prompted until the new capacity is exceeded.
- The cost of each of the expansions that occur across each of the assets and over time is summed, in net present value terms.

As the cost of the adjusted network development scenario is calculated using an identical method to that of the baseline network development scenario, the difference in the costs between the baseline and **adjusted scenarios** (the LRIC) is therefore solely the result of different inputs with regard to the amount, timing and location of firm access (based on the firm access request).

For the purpose of comparison, the prototype pricing model also produces prices based on deep connection and long run marginal costs.

6.10.2 Changes to the prototype pricing betwen October 2014 and March 2015

The Commission has made a number of changes to the prototype between October 2014 and March 2015, in response to known issues and those highlighted by stakeholders.

The key changes were:

- updates to the cost and lumpiness input assumptions for the purpose of costing network expansions, in accordance with EMCa’s proposals;[60]

59 The prototype model does not consider replacement expenditure.

- further automation of the pricing model, so that the results of variations in all the generator-dependent variables (location, access amount and access duration), and a number of independent variables (for example, weighted average cost of capital, demand projections) can be obtained in one model run; and
- the option of running the model using with four pairs of “bi-regions” (combined adjacent regions in the NEM), for the purpose of inter-regional access pricing.

6.10.3 Outstanding issues with the prototype pricing model

There are a number of limitations with the prototype pricing model, including some raised by stakeholders during consultation. Four key improvements that could yet be made to the model are:

- the inclusion of modelled replacement expenditure;
- the inclusion of stability constraints, rather than just thermal constraints, for intra-regional access pricing purposes;
- the more accurate locational representation of industrial load across the network; and
- further improvements to the expansion costing assumptions.

A number of other limitations and potential improvements are listed in appendix C. Many of these improvements are practically achievable, given greater time, resources and access to data. Were optional firm access to be implemented, a more comprehensive pricing model would be created by the AER, which could be fully tested and independently audited.

6.10.4 Key findings of the prototype pricing model

There have been a number of key findings from the development of the prototype pricing model which inform the design of the pricing element of the optional firm access model.

Timely and transparent access prices

The prototype has clearly demonstrated a desirable feature of a stylised approach – the prototype is capable of transparently producing many access prices for many possible access requests in a short space of time.

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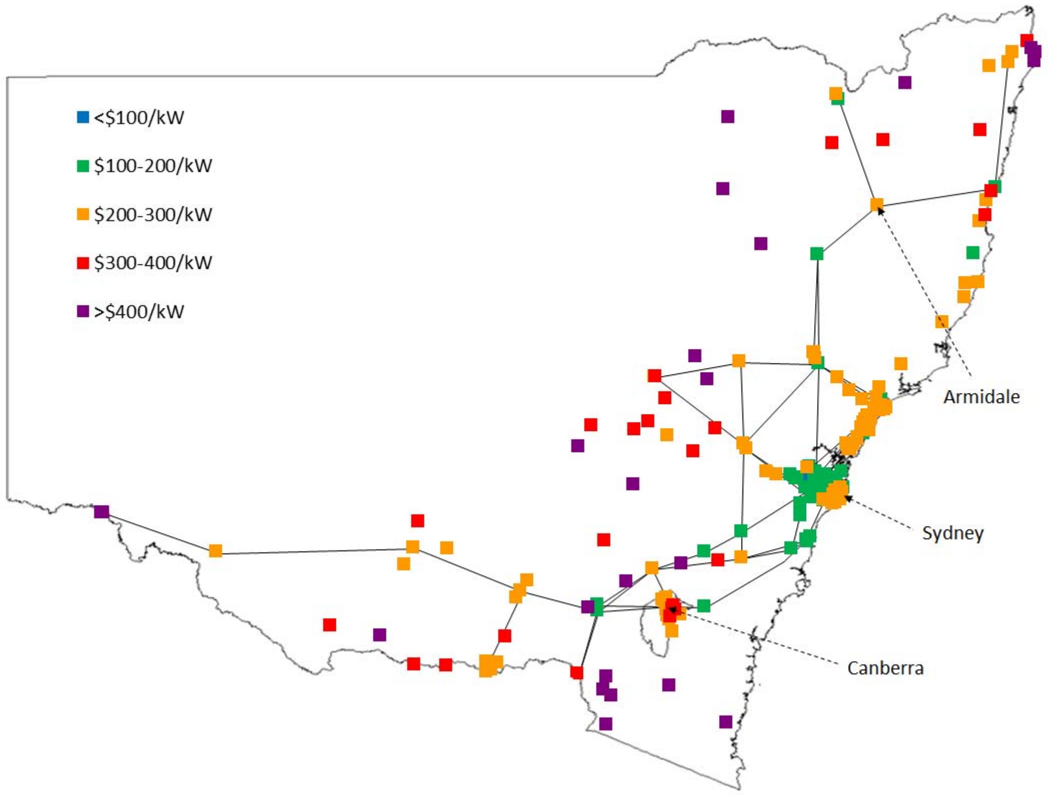
60 Provide cost and lumpiness assumptions to the optional firm access prototype model, EMCa, January 2015.

Locational signals

The prototype pricing model produces prices which demonstrate the right *relativities*, with higher prices for access more remote from the regional reference node or for access in more congested areas. This would result in broadly efficient locational signals to generators, which is a key intended benefit of the optional firm access model.

This is demonstrated in Figure 6.3 below, which shows the access prices produced by the prototype pricing model for a 400MW, 20 year access request at nodes in NSW:

Figure 6.3 Map of indicative LRIC prices for NSW



The map shows that, other things being equal:

- Generators locating remotely from the regional reference node and from other major consumer centres would pay a higher price than generators locating closer to the regional reference node or consumer centre (for example, Sydney), due to the higher cost of longer transmission lines to provide access.
- Generators locating where there is limited spare transmission capacity and where expansion would be required immediately (for example, around the Snowy Mountains) would pay a higher price than generators locating where there is plenty of spare transmission capacity and where no expansion would otherwise be needed for some time (for example, on the Central Coast of New South Wales).

The Commission has produced a substantial amount of results from the prototype pricing model, which demonstrate these findings.

Cost-reflective prices

While the *relativities* in prices are as expected, it is not yet clear whether the *quantum* of the prices reasonably reflect incremental TNSP costs of providing access. In theory, if the limitations discussed above are addressed, prices should become more reflective of costs. This is discussed further in the next section.

6.11 Conclusions from the prototype pricing model

6.11.1 Assessment of model

The Commission continues to favour an LRIC-based, stylised model for pricing. As a stylised pricing model would only approximate TNSP costs, the prices produced would never *fully* reflect the costs incurred by TNSPs in developing their networks to provide access. However, trying to achieve prices that completely match TNSP costs would be a fruitless exercise if access prices are fixed at the start of the registered access, since TNSP costs would only ever be a projection at that stage.

Nevertheless, it is important that the prices generated by the model reasonably reflect incremental TNSP costs of providing access. Achieving reasonably cost-reflective prices is important because if prices do not reflect the incremental costs of providing access, generators may pay more or less than the cost their access actually imposes on the transmission businesses. If priced too low, generators may be encouraged to enter at an expensive location and prompt inefficient transmission investment, the cost of which would be borne by consumers. On the other hand, pricing too high might discourage generators from entering at a cheap location and leave existing network capacity inefficiently underutilised.

While the pricing prototype is producing prices for which the relativities are as expected, the Commission has been unable to determine whether the quantum of the prices reasonably reflect the incremental TNSP costs of providing access.

The reason that prices from the prototype pricing model may not reasonably reflect the incremental TNSP costs of providing access is in part due to the limitations of the prototype pricing model itself. Most, if not all, of these limitations would be expected to be overcome with more time, resources and data availability. This should improve the cost reflectivity of the prices. However, some technical challenges may still remain – for example, stability constraints are harder to build into a model than thermal constraints. There is therefore the risk, initially at least, that there will be some prices produced by the model that deviate substantially from underlying costs.

The Commission also acknowledges concerns regarding the access pricing method being dependent on centrally-developed forecasts. The AER would be tasked with developing a model that produced access prices which reasonably reflect incremental

TNSP costs of providing access. This would require the AER to make decisions about a large number of inputs (for example, on current and future demand), and require expertise in this regard.

The concern about the pricing model being dependent on centrally-developed forecasts may be mitigated through appropriate governance, as discussed in section 6.9:

- the AER's current role would be the best natural fit for the task of access pricing, given its current expertise and experience;
- the AER would be able to obtain information from TNSPs and AEMO for the purpose of access pricing; and
- subject to confidentiality concerns, the inputs to the pricing model would be open to public consultation, so that interested parties, such as generators, could scrutinise them.

If optional firm access was to be implemented, then governance design decisions could be considered further.

6.11.2 Review of prices

Having addressed the limitations of the prototype pricing model, it may still be possible that some prices produced by the model appear to deviate substantially from underlying costs. In these circumstances one option may be for the prices produced by the model to be tested on a case-by-case basis before being applied. This test could determine if the outputs and LRIC prices produced by the model reflect reasonable expectations of projected incremental costs. If not, the relevant inputs into the pricing model could be adjusted until the LRIC prices produced by the model were reasonable.

If this review process was required, governance of its application would be developed, so that it was used appropriately and was not resource intensive. Further, the ability to test and adjust the pricing model on a case-by-case basis could be withdrawn in time, as the model was refined and confidence in it producing sufficiently cost-reflective prices was established.

7 Procurement

Summary of this chapter

Firm access would be procured by generators through a variety of processes.

Long-term (that is, beyond the time that a TNSP would be able to build new assets to meet a firm access request) intra-regional firm access would be procured directly from a TNSP. Because one firm access request could impact on the price of another firm access request, requests would be processed in the order that they would be received.

Generators could also choose to sell back their long-term firm access to a TNSP, at the then current long-run decremental cost (that is, the saving to the TNSP of not providing the firm access).

Long-term, intra-regional firm access could also be procured from other firm generators. This would be effected via the TNSP: one generator would sell back its access to a TNSP, while the other generator would then immediately purchase the firm access from the TNSP.

There is a concentration of bidders for inter-regional access, unlike for intra-regional access, due to the limited locations across which inter-regional access can be bought. This, combined with the large value of investments typically made on interconnectors, means that the bilateral procurement approach used for long-term, intra-regional access would not be efficient in the case of long-term, inter-regional access. To accommodate these characteristics, long-term, inter-regional firm access would be bought and sold by generators in an auction, run by the market operator (AEMO).

The characteristics of short-term firm access also indicate that it would be appropriately bought and sold through a (separate) auction. Unlike for long-term firm access, short-term firm access would be free to provide (as there can be no expansion, and hence no cost, in the short-term), and in limited supply (no expansions means that firm access would be limited to the existing capacity of the network, in the short-term). So, demand for this firm access in the short-term would need to be rationed using an auction, run by the market operator (AEMO).

7.1 Introduction

Procurement refers to the process by which firm access is procured by generators from TNSPs, traded, or sold back to the TNSP. This process differs depending on whether the firm access is:

- bought for the long-term[61] or for the more immediate future (short-term);[62]

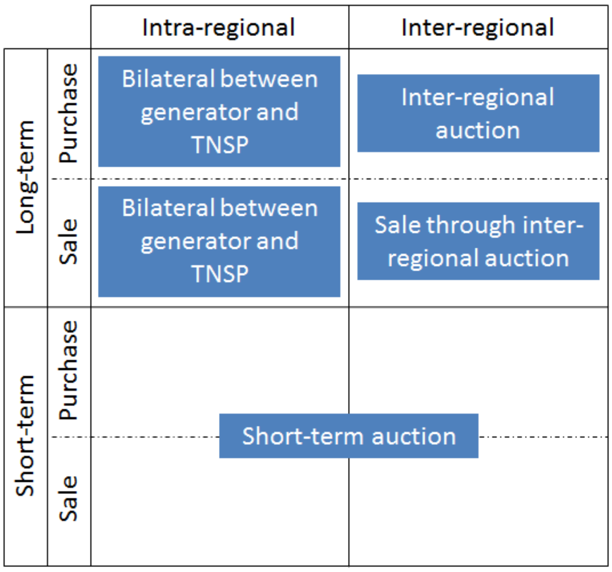
61 Long-term access is that bought from the expansion lead time (three years) out.

- intra-regional[63] or inter-regional;[64] and

- bought from or sold back to the TNSP, or traded between the holders of firm access.

The different processes are summarised in Figure 7.1 below.

Figure 7.1 Overview of procurement processes



This chapter describes and explains the various procurement processes. The chapter discusses:

- procurement of long-term, intra-regional firm access by generators, by way of generators directly approaching a TNSP to procure new or additional access (section 7.2);

- procurement of long-term, inter-regional firm access by market participants, by way of an auction (section 7.3);

- procurement of short-term firm access, by way of an auction (which is separate to the long-term inter-regional auction noted above) (section 7.4); and

- the selling back of long-term intra-regional firm access by generators, arranged bilaterally (section 7.5).

62 Short-term access is that bought within the expansion lead time (three years).

63 Intra-regional access is that from the generator's node to the regional reference node.

64 Inter-regional access is that from one regional reference node to another.

7.2 Procurement of long-term, intra-regional firm access

Long-term intra-regional firm access would be procured by generators directly from the TNSP. The generator could seek the combination of firm access amount, location and duration that best meets its needs and for which it would be prepared to pay the associated firm **access charge** as determined by the LRIC model.

7.2.1 The procurement process

The procurement of long-term, intra-regional firm access would involve an iterative information exchange (as opposed to a commercial negotiation) between the generator and the local TNSP.

The generator would only be able to specify and choose the following **service parameters** in its *formal* firm access request:

- the access unit identifier at which the firm access to the regional reference node applies;
- the start and end years of the firm access request; and
- the amount of firm access (in MW).

The generator would submit a request for access, the request would be priced by the TNSP in accordance with the pricing model (discussed in chapter 6), and the generator could then amend its request in response, to discover the most appropriate access request, based on its commercial needs. In addition, at any stage in the procurement process, the generator would be able to enter into *informal* discussions with the TNSP.

The role of the TNSP would not simply be to provide a price for each request made, but also to advise the generator on possible service parameters that might best meet the generator's needs. A TNSP could advise generators on how different access locations, firm access amounts or access lengths may affect the access charge, and whether small changes in any of these variables could trigger a large change in incremental cost.

As noted in chapter 6, the pricing model described in that chapter would also be available for prospective firm generators to use independently, albeit informally, to help in deciding on their location, access level and access term (noting that these prices could change as other access requests are registered).[65]

Generators would also be liable for the administrative costs incurred by the TNSP in providing information and prices. These costs would be based on a fixed, regulated tariff for request processing, and would be regulated by the AER.

65 Subject to any confidentiality concerns regarding the model and/or the data used in the model.

7.2.2 Ordering of access requests

There is an interaction between the order in which procurement requests would be processed and the price for the access. This is because LRIC prices would be determined by the difference between a baseline network development scenario and an adjusted network development scenario. When an access request is completed and registered, it would be included in the LRIC pricing model by updating the baseline network development scenario. This would change some, but not all, access prices: a change to the baseline scenario at a node is likely to have the largest impact on prices at nearby nodes and possibly no impact on prices at distant nodes. These impacts would result in prices going up or down. Where this is the case, access requests are "competing".

On an ongoing basis there is likely to be a low frequency of competing access requests, which means that the number of access requests impacted by the order in which they would be processed may be low in the long term.[66] Therefore, this problem can be managed through a simple and transparent first-come-first serve mechanism.

Generators would apply to the TNSP in order to join the queue to purchase access. Generators could join the queue at any time. Upon reaching the front of the queue, a generator would then follow a process in which:

- a price would be calculated by the regulated pricing model; and
- the access request would either be agreed and registered, or the generator would withdraw from the queue.

Upon a generator reaching the front of the queue, no other *competing* access requests could be processed while the front generator was being processed. That generator would be given a limited time to make up its mind. These time limits would allow the generator at the head of the queue enough time to consider its purchase and establish the best access request for its needs, but not so long as to unnecessarily inhibit the purchase of competing firm access by generators further down the queue.

Non-competing access requests could be processed concurrently, since they would not impact one another's price. In general, requests from different regions would not compete, but they might occasionally: for example, in the proximity of the NSW-Victoria border. TNSPs would need to be aware of these cross-border issues and manage their queues accordingly.

To prevent tactical lodgement of multiple requests, each generating unit would be restricted to being at only one place in the queue at any particular node or group of proximate nodes.

66 However, the frequency of competing access requests may be high when transitional access ends, and a number of generators may decide, at the same time, to renew their firm access. The impact of multiple transitional access registrations ending simultaneously may be reduced by the proposed staged reduction in transitional firm access.

Generators would be able to withdraw from the process at any stage before the access request was finalised, forfeiting their place in the queue.

There are a number of potential issues that may arise from adopting this first-come-first-serve approach to procurement:

- Given that the order of generators in the queue would be determined on a first-come-first-served basis, multiple access requests may be received at the commencement of optional firm access (almost simultaneously), as each generator tries to secure an advantageous place in the queue meaning it may not be clear the order in which such requests should be processed.
- Generators purchasing access far in advance of the start of the access term, at a price determined by the pricing model based on distance (and therefore possibly uncertain and incorrect) incremental costs.
- Generators speculatively circling the queue with little or no intention of buying firm access.

It is not clear if these issues would be material. If so, solutions to these issues could be developed at the time of implementing optional firm access.

7.2.3 Restrictions on long-term, intra-regional firm access that could be purchased

There would be a number of restrictions on what long-term, intra-regional firm access could be procured:

- There would be an assumed transmission expansion lead time, and long-term inter-regional access could only be purchased for later periods than this time.
- Access could only be purchased in strips, that is, fixed MW amounts over a sequential number of years.
- Access must be purchased for a minimum access term, say, for example, five years.
- No customisation to the terms or firmness of the firm access would be permitted (such as variations to the definitions of firm access planning standard, call options whereby access is only provided when the regional reference price exceeds a certain amount, or scheduled outage windows so that TNSPs and generators could coordinate outages).[67]

The second and third restrictions would be necessary in order to limit potential "gaming" of the pricing model. By purchasing access amounts that vary year by year,

67 TNSPs would be incentivised to efficiently manage scheduled outages, as illustrated in the examples in section B.2.

or for a small amount of time, a generator may be able to avoid paying for access by requesting access amounts equal to any spare capacity projected by the pricing model.

Any customisations or variations to firm access registration would add significant complexity to the model, particularly through access settlement. It would also create a more burdensome and longer procurement process (both in terms of purchasing access, but also in selling back access).

Further, in order to negotiate the customisation, generators may wish to vary the price of firm access. This would raise issues as to how any customisation would be priced by the pricing model to reflect the projected change in cost to the TNSP as a result of the customisation. Any change in price that does not reflect the change in cost to the TNSP would be borne in part by TUOS customers.

7.2.4 TNSP obligations through the procurement process

TNSPs would have a number of obligations through the procurement process. TNSPs would be:

- required to provide information to generators in a timely fashion; and
- required to provide the firm access as requested by the generator, at the price determined through the LRIC pricing model.

When a TNSP is unable to provide firm access within the standardised expansion lead time (for example, because of difficulties in obtaining planning permission), there would be a mechanism whereby a TNSP could seek to delay the commencement of the firm access service.[68]

This mechanism would have suitable governance arrangements, so that:

- it would only be used in those cases where expanding the network within the standardised expansion lead time would not be feasible.
- generators were aware, at the time of the purchase of the firm access, of the likely delay in their receipt of access settlement funds, in order to inform their procurement decision. This delay should also be factored into the access price the generator pays. For example, suppose a generator joins the queue in 2015 aiming to purchase firm access commencing 2018, but the TNSP determines that the earliest it can provide the necessary transmission expansion is 2020. Here, the generator should be able to procure firm access commencing in 2020 and the access price would be calculated accordingly.

68 If a TNSP is unable to provide firm access within the standardised expansion lead time, this does not necessarily put it in breach of the firm access planning standard, since this is a planning standard.

7.2.5 Availability of information through the procurement process

Information availability would change depending on what stage of the procurement process the generator's access request was currently in:

- Informal information exchange between the generator and TNSP would be considered confidential, to protect the generator and TNSP from revealing commercially sensitive information.
- When a generator was in the queue, the queueing order would remain confidential. However, a generator could reveal such information if it wished, for example, in order to form a procurement group.
- Throughout its time in the queue, a generator would be provided information on its place in the queuing order, and the TNSP's estimation of the likely time before it reached the front of the queue.
- Once access is registered (and the procurement process is complete), details of the registered access, such as the location, amount timing and price of access, would become public (for example, for the purposes of access settlement and to update the pricing model to reflect the new baseline).

7.2.6 Secondary trading

Secondary bilateral trading of long-term, intra-regional firm access undertaken directly between generators would be permitted, but this must be effected via a combined sell-back/purchase. The outcome of this would be the same as if generators could bilaterally trade access between themselves. However, using the sell-back mechanism avoids the need for the TNSP having to approve the trade, or develop exchange rates for the trade (that is, 100MW of access at one location is not the same as 100MW of access at another location). A combined sell-back/purchase would take account of these matters automatically. This is discussed in more detail in section 7.5.5 below.

Generators could also offer firm access into the short-term access auction, which is discussed in section 7.4 below. However, access could only be offered on a short-term basis.

7.2.7 Governance of the long-term intra-regional firm access procurement process

Firm access would be recorded in **certificates** issued by the TNSP. This would record the location, amount and term of the firm access. These certificates would be registered with AEMO as market operator, who would maintain a registry of access certificates. This official record of firm access would form the basis for access settlement. Given this, it is sensible for this role to be allocated to AEMO. This is also consistent with governance principle 1: promotes best natural fit. AEMO should also have minimal conflicts of interest, in accordance with governance principle 3.

Both TNSPs and generators (holding firm access) would have obligations in respect of firm access. The TNSP would have no obligations to individual generators; in part this is because payments made to generators holding firm access would come from non-firm generators, through AEMO, as determined through the access settlement mechanism described in chapter 4. Instead, the TNSP obligations would be essentially regulatory in nature and comprise planning and operating the network to meet the firm access planning and operating standards.[69] These obligations would be set out in the Rules.

Generators, on the other hand, would have obligations directly to the relevant TNSP. These would include the obligation to pay the access price, and to provide credit support. These obligations would be set out in a payment deed provided by the generator in favour of the TNSP.

Table 7.1 provides a summary of the certificate-based approach.

Table 7.1 Certificate-based approach to firm access rights

Feature of the optional firm access model	Mechanism
Generator obligation to pay LRIC access price	Set out in a payment deed. LRIC access price (based on pricing model) paid from generator to the relevant TNSP.
Obligation to pay access settlement payments from (typically) non-firm generators to firm generators	Rules-based obligation. Access settlement payments (that is, compensation) administered by AEMO through existing settlements process.
Record of firm access rights	Details of access rights evidenced by a certificate that is issued by the TNSP and registered with AEMO.
Planning obligation to meet network-wide firm access standards	Rules to set out network-wide planning obligation and require TNSPs to develop, have approved and then comply with it.
Credit support arrangements	Rules to prescribe credit support requirements. Actual credit support requirements for payments of the LRIC access price would be set out in the payment deed. (Separately generators would still need to maintain prudentials with AEMO for the purposes of access settlement).
Other elements of the model: operating standards, pricing model, incentives on TNSPs, TNSP revenue regulation.	Found in the Rules.

69 The interconnected nature of the transmission network means it would be very difficult to separate out the planning the TNSP would need to do in respect of one generator's access from planning for other generators and also planning to meet reliability obligations.

7.3 Procurement of long-term, inter-regional firm access

This section discusses the procurement of long-term, inter-regional firm access.

7.3.1 Procurement process

Unlike for intra-regional access, there is a concentration of bidders for inter-regional access due to the limited locations across which inter-regional access can be bought. This, combined with the large value of investments typically made on interconnectors, means that the bilateral procurement approach described above would not be efficient.

Any market participant could purchase a firm interconnector right. Other parties could register as traders in order to purchase firm interconnector rights, in the same way that other parties can currently register as traders to participate in settlement residue auctions.

The objectives of the inter-regional access procurement process are that:

- The mechanism for issuing inter-regional access should accommodate multiple parties, with competing demands for new inter-regional firm access.
- The revenue from the sale of firm interconnector rights should cover the estimated cost associated with providing new firm interconnector rights.
- There should be consistency of pricing and issuance between inter- and intra-regional firm access so that one is not unduly favoured over the other.

In order to meet the above objectives, long-term, inter-regional firm access would be sold through an auction process run by AEMO. An auction process allows multiple parties to reveal their demand for inter-regional access at the same time. It also allows for a limited amount of access to be allocated to those parties who would value it most highly.

AEMO would run an auction for inter-regional access on interconnectors. The auction would be designed to reveal demand for firm interconnector rights. Market participants and traders would bid for these future inter-regional rights, revealing the benefits that would accrue to them through their bids. Participants would bid separately for each **directed interconnector**. A directed interconnector is a regulated interconnector (for example, Heywood) in a specified direction (for example, Victoria to South Australia).

The reserve price in the auction would be set at the estimated access cost. For the auction to clear there would have to be sufficient bid demand such that the auction revenue covers the access cost. The auction would operate as follows:

- if the auction price was at, or above, the access cost, the auction would clear, and so the inter-regional firm access would be sold at the auction price; and

- if the auction price was below the access cost, the auction would not clear, and so the access would not be issued.

The access cost would include the cost of thermal expansions and the cost of stability expansions: expansions to increase capacity on thermal and stability flowgates, respectively. The thermal cost would be estimated using the LRIC pricing method. Stability costs would be estimated using a deep connection charge. The estimated access cost of inter-regional access is discussed further in chapter 6.

7.3.2 Designing an auction

The AEMC engaged an auction expert, Professor Flavio Menezes, from the University of Queensland, to assist with the development of the inter-regional access procurement. His report is published on the AEMC's website.[70]

Professor Menezes notes that finalising an auction design is a complex and time-consuming process. There is a considerable and iterative process that must be followed to create a well-designed auction, including desktop research and design, stakeholder engagement and laboratory testing. Accordingly, the Commission has not settled on a particular auction design. If optional firm access were to be implemented, a detailed auction design (based on this Final Report and the work by Professor Menezes) would need to be developed during the implementation phase.

However, building upon Professor Menezes' advice, the Commission has proposed two possible auction designs (which are preliminary in nature), which are discussed in more detail in the accompanying technical report to this document:

- a static auction (somewhat analogous to the NEM dispatch auction); and
- a dynamic, simultaneous auction (specifically a clock auction).

7.3.3 Governance of inter-regional access procurement

AEMO as market operator would be responsible for running the auction associated with the issuance of inter-regional access. Again, this is consistent with governance principle 1: promotes best natural fit. AEMO currently is responsible for the **settlement residue auction**, where generators can purchase the right to a share of the inter-regional settlements residue that accrues when prices between regions separate. This also fits with the other governance principles.

Most of the features of this process would be included in the Rules; however, detailed requirements would be set out in supporting procedures. This would be similar to the current settlement residue auction arrangements, where there is some detail in the Rules and some in accompanying AEMO procedures.

70 http://www.aemc.gov.au/Markets-Reviews-Advice/Optional-Firm-Access,-Design-and-Testing

Access that was purchased in the inter-regional firm access auction would be registered in a certificate, analogous to the purchase of long-term firm access. All of the details surrounding the certificate would be as set out above in section 7.2.7. Settlement and payment of the inter-regional product would be undertaken via AEMO.

7.4 Short-term firm access procurement

As well as long-term firm access, generators could also purchase short-term firm access for both intra- and inter-regional access.

7.4.1 Procurement of short-term firm access

Short-term firm access would have the following characteristics:

- Short-term firm access would be differentiated from long-term firm access by the assumed transmission expansion lead time: short-term firm access would only be issued for shorter periods than this, and long-term firm access would only be issued for longer periods. Short-term firm access would have equal firmness to long-term firm access.
- Short-term firm access would be issued through an auction.
- TNSPs would be required to offer all network capacity that was in excess of the firm access planning standard level into the short-term firm access auction.
- The revenue from the sale of short-term firm access would offset TUOS charges.
- Secondary trading would be permitted in the short-term firm access auction, that is, generators could also offer access on a short-term timescale.
- Intra-regional and inter-regional short-term firm access would be integrated into the same auction.
- The TNSP incentive scheme would include short-term firm access.
- The auction would be run by AEMO, but the inputs into the auction would come from TNSPs.

These aspects are discussed in more detail below.

7.4.2 Division of short-term and long-term firm access

The division between short-term and long-term for firm access issuance would be fixed, based on a deemed transmission expansion lead time, referred to here as the short-term horizon.[71] Obviously, in practice, the expansion lead time would vary from

71 This is the time it would take the TNSP to develop its network to meet long-term access requests by generators.

project to project. However, it is not feasible for the short-term horizon to vary since the delineation between the short- and long-term procurement processes must be the same for all access requests. The Commission understands that a short-term horizon could be three years. However, the exact specification of this would be determined in any implementation phase.

Thus, a generator would not be able to obtain long-term firm access within the short-term horizon. However, generators could still obtain access: a generator could purchase short-term firm access in the interim. The short-term and long-term firm access products would be equivalent with regard to the level of firmness they provide to the generator.

The division of short-term and long-term firm access is needed to prevent either issuance process pre-empting the other. Short-term firm access auction prices could be below the typical long-run incremental cost of transmission but above zero, so:

- long-term firm access should not be sold within the short-term period at a price (zero) that undercuts the short-term firm access auction price;[72] and
- short-term firm access should not be sold within the long-term period at a price which potentially undercuts the long-term firm access price.

7.4.3 Auction design

An auction would be suitable for issuing short-term firm access. This is because there is only a limited quantity of short-term firm access that could be provided from existing spare capacity at zero cost to the TNSP. So, demand for this firm access in the short-term must be rationed using an auction. It would therefore not be possible to have a bilateral process.

The accompanying technical report contains a description of the design for the short-term firm access auction.[73] Its key features would be:

- Bids at or higher than the marginal bid would be awarded short-term access, subject to the stylised auction constraint equations (see below).
- Winning bids would pay the marginal bid for access.

72 The price of long-term firm access is set at the long run incremental cost of transmission. Within the short-term horizon, the long run incremental cost must be zero, since there is no possibility of – or requirement for – network expansion.

73 The auction clearing process described in the technical report is somewhat analogous to the NEM dispatch auction. In his report, Professor Menezes has stated that an auction analogous to the NEM dispatch auction may not be appropriate in the context of inter-regional access. The Commission considers that an auction analogous to the NEM dispatch auction may be appropriate in the context of the short-term auction because of: the increased frequency of the short-term auction compared to the long term auction; and the successful use of similar auctions in other jurisdictions, such as the Financial Transmission Right auctions in the United States.

- The auction would require *stylised* constraint equations to be developed, which would represent the capacity of various elements of the network under the firm access planning standard conditions.[74] These constraints would be different from those used by AEMO in dispatch.[75]

The auction would have a reserve price of zero.[76] This represents the zero long run incremental cost of transmission during the short-term horizon since any firm access issued in the short term must be backed by existing spare transmission capacity. Negative bids would not be allowed.

The auction would be run on a quarterly basis, starting from three years in advance of the time the access would be in place.

7.4.4 Obligation to sell into the short-term auction

A Rules based obligation would be placed on the TNSP to offer all spare network capacity into the auction. Indeed, the auction constraint equations, based on the firm access planning standard capacity, would mean that the TNSP would automatically offer all existing spare capacity into the auction.

This obligation on a TNSP is appropriate since in the absence of such an obligation, the TNSP may choose to withhold some network capacity from the auction since this would reduce its exposure to the incentive scheme. Therefore, the obligation would promote efficient and transparent allocation and pricing of existing network capacity.

7.4.5 Sales revenue

All of the auction revenue from the sale of existing capacity of the network would be allocated in full to offset TUOS charges, that is, to the benefit of customers. The revenue from access sold by generators in the short-term auction would be allocated to the generators who sold access.

In the First Interim Report the Commission considered whether TUOS customers or TNSPs should be allocated the revenue from the sale of short-term access, and in what proportion.[77]

It was discussed in that Report that allocating some or all of the revenue generated from the short-term auction to the TNSP could incentivise the TNSP to maximise the use of the existing network. It was also considered that this might have the advantage of alleviating or removing the need to require the TNSP to sell all spare capacity in the

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74 Those constraints would also be used when transitional access is allocated pro rata to existing generators (see chapter 8); and the auction of transitional access up to the firm access planning standard capacity of the existing network is undertaken as described in chapter 8.

75 The process of developing constraints feeding into NEMDE and dispatch would be unchanged.

76 Other than where generators are selling their existing access, whereby they could set a reserve price.

77 AEMC, Optional Firm Access, First Interim Report, July 2014, p. 90.

short-term auction (with its associated possible governance issues), because the TNSP would instead be incentivised to do so.

However, this approach would create some implementation challenges.

Through the operation of the incentive scheme (as discussed in section 5.3), TNSPs would have an incentive to reduce shortfall costs arising from flowgate capacity being below the firm access planning standard target. This incentive conflicts with an incentive on the TNSP to increase the use of the existing network by increasing the amount of access sold in the short-term auction, since selling access in the short-term auction makes the firm access planning standard target more onerous. Conflicting incentives are not necessarily problematic. If the incentives were well balanced, this could create an overarching incentive on the TNSP to efficiently use the existing network, taking into account shortfall costs which arise from congestion. However, it may be difficult to appropriately balance the strength of the two incentives, creating perverse incentives to inefficiently over- or under-sell short-term access.

Furthermore, conceivably, as monopoly providers of short-term access TNSPs may have an incentive to withhold access in the short-term auction. This would have the effect of driving up the price of short-term access, potentially to the extent that the impact on revenue of a decreased volume of sales is more than compensated by an increase in price. This would not maximise the use of the existing network.

Therefore, it is more appropriate for all of the auction revenue to be allocated to offset TUOS charges. This would avoid creating perverse incentives for the TNSP.

7.4.6 Secondary trading through the short-term firm access auction

Efficient allocation of firm access requires efficient secondary trading mechanisms as well as efficient processes for TNSPs to issue short-term firm access. It may be the case that holders of existing firm access (whether short-term or long-term) value their holdings less highly than others who would be seeking additional firm access. Therefore, short-term firm access trading mechanisms would also allow the secondary trading of firm access: the purchase of firm access from an existing holder rather than from the TNSP.

Generators could sell long-term access, either to the TNSP, or via the TNSP to another generator, through the sell-back process described in section 7.5.

Generators could also offer secondary trades of access for the short-term through an auction (although they could only offer into the auction access up to the short-term horizon). Secondary trades would only clear if a buyer and seller share a binding constraint in the auction dispatch.

7.4.7 Integration of inter-regional short-term firm access

Integrating inter-regional access into the short-term firm access auction would allow network capacity to be allocated from intra-regional to inter-regional firm access, or vice versa.

This would help facilitate the most efficient overall use of the network. For example, the Queensland - NSW Interconnector (QNI) participates in many Queensland constraints, along with Queensland generators. Some of the Queensland generators who hold firm access could sell some of their firm access into the auction. This potentially could be converted into firm interconnector rights (provided the interconnector is not constrained within New South Wales).

For inter-regional access to be included in the short-term firm access auction, market participants and traders would make bids for firm interconnector rights, with these bids aggregated by AEMO as part of the auction design.

To facilitate the integration of inter- and intra-regional short-term firm access into a single auction, the auction constraints, based on the firm access planning standard capacity, may need to be developed on a NEM-wide basis. This is discussed further in section 5.5.

7.4.8 Incentive scheme implications

The implications for the TNSP incentive scheme as a result of short-term firm access are described in section 5.3.

7.4.9 Governance of short-term access procurement

AEMO, as market operator, would run the short-term firm access auction. The main features of the auction would be set out in the Rules; however, the more detailed matters about how the auction would be run would be contained in AEMO procedures and/or guidelines. This would be similar to the current arrangements for the Settlement Residues Auctions, as discussed above, and so is consistent with governance principle 1: promotes best natural fit.

Since the TNSP knows its network the best, the TNSP is the appropriate body to develop the stylised constraint equations which feed into the auction. To further facilitate the national focus, the National Transmission Planner could have a role in assisting TNSPs with the constraint formulation, which would provide better integration among all the TNSPs.[78]

The Commission notes that the constraints feeding into NEMDE and the stylised constraint equations described above would be developed by different parties (AEMO

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78 These constraints would also be used when transitional access is allocated pro rata to existing generators (see chapter 8); and the auction of transitional access up to the firm access planning standard capacity of the existing network is undertaken as described in chapter 8.

and the TNSPs respectively). This is appropriate since they are developed in different ways and used for different purposes. However, there may potentially be conflicts. During any implementation phase for optional firm access, the materiality of this issue would be investigated further.

Access that was purchased in the short-term firm access auction would be registered in a certificate, analogous to the purchasing of long-term firm access. All of the details surrounding the certificate would be as set out above in section 7.2.7.

7.5 Sell back of firm access

Sell-back would be the right of a generator to sell its existing firm access to the TNSP, at the current long run decremental cost (LRDC, as discussed in chapter 6). Sell-back would be optional for the generator but compulsory for the TNSP, if a generator were to request to sell back its access.

The sell-back element of optional firm access is designed to address concerns from stakeholders that since the TNSP would be required to plan its network over the entirety of the access term to meet the firm access planning standard, this could potentially lead to inefficient build, particularly later in the access term.

For example, a large smelter located close to a generator may close. This could require the TNSP to develop its network in order to continue to meet the firm access planning standard. In the absence of some sort of mechanism that allowed generators to sell back access, the TNSP could be required to spend money in order to provide access to generators that they may no longer value. In order to address those concerns, the generator would be permitted to sell back its access to the TNSP at the current cost of that access. Alternatively, a generator may wish to exit the market, and in doing so recover costs by selling back its firm access.

There should be no overall impact on TNSPs and TUOS customers; so long as the LRDC calculation reasonably estimates the avoided costs associated with the sell-back, consumers would be no worse off.[79]

As with buying firm access, the option to sell back firm access (at a price derived from the pricing model) is a right of generators, and must be accommodated by the TNSP. However, since it is the TNSP that best knows when an expansion is likely, a TNSP could initiate the process. A TNSP may approach a generator to inform it that, due to an imminent expansion, the LRDC for a particular sell-back is high, and so prompt the generator to consider whether it values its access more or less than the amount it would receive for selling it back. However, the generator would need to agree to have its access sold back.

79 Sell-back prices (based on LRDC) may be different to the actual costs avoided by the TNSP (just as the LRIC may be different to the actual costs incurred by the TNSP). Therefore, the conclusions on access pricing, discussed in chapter 6, apply here.

For example, a TNSP would need to undertake a RIT-T in order to assess what investments it needs to make in order to continue to provide access to a generator following a closure of a large consumer. It could informally approach generator(s) whose access would be affected by the consumer shutting down to ask them if they would consider selling back their access. If a generator agreed, then the need to develop the network would be circumvented, and investment avoided.

7.5.1 The process by which firm access is sold back

As described in chapter 6, the mechanics of sell-back pricing would be very similar to those of access pricing, and so it is appropriate that the associated procurement processes would also be similar. Therefore, as with buying access:

- Sell-back requests would be queued.
- On reaching the head of the queue, the generator would enter into a process of finalising its sell back. Of the firm access it currently holds, the generator would seek the highest LRDC payment for sell-back of firm access, given the amount of value that it places on the amount, location and duration of the access that it would forgo.
- The generator would be able to accept a price, and so sell back access; or decide against selling back any firm access, in which case the access service continues unchanged, and the generator is removed from the queue.

Any completed sell-backs would then be immediately incorporated into the baseline scenario for future LRIC and LRDC pricing. Therefore, sell-back requests and procurement requests would need to be held in a single, common queue (subject to whether the requests would be competing, as discussed above). If they were in separate queues for sell-back and purchasing firm access, it would be uncertain as to which to process first.

7.5.2 Calculation of payment to generator

Significantly, the exercise of a sell-back option by a generator would not relieve it of its obligations to pay for the firm access it would have previously procured. When a sell-back was agreed, all the relevant outstanding accounts would be reconciled and paid off as a lump sum, so that no outstanding debts or credits remain.[80]

For example, as discussed in chapter 6, payments for new access would be amortised over the access term. A $10 million charge for 10-year access could be paid off at $1.63 million per year, given a cost of capital of 10 per cent.[81] Suppose four years into its term, the generator decided to sell back the access at an LRDC of $2 million. This $2

80 The alternative would be that the generator no longer holds any firm access, since this has been sold back, but continues to pay the annual payment to the TNSP. The Commission does not favour this approach.

81 Assuming end of year payments.

million sell-back credit would be netted off the $7.09 million (in net present value terms) that remained owing on the original access charge. The $5.09 million that the generator owed would be required to be paid immediately.[82]

7.5.3 Buy/sell spread

The sell-back price would be set at a small discount to the calculated LRDC, for example, five per cent. So, for the purposes of illustration, a generator who purchased access and then sold it back immediately (although they would not be allowed to do so, see section 7.5.4 below), would be out of pocket by the amount of this discount, commonly referred to as a "spread". The spread is designed to discourage gaming through churning (rapid buying and selling of access), to reduce the risk that a TNSP may be left out-of-pocket from such churning, and to help to cover the transaction costs incurred by the TNSP.

7.5.4 Restrictions on sell-back

Sell-backs would also have some restrictions similar to purchase requests:

- Sell-back must be in strips (a fixed MW amounts over the course of the access request). This is so that a generator is not able to create an access amount that varies by year, via the purchase of strips and the subsequent sell-back of access by an amount that varies by year.
- The price at which the sell-back occurs would be fixed at the LRDC, and could not be negotiated between the TNSP and generator.
- Sell-back would be restricted to the long-term (for example, beyond three year) time period. The short-term access auction (discussed in section 7.4) is the mechanism by which generators can sell (and buy) access in the short-term.

A number of additional restrictions would be required for sell-back:

- Transitional access could not be sold back, to prevent generators monetising access which has been allocated to them at no cost, or at an expected low cost. This is discussed in chapter 9.
- There would be a minimum holding period for firm access before it could be sold back, for example three years. This is designed to discourage speculative activity on the part of generators in gaming the pricing model and churning.

82 In the event of firm access being cancelled (for example due to generator payment default), the LRDC would be netted off the generator's outstanding debt. The calculation of the net outstanding debt (the difference between the outstanding access charges and the current LRDC) may inform an appropriate level of credit support requirements on the part of the generator. There may be administrative costs associated with changing the level of credit support on a regular basis as both the outstanding access charges and the LRDC change over time. LRDC could be used to guide the fixed level of credit support.

7.5.5 Sell-back as a mechanism to facilitate trade

As discussed above, generators would be able to bilaterally trade long-term intra-regional access through the sell-back mechanism. This could be two companies selling to each other, or one company transferring access between different power stations. As noted above, using the sell-back to facilitate this has the same outcome as two generators bilaterally trading access, but avoids the process of the TNSP having to set exchange rates in order for the generators to transfer access between two locations.

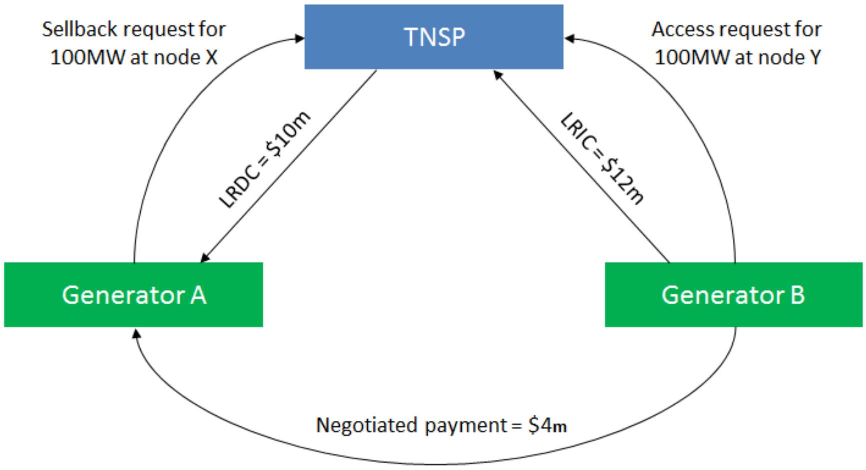
Bilateral long-term intra-regional access trades would be done through the parties submitting two requests to the access processing queue: a sell-back request at the from-node; and then a procurement request at the to-node, directly behind in the queue. The overall payment to (or from) the TNSP from the two transactions would be the difference between the LRIC at the to-node and the LRDC at the from-node. This difference could be positive or negative. In the case of a trade between two companies they may also agree to an additional bilateral payment.

For example, consider the situation illustrated in Figure 7.2 below. Generator A owns access at node X and now wishes to sell 100MW of this access. Generator B wishes to purchase 100MW of firm access at node Y. Were generator B to proceed with the purchase without generator A selling its access, the LRIC would be $30 million. However, were generator A to sell its access (at a LRDC of $10 million), the price of generators B's access request drops to $12 million – due to the spare capacity created as a result of generator A's sell-back.

A and B wish to exchange the access, which is done via the TNSP. A joins the queue immediately before B. Upon reaching the head of the queue, A's sell-back request is finalised and so A receives $10 million from the TNSP. B's procurement request is then finalised and it pays $12 million to the TNSP. The TNSP has received a net payment of $2 million, which represents the incremental cost of providing 100MW of firm access at node Y instead of node X.

In addition to these regulated payments, A and B may agree to separate bilateral payments between themselves. For example, assume that generator A values its access at $13 million. Without a separate payment from generator B, generator A would value its firm access more that than the payment it would receive from the TNSP, and so would not sell back. Generator A requires an additional payment from generator B of at least $3 million. Assume that the generators agree a negotiated payment of $4 million. Generator A has received a total of $14 million (which is greater than what it values the firm access it is selling) and generator B has paid a total of $16 million, which is less than the $30 million it would have paid had it not purchased generator A's firm access via the TNSP. These separate bilateral payments would be unregulated.

Figure 7.2 Sell-back example



In the case that access is being traded at the same node (for instance, between two generators which have generating units at the same node), the LRDC that would be received by the selling generator and the LRIC that would be paid by the buying generator would be the same. There would be no net payment to the TNSP as a result of the transfer, which is appropriate given that the transfer of access between generating units at the node has not affected the access that the TNSP has to provide from the node.

The combined requests at the same node would also not be competing with any other request, as they result in no net change to the price for other access requests. As a result, the trade would not have to be queued.

In effect, generators with access at same node would be free to trade their access at a bilaterally negotiated and unregulated payment, without delay, subject to appropriate registration and any prudential requirements. In these circumstances, the trade should not be subject to the buy/sell spread because there would be minimal administration costs for the TNSP.

7.5.6 Governance of sell-back

The governance arrangements for sell-back can be considered analogous to the purchasing of long-term intra-regional access. Generators would approach the TNSP to sell back their access. The TNSP's and generator's obligations under sell-back would be set out in the Rules. Since this process can be considered analogous to the purchasing of long-term intra-regional access, similar reasoning applies for this allocation of roles.

The price at which the sell-back occurs is set through the pricing model, which would be developed and maintained by the AER in accordance with the Rules.

Upon sell-back of access, the access certificate would be de-registered or updated (in the event that the generator does not sell back all of its access) in the access registry.

8 Other changes to existing regulatory processes

Summary of this chapter

The existing TNSP revenue regulation and the regulatory investment test for transmission would need to be modified to accommodate the optional firm access model.

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 the firm access service. There would continue to be a maximum allowed revenue from TUOS charges. However, 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.

Firm generator benefits would be included as part of the cost-benefit analysis for a RIT-T. In contrast, non-firm generator benefits would not be included in a RIT-T. Benefits that accrue to other parties (consumers, TNSPs) would still be included in the RIT-T assessment.

8.1 Introduction

A number of existing processes would need to be changed were optional firm access to be introduced.

Firm access rights would be underpinned by transmission capacity on the shared network, the provision of which is a regulated monopoly. Since the shared network would be providing firm access as well as meeting the relevant jurisdictional reliability standards, the firm access service would be treated as a prescribed service, consistent with the current regulation of shared network services for customers.

With some modifications, the existing revenue regulation approach that applies to TNSPs for prescribed services can accommodate the introduction of optional firm access.

The RIT-T would also need to be modified, to accommodate that generators have already indicated, via their procurement decisions, whether firm access is of positive net benefit.

This chapter discusses the changes to existing processes that would be required under optional firm access. It sets out:

- how revenue regulation would be modified, highlighting the similarities of the revenue regulation under option firm access as compared to the current regime (section 8.2);
- how the RIT-T would be modified (section 8.3); and

- the governance arrangements for revenue regulation and the RIT-T (section 8.4).

8.2 Revenue regulation

8.2.1 Revenue allowances

Consistent with the current arrangements, the AER would determine, at each regulatory reset, an aggregate annual revenue requirement (AARR) for shared network services over a regulatory period. This allowance would be based on the efficient cost for a prudent operator of building, owning and operating a shared network capable of providing for current and projected levels of consumer demand and firm access services to meet the relevant reliability and firm access standards.[83]

As is currently the case, this would involve the AER setting both capital and operational expenditure allowances. The allowances would be set with regard to reliability standards, as they are now, and, additionally, the committed and projected firm access for the upcoming regulatory period.

Each of the capital and operational expenditure allowances would be set with regard to the combined cost of meeting the reliability and firm access standards. Separate allowances for reliability standards and firm access would not be set.

The capital and operational allowances would continue to be set on an ex ante basis, since ex ante revenue allowances provide a strong incentive for TNSPs to minimise their costs over the regulatory period. TNSPs are able to profit by spending less than their allowed revenue allowance, or bear costs if they spend above it. Ex ante revenue allowances also provide incentives for TNSPs to reduce their overall costs by making trade-offs across their network and prioritising projects.[84]

In the next regulatory period the *actual* capital costs of investments would form part of the Regulatory Asset Base,[85] as is currently the case.

Optional firm access may change the risk profile of TNSP businesses. Given the potential change in the risk profile for TNSPs, it may be appropriate to allow for this in TNSPs revenue allowances. How this compensation would be allowed for would be considered further in any implementation project for optional firm access.

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83 The AER would not assess whether actual access requests by generators, or the resultant level of the firm access standard, are appropriate. It would be for generators to decide whether they consider access requests to be appropriate.

84 In addition to the incentives provided by the ex ante allowance, TNSPs would also face operational incentives under the optional firm access incentive scheme as discussed in section 5.3.

85 Subject to the possible reduction for inefficient expenditure. See S6A.2.2A of the NER.

8.2.2 Recovery of revenue allowances

Currently, a TNSP recovers its costs (as set in the revenue allowance) incurred in building and operating the transmission system from customers within its region. This occurs through recovering TUOS charges from customers.

Under optional firm access, in order to calculate TUOS revenue, the amount of revenue expected to be received from providing firm access would be estimated, and by subtracting estimated access revenue from the allowed annual revenue requirement, a maximum allowed revenue from TUOS customers would be derived. The maximum allowed revenue from firm access sales would not be set by the AER; instead firm access prices would be regulated as described in chapter 6.

In other words, firm access revenue for the period would be estimated, based on current and projected future access agreements and deducted from the AARR to determine the maximum allowed revenue from TUOS customers, in order to prevent those costs being recovered twice – once through TUOS charges, and once from firm generators.

TUOS *prices* would then be determined as they are at present. That is, the TUOS prices would be adjusted as necessary in order to reflect any volume changes that may occur over the period. However, the maximum allowed TUOS revenue would never be adjusted during the regulatory period.

Within a regulatory period, there could be a profit impact for a TNSP arising either from the quantum or timing of firm access revenue or cost, compared to that projected at the start of the regulatory period:

- If the revenue from firm access arrangements within a regulatory control period was higher than projected at the time of the revenue determination (for instance, because of an unforeseen access request), the TNSP would recover more revenue than its AARR, because the maximum allowed revenue from TUOS customers would be unaffected. This would be broadly appropriate since the TNSP's costs would be correspondingly higher (although not necessarily by the same amount).

- Similarly, if the revenue from firm access arrangements within a regulatory control period was lower than projected at the time of the revenue determination, the TNSP would recover less than its AARR, because the maximum allowed revenue from TUOS customers would prevent the difference being recovered from TUOS customers.

If the possible profit impact on a TNSP was material, the AER could implement a revenue regulation adjustment mechanism for the subsequent regulatory period.

8.3 RIT-T

Under the optional firm access model, a TNSP would be required to meet the reliability and firm access planning standards.

In order to undertake a major investment to maintain reliability and/or firm access planning standards, a TNSP would be required to undertake a regulatory investment test for transmission (RIT-T, essentially a cost-benefit analysis), and select the option which maximises net present value.

TNSP estimates of firm generator benefits would be included as part of the cost-benefit analysis, but not for non-firm generator benefits.

A non-firm generator is not willing to pay anything for access, so the TNSP would not be compensated for spending anything on non-firm generators' access (beyond that required by the reliability standards).

8.4 Governance of existing processes

Under the optional firm access model, the AER would continue to have responsibility for revenue regulation aspects, as it currently does in the NEM. Allocating this function to the AER is therefore consistent with the governance principles, most notably, principle 1: promotes best natural fit, both in terms of existing processes and accountability, and also consistency with the current regulatory framework.

The Rules would be modified in order to give the AER the associated functions. Consistent with the current Rules, the level of prescription around the AER's role would be relatively detailed.

The governance of the RIT-T would be unchanged from the current arrangements.

The AER would be responsible for administering the incentive scheme. This is discussed in further detail in section 5.3.

9 Transitional access arrangements

Summary of this chapter

The Commission has articulated four objectives for the transition to optional firm access:

- to mitigate any sudden changes to prices and margins for market participants (generators and retailers) on commencement of the optional firm access regime;
- to encourage and permit generators to acquire and hold the levels of firm access that they would choose to pay for;
- to give time for generators, TNSPs and other market participants to develop their internal capabilities to operate new or changed processes in the optional firm access regime without incurring undue operational or financial risks during the learning period; and
- to prevent abrupt changes in aggregate levels of agreed access that could create dysfunctional behaviour or outcomes in access procurement or pricing.

Over the course of this review, the Commission developed its preferred design for the transitional arrangements of the optional firm access model, were optional firm access to be implemented immediately. This design is outlined in this chapter:

- At the start of optional firm access, existing generators would be allocated transitional access. Transitional access would function identically to firm access, but would be procured differently and sculpted back over time.
- Some transitional access would be allocated to all existing generators for free. The remaining network capacity would be auctioned as either transitional access to generators, or transitional firm-interconnector rights. There would be an ability for participants to secondary trade the provided transitional access. The transitional access allocation would be provided in a manner so that the TNSPs would be firm access planning standard compliant with the existing network.
- There would initially be a period of five years where the transitional access, regardless of how it was procured, would remain at the level purchased.
- All transitional access, regardless of how it was procured, would be sculpted back over the subsequent ten years. As generators would have their transitional access sculpted back, they would have the right to purchase firm access through a renewal process that could represent a saving over the cost of firm access purchased in the standard procurement system.

However, as set out in Volume 1, the Commission considers that implementing optional firm access immediately does not meet the National Electricity Objective in the current environment – but it could at some future time. Therefore, the design developed by the Commission for transitional access and presented in this chapter may not be the appropriate design were optional firm access to be implemented at some point in the future. If optional firm access were to be implemented, the transitional access arrangements would need to be reconsidered at that time, taking into account the above principles for transitional access allocation, and the market situation at that time.

9.1 Introduction

Over the course of this review, the Commission has developed its preferred design for transitional access arrangements for the optional firm access model, were the optional firm access model to be implemented immediately. This design is outlined in this chapter.

Were the optional firm access model to have been implemented immediately, access would be provided to existing generators for a transitional period. Transitional access would be functionally the same as firm access, but would be procured differently and would be sculpted back over time.

However, as set out in Volume 1, the Commission considers that implementing optional firm access immediately does not meet the National Electricity Objective in the current environment – but it could at some future time. Therefore, the design developed by the Commission for transitional access and presented in this chapter may not be the appropriate design were optional firm access to be implemented at some point in the future. The COAG Energy Council should take into account the rationale for transitional arrangements (outlined in section 9.2) and draw, as appropriate, on features of the Commission's preferred design for transitional access were optional firm access to have implemented immediately (outlined in sections 9.3 to 9.5).

9.2 Rationale for the design of transitional access arrangements

9.2.1 Rationale for providing transitional access arrangements

The Commission has articulated four objectives for the transition to optional firm access:

- to mitigate any sudden changes to prices and margins for market participants (generators and retailers) on commencement of the optional firm access regime;
- to encourage and permit generators to acquire and hold the levels of firm access that they would choose to pay for;
- to give time for generators, TNSPs and other market participants to develop their internal capabilities to operate new or changed processes in the optional firm

access regime without incurring undue operational or financial risks during the learning period; and

- to prevent abrupt changes in aggregate levels of agreed access that could create dysfunctional behaviour or outcomes in access procurement or pricing.

In general, where there are significant regulatory changes in the electricity sector it is in the long-term interests of consumers that there be an appropriate transition for investors in the sector. Currently, generators have some expectation of access to the regional reference price, though this implicit access can be degraded through changes to network conditions or the presence of new entrants.

The implementation of optional firm access would represent a substantial alteration to the operation of the NEM. Generators have made investment decisions based on the prevailing market conditions. Transitional arrangements, such as the provision of transitional access to existing generators, would help to mitigate the commercial and financial impacts of the implementation of the model on generator balance sheets.

The four objectives outlined above would need to be taken into account by policy makers at the time of any future implementation of optional firm access in recommending the most appropriate transitional arrangements that should be implemented. For example, the recommended reporting regime, described in volume 1 of this report, may mitigate the suddenness of the impact of implementing optional firm access.

Another benefit of transitional access arrangements are that they would allow a learning period for participants. During any transition period, all participants would gain experience in the operation and impacts of optional firm access. With transitional access, generators would be able to gain first-hand experience on how optional firm access impacts on their business, without needing to purchase access. This would allow them to develop their internal capabilities to operate new or changed processes without incurring undue operational or financial risks. The COAG Energy Council should also take this into account when determining the appropriate transitional arrangements were optional firm access to be implemented.

9.2.2 Rationale for sculpting transitional arrangements

Whatever transitional arrangements that are put in place at the start of optional firm access, these arrangements should be sculpted back over time.

Part of the rationale for the introduction of optional firm access is to create a price signal for generators so that, through their procurement decisions, they can demonstrate how much they value access to the network. Limited price signals are created when generators receive firm access for free or can buy it cheaply as part of transitional access allocation. By sculpting back transitional access, generators that prefer to remain firm would be required to purchase firm access. Consequently, there would be transparent signalling of the value of the transmission network.

Further, TNSPs would be required to develop or maintain their networks to support the level of firm access held by participants (including that allocated through transitional processes). If transitional arrangements are not sculpted back, then they may drive network replacements or developments, ultimately funded by consumers. This would be the case even where a generator did not value the transitional access allocated to it. This would run contrary to the concept of transmission investment being led by generators.

In addition, concerns have been raised that transitional arrangements may represent a barrier to entry for new entrants. To be firm, a new entrant generator must purchase access, either from TNSPs or other generators. The costs involved with such purchases would be avoided by existing generators in respect of the transitional access they hold. If transitional access is granted for too long a period, this may disadvantage new entrants compared to existing generators.

In summary, the future design of transitional access arrangements should represent a trade-off between:

- managing the impacts of optional firm access on the investors in existing generators, along with providing a learning period to all participants; and

- encouraging generators to purchase the level of firm access that they value.

In light of the above considerations, the rest of this chapter provides, for illustrative purposes, the Commission's preferred transitional access arrangements design were optional firm access to be implemented immediately. The COAG Energy Council may consider drawing upon aspects of this design were optional firm access to be implemented.

9.3 Providing transitional access

9.3.1 Background

If optional firm access is implemented, access to the existing network would be provided to existing generators and potential firm interconnector right holders. The method used for the provision of transitional access would need to be based on TNSP obligations being met by the existing network. That is, the network would be firm access planning standard compliant at the start of optional firm access and no new network build would be required to provide transitional access.

In the Transmission Frameworks Review and the First Interim Report for this review, it was proposed that transitional access allocation should be based on an allocation to generators, with any residual access to be sold as firm interconnector rights. However, in response to the First Interim Report some stakeholders considered that an auction would be a more preferable method of providing transitional access.

Consequently, we have examined three options for determining the provision of transitional access. The options developed were:

- Option i: an initial allocation consistent with that described in the First Interim Report (see section 9.3.2);
- Option ii: an auction of all capacity (see section 9.3.3); and
- Option iii: a hybrid approach (see section 9.3.4).

A summary of the options can be seen in Table 9.1.

Table 9.1 Options of providing firm access

Option i (pure allocation method, discussed in First Interim Report)	Option ii (pure auction method)	Option iii (hybrid method)
• Access is allocated for free to existing generators using an allocation method that attempts to simultaneously dispatch all generators at their historical capacity • Residual access to be auctioned as firm interconnector rights • Transitional access would be sculpted	• Access is auctioned to existing generators, and market participants and traders (for inter-regional access) • Transitional access bought in the auction would be sculpted	• Access is allocated for free to existing generators pro rata to capacity and regional peak demand • Remaining transmission capacity would be auctioned to existing generators, market participants and traders as either firm intra-regional or firm interconnector rights • Transitional access (both that allocated, and that bought in an auction) would be sculpted

Table 9.1 refers to existing generators, market participants and traders taking part in an auction for Options ii and iii. The details around what constitutes an existing generator, market participant or trader would be determined as part of the further implementation of optional firm access. For example, it may be that a generator that is not yet operational but is in the final stages of commissioning should be able to bid in such an auction.

For all three options, it would be necessary to develop a model of the network to determine the provision of transitional access. This model would simulate the network as it would exist at the commencement of optional firm access. The model would be used to determine how to allocate firm access to generators and firm interconnector rights holders while continuing to meet the firm access planning standard. This would be the same model used in the firm access planning standard as described in section 5.5.

This process for determining capacity available to be allocated to generators would be the same as the process underpinning the short term firm access auction (described in section 7.4), except initially the whole network would appear "spare".

As discussed below, the hybrid approach (Option iii) represents the Commission's preferred method of providing transitional access.

9.3.2 Option i: Allocation of all capacity for free

Description of Option i

Option i represents all capacity being allocated for free among generators and to firm interconnector rights holders (that is, there would be no auction). This was the method described in the First Interim Report.

Under this option, a network simulation model (simultaneous feasibility model) would be created in which every generator would offer its capacity at identical pre-determined price steps. Additional simulated load would be added at the regional reference node so that total demand would equal the sum of the capacity of all generators in each region. Under these conditions the model would evaluate the allocation for each generator.

If the model were to indicate that a generator would not be constrained in these circumstances, the generator would receive transitional access equivalent to its capacity. If a constraint binds, the participating generators would receive a level of transitional access equivalent to their simulated dispatch in the model.

Any residual capacity after the allocation to existing generators would be allocated to firm interconnector rights.

Assessment of Option i

Compared to the other options, this option would best minimise the impacts on generators of the regulatory change, since all transitional access available would be allocated for free and in some relation to the implicit access the generator currently experiences.

However, this method requires a range of arbitrary decisions to be made. For example some party would be required to set a number of parameters, such as the offers that each generator is assumed to place in dispatch (the price steps referred to above). Since the level of these offers would affect the equity of the transitional access allocation, setting these factors could potentially be very contentious.

AEMO has undertaken tests on the Option i methodology for allocating transitional access. Further tests were conducted following the First Interim Report. A report on this work can be found on our website.[86]

The work undertaken by AEMO, both for the First Interim Report and subsequently, demonstrates a number of challenges with the initial allocation method used in this

86 AEMO, Transitional access round 2 report, 2014.

option, most notably the impact of choices of bid parameters on the results. If this option were to be chosen, these technical issues would need to be worked through during implementation.

9.3.3 Option ii: Auction of all capacity

Description of Option ii

Under Option ii, all of the capacity of the network would be auctioned as transitional access to existing generators and market participants. This access could be purchased by generators as intra-regional access, or by market participants or traders as firm interconnector rights.

Some stakeholders raised the option of an auction so as to allow a market based allocation of transitional access, rather than through a mathematical model as was considered for Option i. Furthermore, the development of an auction would avoid the need to make contentious decisions on the parameters that lead to different allocations.

If an auction were to be used for the allocation of transitional access, it could operate using a simultaneous feasibility of bids in the model described in section 9.3.1. However, unlike in Option i, the bids would be determined by generators or potential firm interconnector right holders, as opposed to being set arbitrarily.

There would be no reserve price in the design of the auction. For a number of generators, depending on the flowpaths to the regional reference node, this means that the price faced for transitional access would be low. Conversely, generators in more congested parts of the network would compete for scarce capacity leading to potentially higher prices.

The auction would be based on simulated flows through the network. Therefore, where a flowgate is congested, the participation factors of generators would impact on the result of the auction in addition to the bid.[87] Therefore the auction would reflect the physical nature of the network, as represented by constraint equations.

Given that the existing network was funded by consumers, all revenue raised through the auction process would be used to offset TUOS charges.

Assessment of Option ii

An auction represents a more transparent approach to allocating transitional access, involving fewer arbitrary decisions than for Option i.

87 Consider a situation where there are two generators participating at a congested flowgate. One generator has a participation factor of 0.1 and the other a participation factor of 1. For the low participation factor generator to receive a marginal increase in transitional access, its bid would need to be ten times that of the high participation factor generator.

However, unlike Option i, an auction would require generators to purchase transitional access. Transitional access may not be as closely matched to existing levels of access and balance sheet impacts on generators may not be mitigated. While transitional access could be purchased at a relatively low price where there is spare transmission capacity, there are areas of the network that are currently constrained, and so some generators could potentially pay a high price for some of the transitional access.

In the period leading up to the auction, generators would be uncertain of the level of transitional firm access they would eventually hold. This uncertainty may cause generators to be reluctant to offer as much capacity in the contract market. This may reduce contract market liquidity.

Further, choosing this option would mean the generator would have to make a commercial decision about the level of transitional access it wanted to buy before observing access settlement. This could limit the benefits associated with having a learning period.

9.3.4 Option iii: Hybrid model

Description of Option iii

Option iii would combine elements of Option i and Option ii. The process of undertaking the hybrid transitional allocation would comprise two stages:

- Stage 1: A free pro rata allocation of access to existing generators. The ratio of total generation capacity to total demand under the firm access planning standard specified conditions would be estimated. A level of transitional access equivalent to this ratio would be allocated amongst generators pro rata to generation capacity. If this level is not compliant with the firm access planning standard, then the pro rata transitional access would be reduced for all generators so that compliance is achieved.

- Stage 2: There would be an auction of the remaining network capacity that was not allocated through Stage 1.

The pro rata allocation in the first stage of this option differs from the allocation method used in Option i. The determination of the pro rata allocation would be more transparent. All generators in a region would receive the same proportional amount of allocated access relative to their generation capacity. If the initial allocation does not provide a generator with the level of transitional access that it prefers, the generator would be able to purchase additional firm access through the Stage 2 auction.

One of the test runs as part of AEMO's transitional access project attempted a pro-rata allocation using the NEMDE Queue system. The results were the same for all generators in each region and were between 50 to 70 per cent of capacity.

It is important to note that these values represent the amount from a test run based on historical values and not the actual allocations that generators would receive if optional firm access were to be implemented.

The residual network capacity that was not allocated would be auctioned to generators (for intra-regional transitional access) and market participants and traders (in the case of inter-regional access). This auction would occur through the auction engine as described for Option ii.

A generator could sell its transitional access in the short-term firm access auction.

Assessment of Option iii

This option offers some of the benefits of the previous two options while minimising the disadvantages. Generators would receive some transitional access allocation while there would also be an auction allowing the value generators place in access to be determined.

9.3.5 Conclusion

The Commission considers that Option iii - the hybrid model, should be the transitional allocation method used if optional firm access was implemented. This option achieves the best balance of transparency while minimising the impacts on generators of regulatory change. It would reduce the number of arbitrary decisions that would need to be made in developing the allocation methodology, providing for more transparency compared to Option i. At the same time it still provides for some transitional access to be gifted to existing generators to mitigate the impacts of optional firm access and cover most of their contract position. By incorporating an auction, it may also make it easier for new entrants to acquire some transitional access.

9.3.6 Further issues

Secondary trading

Market participants would be able to be trade any transitional access they hold. This would occur on a short-term basis through the short-term firm access market.[88] This would bring a level of liquidity to transitional access.

Generators connected at the same node would be free to trade their transitional access directly between each other.

It would not be appropriate for transitional access – much of which will have been given to generators for free – to be able to be sold back to TNSPs. This would result in consumers funding the sell-back of the transitional access. Transitional access is to

88 Under Option i there would an auction of short term firm access immediately after the initial allocation.

minimise the regulatory shock of the introduction of optional firm access and not to provide financial compensation to generators. This means that the sell-back option described in chapter 7 would not be available for transitional access.

Interconnectors

Stakeholders have raised concerns relating to the low allocation of transitional access to interconnectors in the test runs on transitional allocation undertaken for the First Interim Report. These stakeholders consider that if there are not enough firm interconnector rights available at the implementation of optional firm access, inter-regional trade may be impacted.

It is important to remember that, while the interconnector right allocations under Option i were low in the tests runs, this may not be the case if optional firm access is implemented. Between the test runs and any transitional allocation there may be changes to the network, especially considering the current upgrade of the Heywood interconnector.

Choosing Option iii may partly overcome concerns about the treatment of interconnectors. The Stage 2 auction would allow transitional access to be allocated to those who value it most, including those who might seek it with respect to interconnectors. Option iii might be favoured because it would be likely that there would be more allocated to its auction than would be residual under Option i.

In addition, if liquid secondary trading of transitional access occurred through the short term auction this would represent another means of purchasing firm interconnector rights. This would be the case for all of the three options considered above. It is important to recognise that transitional access (as with all access) is tradeable between generators and firm interconnector right holders. In theory, this should lead to an efficient level of firm interconnector rights access being held over time.

New entrants

One area of concern raised by stakeholders is the treatment of generators who enter the market during the transition period. The distinction between existing generators and new entrants would be determined if optional firm access was implemented. Existing generators are likely to be those which have already been commissioned and commenced operation. It may also, for example, extend to those in the final stages of commissioning.

New entrants - those generators which did not yet meet the definition of an existing generator - would not receive any transitional access in the initial allocation or auction. The concern is that these generators would face a barrier to entry or competitive disadvantage compared to those who receive transitional access.

In general, new entrants would be able to purchase transitional access from other generators through the short term auction. These generators could also purchase long term firm access from the TNSP using the process described in chapter 7.

Some stakeholders consider it would be appropriate to allocate new entrants transitional access if they were to enter the market during the transitional period. It was proposed that this could be done by setting aside some of the initial transitional access for these new entrants.

Incorporating this "reserved" access into the other elements of the model (such as the incentive scheme, short term firm access, pricing and access settlement) would create challenges.[89] Therefore, reserving access for new entrants would not be feasible.

Further, it is practically difficult to consider how reserved transitional access could be released to new entrants. If a new entrant locates at a node where there is currently minimal network or generation, equivalent transitional access may not be able to be allocated without consumer funded expansion. Any such expansion would place costs on consumers. It may also mean the generator does not receive the appropriate signal about where to locate. Even if transitional access could be provided to new entrants with existing transitional capacity, it would be difficult to reserve as the location of the new entrant could not be predicted.

9.4 Sculpting parameters

9.4.1 Position in First Interim Report

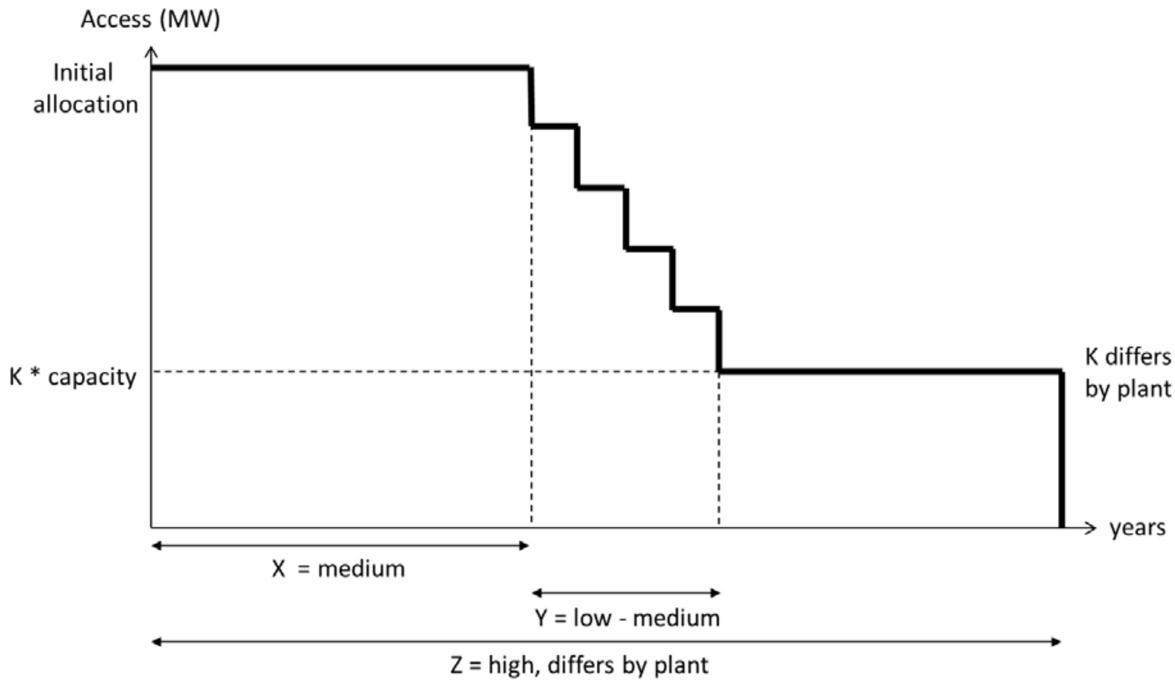
After the initial provision of transitional access, it would be sculpted back over time. Sculpting encourages generators to acquire and hold the levels of firm access they value. The Commission stated in the First Interim Report that any transitional access would be sculpted back with a shape dictated by parameters labelled as X, Y and Z and K.

- X years would be the length of time the generators would have the full initial level of transitional access.
- Over Y years the transitional access would be sculpted back.
- At the end of the Y period, generators would retain a residual K amount of transitional access for Z years.

X, Y and K were to be common to all generators while Z would be individually determined. Figure 9.1 shows the sculpting profile as of the First Interim Report.

89 Much of optional firm access design assumes that all network capacity is held as firm access by a particular participant.

Figure 9.1 Transitional access sculpting in the First Interim Report



9.4.2 Overview of sculpting factors

This section lays out the sculpting of transitional access if optional firm access were implemented.

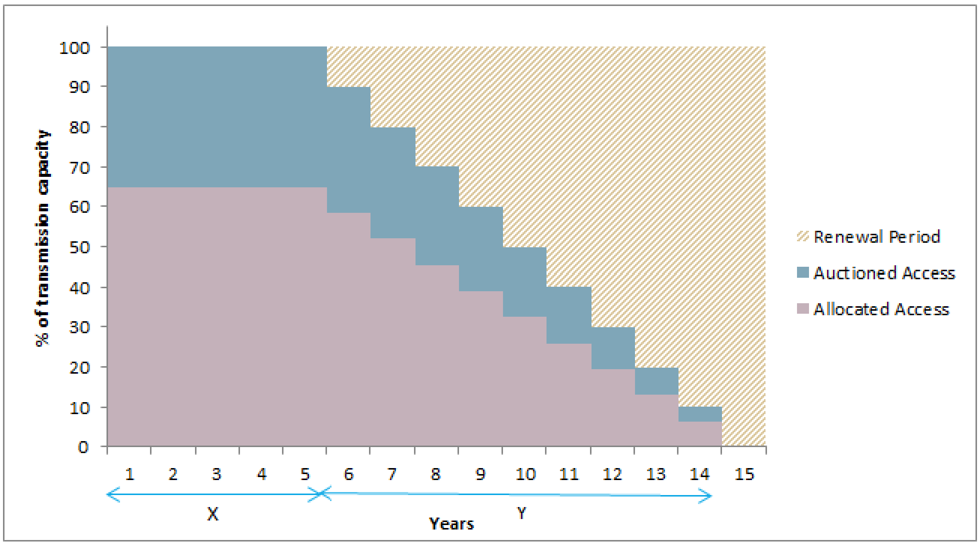
The sculpting parameters would be set with:

- X period – five years; (as described in section 9.4.3);
- Y period – ten years (as described in section 9.4.4); and
- a **renewal right** as the transitional access is sculpted away instead of a residual access level (as described in section 9.4.5).

The allocated transitional access and the auctioned transitional access would be sculpted at the same rate. That is, whether 1 MW of transitional access was allocated to Generator A, or purchased in the auction by Generator A, the 1 MW would be "sculpted" back over time the same way.

Figure 9.2 shows the sculpting profile of transitional access. It includes an arbitrary division of 65 per cent allocated, and 35 per cent auctioned transitional access.

Figure 9.2 Transitional sculpting diagram



9.4.3 Setting the X period

Length of the X period

The X period represents the length of time that transitional access would be held at the initial level at the implementation of optional firm access. The Commission considers the X period should be five years.[90]

In determining the X period, there is a trade-off between the different goals of transitional access sculpting. The X period must be:

- short enough so that the benefits that flow from optional firm access, including generators purchasing the amount of firm access they value, begin as soon as possible. It should also be short enough so that no significant network asset replacements are triggered by the transitional access and that new entry can be facilitated; but
- long enough to provide a learning period to market participants and mitigate balance sheet impacts on generators.

X must be long enough for a generator to be able to procure long-term firm access before sculpting (the Y period) commences. If a shorter time were chosen generators could not purchase new long-term access early enough to replace transitional access as it was sculpted away.

The expected lead time for commencement of new firm access is three years. That is, it would take a TNSP three years to develop its network to meet firm access requests as

90 This may need to be re-evaluated during the implementation of optional firm access to take into account any network assets that may be considered to be taken out of service or replaced during the transitional period.

discussed in chapter 7. In addition, the procurement process would run for a year. Consequently, the minimum possible length of the X period is four years. To allow an additional year for learning the X period would be five years.

Firm access planning standard amnesty period

A TNSP must plan its network so that it is compliant with the firm access held (including transitional access). As described above, the total amount of transitional access would be set such that it is equivalent to the capacity of the network at the start of the transitional period. This should mean that the TNSP would not need to develop or replace its network to accommodate transitional access. This is appropriate since otherwise consumers would fund the relevant development or replacement.

However, it is possible that the level of transitional access could be inadvertently set above the capacity of the network. Alternatively the network capacity could fall. In order to avoid these circumstances driving network build, during the X period there would be firm access planning standard "amnesty".

During the amnesty period, TNSPs would still be expected to plan to provide network capacity, including in respect of new requests for long term firm access. However, the firm access planning standard would not be enforceable in respect of transitional access.[91] The TNSPs would still need to comply with the firm access operating standard and would be bound by the incentive scheme.

The firm access planning standard amnesty must not be much longer than the procurement lead time, since otherwise the TNSP's network may not be appropriately planned. This would be another reason why the X period would need to be short.

9.4.4 Setting the Y period

The Y period represents the length of time over which transitional access is sculpted back. The Y period would be ten years, with ten percent of transitional access released each year.

The main concern with the setting of the length of the Y period is the interaction between the release of sculpted access and the procurement process. If too much access is sculpted back at any one time, there may be a large impact on the prices produced by the LRIC pricing model due to substantial amounts of access being purchased. It may also result in queueing problems if too many generators are seeking to renew their access at the same time. The best way of managing this issue is to undertake the sculpting back with small steps. Inherently this implies a longer Y period than X period.

91 A legal mechanism may be required to give effect to this and clarify what discretion the AER should have. This would be developed at the implementation if optional firm access is implemented.

All transitional access, whether acquired though the auction or from the pro-rata allocation would be sculpted equivalently. The firm access planning and operating standards would apply over the entirety of the Y period.

9.4.5 Alternative to the Z period

Determining Z for each generator in the NEM would be a complicated task. It would involve first having to decide whether this assessment was based on an engineering or an economic end of plant life. Even once a standard definition was reached, there would need to be numerous assumptions made to estimate the end of life for each generator. A decision would also have to be made for each generator.

Due to the arbitrary nature of this task a different approach would be taken. Transitional access would not be allocated for free for a period of Z years. Instead, it would be sculpted away completely during the Y period.

However, it would still be appropriate to provide a mechanism to minimise the impacts on a generator of purchasing firm access over its entire life. This is because it would have made a locational decision before optional firm access was introduced, which could not be reversed.

The mechanism by which this would be achieved would be through renewal rights. The generator would have a right of renewal for its transitional access for a period of years as access is sculpted back. This right would only affect the price of any access purchased and would not involve the gifting of free access. Renewal rights are explained in Box 9.1.

The renewal right would allow renewal of transitional access for periods up to a certain term. This term would be a proxy for the lifetime of the generator. The term could be set individually for each generator or be set to be the same for all generators in the NEM. If it were set individually for generators there would still be some of the challenges that were described above in the context of determining the length of the Z period.

Importantly, the generator would need to signal through its willingness to pay if it wants to continue to receive firm access. Therefore, generators would be less likely to obtain firm access that they do not value. This should also reduce the risk that access that has been granted for free drives network development.

In addition, the consequences of the decision about the lifetime of the generator would be less significant than for the previous approach where there was a Z period. This is because the generator would only be gaining a discount in the cost of access over the period, as opposed to receiving access for free.

Box 9.1 Renewal rights

Renewal rights are made possible by the LRIC pricing method. For background to this method, see chapter 6.

The LRIC model has a baseline level of access built into it, from which a baseline cost is determined. The access price is determined as the difference between the adjusted cost taking into account the new access, and the baseline cost.

The amount of firm access in the baseline affects the LRIC price, since it influences the level of spare capacity that is observed on the network. The baseline includes all previously purchased firm access and committed firm access requests. It must also make assumptions about future firm access requests. One of these assumptions would be that any generator with a renewal right would renew its firm access when it expires. This means such firm access would remain in the baseline for a period of time.

This also means an access renewal request would have to be treated differently than other requests for access. The continued presence of that renewed generator would be removed from the baseline used for pricing that generator's renewal requests. It would remain in the baseline for all other requests. If not it would be in both the baseline and adjusted scenarios and would be double counted for the purpose of the access price.

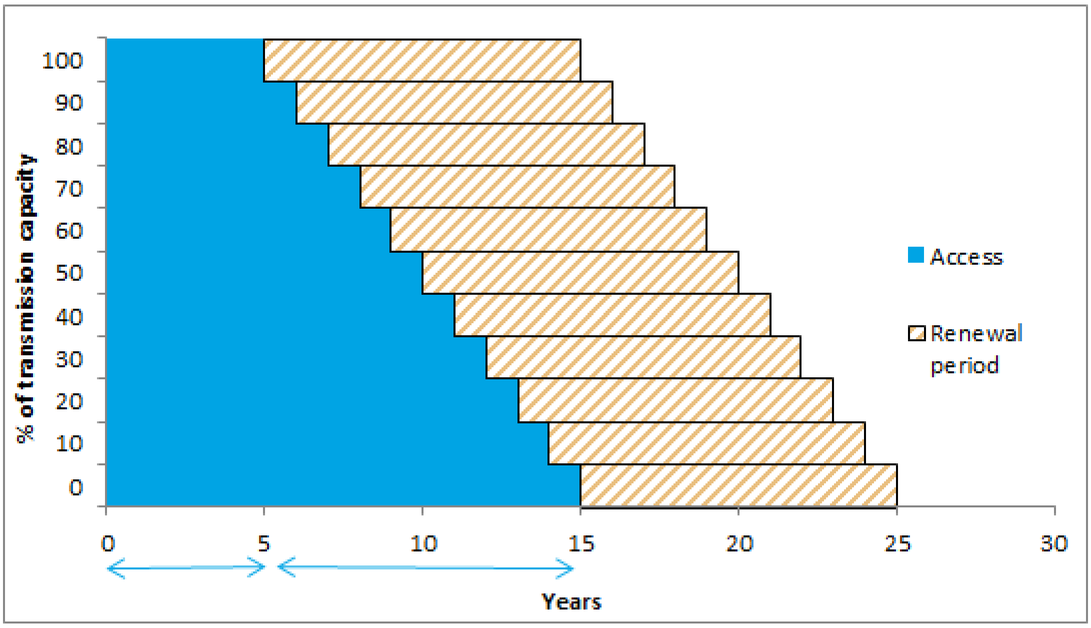
The access price for the renewal request would be different from the access price for an equivalent generator without a renewal right. While access pricing is usually based on LRIC, renewal requests are effectively priced using LRDC (that is, the cost that the TNSP avoids if the renewal does not occur).[92] In almost all cases the LRDC would be less that the LRIC, meaning having the renewal right would confer a financial benefit.

If a generator does not exercise its renewal right for transitional access as it is sculpted away, it would lose the right in respect of that transitional access. However, in subsequent years, the generator would have a separate renewal right for any newly sculpted transitional access. Over the Y period the generator could choose to renew ten per cent of its access ten times.

Figure 9.3 shows an example of how this would operate for a generator with a right to renew access for a period of ten years. For example, at the fifth year, the generator would have its transitional access sculpted back by ten per cent. It could choose to have this ten per cent of transitional access renewed by paying the LRDC access price. If it chooses not to renew some or all of its access at this point it loses the renewal right for that part of its access. Regardless of this choice, the generator can make the renewal right choice for every subsequent year until the end of the Y period. In the fifteenth year, the generator would be able to renew the final amount of access that is being sculpted back by ten years.

92 See section 6.5.3 for a description of how LRDC would be calculated.

Figure 9.3 Sculpting profile with ten year renewal period



9.5 Governance of transitional access

9.5.1 Allocation and auction

In respect of Option iii decisions would need to be made regarding governance for both the allocation and the auction for transitional access.

Allocation

The key issue in respect of governance of transitional access is the amount of detail to be included in the Rules in respect to the initial allocation of transitional access. This could be either:

- actual numbers, being the actual allocation to all of the generating units in the NEM;
- a detailed methodology, which would leave little discretion in how it is to be applied to determine allocations to generating units; or
- principles, which would give discretion for determining the allocations to the market body to whom the function is assigned.

The best approach would be to have the allocations to generating units specified in the Rules. For this to happen, there would need to be a rule change process during the implementation stage of the option firm access model. The rule change process would involve the AEMC, using the method specified in this chapter, determining the pro rata allocation of transitional access to all generators. This provides maximum clarity as to what allocations would be made, and would not involve including the allocation methodology in the Rules.

AEMO as market operator is likely to be required to provide technical assistance during the rule change process in applying the methodology to generate these final allocations. The market operator is the body with the most experience of dispatch and settlement and the relevant systems to perform the necessary calculations. This fits with governance principle 1: promotes best natural fit.

As noted in section 7.4.3, a network model, incorporating stylised constraints reflecting the firm access planning standard conditions would need to be developed to facilitate this auction and allocation (discussed below). The governance of this was discussed in section 7.4.9.

Auction

AEMO as market operator would run the auction of transitional access. Consistent with the above rationale, the market operator is the body with the most experience of dispatch and settlement to perform the necessary calculations. This fits with governance principle 1: promotes best natural fit.

There would need to be Rules around how the auction would be run, and how purchases are given legal effect. This could reflect the current detail in the Rules regarding settlement residue auctions with some detail in the Rules and further detail in AEMO guidelines/procedures.

9.5.2 Sculpting parameters

If optional firm access were to be implemented the sculpting parameters would need to be written into the Rules as part of the rule change request to introduce optional firm access. This would include the term of the renewal right.

Abbreviations

AARR	aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AUID	access unit identifier
COAG Energy Council	Council of Australian Governments Energy Council
DCC	deep connection charge
DUID	dispatch unit identifier
FL-LRIC	Forward-looking long run incremental cost
LRDC	long run decremental cost
LRIC	Long Run Incremental Cost
LRMC	long run marginal cost
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NER	National Electricity Rules
NPV	net present value
NTNDP	National Transmission Network Development Plan
QNI	Queensland - NSW Interconnector
RIT-T	Regulatory Investment Tests for Transmission
RMID	revenue meter identifier
SCADA	Supervisory Control and Data Acquisition
SCER	Standing Council on Energy and Resources

SRA	Settlement Residue Auctions
STPIS	service target performance incentive scheme
TNSP	Transmission Network Services Provider
TUOS	Transmission use of service
WACC	weighted average cost of capital

A Access settlement

A.1 Specification of access settlement

As part of its terms of reference, AEMO has developed a specification of access settlement. While working to develop this specification, there have been a number of access settlement design decisions that have needed to be clarified. These were resolved jointly between AEMO and the AEMC. This section examines the main issues that have been considered. These issues, along with additional issues relating to access settlement, are discussed further in the accompanying Technical Report.

A.1.1 Flowgate support generators

As discussed in section 4.3, generators with a negative participation in a binding constraint add to the effective flowgate capacity and are referred to as flowgate support generators. Often such generators are dispatched even though their offer price is higher than the regional price; that is, they are **constrained on**, and may respond by bidding unavailable.

In optional firm access, flowgate support generators would always earn the regional price regardless of whether they were firm or non-firm. The sum of all payments made and received among generators in access settlement is zero and so paying flowgate support generators would require either funds to be supplied externally or a reduction to payments to firm generators in the same flowgate.

Some stakeholders consider that flowgate support generators should receive payments for being such through the procurement system of firm access (that is, a negative LRIC). However, the Commission considers that there are existing processes for TNSPs to fund network support. TNSPs are already required under the Rules to consider (through the RIT-T) the possibility of network support being used as an alternative to developing the network. Here, generators would be paid for supplying network support.

Therefore, the Commission considers that implementing arrangements for flowgate support generators as part of optional firm access would duplicate existing arrangements, and would likely be more complicated. Accordingly, under optional firm access, flowgate support generators would be paid the regional reference price.

A.1.2 Access settlement on trading intervals

The settlement period would be a trading interval (30 minute period), the same as for existing NEM settlement processes.

However, many of the dispatch variables - such as flowgate prices - are calculated by NEMDE each dispatch interval (five minute period). The flowgate prices would be converted in access settlement to 30 minute equivalents through simple arithmetic averaging. Flowgate usage would be based on 30 minute revenue metered quantities.

In summary, the settlement approach of optional firm access can be described as: calculating 30-minute average dispatch outcomes and then applying the access settlement algebra to those 30-minute outcomes to calculate a 30-minute settlement amount.

One potential concern with this approach is that in some circumstances it may be possible for multiple different constraints to bind over different parts of the same trading interval. Further, even if a constraint binds over the course of a trading interval, the participation factor of generators could change. Accordingly, in some circumstances, undertaking access settlement on a trading interval basis may not provide a representative view of market conditions. An alternative access settlement approach - such as undertaking access settlement on a trading interval basis, but with a method flexible enough to take into account changes in flowgate prices - would resolve such concerns.

However, the Commission does not have enough information as to whether this alternative approach would provide more benefits than the trading interval approach. The Commission considers that such alternatives should be considered during any implementation phase for optional firm access. In the meantime, the Commission's considers that access settlement should take place on a trading interval basis.

A.1.3 Settlement of non-scheduled generators

Currently, scheduled and semi-scheduled generators feature on the left hand side of AEMO's constraint equations,[93] while non-scheduled generators are on the right hand side of the equations. When a constraint binds, scheduled and semi-scheduled generators may have their dispatch reduced while this risk is not faced by non-scheduled generators.

Non-scheduled generators generally (there are exceptions) are units that:

- have a generation capacity less than 30MW; or
- are technically unable to participate in dispatch.

AEMO is the body responsible for assessing whether a generator can be classified as non-scheduled or not with reference to principles set out in the Rules.

Under the optional firm access model, the left hand side of the constraint equations would represent the participation of each generator in access settlement. Attempting to integrate non-scheduled generation into the optional firm access model would raise significant practical implementation problems as non-scheduled generators are only implicitly included on the right hand side of these equations.

93 As long as the generator's participation factor in the particular constraint is larger than 0.07.

With the implementation of optional firm access a non-firm scheduled or semi-scheduled generator would receive the local price, which may be different from the regional reference price. A market non-scheduled generator would continue to receive the regional reference price for all of its generation, regardless of the constraints in the network.

A number of stakeholders have raised concerns that optional firm access may lead to increased incentives for generators to request to be registered as non-scheduled so as to receive access at no cost. Under the Rules it is the responsibility of AEMO to consider requests to classify a generating unit as non-scheduled as part of the registration process. It may be prudent to examine the assessment procedure for making this decision as part of the implementation of optional firm access, were it to be introduced.

A.1.4 Embedded Generation

The optional firm access model is focussed on generators' interaction with the transmission network. Access settlement would be undertaken in relation to each generator's participation in a flowgate. Similarly, the **firm access planning standard** and **firm access operating standard** would provide obligations on TNSPs to provide efficient levels of access for firm generators through the planning and operating of their networks.[94]

Embedded generators are those generators that are connected to a distribution network. Any scheduled or semi-scheduled generator becomes part of the optional firm access model. Therefore, embedded generators that are scheduled or semi-scheduled would be part of the optional firm access regime and therefore could procure firm access on the transmission network. However, embedded generators would not be able to procure firm access on the distribution network.

Firm embedded generators would be able to obtain access on all flowgates, but radial constraints on distribution networks are not flowgates.[95] If they were non-firm (and were scheduled), they would still be subject to making compensation payments where they constrained off other generators through the firm access regime.

A.1.5 Local prices below the price floor

In situations where the marginal generator on a **congested flowgate** has a low participation factor there is a possibility that this would lead to very high flowgate prices. This is because the flowgate price is the difference between the regional reference price and marginal generator's offer divided by this generator's participation factor in the flowgate. A high flowgate price could lead to other generators with large participation factors in the same flowgate facing an extremely low local price, possibly below the market floor price. An example of this is shown in Box A.1

94 As described in chapter 5.

95 Some distribution assets are dual function, and thus also transmission assets. Flowgates may arise on these assets.

Box A.1 Example of local price below the market price floor

Assume the RRP is $5,000/MWh.

The following constraint is binding and Generator 2 is the marginal generator.

$1 \times G_1 + 0.1G_2 \leq RHS$

Generator 2 has a price setting offer of $0/MWh and thus the local price for G_2 is $0/MWh. The flowgate price would be the difference between the regional reference price and the marginal generator's local price divided by the marginal generator's participation factor.

In this example the flowgate price for all generators in the flowgate would be calculated as follows:

Flowgate price = ($5,000/MWh - $0 MWh) / 0.1

Therefore, the flowgate price would be $50,000/MWh.

The flowgate price would be used to calculate the local price for all the other generators participating on the flowgate. If only Generator 1 participated in this single flowgate then its local price would be the regional reference price minus its flowgate participation multiplied by the flowgate price.

Local price of Generator 1 = $5,000/MWh - (1 × $50,000/MWh)

Therefore, in this example, Generator 1 faces a local price of -$45,000/MWh which is substantially lower than the current market price floor (-$1,000/MWh).

If the local price were to drop markedly below the market price floor, then any inflexible non-firm generators which receive the local price could be exposed to large liabilities in a short period of time. Such a situation could be potentially concerning as this would place non-firm generators under considerable risk in the face of constraints.

The introduction of optional firm access could reduce the occurrence of generators bidding at the market floor price since it would change incentives relating to generator bidding behaviour. Under optional firm access, a generator would face lower dispatch risks that might otherwise encourage it to place offers near the market price floor. Consequently, generators may make their minimum offer closer to their short run marginal costs. Therefore, local prices could be less likely to diverge markedly from the regional reference price and be less than the market price floor when constraints bind.

However, since it is difficult to determine how frequently the local price would drop below the market floor price following the introduction of optional firm access, there would be a process put in place to remove any large negative local prices that may occur. Such a process would result in reduced firmness for firm generators, because any alterations to local prices faced by a generator would require amendments to the local prices to other generators in the same flowgate so that access settlement would balance. The Commission considers that reduced firmness of the access product is likely to be preferable to exposing generators to large liabilities, as discussed above.

There are multiple methods that could be used so generators do not face large negative local prices. These include:

- applying the current market price floor (-$1,000/MWh) to also be the minimum local price allowed;
- capping flowgate prices so the local price would always be above some predetermined level; or
- setting the local price floor to a different value to the market price floor.

The example in Box A.1 only shows a simple situation where there is a single congested flowgate. If there is minimum price for local prices, it is possible that the price at some nodes may be set by multiple flowgates experiencing congestion in the same trading interval. The cumulative impact of the multiple flowgates lead to local prices below the minimum allowed. The Commission has not determined the response to these situations but notes that it would be possible to:

- iteratively scale each contributing flowgate price, largest impact first, until the local price for all nodes is above the market price floor; or
- simultaneously scale the multiple flowgates to make the local prices for all nodes above the market price floor.

The best process for maintaining local prices above a minimum value would be determined during any implementation process for optional firm access.

A.1.6 Treatment of losses

Within the existing settlement and dispatch system marginal loss factors are used to account for transmission and distribution losses between the generator and the regional reference node. It needs to be decided whether and how these loss factors would apply to access settlement.

A fundamental principle that applied in respect to access settlement is there be “no dispatch regret”: generators would only be dispatched when their local price exceeds their offer. To maintain this principle, the treatment of losses in access settlement must reflect how loss factors are applied in dispatch.

Dispatch in the NEM is currently based on loss-adjusted generator offer prices; the offer price is divided by the relevant marginal loss factor before being entered into the NEM dispatch engine. Under optional firm access, the local prices generated by access settlement would also be loss-adjusted. The loss-adjustment would best be done by determining a generator’s usage of a flowgate on its loss-adjusted output: its metered output multiplied by its marginal loss factor. For example, a generator with an access level of 100MW and a marginal loss factor of 0.95 would be using 95 MW of the flowgate capacity.

Note that if a generator has a distribution loss factor (for example, it is an embedded generator) then this would also be applied in access settlement. However, loss factors would not be applied to the usage of directional interconnectors.

Therefore, under optional firm access when constraints were not binding, the settlement of losses would remain unchanged from the status quo. When constraints were binding, the loss factors would be applied to the local price.

In addition to scaling each generator's usage as described above, a generator's entitlements would be scaled by the loss factor in a similar method. Therefore, a generator who has purchased 100 MW of firm access with a marginal loss factor of 0.95 would have an entitlement of 95 MW of firm access. This would maintain consistency between a generator's access entitlement and usage. Furthermore, scaling entitlements means that, for a fully firm generator, the amount a generator can expect to have dispatched, considering losses, would match the purchased level of firm access regardless of movement in loss factors over time.

Loss factors would not apply to the usage of directional interconnectors.

A.1.7 Generator entitlements

Under optional firm access, a generator's entitlement to purchase firm access should have a cap. This is so that firm access would act as a hedge against congestion risk, and would not be a purely financial right.

The best form of entitlement cap would be the capacity of the generator. An alternative cap for entitlements would be the generator's **availability**. Capacity would be preferable as using availability could create an incentive for generators to constantly make very high dispatch offers, for example, at the market price cap, in order to receive firm access payments. By making very high offers, the generator would appear available but would consider it likely that it would not be dispatched. This could represent a security risk and would be inefficient.

However, one issue with using a capacity based method of setting entitlements is that rated capacity is not currently defined in the Rules. A definition of capacity is essential in order to limit entitlements by capacity. Such a definition could be determined through multiple methods, with one example being that proposed in the First Interim Report for this review, and expanded below:[96]

96 It would be possible for a generator to have its capacity, and thus entitlement, determined to be less than its previously purchased level of firm access. In this situation the generator could choose to: request a reassessment of its capacity; sell some of its long-term access in the short term auction as described in chapter 7.

- For new generators, or generators that have been operating for less than two years, it would be based on nameplate specifications for the associated generating plant, allowing for auxiliary load, as described in section A.2.2.[97]

- For generators that have been operating for more than two years, rated capacity would be based on maximum historical output as measured by the access unit identifier over a two year period.[98]

- Beyond the first two years, capacity would be recalculated annually. If a generator's circumstances were to change within a year (for example, it returns from being mothballed) and it were to consider that its registered capacity should be increased, it would be able to request an ad hoc recalculation of its rated capacity using the above method.

An alternative definition of capacity would be to use the data that are provided under Schedule 3.1 of the rules, relating to the maximum generation of the scheduled generating unit.

An appropriate definition of capacity should be determined at the time of optional firm access implementation.

A.2 Generator requirements for access settlement

Currently, the market operator (AEMO) dispatches generating units and determines revenues in settlement using different metering systems.

However, under optional firm access, it would be necessary to integrate the dispatch and revenue metering systems for access settlement to function. Such a change would also require alterations to how generators' auxiliary load is treated.

This section discusses the metering system under optional firm access and also how auxiliary load would be treated. It also discusses grandfathering of arrangements for existing generators.

A.2.1 Metering and access unit identifiers

Current metering arrangements

The current AEMO dispatch process determines targets for dispatch units, which AEMO refers to by their dispatch unit identifier (DUID). Typically, these are individual physical generating units. However, in some cases they are logical "aggregated units"

97 The use of nameplate information is appropriate for new generating plant as it represents the best estimate of the generating plant's capacity.

98 For plant that has been operating for an extended time, the maximum dispatch over a period would demonstrate with better accuracy what the actual capacity is. A two year window would be a long enough period of time for most intermittent or peaking generators to be able to demonstrate their full capacity.

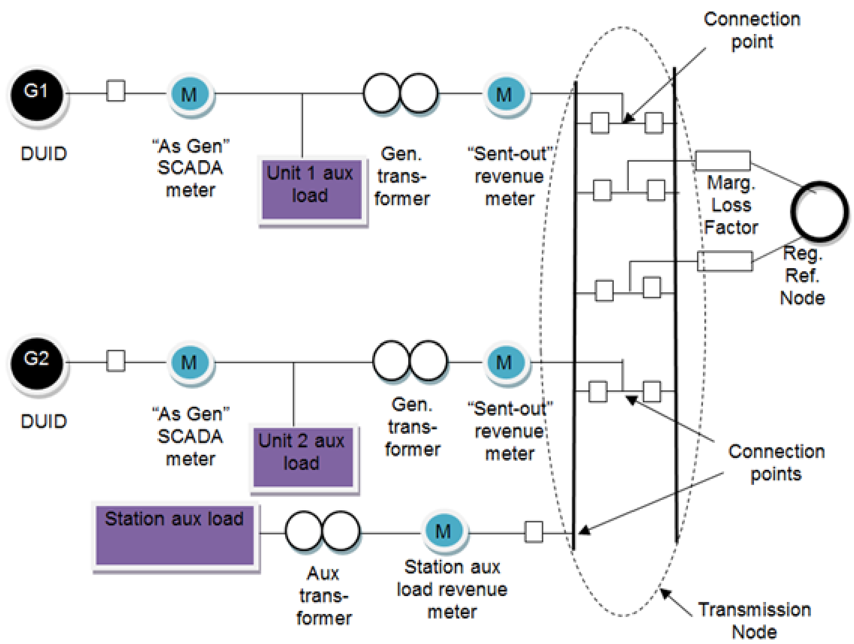
which represent the aggregate output of a number of specified physical units. An example of this would be the situation in many wind farms.

Since dispatchable unit identifiers are dispatched, it is these entities which appear on the left hand side of the constraint equations, with participation factors applied. Consequently it is these terms that would be used in access settlement to determine a generator's compensation from its participation in a flowgate.

Dispatch is predicated on SCADA meters[99] which are attached to the terminals of a physical generating unit. These meters are sufficiently accurate for use in dispatch, but not for settlement. Instead, settlement for generators is based on revenue meters, which are more accurate meters placed somewhere between generating unit terminals and the connection to the shared network. The information from these settlement meters is not received in real time and so cannot be used in dispatch.

Figure A.1 shows a possible metering arrangement of a power station with two generating units. In this example it can be seen that each of the two separate generating units have their own SCADA and revenue meters.

Figure A.1 Metering of a standard power station



Generating units consume electricity while operating, known as auxiliary load. These auxiliary loads are currently connected in a number of different ways. This includes the load being:

- connected between the generating unit and the revenue meter and thus only implicitly metered; and

99 Supervisory Control and Data Acquisition (SCADA) meters provide real time information which can be remotely accessed.

- separately metered and thus deducted out explicitly during settlement. The connection of these auxiliary loads to the transmission network may be electrically remote from their associated generating unit (for example, some mines are considered auxiliary load while being remote from their associated generators).[100]

In Figure A.1 the generator has an explicitly metered load for supplying the station (Station aux load). In addition, there are separate loads (Unit 1 and 2 aux loads) that are implicitly metered from the output of the dispatchable units.

In the dispatch process, auxiliary load is an implied part of the total load calculations that AEMO uses to determine the right hand side of constraint equations.

Load pays the regional reference price regardless of whether the load results in either an offset in generation or a purchase from the wholesale market. This means that there is a modest incentive, from a settlement perspective, to class load as auxiliary to generation (compared to being a separately metered load). There are benefits in having loads netted off before market settlements because of reduced exposure to participant fees and ancillary services charges as well as not being responsible for losses.

Recommended arrangements

Under optional firm access, settlement would be resolved through the concept of an access unit identifier.[101] The access unit identifier would be created by allocating each generating station's auxiliary load across associated dispatchable units. All access settlement would therefore be undertaken on the difference between generation and consumption at each access unit identifier.

In the same way that a generating station can be composed of multiple dispatch unit identifiers, it would be capable of being composed of multiple access unit identifiers. An access unit identifier may measure the output of one or many dispatchable units, net of one or more auxiliary loads.

By virtue of dispatch unit identifiers and auxiliary loads being connected via a single metering point, they all must have the same participation factors in constraints. Thus, the participation factor for a physical access unit identifier can be defined as being the (single) participation factor of its associated dispatch unit identifiers and auxiliary loads. This makes it suitable for use in access settlement, which requires participation factors to be well defined.

Refer back to the example seen in Figure A.1. In this situation, each of the revenue meters would become an access unit identifier with a single associated dispatchable

100 If an auxiliary load and generating unit are located on different parts of the network an increase of the auxiliary load may not have the same impact on flowgate capacity as a decrease of generation by the same amount.

101 In the First Interim Report this concept was referred to as a revenue meter identifier (RMID).

unit. The generating unit loads would be implicitly netted out in dispatch while the station load would be logically mapped between the two access unit identifiers.

A.2.2 Auxiliary load

Depending on the prevailing nature of constraints at a location, there may be stronger incentives under optional firm access for load to be classified as auxiliary load for the purposes of access settlement. This would mean that the load pays the local price rather than the regional reference price. To minimise this occurrence, guidelines would be created for what could be new auxiliary load. The following principle would be used to match a load to the appropriate access unit identifier.

Box A.2 Principle for the treatment of auxiliary load

Load can only be classed as auxiliary load if it is operationally, commercially and temporally associated with, and electrically close to, the dispatch unit identifier(s) associated with an access unit identifier(s).

This principle can be applied to new auxiliary load, whether associated with new or existing generation. The principle is defined below:

- A load is *operationally associated* with a dispatch unit if the load is required for the generating unit to operate. It is also operationally associated if the load and generation are part of the same industrial process so that the generation cannot operate without the load being present. This is the case with many co-generation systems.
- A load is *commercially associated* with a dispatch unit if the same party is financially responsible for both the generating unit and the load. If two or more companies have generators at the same physical site, all load and generating units of the different companies would be required to be separately metered.
- A load is *temporally associated* with a dispatch unit if, under normal circumstances, the load consumes electricity at the same time as the generating unit is operating.
- A load is *electrically close* to a dispatch unit if the load is connected to the same location of the transmission network. This results in the load and generation having the same participation on flowgates.

A.2.3 Grandfathering

The Commission notes that some existing generators have metering and auxiliary load arrangements that would not comply with the principle laid out in section A.2.2. However, changes to the existing metering and network arrangements may be costly. Therefore the Commission recommends that grandfathering arrangements are developed for existing generators.

In situations where an existing auxiliary load is electrically close to an associated dispatch unit identifier even if it is not operationally, commercially or temporally associated with that dispatch unit identifier, it would be authorised as an auxiliary load. In this situation AEMO would be required to develop a mapping of auxiliary loads to access unit identifiers that may operate as an exemption to the above principle. These arrangements would continue for the remaining life of the generator.

However, it would be inappropriate to similarly grandfather existing auxiliary loads that are not electrically close to the associated dispatch unit identifiers. This is since the auxiliary load and the generating unit may have different participant factors in the flowgates. In this situation the load may be required to change its connection point if it wishes to be authorised as an auxiliary load.

These principles and processes would only apply in relation to access settlement. The Commission understands that around five generating stations in the NEM would not be able to continue their current metering arrangements under this proposal.

B TNSP incentives

This appendix provides further detail on the TNSP incentive scheme, as described in chapter 5. In particular it:

- discusses the factors that the AER might consider in setting the incentive scheme's parameters; and
- provides examples of possible impact of the incentive scheme on TNSPs.

B.1 Setting the incentive scheme parameters

The parameters of the incentive scheme (the annual shortfall cost benchmark for the TNSP, and the caps) would be set by the AER. These parameters would determine the strength of the incentive scheme and influence the size of payments to and from firm generators as a result of the scheme. The factors that the AER might consider in setting the incentive scheme's parameters include:

- minimising the ability of the TNSP to "game" the incentive scheme – the TNSP may be able to "tank" historical performance in order to obtain a more favourable annual shortfall cost benchmark in subsequent years;
- providing some certainty to generators around access firmness – if the annual shortfall cost benchmark was able to change rapidly or become volatile this may undermine a generator's confidence in procuring long-term access;
- the financial position of a benchmark-efficient TNSP;
- the impact of the resultant risk on a benchmark-efficient TNSP – ideally this could be incorporated in the cash flow-modelling underpinning the determination of regulated revenues and prices, but alternatively it could be reflected through the return on equity;[102] and
- creating sufficiently strong incentives for the TNSP to deliver firm access as efficiently as possible.

The efficient annual shortfall cost benchmark for each TNSP would not be readily identified. It could be progressively discovered over time by TNSPs operating under an effective incentive scheme. The AER could consider historical performance when setting the incentive scheme parameters.[103]

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102 More generally, elements of the optional firm access model other than the incentive scheme may also impact on the risk of a benchmark-efficient TNSP, which the AER may incorporated in cash flow-modelling for determining regulated revenues or through the return on equity.

103 In other incentive schemes (for example, the STPIS), the AER typically sets a benchmark of performance for a network service provider based on rolling performance. As a result, the benchmark set by the AER converges to the optimal level over time, tracking actual performance

By balancing the reward gained through improvements with the expenditure required to make improvements, over time the TNSP should reveal the most efficient shortfall cost. The AER could set the annual shortfall cost benchmark for the TNSP based on a trailing average of shortfall costs in preceding years. The TNSP would have to beat its historic performance in order to earn rewards, and so its performance is likely to converge towards the efficient level.

How (either formulaically or "from scratch"), and how often, the parameters should be reset by the AER would need to balance:

- the uncertainty that reset parameters may create for firm generators (in terms of firm access settlement outcomes and incentive scheme payments), which they may factor into their long-term access procurement decisions; and
- the need for the incentive scheme not to result in unforeseen incentives, or windfall gains/losses for TNSPs and firm generators.

As a result, the incentive parameters might be reset on an annual basis early after the introduction of optional firm access, before being reset more infrequently or more formulaically once the AER was confident that the scheme was functioning as intended. Furthermore, over time, the AER may consider making the incentive scheme higher powered, as confidence in the scheme was established.

B.2 Examples of possible impact of the incentive scheme on TNSPs

Through the use of a continuous incentive, and nested caps, the incentive scheme aims to filter out – as far as possible – the unmanageable risks (for example, the timing of forced outages) while leaving a TNSP exposed to manageable risks (for example, the timing of planned outages).

Differently structured penalties apply to the different conditions, because the shortfalls during these different conditions have different intrinsic characteristics which interact with the scheme in different ways.

This philosophy and approach is best explained through illustrative examples. Three example conditions are considered in turn below: a planned outage, a forced outage and system normal. The extent to which the annual shortfall cost benchmark is "used up", or exceed, over the course of the year is derived based on the example of nested caps specified as follows:

- no more than $10 million in a year;
- no more than $200,000 in a day (one 50th of the annual cap); and
- no more than $20,000 in a trading interval (one 10th of the daily cap) on any flowgate.

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but with some lag, to allow a network service provider to be rewarded for performance improvements.

B.2.1 Planned outage scheduling incentives and behaviour

The characteristics of, and objectives for, planned outages are understood to be as follows:

- They typically have an extended duration, from one day to several weeks.
- Advance notice of planned outages to market participants is generally possible and desirable.
- They should be scheduled for periods when congestion costs are likely to be low.
- They should be cancelled, where practical, if conditions change adversely from those expected.

Consider a planned outage with the following characteristics:

- It is of six weeks' duration.
- It reduces the flowgate capacity by 1000MW below the target flowgate capacity on a particular flowgate.
- It gives rise to an expected flowgate price of $5/MWh on that flowgate for ten hours (20 trading intervals) per business day.

Under the incentive scheme, the annual shortfall cost benchmark would be "used up" (or exceeded) over the course of the year as follows:

- $2,500 (1000MW x $5/MWh x 0.5) per trading interval: this does not hit the trading interval cap.[104]
- $50,000/day (20 x trading interval penalty), which does not hit the daily cap.
- $250,000/week (5 x daily penalty) and so $1.5m for the six-week duration.

Therefore, a TNSP has a strong incentive to reduce its exposure to penalties by:

- Rescheduling the outage to a period with a lower expected flowgate price.
- Shortening the outage duration: for example, by overnight or weekend working.
- Reducing the flowgate capacity impact: for example, through live line working.
- Giving generators advance notice: possibly encouraging (potentially by paying them) them to align their own outage plans or otherwise to change operating or trading plans to reduce congestion costs.[105]

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104 This is multiplied by 0.5 since a trading interval is half an hour, and MWh has an hourly basis.

105 Note that firm generators are not exposed to congestion costs in this example, but non-firm generators might be.

In summary, the typical characteristic of the planned outage – and the design of the caps – means that a TNSP is likely to have a high exposure to the consequential shortfall costs.

B.2.2 Forced outage incentives and behaviour

Next, a forced outage is considered. It is assumed to occur in a peak period on a major flow path and so create severe congestion. Its assumed characteristics are as follows:

- It reduces the flowgate capacity by 1000MW below the target flowgate capacity on a particular flowgate.
- It creates a flowgate price of $1000/MWh on that flowgate, which remains high until the failed element is restored.

The annual shortfall cost benchmark would be "used up" (or exceeded) over the course of the year as follows:

- The shortfall cost is $500,000 per trading interval: the TNSP penalty is therefore capped at $20,000 per trading interval.
- This continues until the daily cap of $200,000 is hit (after five hours, that is, 10 trading intervals) or the element is restored.
- This repeats the following day, and so on, until the element is restored.
- The annual cap would only be hit if the forced outage continues for 50 days.

The TNSP has an incentive to ensure the element is returned within five hours. If it does not achieve this, the incentive is then to return the element before the next day. And this incentive keeps repeating, day after day, for a maximum of 50 days.

The TNSP also has an incentive to reduce the frequency of forced outages. It is recognised that in the above example, the TNSP is exposed to only a small percentage (four per cent) of the estimated shortfall cost. However, there would be other forced outages during less stressful conditions when the percentage exposure would be higher.

Because any severe congestion caused by a forced outage would cause the trading interval cap to be hit, the incentive scheme penalty is similar to a tariff: $20,000 for each trading interval in which a major forced outage occurs and then $200,000 for each day it continues. This is not dissimilar – in structure – to the existing incentive in the market impact component of STPIS for forced outages.

B.2.3 System normal incentive and behaviour

A third possible example is of a flowgate shortfalls occurring during system normal periods. This may be due to a planning failure: for example due to a TNSP deliberately delaying a planned expansion in order to reduce capital expenditure.[106] Alternatively, it might be because flowgate capacity is below the specified firm access planning standard level.

The assumed characteristics are:

- A relatively low flowgate capacity shortfall of 100MW on a flowgate.
- A modest average flowgate price of $2/MWh on that flowgate.

On these assumptions, the annual shortfall cost benchmark would be "used up" (or exceeded) over the course of the year as follows:

- $100 shortfall cost per trading interval, which does not hit the trading interval cap.
- $4,800 shortfall cost per day, which does not hit the daily cap.
- $1.7m per year, which does not hit the annual cap.

In this case, the TNSP could be fully exposed to the shortfall costs (depending upon what other incentive penalties accumulate during the year) and would have an incentive to undertake the necessary capital expenditure or otherwise ameliorate the situation. Of course, under more severe assumptions, the annual cap would be hit and the degree of incentive reduced.

Because the TNSP is fully exposed to the shortfall cost, firm generators are fully compensated for the shortfall. They should be financially indifferent as to whether the shortfall is ameliorated (at a cost to the TNSP) or not. This outcome only holds true to the extent that the TNSP is fully exposed to the shortfall cost, including that insufficient shortfall costs were accumulated during the year on other flowgates to meet any nested caps.

This also raises the question as to whether anticipated shortfall costs should be included within the RIT-T. This is discussed further in chapter 8.

B.2.4 Summary

The above examples illustrate how the incentives on a TNSP under the incentive scheme may vary depending upon the underlying conditions causing flowgate shortfall costs. For a planned outage, a TNSP would be very sensitive to the expected flowgate price and would either seek outage periods where the flowgate price is likely to be low or aim to minimise duration and flowgate capacity impact. For a forced outage, a TNSP instead aims to reduce average forced outage frequency and duration, and it can perhaps respond to severe outages in order to reduce the duration of that particular outage. For a system normal shortfall, a TNSP may be incentivised to undertake capital expenditure.

106 In such instances, the AER could also take enforcement action for breaching the planning standard.

The assumptions presented above are illustrative only. In practice, typical outage characteristics may vary substantially from those presented. The parameters of the real scheme would be tuned to actual outage characteristics, based on quantitative and historical analysis.

It should also be noted that the examples above involve only a single congested flowgate. In practice, multiple flowgates would bind over a period. The trading interval cap would apply to each individual flowgate, but the other caps would apply in aggregate across all flowgates.

With the assistance of AEMO, the Commission has calculated what payments would have been for TNSPs if the incentive regime had been in place historically. This analysis is discussed in appendix F of volume 1 of this report.

C Pricing

This appendix discusses a variety of access pricing related topics:

- the value of spare capacity, and how each of the pricing methodologies (LRIC, LRMC and DCC) takes this into account (section C.1);
- how the stylised model would be updated to take account of changes to actual and projected access (section C.2);
- how the stylised model would take account of projected line flow growth (section C.3);
- the process by which the Commission created a prototype pricing model (section C.4)
- changes made to the prototype pricing model since October 2014 (section C.5);
- results (section C.6) and sensitivity testing (section C.7) on the prototype pricing model; and
- a case study of the prototype pricing model for access prices Queensland (section C.8).

C.1 Value of spare capacity

One important property of the long run incremental costing method is that it would appropriately value spare transmission capacity. It would allow generators to pay for the capacity they use, whether that capacity was to be developed especially for the generator (where its access triggers an immediate expansion) or was provided by an earlier lumpy expansion.

Any new access would change the amount of spare network capacity. If the new access were to prompt immediate lumpy expansion, the amount of spare capacity would be likely to increase, as the lumpy addition would typically exceed the new access requirement. Alternatively, if no immediate expansion was required, the amount of spare capacity would decrease, as some of it would now be used to provide access.

Although spare capacity would be, by definition, unused at the time of the access request, it would be likely to have some value due to the possibility of it being used to provide some future access. Because of discounting, this (net present) value depends upon how quickly that future use occurs which, in turn, depends upon the amount of spare capacity at the time of the access request and the anticipated rate of flow growth. If spare capacity is high and/or flow growth low, future use would be distant and so net present value low.

The long run incremental cost method would charge the access-seeking generator the value associated with any reduction in spare capacity: when there is no immediate expansion, the access charge would reflect the opportunity cost (in present value terms) of using the spare capacity to provide access to that generator rather than to a future access seeker. It would credit the generator with the value of any increase in spare capacity in the form of a discount to the access price: when there is an immediate expansion, the access charge would reflect the cost of the expansion minus the (present) value of the additional spare capacity providing future access.

As a special case, the long run incremental cost would give a zero charge where existing spare capacity is sufficient to meet the access request, and that capacity is estimated to have zero value - because it would not be expected to be used for future access.

Figure C.1 illustrates how the incremental access price (incremental cost divided by the incremental usage) would theoretically vary with projected growth for a single network element. The LRIC local curve represents the access price on a local network element, where projected growth is lower. The LRIC core curve represents the access price on a core network element, where projected growth is higher.

On the left hand side of the figure, spare capacity is plentiful: incremental usage is less than initial spare capacity. No immediate expansion would be triggered, and the price reflects the value of existing spare capacity. On the right hand side of the figure, spare capacity is insufficient: incremental usage is greater than initial spare capacity. An expansion "lump" would be triggered, and the price would reflect the value of the new spare capacity that is created.

For comparison, two other charges are illustrated:

- A deep connection charge, where the access price is either zero (incremental usage is less than initial spare capacity) or the full expansion cost (incremental usage exceeds initial spare capacity), which decreases on a per unit basis as incremental usage increases.

- A long run marginal cost (LRMC), which ignores spare capacity and charges a constant unit cost regardless of incremental usage, based on the average unit cost of capacity expansion.

Figure C.1 Theoretical comparison of LRIC, LRMC and DCC for a single element with different growth projections

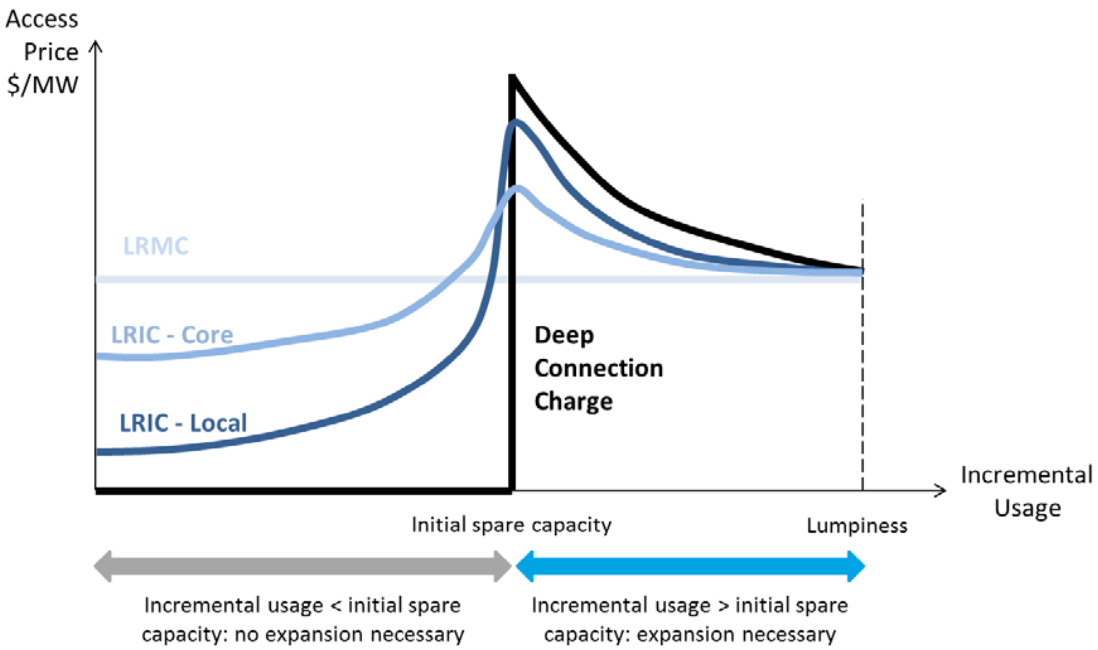
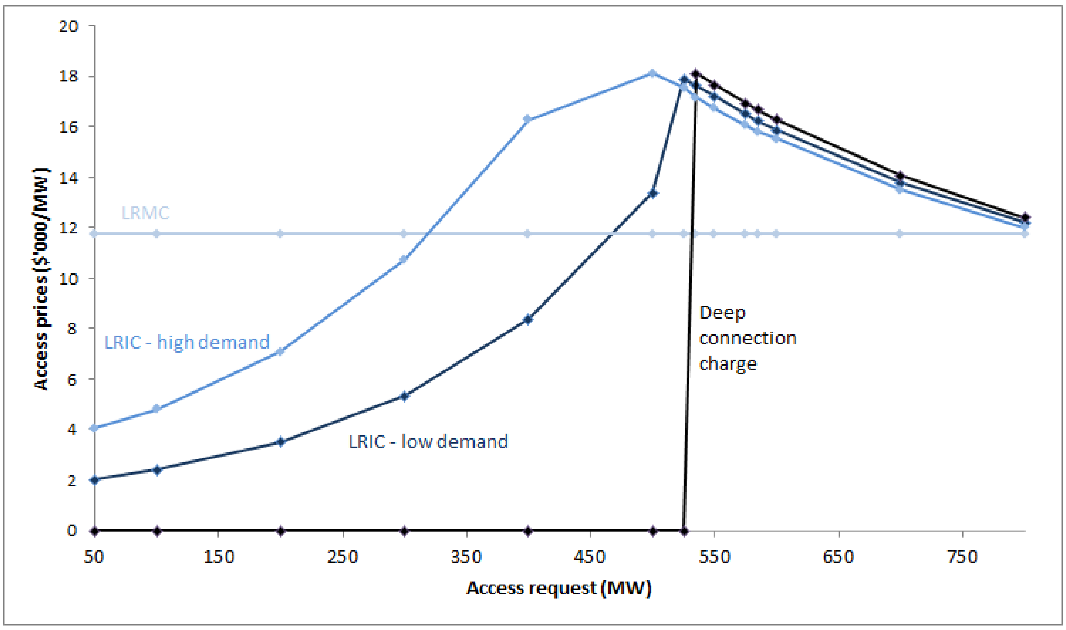


Figure C.2 illustrates actual results from the prototype pricing model for a single network element. It illustrates the LRIC/MW with low projected demand growth, the LRIC/MW with high projected demand growth, the LRMC/MW and the DCC/MW for an access request in Victoria.[107]

Figure C.2 Comparison of LRIC, LRMC and DCC for a single element with different growth projections as observed from prototype pricing model



107 Element 3DED220_3DED330 (the 220kV to 330kV transformer at Dederang in Northern Victoria) for an 86 year access request from Dederang (3DED330).

Figure C.1 is a simplified representation of the relationship of LRIC, LRMC and DCC, presented for illustrative purposes, with the following assumptions:

- the access term is infinite; and
- there is linear demand growth.

Figure C.2 (which has similar assumptions to Figure C.1) demonstrates a near perfect resemblance of the theoretically expected results as given in Figure C.1.

It can be seen from Figure C.1 and Figure C.2 that:

- Where spare capacity is plentiful (incremental usage is less than initial spare capacity), a higher projected growth assumption would increase access prices. On the left hand side of the figures, the LRIC core curve (representing higher projected growth) is higher than the LRIC local curve (representing lower projected growth). There would be a greater opportunity cost in using spare capacity when future use is near because flow growth is high.
- As spare capacity becomes scarce (incremental usage approaches initial spare capacity), the access prices delivered by the long run incremental costing method increase. Where incremental usage triggers an expansion (incremental usage exceeds initial spare capacity), a higher projected growth assumption would decrease access prices. On the right hand side of the figures, the LRIC core curve (high demand curve) is lower than the LRIC local curve (low demand curve). There is greater value in the spare capacity that is created when future use is near, and so a greater discount to the current access seeker.
- In the special case that there is zero projected growth on an element, then the long run incremental costing access price would be the same as the deep connection charge curve. This is observed in results from the prototype pricing model.
- In the special case that there is very high projected growth on an element, then the long run incremental costing access price would approach the LRMC curve. This effect is also observed in results from the prototype pricing model (for example, setting the long term line growth rate very high).
- In the special case that incremental usage equals the expansion size then all three pricing methods deliver the same charge. In this case, the amount of spare capacity is unchanged and so the value of the change in spare capacity is zero. Therefore the access charge would simply reflect the expansion cost. Again, this is observed in results from the prototype pricing model.

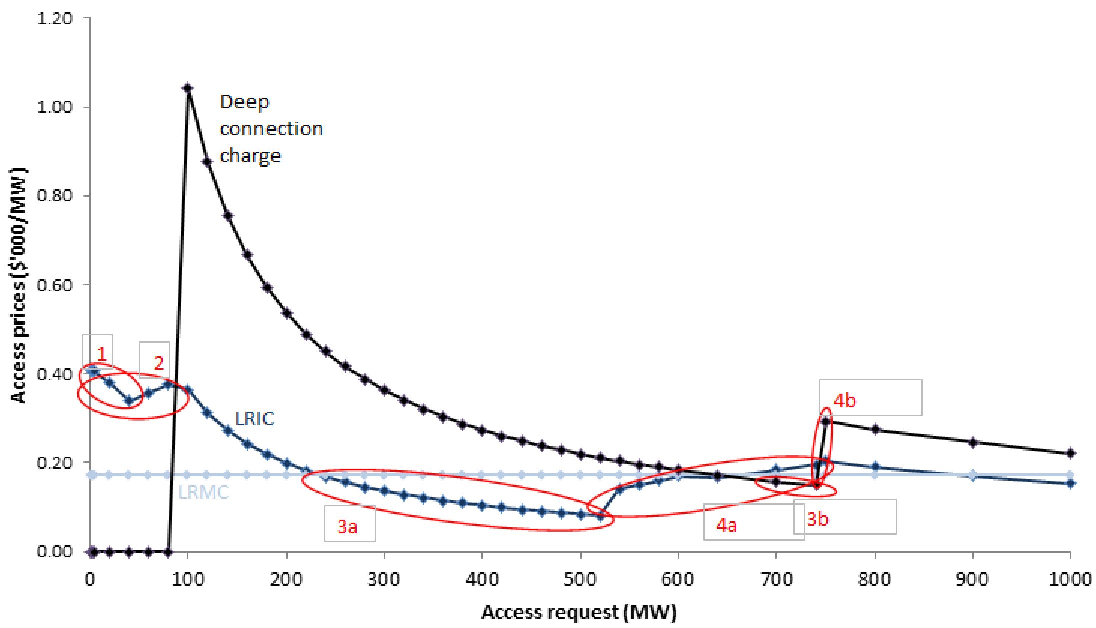
In conclusion, except in the special cases listed above, only the long run incremental costing method would appropriately value spare capacity. The alternative pricing methods would deliver efficient prices (ones that appropriately value spare capacity) only in the special cases that there is no expectation of growth (deep connection charge) or an expectation of very high growth (LRMC). In other words, any access price implicitly contains a projection of growth – and would give inefficient signals when that projection differs significantly from actual growth. Better price signals would be achieved by explicitly taking a view of the future and using the best information available – projections that recognise that growth varies over different parts of the network and over time.

In some cases the results derived from the prototype pricing model are not as expected from examining Figure C.1. In each case where results diverge from Figure C.1, these can be explained because Figure C.1 is a simplification of the actual relationship between LRIC, LRMC and DCC, as discussed in the following case study. Importantly, the conclusions given above regarding the value of spare capacity and the relationship of LRIC, LRMC and DCC remain valid.

C.1.1 Case study: refinements to the theoretical relationship of LRIC, LRMC and DCC

The Commission has observed four results that do not conform to Figure C.1. Each is explained below, with reference to Figure C.3.

Figure C.3 Pricing results that do not conform to the theoretically expected relationships[108]



1. **The LRIC/MW is not monotonically upwards sloping for access requests smaller than the initial spare capacity (that is, to the left of the point where DCC/MW goes vertical).** Although LRIC/MW will tend to increase as the access request becomes larger, there is no fundamental reason why this should be the case for each marginal increase in MW. For the LRIC/MW to increase as the access request increases, the percentage change in LRIC must exceed the

108 Element 3DED330_3SOU330 (the 230kV line from Dederang to South Morang) for an 20 year access request from Dederang (3DED330).

percentage change in MW. Particularly in the case of for low access requests this may not be the case: for example, a doubling of the access request from 1MW to 2MW may not more than double the LRIC.

2. **LRIC/MW is greater than LRMC/MW for access amounts smaller than the initial spare capacity.** In Figure C.1, to the immediate left of where DCC/MW goes vertical, LRIC/MW is greater than LRMC/MW. In Figure C.3, there is so little spare capacity that even a small access request means the LRIC/MW is greater than the LRMC/MW. The immediate left of where DCC/MW goes vertical in Figure C.1 is the same area as the entire left-hand-side of Figure C.3.

3. **The LRIC/MW and DCC/MW decline below the LRMC/MW, despite the access request exceeding the initial spare capacity.** Figure C.1 implies that LRIC/MW and DCC/MW tend to LRMC/MW for large access requests. As discussed above, when the incremental usage on a line is equal to the size of the expansion on the line, then LRIC, LRMC and DCC are equal to one another. Necessarily, this requires the DCC/MW and LRIC/MW lines to be less than the LRMC/MW line at some points (at 3a and 3b in Figure C.3). Note how the three lines intersect at an access request of approximately 640MW, when the incremental usage on the line is equal to the size of the expansion on the line. This is not observed in the case of Figure C.2 because the x-axis of the graph is cut off, and, in the case of Figure C.1, because it was drawn to only represent one expansion to the element.

4. **The LRIC/MW and DCC/MW increase as the size of the access request increases, despite the access request exceeding the initial spare capacity.** Figure C.1 is scaled such that the effect of only one expansion on the element is illustrated. At 4b in Figure C.3, the access request is sufficiently large to prompt a second expansion on the line in year 1. At 4a in Figure C.3, the second expansion is progressively being brought forward as the access request increases, at a higher cost in NPV terms. In effect, the shape of the graph in figure Figure C.1 repeats itself, but with increasingly shallow peaks, as multiple expansions are prompted by increasingly large access requests.

In light of these observations, the overarching conclusions regarding the value of spare capacity and the relationship of LRIC, LRMC and DCC remain valid. In particular, Figure C.2, based on actual results from the pricing model, demonstrates that as forecasts of demand growth increase, the shape of the LRIC/MW curve changes from one that resembles the DCC/MW curve to a flatter line, more akin to the LRMC/MW line.

C.2 Updating the LRIC stylised model

The LRIC pricing method would approximate the *additional* cost imposed on the TNSP as a result of that specific access request. A stylised model would be created, which would produce the LRIC prices.

An individual access request could impact on the additional cost of another access request – as access requests can use up spare capacity or prompt expansions or renewals. Access requests would need to be included in the baseline modelled network development, so that the incremental cost of subsequent access requests could be calculated.

Access requests would be included in the baseline as follows:

- All completed access requests would immediately be included in the baseline and so be present for the pricing of all subsequent requests.
- All transitional access would be projected to be renewed for a specified term, but all other firm access would be projected not to be renewed (see chapter 9 for a more detailed description).
- No anticipated firm access would be included in the baseline.[109]
- Modelled firm access would be included in the baseline.[110]
- No sell-back would be assumed in the baseline.

The rationale for these assumptions is discussed in further detail in the technical report.

C.3 Projection of flow growth

The stylised model would need to include accurate, objective and transparent modelled entry for new generation, and so flow growth on the network. Below sets out where the data for this would come from. The inputs into the pricing model would be consistent with assumptions made in TNSPs' regulatory determinations.

- Short-term firm generation projections would be based on current firm access arrangements and requests.
- Medium-term projections of flow growth would be based on projections of end-user demand and firm generation. These projections would be based on the National Transmission Network Development Plan (NTNDP), which is the product of an open and transparent process, or other similar information developed and published by AEMO.
- To simplify the access pricing model, projected flows would be stylised rather than precise beyond a certain point (say 10 years out). The pricing model would need to cover many years into the future, given the long-lived nature of

109 *Anticipated* firm access would relate to specific projected firm access requests, at a particular node for a particular amount, which has yet to be completed. For instance, if a generator has announced its intention to build a power station at a particular location, any firm access request that has not been completed at that location in relation to that power station would be *anticipated* firm access.

110 *Modelled* firm access is projected future firm access (as a result of generators seeking firm access) that is expected to be added across the network, rather than at a particular node. For instance, if it is expected that there will be 1000MW of additional firm access over the next ten years within a region, 100MW of additional access might be modelled annually across the nodes in that region.

transmission assets and the relatively low discount rate applicable to network businesses. On the other hand, projected flows become increasingly uncertain into the future, and discounting diminishes the influence of longer-term projections. Therefore, there is a point where including detailed projections does not substantially improve accuracy of the modelling.

C.4 Developing the prototype pricing model

As mentioned in chapter 6, the Commission has developed a prototype pricing model to assist stakeholders in understanding how the LRIC method would be used and applied.

The Commission engaged a software consultant to develop the prototype.

The prototype comprises three main elements:

- a model of the NEM transmission network[111];
- other input data (such as demand growth); and
- the program itself, which calculates the LRIC prices.

The prototype allows the user to select a location that it wants access from, a length of time that it wants access for, and an amount of access that it wants. The model then uses this information, and the input data, in order to calculate an LRIC price for these characteristics. The network model and input data can be varied by the user.[112]

Data for the model was provided by AEMO and the TNSPs, who both also reviewed the model prior to its release in October 2014, and provided feedback. The Commission would like to acknowledge the considerable effort made by AEMO and the TNSPs in assisting the AEMC in this regard.

C.5 Changes to the prototype pricing model

Since the October 2014 version of the model, the Commission made a number of amendments for the model's March 2015 release:

- Cost and lumpiness assumptions have been changed based on advice from EMCa.[113] This included the addition of a fixed component to each asset expansion, in addition to the variable component (per km per MW, or per MW, for lines and transformers, respectively).

111 The prototype pricing model is not currently producing representative prices for Tasmania, for the reasons discussed in section 3.4.4 of the Supplementary Report on Pricing (AEMC, October 2014). The results presented in this appendix do not include results from Tasmania.

112 Further information on how to do this is contained in the user guide that accompanies the model. Details on how to access the model are set out in chapter 1.

113 Provide cost and lumpiness assumptions to the optional firm access prototype model, EMCa, January 2015.

- Further automation of the pricing model, so that the results of variations in all the generator-dependent variables (location, access amount and access duration), and a number of independent variables (for example, weighted average cost of capital, demand projections) can be obtained in one model run. The prototype pricing model user guide discusses this in more detail.

- The option of running the model using four pairs of "bi-regions" (combined adjacent regions in the NEM), for the purpose of inter-regional access pricing. This includes inputting into the model assumptions regarding the level of firm inter-connector rights held. The prototype pricing model user guide discusses this in more detail.

- Various minor adjustments to the input assumptions files. The complete list of input assumptions are discussed in appendix D.

No further changes have been made to the prototype pricing model since March 2015. Stakeholders can download the March 2015 version of the prototype from the AEMC website.

C.6 Results from the prototype pricing model

C.6.1 Parameters used throughout this section

In calculating the access prices presented in the rest of this section, the following parameters were used:[114]

- a 400 MW firm access request; and

- a firm access request of 20 years (2014-2033).

These inputs are pre-loaded into the version of the prototype pricing model that is available for stakeholders. However, all inputs can be changed by users when using the model.

C.6.2 Indicative access prices by location

Locational LRIC prices

Figure C.4 to Figure C.7 set out prices by location when the pricing model is run using the above inputs.[115]

The expected characteristics of the LRIC pricing method include that, all other things being equal:

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114 Where a parameter is varied in order to establish the relationship between that parameter and price, all other parameters were fixed at the above values.

115 The maps below plot all generator nodes in the network, but only high-voltage lines.

- generators locating remotely from the regional reference node and from other major demand centres (for such as Far North Queensland, and on the Eyre Peninsula) would pay a higher price than generators locating closer to the regional reference node or demand centre (such as at Sydney and Melbourne), due to the higher cost of longer transmission lines to provide access; and
- generators locating where there is limited spare transmission capacity (such as around the Snowy Mountains) and where expansion would be required immediately would pay a higher price than generators locating where there is plenty of spare transmission capacity (such as on the Central Coast of NSW) and where no expansion would otherwise be needed for some time.

However, since both of these characteristics (distance from regional reference node, and level of spare capacity) affect the level of the LRIC it can be difficult to discern through these maps which characteristic most significantly influences the LRIC at a particular location.

Figure C.4 Map of indicative LRIC for Queensland

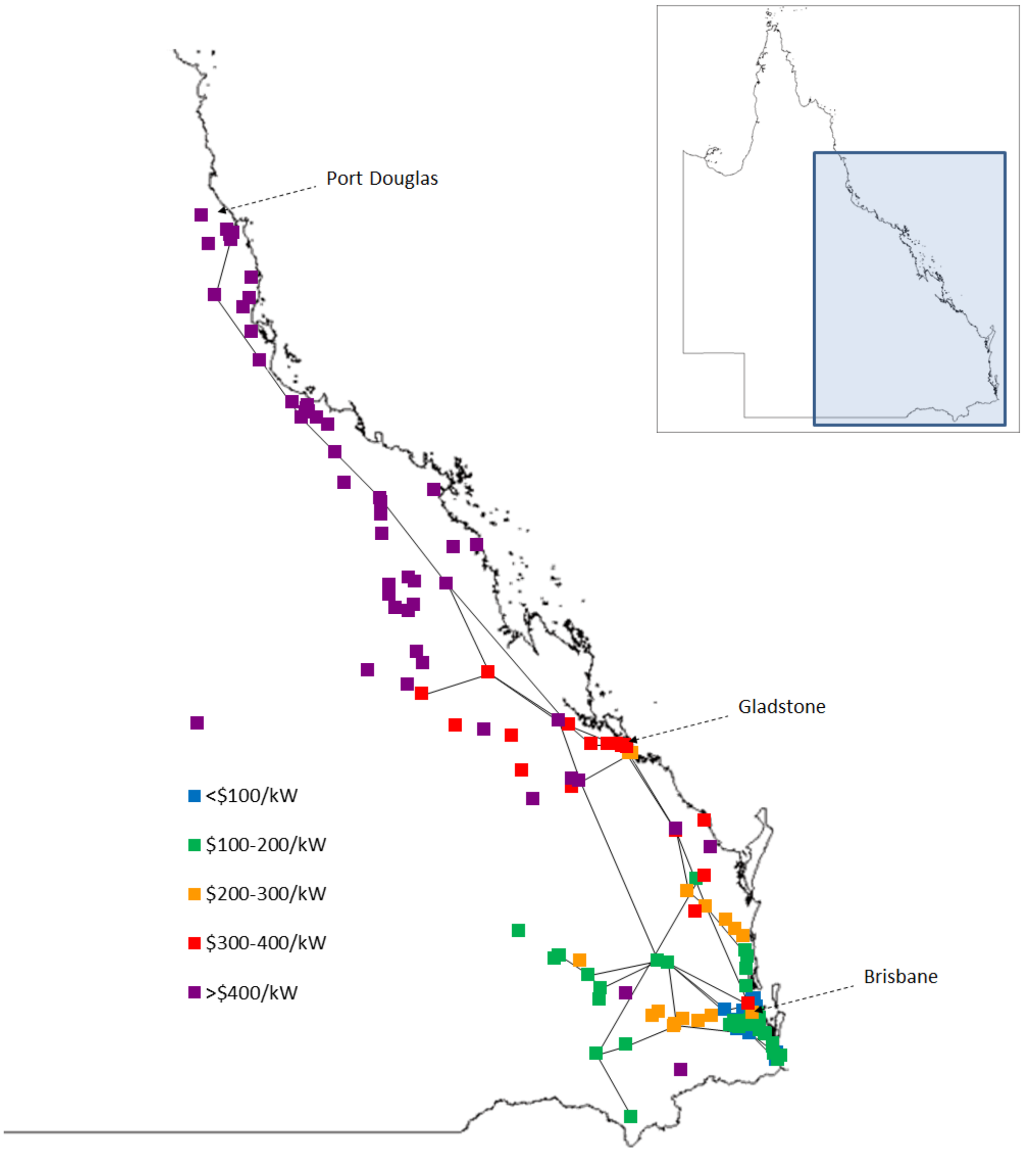


Figure C.5 Map of indicative LRIC for New South Wales

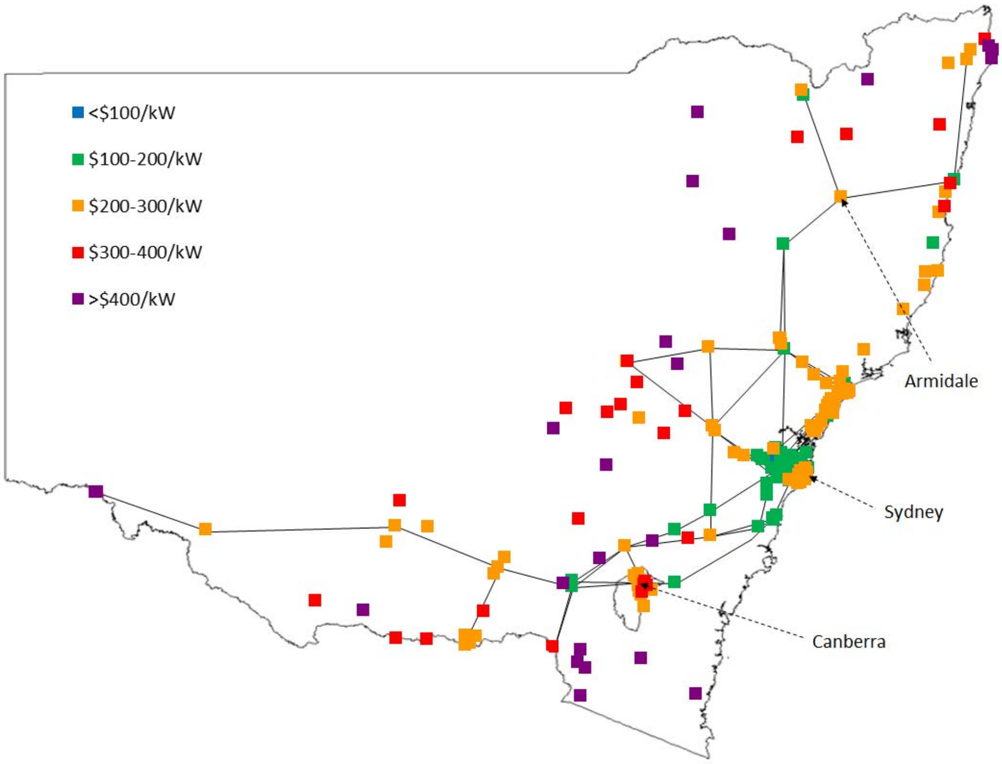


Figure C.6 Map of indicative LRIC for Victoria

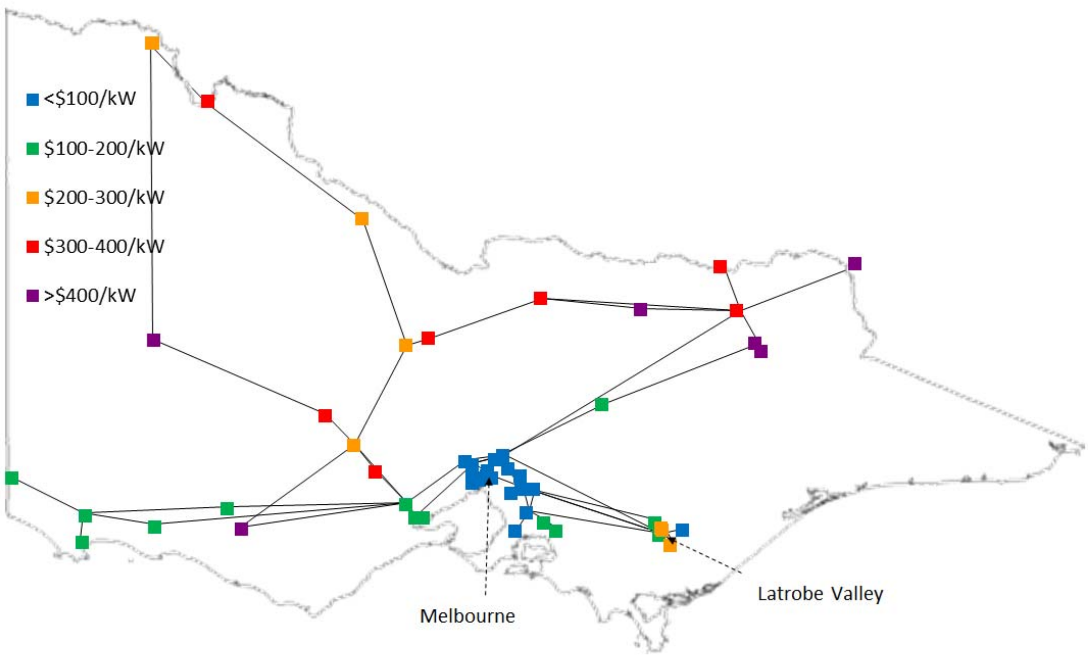
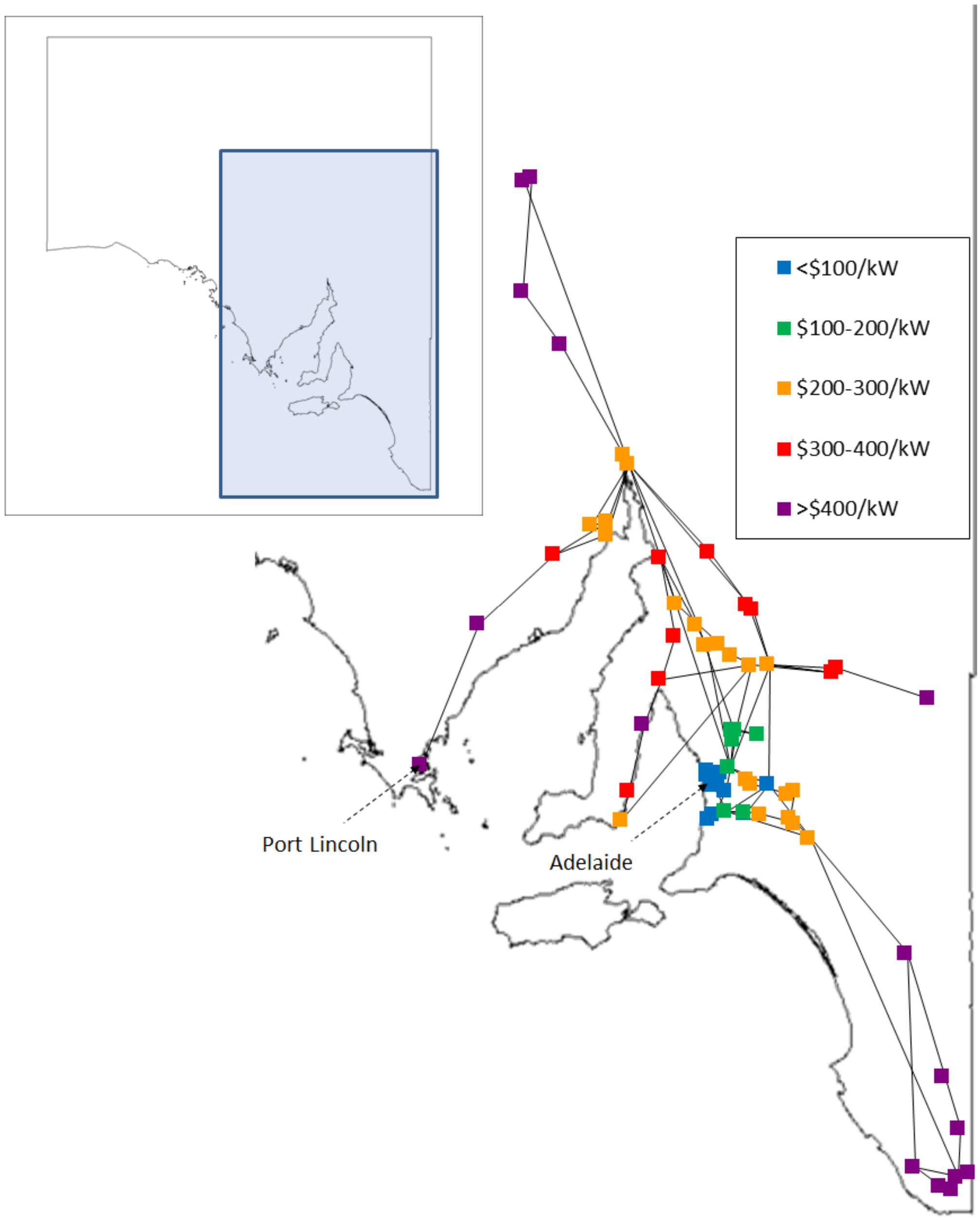


Figure C.7 Map of indicative LRIC for South Australia



LRIC/LRMC value

One way to more clearly understand these results is by considering the relationship between the LRIC and the LRMC.

The LRIC method charges the opportunity cost associated with using spare capacity. When spare capacity is plentiful, this opportunity cost is low, and so nodes with plenty of spare capacity are charged less than nodes with little spare capacity (all else equal). This contrasts with the LRMC pricing method. The LRMC method does not take account of spare capacity on the network: LRMC charges a constant unit cost regardless of incremental usage, based on the average unit cost of capacity expansion. Therefore, under the LRMC method, those generators at locations remote from the regional reference node would pay higher prices than those generators locating closer, regardless of the level of spare capacity.

As a result, the LRIC is relatively low compared to the LRMC when there is plenty of spare capacity, and relatively high compared to the LRMC when there is scarce capacity.

Figure C.8 to Figure C.11 present maps of different locations around the network, showing the ratio between the LRIC and LRMC. This ratio represents an approximate measure of the spare capacity of the network (after transitional access levels have been met),[116] and so is useful in that it disaggregates spare capacity from distance, in order to see what influences LRIC price more. For example:

- In Northern Queensland, the LRMC is substantially higher than the LRIC (that is, LRIC/LRMC is relatively low compared to other nodes in Queensland), implying that there is plenty of spare capacity on the network here. The high LRIC in northern Queensland is therefore primarily caused by its distance from the regional reference node, as opposed to scarce capacity.

- Around the Southern NSW Snowy region, the LRMC is not substantially higher than the LRIC (that is, the LRIC/LRMC is relatively high compared to other nodes in NSW), implying that there is little spare capacity on the network here. The high LRIC around the Southern NSW Snowy region is therefore primarily caused by scarce capacity.

Overall, the model is likely to be producing LRIC values that are consistent with the degree of spare capacity.

116 Since transitional access values have been used as an input into the prototype pricing model, this "spare capacity" is the residual after the transitional access inputted into the prototype pricing model has been serviced.

Figure C.8 Ratio of indicative LRIC:LRMC for Queensland

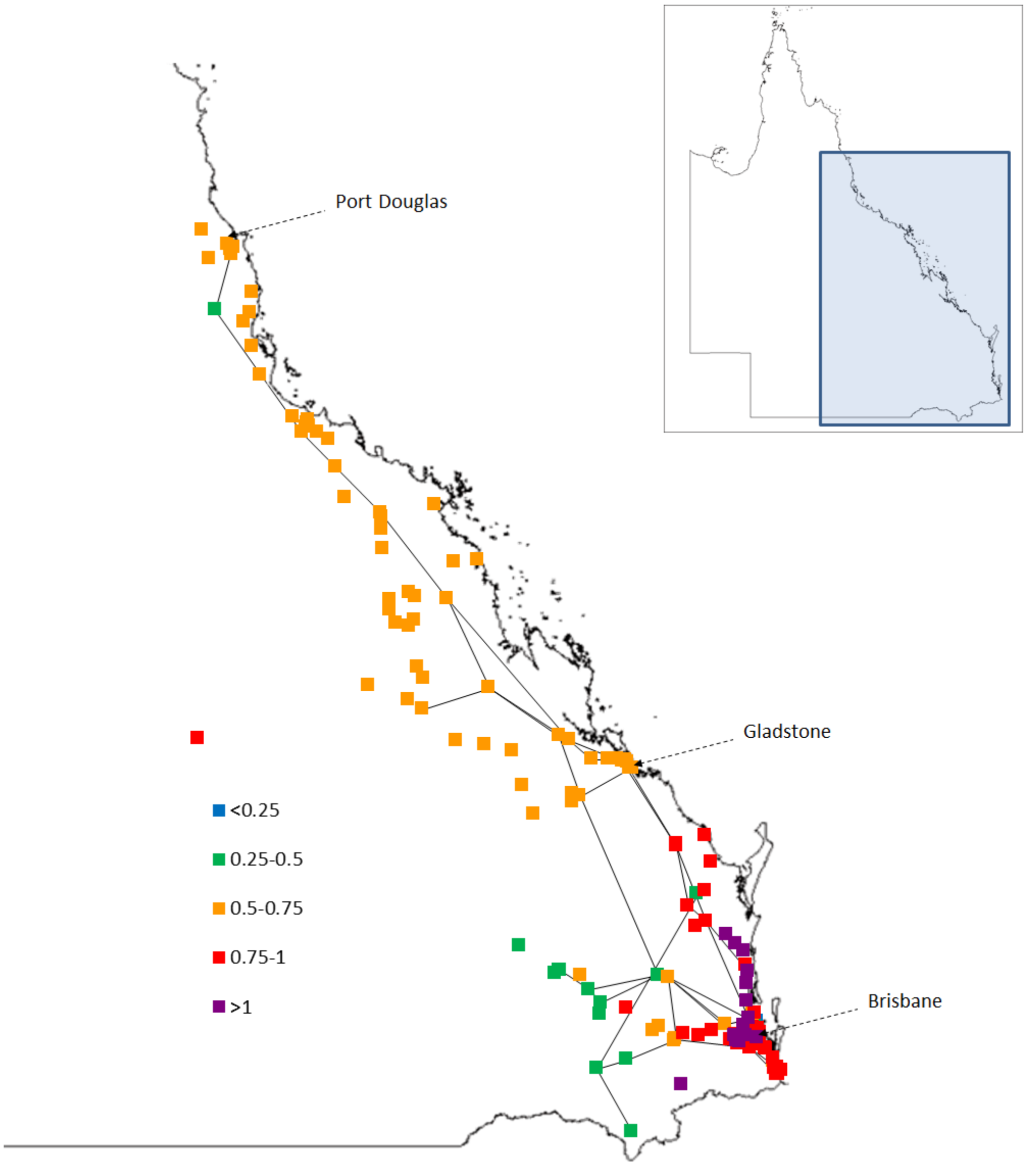


Figure C.9 Ratio of indicative LRIC:LRMC for New South Wales

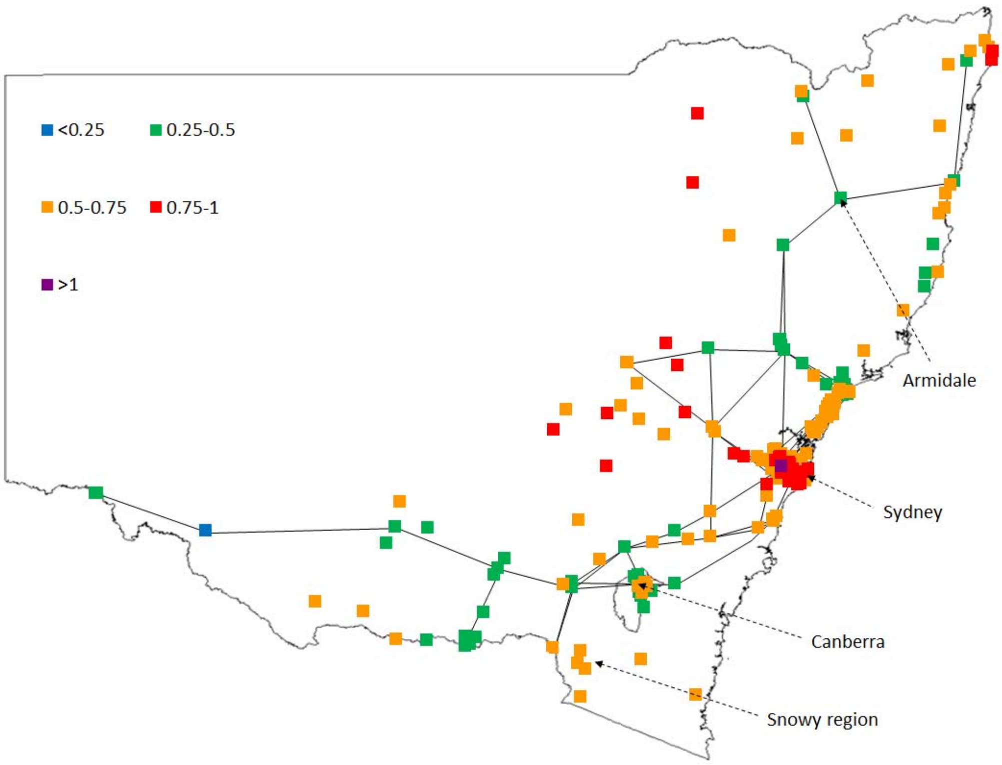


Figure C.10 Ratio of indicative LRIC:LRMC for Victoria

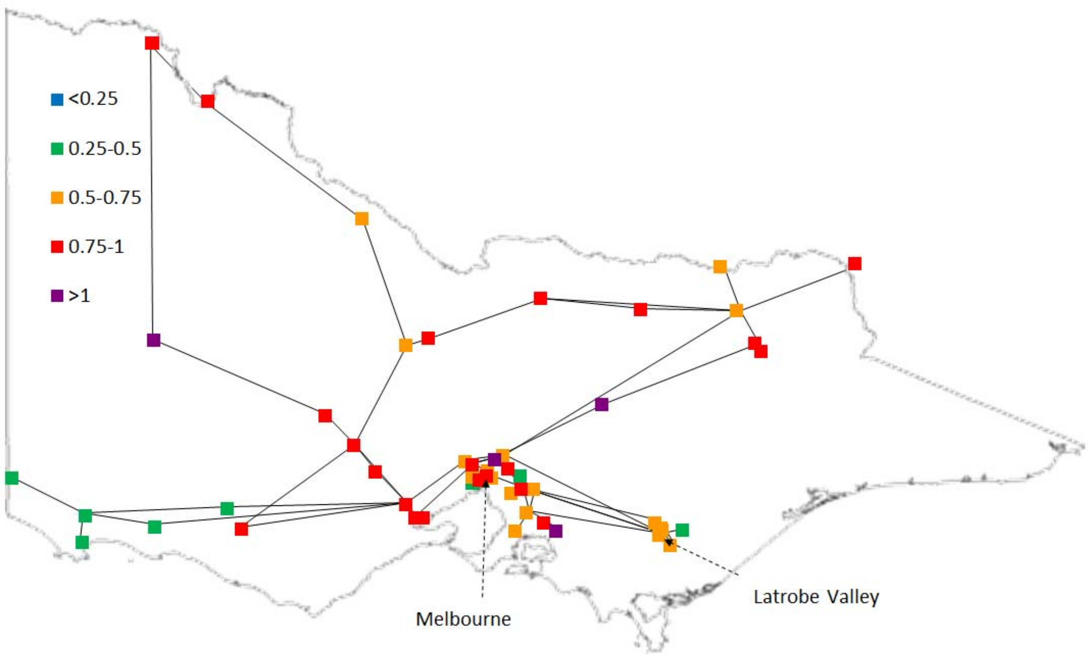
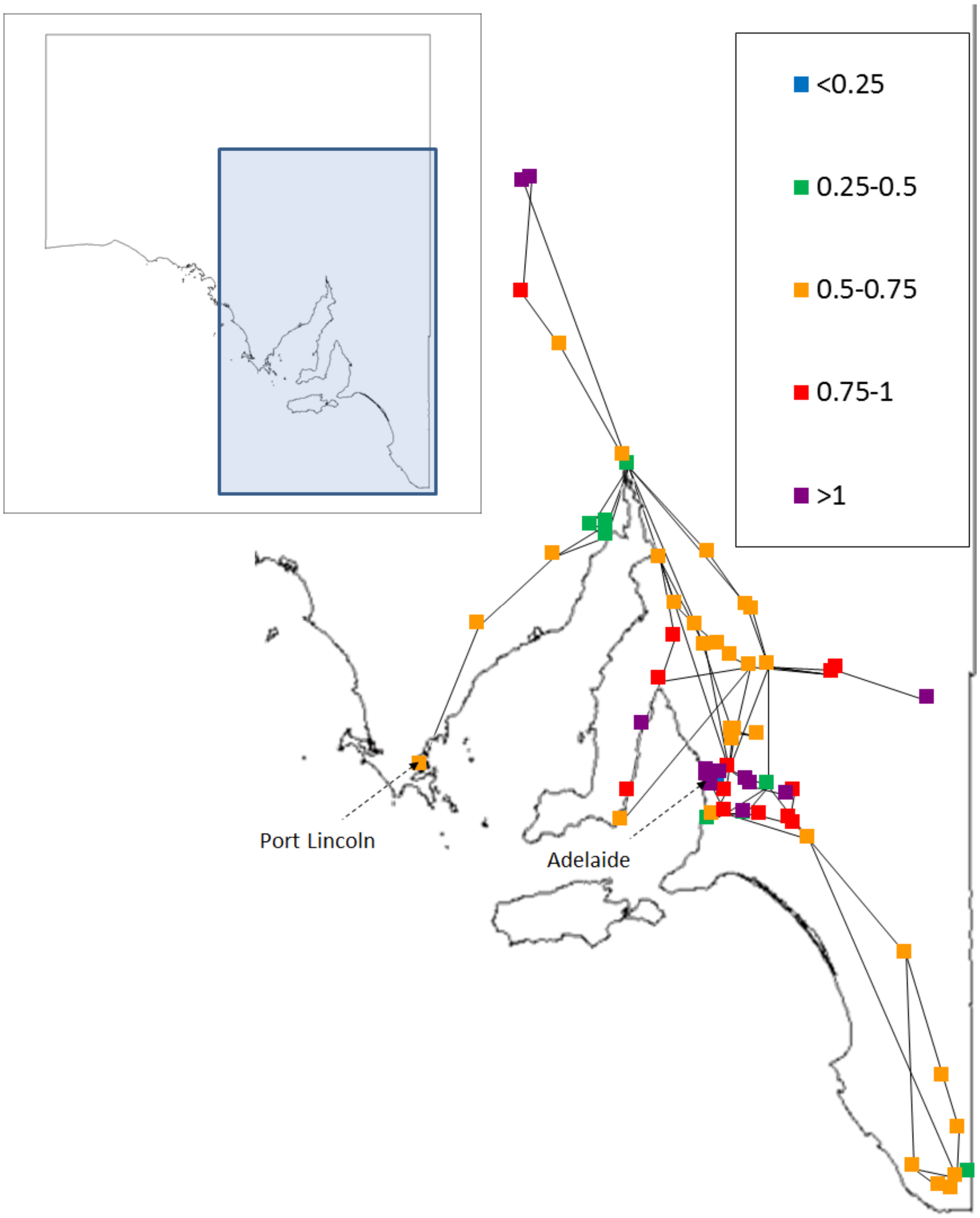


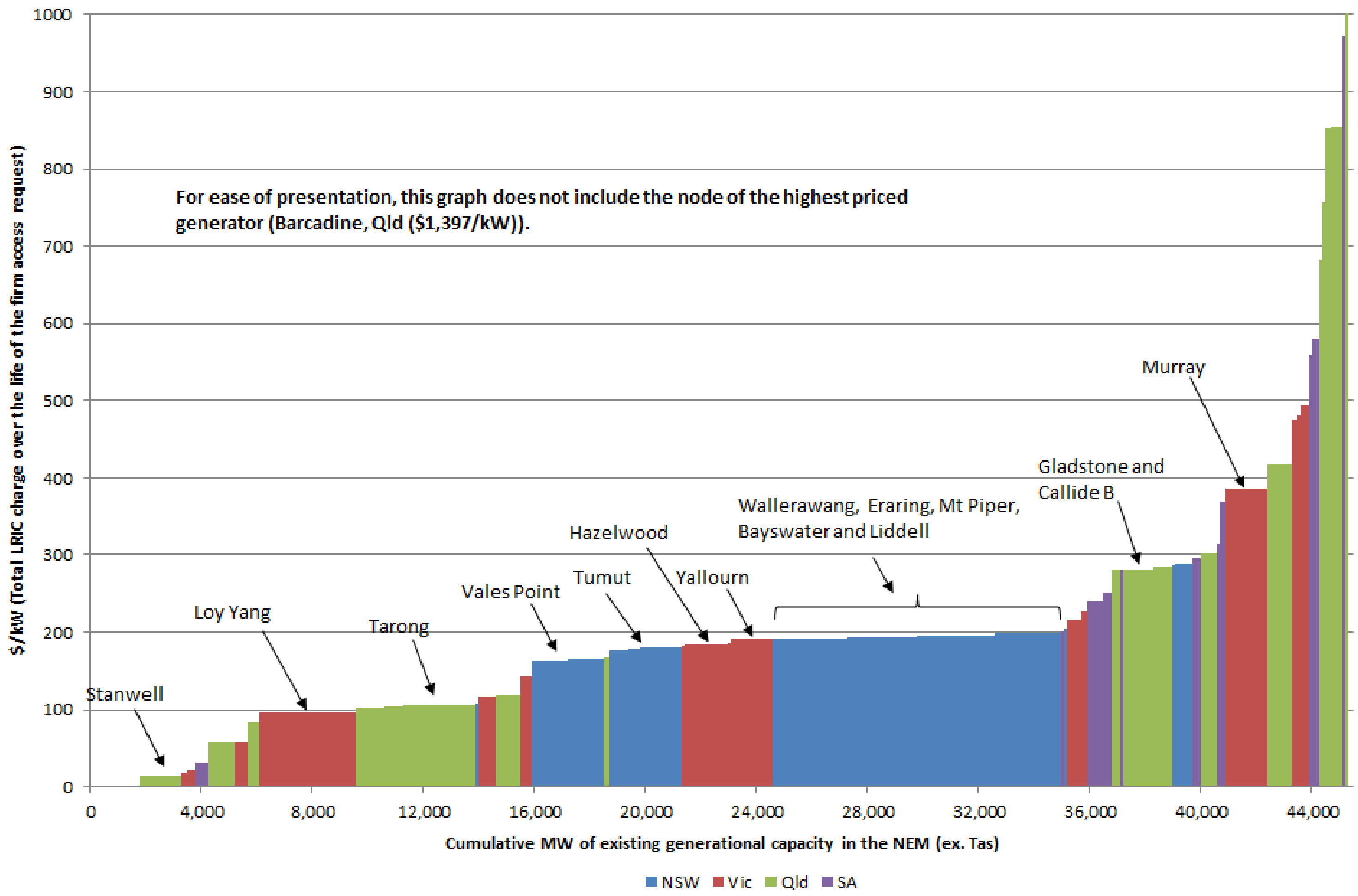
Figure C.11 Ratio of indicative LRIC:LRMC for South Australia



Distribution of access prices

The above maps also demonstrate a large variety in price across locations. This is further illustrated by Figure C.12, which sets out the indicative price of firm access at each node in the NEM where there is currently a generator (excluding Tasmania). The horizontal axis represents the amount of cumulative generation capacity in the NEM (excluding Tasmania).

Figure C.12 **Distribution of access prices in the NEM for a 400MW access request for 20 years, by cumulative generator capacity and region (excluding Tasmania)**



The figure demonstrates the large variety in access prices across locations, from $0/kW (for generators connected at a regional reference node) to $1,397/kW over the life of the firm access request for Barcaldine in Central Queensland (very remote from the regional reference node).

Locations comprising half of the generation capacity (22,500MW) have an indicative firm access price of less than $182/kW. Approximately eighty per cent of the current capacity is at locations that have indicative LRIC prices of less than $200/kW.

An indicative cost of a new wind generator is approximately $2,500/kW (with an expected life of 20 years).[117] Therefore, for a median access price of $182/kW, access is expected to cost around seven per cent of the capital cost of a wind farm.[118]

In summary, the prototype is producing LRIC prices that are reflective of LRIC's intended characteristics with respect to location. It produces locational signals reflecting both distance and spare capacity on the network, and so the cost of providing firm access. By exposing generators to the long-term transmission costs associated with their locational decision, it would help to co-optimise generation and transmission investment, by promoting the efficient utilisation of the existing spare capacity on the network.[119]

C.6.3 Indicative access prices by access amount

Given the above analysis which demonstrates the wide variability in price across locations, analysis of *average* prices is of limited value. Indeed, a key intended feature of the LRIC methodology is that it creates locational signals for generators, which averages do not take into account.

As a result, the Commission has not undertaken analysis on average prices. Instead, analysis is presented for five locations in Victoria. Victoria was chosen since the trends observed are consistent with those observed in the other regions. The specific locations are chosen because they appear to be likely places in the network where future generators may locate (for example, Terang in Central Victoria since it is a good location for wind).

117 See: AEMO's planning assumptions available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.

118 If the windfarm chooses to be fully firm, which may be unlikely. Further, analysis of average prices is of limited value.

119 A deep connection charging method also provides signals that reflect both distance and spare capacity on the network. However, a deep connection charging method does not reflect the *value* of spare capacity.

Table C.1 Nodes selected for analysis

Node reference	Name	Region	Zone (as specified in the NTNDP)
3TER220	Terang	Victoria	Central Victoria
3MRT500	Mortlake	Victoria	Melbourne
3MUR330	Murray	Victoria	Northern Victoria
3BAL220	Ballarat	Victoria	Central Victoria
3LYB500	Loy Yang	Victoria	Latrobe Valley

Indicative prices are presented below, by region, on a $/kW basis.

Figure C.13 Access prices, by access amount, selected Victorian locations

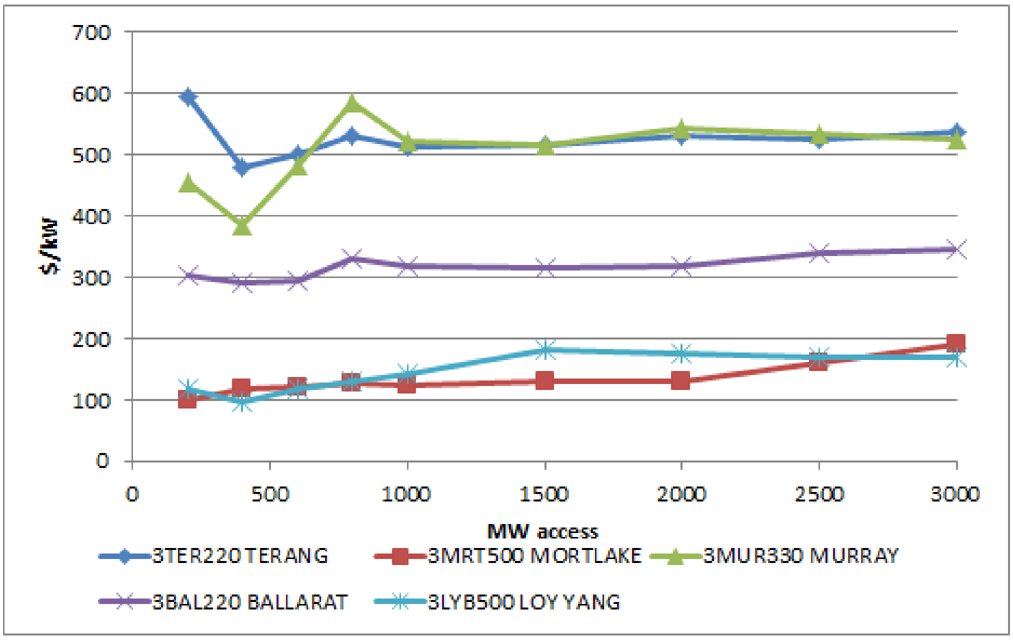
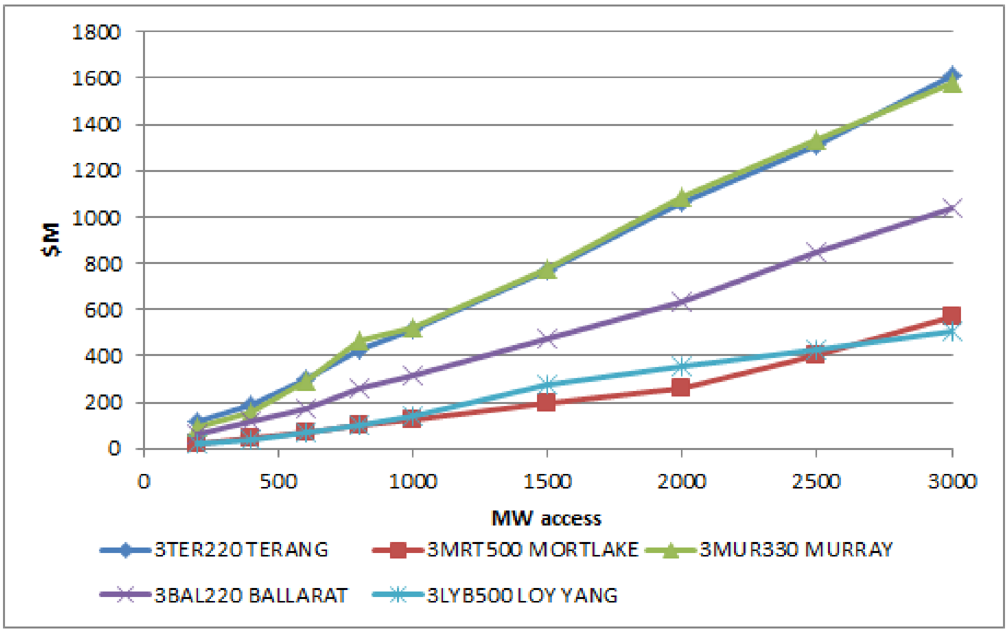


Figure C.13 demonstrates:

- There is sometimes an upwards trend in price per MW of access. This occurs because larger amounts of firm access are more likely than smaller amounts to trigger expansions. That is, more spare capacity would be "used up" by the access request.
- There are also sometimes downward movements in price as access amounts increase. This is because where an expansion on a line occurs, the line would have had higher total capacity than before the expansion (that is, spare capacity is created). This reduces the cost, per kW, of subsequent access request.

Figure C.14 demonstrates that while there may be variability in how prices per kW differ by the amount of access requested, the *total* amount paid for access always increases as more access is requested. It is never cheaper, overall, for a generator to request a greater amount of firm access.

Figure C.14 Total access payment, selected Victorian locations



C.6.4 Indicative access prices by access term

This section provides an analysis of the relationship of access term (in years) to price. Indicative prices are presented below on a $/kW basis.

Figure C.15 Access price for 400MW of access, by access term, selected Victorian locations

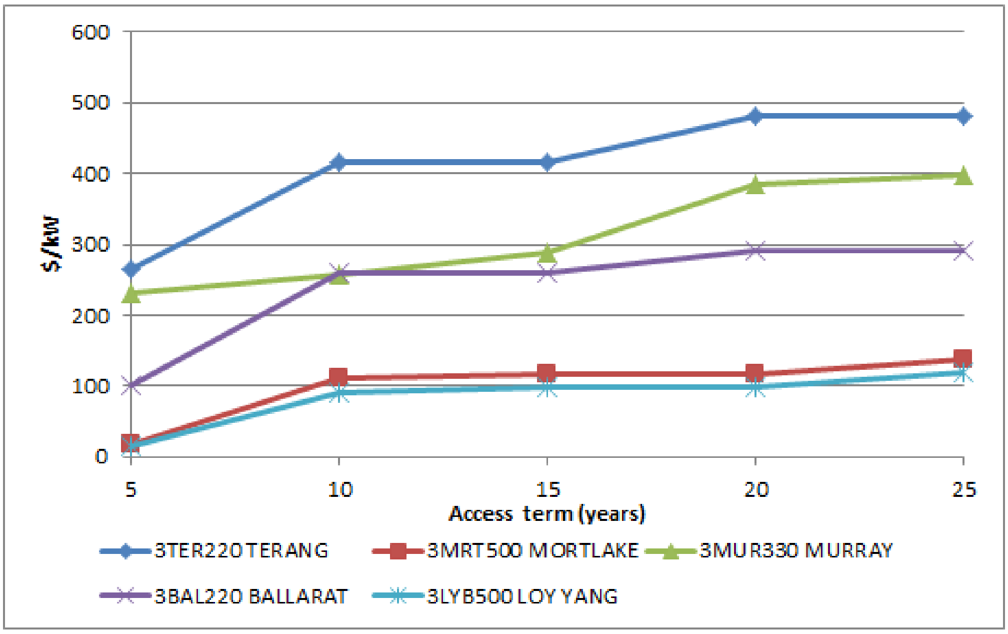


Figure C.15 demonstrates that:

- access price per kW always increases as the access term increases.[120]
- the rate of increase is not the same across locations.

These results reflect the situations where:

- if the access term were to end immediately prior to a required baseline expansion, then the access request would not affect the timing of the expansion and so there would be no cost in LRIC associated with advancing that expansion; while
- if an access term were to end after a required expansion, then the access request would affect the timing of the expansion, and so there would be costs in LRIC associated with advancing that expansion.

Generators may seek to vary the length of their access to receive lower prices, for example, by requesting an access term that ends just prior to a planned expansion occurring. However, access prices would be calculated as the difference in net present costs between the baseline and adjusted development scenarios across the *whole network*, as opposed to just on an *individual* line. For those access requests which would increase flows across multiple lines, it would be likely (in most situations) to be difficult to significantly influence the price by varying the access term. A marginal change in access term would likely only avoid the cost associated with one particular line.

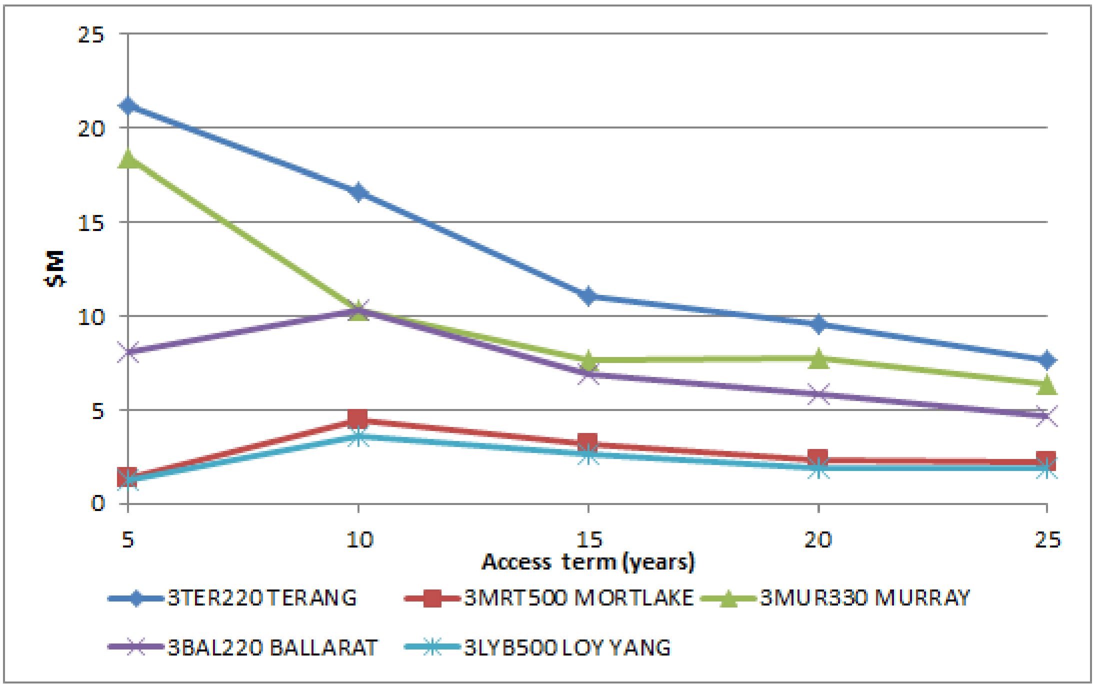
Figure C.16 shows the indicative annual payment that a generator would make for a given access request length (assuming a fixed annual payment that, in net present value, is equal to the calculated access charge).

This demonstrates that:

- in most cases, the annual payment would decrease with an increasing length of the firm access request, even as the total payment made over the life of the firm access request increases, due to the length of time over which the annual payments are being made; however
- in some cases, the cost of access per year increases as access term increases. This is because the cost per kW of access has increased by a significant proportion as the access term has increased (refer to Figure C.15), meaning that the generator would pay more on an annual basis (and, as the access request is longer, also for more time).

120 The total access charge (or total access price) also increases given that the access amount is fixed in this analysis at 400MW.

Figure C.16 Total annual access payment by access term, Victoria



C.7 Sensitivity testing of prototype pricing model

C.7.1 Sensitivity testing

The Commission undertook sensitivity analysis on a number of variables in the model:

- assumed annual growth in line flow, in the long term;
- assumed annual growth of firm access and demand, in the short term; and
- the discount rate used in the NPV calculation (that is, the weighted average cost of capital (WACC).

The trend in average prices against these variables is demonstrated and explained below in respect of each of the regions in the NEM (excluding Tasmania).

Sensitivity to change in line flow, in the long term

As described in appendix D, beyond the projecting horizon[121] in the model (ten years), peak flow on each line is assumed to grow by a percentage of the rating of the corresponding line. Our sensitivity testing shows that the impact of long-term flow growth on price is not strong.

121 The projecting horizon in the pricing model (of ten years) is different to the timeframe for the definition of the short-term access product. Here, when the short-term horizon is referred to, this in the context of the pricing model, which is assumed to be ten years.

Line flow growth has two competing effects on price:

- Higher long-term line flow growth would attribute a higher value to any spare capacity that exists on the network currently, since this spare capacity is expected to be soaked up rapidly rather than not being used. So, if an access request causes a reduction in spare capacity (for example, if no expansion is prompted), then the higher value of that spare capacity - under a high growth assumption - would lead to a higher access price.

- Conversely, if the request causes an increase in spare capacity (because a lumpy expansion is prompted) then the value of that spare capacity is credited against the cost of expansion. So, a higher growth assumption would lead to a lower access price.

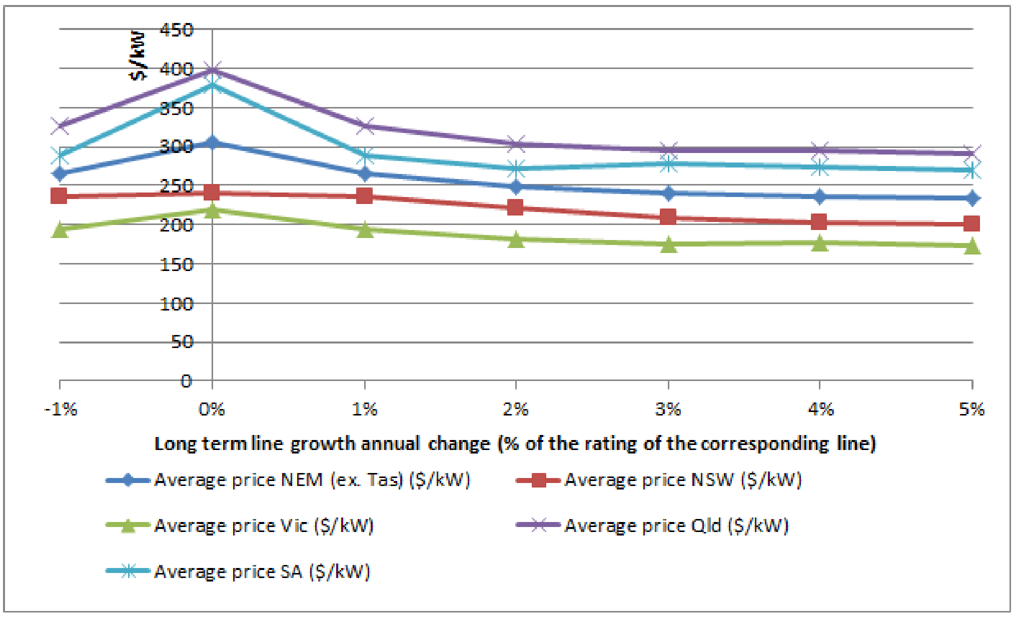
The prototype pricing model has been used to assess the overall impact from these two competing effects.

Figure C.17 illustrates the relationship between the long-term line flow growth and price. It shows that:

- There is generally a slight negative relationship between price and line flow growth. This demonstrates the potential net impacts of the two competing effects described above.

- The sensitivity of the access price to long-term flow growth is not strong, although the sensitivity appears greatest around the zero per cent growth change. Low sensitivity to long term line growth is partly because the long-term flow growth variable only alters development scenarios beyond 2023 (that is, ten years into the future), when discounting is likely to reduce the materiality of the impact of the variable on price.

Figure C.17 Sensitivity of access prices to long-term line flow growth



Sensitivity to changes in firm access and demand in the short-term

Two of the inputs to the model are, for each year up to the defined short-term horizon, the assumed amount of:

- baseline firm access at each node; and
- peak demand at each node in the network.

Our analysis shows that access prices are sensitive to these inputs.

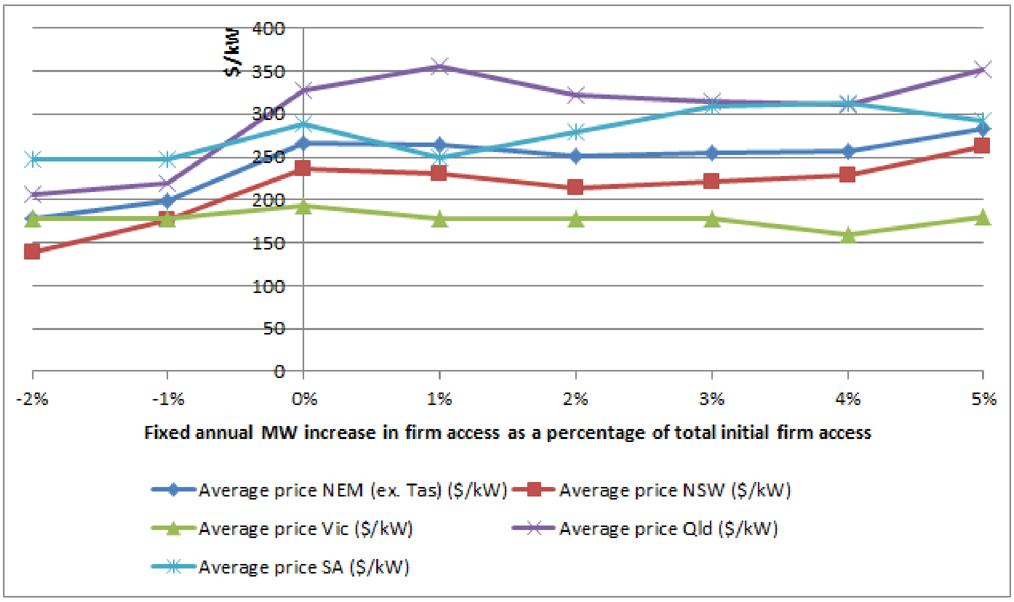
As discussed in the previous section, faster line flow growth can, theoretically, lead to high or lower access prices, due to two competing effects. However, practically, it generally leads to higher access prices.

In the short-term, line flow growth is not set directly, but rather reflects the assumed demand and access growth, driving changes in load flows on the network. Generally, higher access (or lower demand) would lead to higher line flows, although there are exceptions, due to loop-flow effects. Therefore, one would expect that higher growth in access (or lower growth in demand) would generally lead to higher access prices.

Our analysis confirms this expectation.

Figure C.18 plots price as a function of the annual change in baseline firm access at each location in the network.[122]

Figure C.18 Sensitivity of access prices to short-term firm access growth



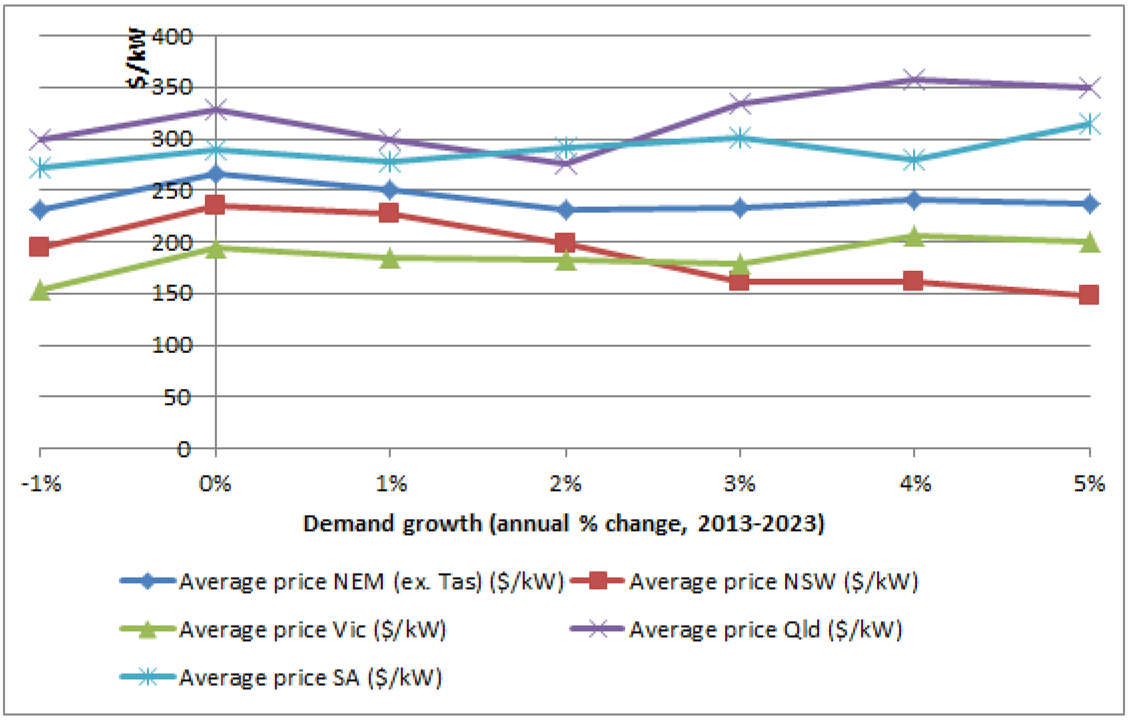
122 Within the current design of the model, the annual change in firm access at each node in the network up to the short-term horizon is a fixed MW amount. Figure C.18 illustrates the sensitivity of price to this fixed MW amount of annual change in firm access. The x-axis represents the annual MW change in access across the region as a percentage of the initial allocation of access across the region. The annual MW change in access across the region is distributed across the nodes in that region in proportion to the current (2013) level of generation capacity in the zone.

The figure demonstrates:

- a general upwards trend in price relative to the annual change in firm access within the baseline. This suggests that the access requests do not prompt substantial immediate expansion; however
- the relationship is neither smooth nor one-directional, reflecting the complexity in the relationship as discussed above.

Figure C.19 plots price as a function of the annual change in demand at each location in the network.[123] Again, the relationship of peak load growth to price is neither smooth nor one-directional.

Figure C.19 Sensitivity of access prices to short-term demand growth



Results from the prototype have demonstrated that prices are likely to be reasonably sensitive to assumptions for both firm access growth and demand growth. Care would therefore need to be applied to projecting these two variables.

However, firm access growth and demand growth are likely to be correlated, that is, higher demand growth is liable to prompt more generation entry and so more growth in access. Holding one assumption constant while altering the other is not necessarily realistic. This correlation, if reflected in the model inputs, may dampen the impact on price (as an identical increase in firm access and demand at a node will have no impact on line flows, and hence no impact on price).

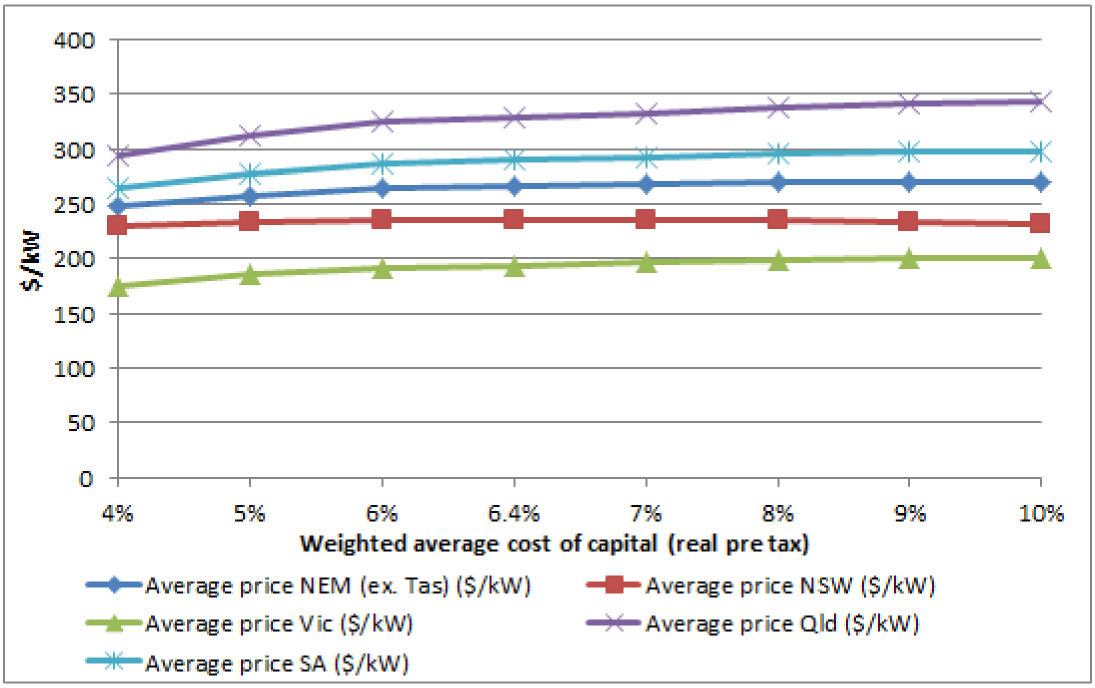
123 Within the current design of the model, the annual amount of demand at each node is a separate input in the model up to the short-term horizon. Figure C.19 illustrates the sensitivity of price to an exponential growth in demand at each location. The x-axis represents the annual, year-on-year percentage increase in demand at each location.

Sensitivity to change in the WACC

The possible sensitivity of the LRIC price to changes to the WACC is outlined in Figure C.20 below. The results show that, for the input assumptions used, WACC is not strongly correlated to LRIC price.

The LRIC, which represents the cost difference between two development scenarios, is the discounted cost of advancing an expansion. The impact of WACC on price for any individual line therefore depends on both how far in advance the original expansion on that line was, and by how much the expansion is being advanced. The LRIC is then the summation of bring forward costs across all the affected lines. There is therefore no simple relationship of WACC to LRIC.

Figure C.20 Sensitivity of access prices to WACC



C.8 Case Study: impact of changes to industrial demand and changed unit costing inputs on Queensland firm access prices

As described in appendix D, one limitation of the current model (and the version of the model made available in October 2014[124]) is that all industrial demand connected directly to the transmission network is modelled to occur at the regional reference node.

The Commission has undertaken analysis on the impact of a more realistic distribution of industrial demand across the transmission network in Queensland.

124 Version number ending "76ee"

For the purposes of this case study, demand projections were updated to take account of an estimated 99 per cent of industrial demand.[125] Estimates of industrial demand were added at nodes:

- near Gladstone (demand for alumina and aluminium smelting);
- near Townsville (demand for zinc smelting);
- west of MacKay (demand for mining); and
- South West Queensland (demand for liquefied natural gas works).

Correspondingly, the equivalent amount of demand was removed from the regional reference node. One per cent of industrial demand remained represented at the regional reference node.

This change was made *in addition* to the changes made to the model between the October 2014 and current (March 2015) versions of the model. Of those changes, the most material was updating the costing and lumpiness assumptions, including implementing a fixed and variable (per km per MW) cost component to transmission element upgrades.

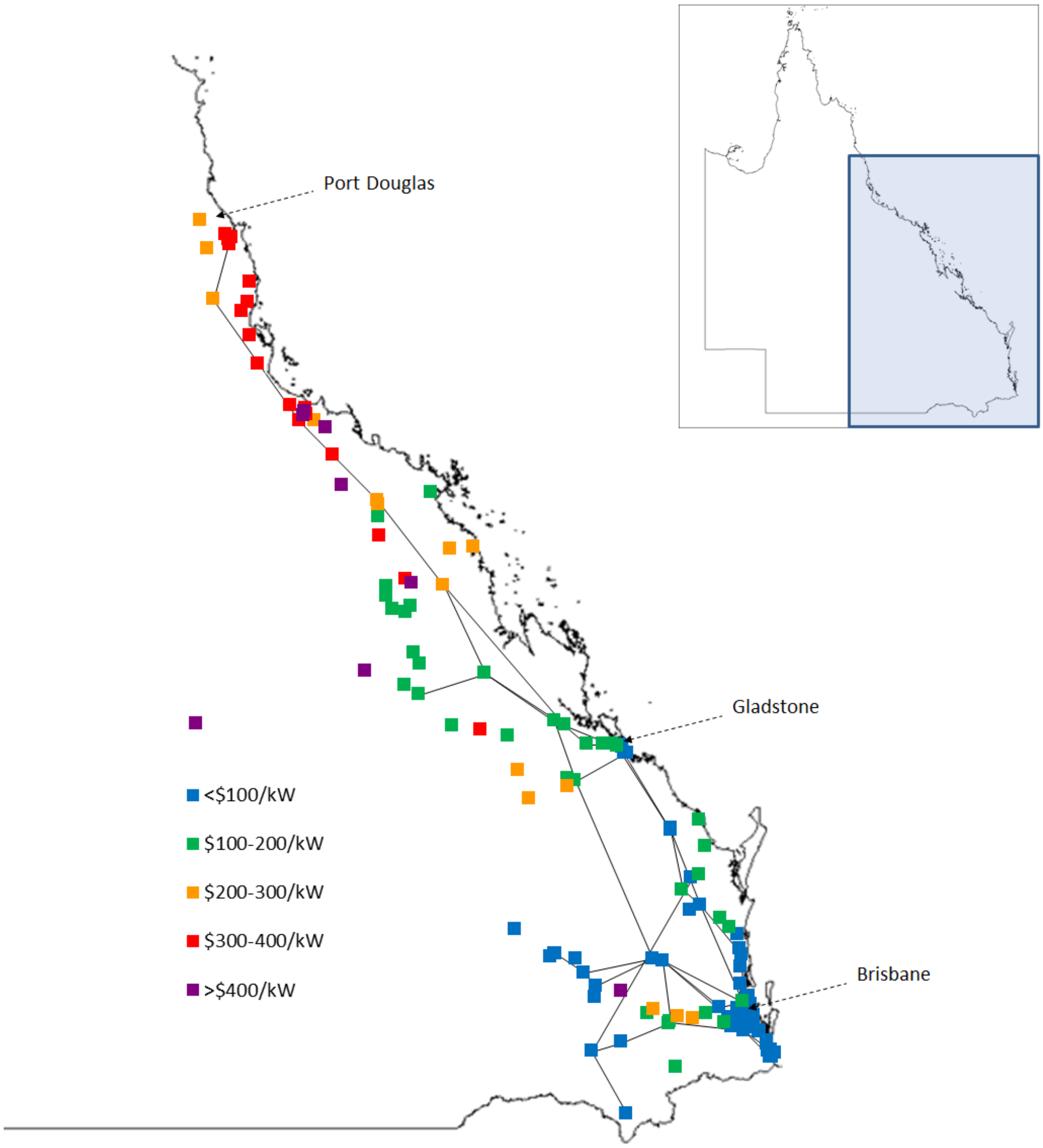
Therefore, this case study examines the impact of two changes made simultaneously:

- changing unit cost and lumpiness assumptions (the change between the October 2014 version and March 2015 version of the model); and
- changing industrial demand locational representation (the additional change).

Access prices from nodes in Queensland corresponding to these two changes are represented in Figure C.21 below.

125 Based on publicly available information, primarily table A.5 of Powerlink's 2014 Annual Planning Report and table A.1 (bottom) of Powerlink's 2013 Annual Planning Report.

Figure C.21 Map of indicative LRIC for Queensland (including changed industrial demand)



For comparison:

- access prices corresponding to the March 2015 version of the model (without the changed industrial demand) are given in Figure C.4, above; and
- access prices without either of the two changes (as per the October 2014 version of the model), are represented in Figure C.22, below.

Figure C.22 Map of indicative LRIC for Queensland (October 2014 version of prototype pricing model)

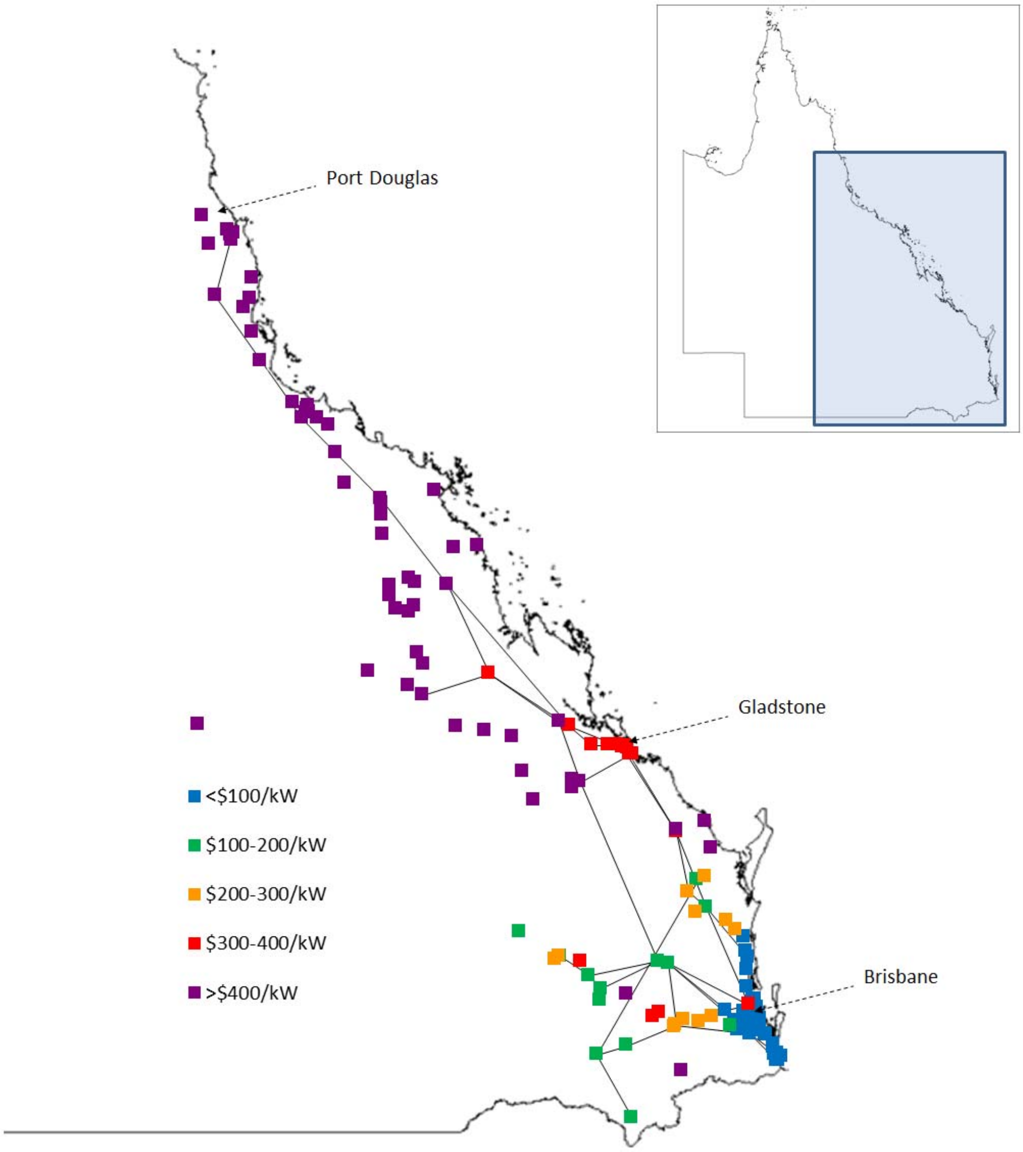
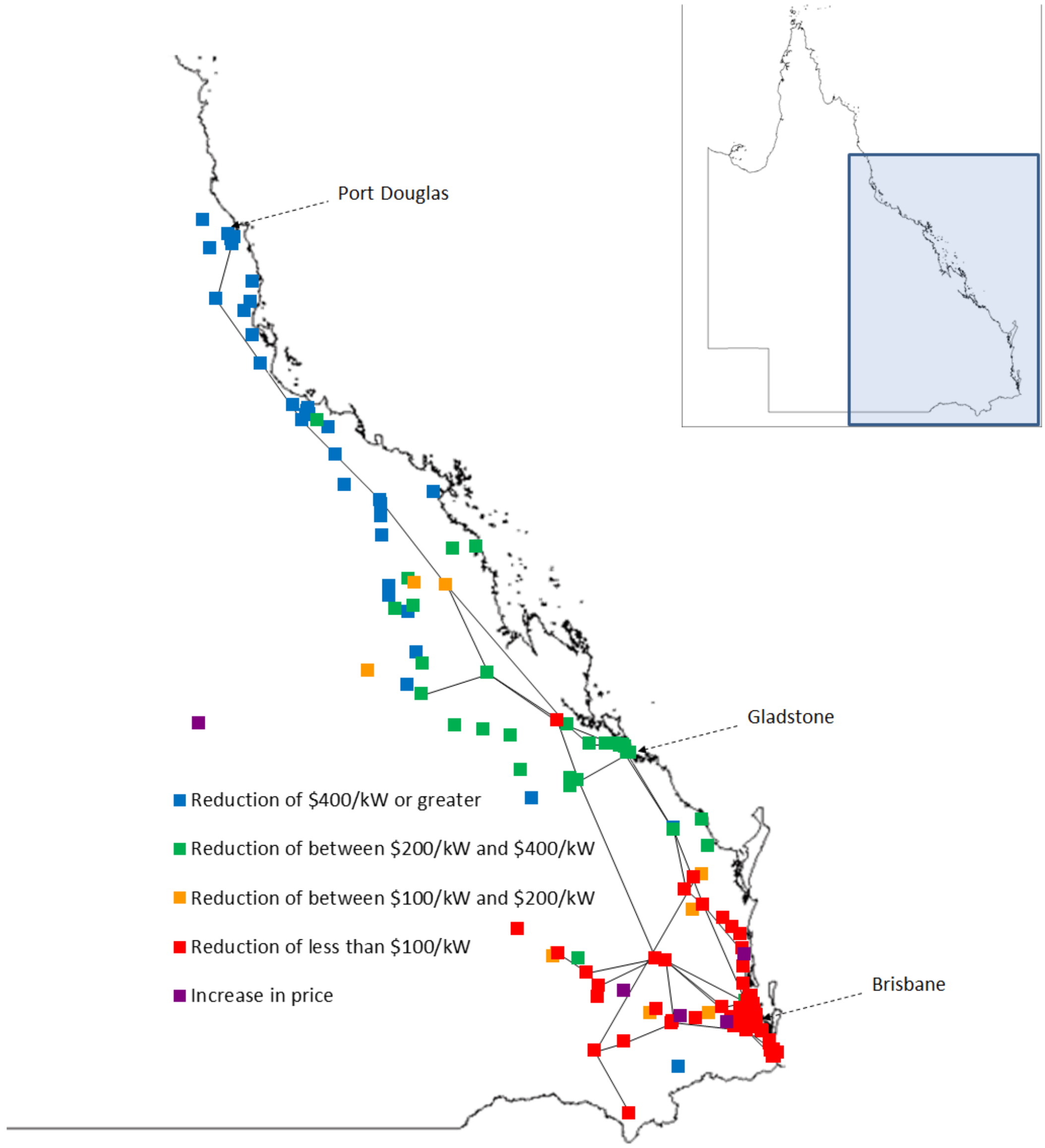


Figure C.21 demonstrates that, consistent with the expectations of the LRIC pricing method, prices are higher the further from the regional reference node. However, as demonstrated in Figure C.23 below, this trend is less pronounced in the updated version of the model:

- there are substantially lower prices in the altered version of the model than in the October 2014 version of model in the north of state; and
- there are lower prices in the altered version of the model than in the October 2014 version of the model near the regional reference node in Brisbane.

In some cases, the changes between prices produced by these two versions of the model are considerable.

Figure C.23 **Dollar change between updated version of model (including industrial demand change) and October 2014 version of model**



The reasons for these impacts are:

- In the updated version of the model, each line expansion has a fixed and variable (per km per MW) component. Long lines (typically farther from regional reference node) have proportionally low fixed costs, whereas short lines (typically closer to regional reference node) have proportionally high fixed costs. On a dollars per kW access request basis, this change tends to cause lines distant from the regional reference node to become cheaper, and nodes closer to the regional reference node to become more expensive, compared to the October 2014 version of the model. The model retains a component of the price which is derived on a per km basis, so distant nodes from the regional reference are still more expensive overall.
- Moving estimates of industrial demand from the regional reference node to more representative nodes increases demand in regional Queensland and reduces the

concentration of demand at the regional reference node. This has the general effect of reducing prices throughout the state – individual lines are less congested as the demand is more evenly spread.

- Clearly, the net impact of two downward impacts on prices at nodes distant from the regional reference node is to reduce prices at these nodes. The net impact of the two counter-active effects for nodes close to the regional reference node is also to reduce prices for these nodes, but to a far smaller extent than for distant nodes (that is, near to the regional reference node, the upward impact on prices of the high fixed component of costs is smaller than the downward impact on prices of redistributed demand).

D Input assumptions for the prototype pricing model

The prototype pricing model is not the final pricing model which the AER would use were optional firm access to be implemented:

- the input data that feeds into the model may not be fully accurate (Table D.1); and
- there are a number of methodological assumptions that have been made (Table D.2).

The Commission developed the prototype pricing model in order to better understand how the LRIC pricing method could be implemented in practice, and the strengths and weaknesses of using the LRIC method to calculate access prices.

This section sets out the various sources of input data and the methodological assumptions made. It also set out where these inputs and assumptions could potentially be improved were optional firm access to be implemented.

Table D.1 Input data

	Input data	Possible improvement(s) to the model (where appropriate)
Peak demand projections	Peak demand projections based on peak demand at each node as provided in the TNSP's 2013 Annual Planning Reports (which provide projections up to 2023).	
	The TNSP Annual Planning Reports do not include major industrial peak demand dis-aggregated at specific nodes. In order for the line flow calculations within the model to operate, an amount that represents the major industrial demand was added to the regional reference node. This is discussed further below in methological limitations.	There may be an impact on the LRIC prices due to an inaccurate representation of demand projections. This may impact the line flows around the regional reference node as well as around those locations near major industrial demand. If optional firm access was to be implemented, then the AER could require that the commercial-in-confidence major industrial demand data is provided to it. The AER could take necessary steps to protect the confidentiality of that data.
	The peak demand projections in the TNSP Annual Planning Reports are net of embedded generation (that is, connected to the distribution network). They do not include non-scheduled generation connected to the transmission network. It is appropriate for non-scheduled generation to be included in the model, otherwise the load flows may not adequately reflect local generation conditions. Therefore, all *current* non-scheduled generation greater than 25MW capacity (excluding wind) was added into the demand projections in each year until 2023 (since beyond 2023 the model assumes a stylised line growth), as sourced from the generation registration list available on AEMO's website.	A projection of *all* non-scheduled generation at each node would be incorporated into the finalised pricing model. This would require appropriate assumptions regarding the output by each non-scheduled generation at times of peak demand.

	Input data	Possible improvement(s) to the model (where appropriate)
	Non-scheduled generation was assumed to operate at its full capacity at times of peak demand.	
	In the shorter term (until 2023), line growth is based on DC lossless load flow equations, given the net access or demand at each node and physical and electrical characteristics of the lines, as provided by the National Transmission Planner.	Load flows only approximate actual load flows in an AC load flow with losses included. The AER could consider an AC load flow with losses included for the finalised pricing model.
	In the long term (beyond 2023), the peak flow on each line is assumed to grow by a percentage of the rating of the corresponding line.	Sensitivity analysis (Figure C.17) indicates that LRIC prices are not particularly sensitive to long term peak line flow.
Access allocations	Existing access allocations are based on the results of the transitional access allocation test undertaken by AEMO, which are set out in appendix A of the First Interim Report. This Final Report sets out a different approach to providing transitional access (see chapter 9), including the partial auction of transitional access. Possible auction results have not been modelled for inclusion in the prototype pricing model. For the purpose of the prototype pricing model, transitional access was assumed to be renewed indefinitely.	If optional firm access was to be implemented, the transitional access allocation would be determined at that time. As such, the actual transitional access would be different from that included in the prototype pricing model. The transitional access numbers would also reflect sculpting of access and assumptions regarding the renewals.
	Generator entry is sourced from data from the 2013 National Transmission Network Development Plan (NTNDP). This is provided at a zonal level. Generator entry was assumed to occur across nodes within a zone in proportion to the existing generator capacity at nodes within that zone.	If optional firm access was to be implemented, then the AER could model (or ask AEMO to model) generator entry and could make assumptions regarding access firmness (in keeping with the approach discussed in C.2).

	Input data	Possible improvement(s) to the model (where appropriate)
	The exception to this is in the Northern Victoria zone. In this case, there is currently only one node with generator capacity, meaning that all additional access within that zone would be connected at this single node. Generator access is assumed to be added over time at three nodes in Northern Victoria. Implicitly, it was assumed that all generator entry projected in the NTNDP will procure access to become fully firm.	
Transmission network	Data detailing the physical and electrical characteristics of the lines used to model the peak line flows was obtained from both AEMO and TNSPs. The Commission acknowledge the considerable effort to date of AEMO and TNSPs in assisting the Commission in compiling this data set. However, some issues may remain, including, but not necessarily limited to: • inaccuracies in the line/transformer ratings; • inaccuracies in lines length; and • misrepresentations of the network topography.	There is a possibility that the line flow is inaccurately modelled due to inaccurate input data. Further, lines with modelled line ratings of zero will require immediate expansion, in both the baseline and adjusted scenarios, altering the relative cost between these plans (and so the LRIC price).[126] Were optional firm access to be implemented, the AER could create a more accurate data set, utilising its information gathering powers.
Costs	The model assumes assets categorised on the following criteria: • asset type (line or transformer);	Inaccurate costing of assets will result in inaccurately costed expansion plans, and ultimately inaccurate LRIC prices. The model could be updated to reflect more categories of assets based on more characteristics, in keeping with advice from EMCa.[128] This would

126 95 of the 756 lines have a zero rating. However, all but one of these are low voltage lines, which are likely to have a less significant impact on prices than high voltage lines.

128 Provide cost and lumpiness assumptions to the optional firm access prototype model, EMCa, January 2015.

	Input data	Possible improvement(s) to the model (where appropriate)
	• size (low, medium or high); and • voltage. Therefore, the projected expansions do not take into account other potential transmission assets, such as substation bays. The cost of each of the categories of assets is based work undertaken by EMCa on behalf of the Commission.[127]	provide more granular costing of assets, and hence more accurate costing of expansions.
	The size of expansions in MW is an assumed economic lumpiness of expansion (in MW of capacity), divided by the "meshedness" of the line. The assumed efficient lumpiness of assets is based work undertaken by EMCa on behalf of the Commission.[129] Meshedness is a measure of the extent to which electricity will flow along alternative paths in the network between the two ends of the line.	To the extent that the assumed efficient lumpiness of assets is inaccurate, the modelled expansion will not accurately reflect actual expansion. The division of efficient lumpiness by meshedness means that individual lines will not be modelled to expand in as large a lump as would be the case in reality. However, the model stylises that multiple lines will expand. The total modelled cost of expansion across all the lines may not be representative of the actual efficient cost of expansion, due to the fixed cost component of each asset expansion.
	Only capital costs of expansions are modelled.	Costs will be less than the total life-time cost of an expansion, due to ignored operating and maintenance costs. The AER would include whole of life costs into the pricing model.

127 Provide cost and lumpiness assumptions to the optional firm access prototype model, EMCa, January 2015.

129 Provide cost and lumpiness assumptions to the optional firm access prototype model, EMCa, January 2015.

Table D.2 Methodological assumption issues

	Methodological assumptions	Possible improvement(s) to the model (where appropriate)
Replacement expenditure	The model assumes that all assets have infinite life.	The AER would incorporate replacement of assets into the LRIC pricing model.
Non-thermal constraints	Only thermal constraints of the lines have been modelled. Stability constraints have not been included.	Only thermal constraints have been modelled. The rule-of-thumb approach to stability constraints has not been included in the prototype pricing model. The AER could include the rule-of-thumb approach in the model.
Dynamic aspects of the transmission network	System protection schemes, run back schemes and other dynamic line ratings are not included in the model.	The model may not accurately represent physical and electrical characteristics of the lines. The AER could improve this aspect of the model.
Electrical characteristics of the lines	Electrical characteristics of the lines are fixed at the start of the model, and not subsequently updated to reflect changes in load flows and network topology (for example, admittance of lines is assumed to be fixed for the life of the line).	The model does not dynamically update these assumptions over the life of the access request. This means that modelled line flows may over time diverge from actual line flows. If optional firm access were implemented, the pricing model could recalculate the relevant characteristics of the lines each year.
Reliability access	Where aggregate firm access is less than aggregate demand, reliability access is included in addition to firm access so that total access (reliability plus firm) equals demand. This mimics a situation where a TNSP provides additional reliability access so that demands-side reliability standards are met. In effect, the model adjusts the assumed rates of access growth per zone (as per the NTNDP) so that aggregate firm	The addition of reliability access above existing generation capacity does not imply that any individual existing generators are purchasing firm access, or generating, above their current capacity. Instead, the model is recognising that in instances where aggregate demand exceeds aggregate access, the TNSP would be required to provide access to meet demands-side reliability standards. The assumed distribution of reliability access may result in modelled access (reliability and firm) per node that is different from actual access

	Methodological assumptions	Possible improvement(s) to the model (where appropriate)
	access meets aggregate demand. This additional reliability access is then distributed across the nodes within a zone in proportion to existing generator capacity at the nodes in the zone, in the same manner as firm access (as described above).	(reliability and firm) per node. The AER could consider improved assumptions regarding the distribution of modelled access (reliability and firm).
Additional demand added to the regional reference node	For the line flow calculations within the model to operate, the total firm access amount in a region must be equal to the total demand in a region, that is, demand and access must balance. Where access allocations are higher in total than demand in total, some "virtual" demand is required to balance the system. The model treats the regional reference node as the "slack node" which means that demand is added at the regional reference node to balance the system.	This assumption is appropriate, since the firm access product provides generators with access to the regional reference node. Further, the additional demand that is added in our method is not to represent network topology, but rather to allow the system to balance in the model and this is best located at the regional reference node.
Security adjustments	Network capacity is adjusted by an adjustment factor that reflects the need to enable there to be sufficient network capacity to have system security. The modelled security adjustment is an approximation of the actual security adjustment that the TNSP would make so that it planned its network to meet the firm access planning standard. This security adjustment is calculated once (at the start of the model) and applied for all years of the model, rather than adjusting dynamically.	Security adjustments may differ from those actually made by the TNSPs in planning their networks, meaning that network capacity is not accurately represented. Were optional firm access to be implemented, the AER could model more appropriate security adjustments.

	Methodological assumptions	Possible improvement(s) to the model (where appropriate)
Inter-regional elements	The transmission network has been split into regional elements to increase the speed at which the prototype produces LRIC prices. Additionally, "bi-regions" have been created (combining each combination of two adjacent regions in the mainland NEM), to estimate the inter-regional firm access prices.	Bi-regions only provide an estimate of the inter-regional firm access prices were the whole NEM combined. The AER could develop a whole of network model, that would allow calculation of inter-regional elements.
Expansion scenarios	Expansions on a line are prompted once the flow on the line exceeds its capacity. The modelled expansion scenario is therefore not based on the current projected expansion plans of the TNSPs, but instead on the modelled flow across the network. The model also makes a simplifying assumption that the expansion of the line occurs by replicating the same line (for example, voltage) and route of the existing line.	Modelled expansion scenarios may vary from TNSPs' projected expansion plans. Up to the TNSPs' short-term planning horizon, the modelled expansion scenario could be based around the TNSPs' projected plans. However, this would require substantial changes to the stylised nature of the prototype pricing model. Indeed, these plans would only be appropriate if driven by identical assumptions as those used in the LRIC model.

E Submissions - optional firm access model

This appendix sets out a summary of the issues raised relating to the optional firm access model in stakeholders' submissions throughout this project. 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 collectively.

Table E.1 Summary of submissions

Issues raised	Stakeholder	AEMC response
Access settlement		
Consideration must be given for industrial facilities with co-generation in designing the access settlement regime.	Major Energy Users (MEU), First Interim Report submission, p. 16.	As described in section A.1.3, access settlement arrangements, including metering, would only apply to scheduled and semi-scheduled generators and therefore would exclude most co-generation facilities. Any existing industrial facilities with scheduled or semi-scheduled co-generation would be covered by the grandfathering of existing metering arrangements.
Five minute access settlement could be operated with SCADA data used for dispatch targets.	CS Energy, First Interim Report submission, p. 24; CS Energy, Draft Report submission, p. 8.	Access settlement would operate on a thirty minute basis. However, as described in section A.1.2 other options could be considered during any implementation phase, including potentially using a weighted average approach.
Oppose the market moving towards a five minute settlement due to high costs relative to low benefits.	Hydro Tasmania, First Interim Report submission, p. 3.	
It is unclear who make access settlement payments when interconnector participation in a flowgate is larger	Stanwell, First Interim Report submission, p. 9.	Firm interconnector right holders would receive payouts associated with their holdings. The remainder of the inter-regional settlement residue that is

Issues raised	Stakeholder	AEMC response
than the directed interconnector's entitlement.		allocated to interconnectors would be paid back into access settlement.
If counter price flows are occurring, does the interconnector receive a zero or negative usage value for access settlements? Either approach will have ramifications.	Stanwell, First Interim Report submission, p. 9.	Payments to firm interconnector rights would not be based on flow, but rather on the level of firm interconnector right entitlements. Depending on the cause of the counter-price flow the outcomes would differ: • Entitlements equal to the target entitlements (that is, purchased firm interconnctor rights): if the counterprice flow is caused only by non-firm generators being dispatched, in this case firm interconnector right holders get their full payments; • Entitlements below target: if the counterprice flow were to occur at a time when inter-regional flowgate capacity is below target, then firm interconnector right holders receive partial compensation; and • Entitlements negative (that is, inter-regional flow is providing network support): the TNSP would fund the negative inter-regional settlement residue, as they do now.
Access settlements should operate on the same basis as is currently used in the market – dispatch meters are used to define the “intent” of the market operator while revenue meters are used to determine all settlement values.	Stanwell, First Interim Report submission, p. 31.	Participation in constraint equations, and thus flowgates, would be specified on a dispatch unit basis. Therefore, as set out in section A.2, access settlement would require a process of applying these participation factors onto revenue meters. Revenue meters would continue to be used for all billing.

Issues raised	Stakeholder	AEMC response
“Net negatives” should be kept to a minimum in this logical mapping of auxiliary loads to access unit identifiers, even if this requires some element of dynamic (but predictable) allocation.	Stanwell, First Interim Report submission, p. 31.	As described in section A.2 there would be no dynamic mapping of loads to access unit identifiers. This could lead to net negative flows occurring to some access unit identifiers. Dynamic mapping would require real time decisions to be made by the market operator, which may be difficult.
Support the proposal to require auxiliary load and generation to be electrically close.	Stanwell, First Interim Report submission, p. 32.	Noted. See section A.2.
In relation to network management, the operational and commercial association rules for auxiliary loads may not be meaningful if the load and generator are electrically close.	Stanwell, First Interim Report submission, p. 32.	See section A.2.2.
There is likely to be a net auxiliary draw in the period prior to a unit being synchronised which does not sit well with the definition of temporal association.	Stanwell, First Interim Report submission, p. 32.	For most generators, auxiliary load associated with a generating unit would be operating in the same trading interval as the unit is exporting, even if this is not simultaneous.
Concerned for the cost to the “around five generating stations” who would not receive grandfathering arrangements for their metering - request more information on this point.	Stanwell, First Interim Report submission, p. 32.	This estimate was based on the number of generators that currently have auxiliary load that is not electrically close to generation. These generators would be informed during any implementation phase for optional firm access.
Concerned that proposals incentivise pursuing non-scheduled generation registration.	Stanwell, First Interim Report submission, p. 32.	Noted. See section A.1.3.
Embedded generation is likely to have multiple connection points to the transmission network, it may be complex and subjective to evaluate access as a result.	Stanwell, First Interim Report submission, p. 32.	The market operator would determine the participation of embedded generators in transmission network constraints. This process would be unchanged by the implementation of optional firm access.

Issues raised	Stakeholder	AEMC response
Concerned that the usage of capacity for entitlement means that generators receive firm access payments when offline. May create inefficient behavioural incentives.	AGL, First Interim Report submission, p. 3; Centre for Energy and Environmental Markets (CEEM), First Interim Report submission, pp.30-33.	See section A.1.7.
Consider the usage of capacity as maximum entitlement is appropriate.	CS Energy, First Interim Report submission, p. 24.	
It may be significantly simpler to use the rated nameplate capacity rather than historical output to cap entitlements. This would remove the market distortion caused by each generating unit having to run at maximum output at least once every two years.	Stanwell, First Interim Report submission, p. 32.	See section A.1.7. Also, the Commission understands that many generators would need to operate at full capacity at least once over a two year period for testing purposes so the impact would be minimal.
Access settlement either exposes non-firm generators to large negative prices or dilutes firmness for all participants.	EnergyAustralia, First Interim Report submission, p. 2.	See section A.1.5.
Flowgate support generators should be rewarded for the service they provide. This could be done by paying them a negative LRIC price.	CS Energy, First Interim Report submission, p. 11.	See section A.1.1.
Loss factors are already taken into account in determining local prices so why do losses need to be especially considered in access settlement?	CS Energy, First Interim Report submission, p. 24.	See section A.1.6.
Note a possible error in the marginal loss factors formulae in the Transmission Frameworks Review Technical Report.	CS Energy, Draft Report submission, p. 7.	Noted. The error has not been corrected. See the accompanying Technical Report for corrected marginal loss factor formulae.

Issues raised	Stakeholder	AEMC response
Firm Access Planning Standard		
Agree with the AEMC that the firm access planning standard and the firm access operating standard should be separate.	GDF Suez Australian Energy (GDFSAE), First Interim Report submission, p. 2; MEU, First Interim Report submission, p. 13; Lumo, First Interim Report submission, p. 2; Grid Australia, First Interim Report submission, p . 5; CS Energy, First Interim Report submission, pp. 10-11.	Agreed. See chapter 5.
Consumers may be exposed to the costs for TNSPs meeting the firm access planning standard.	MEU, First Interim Report submission, p. 13.	Firm generators would have paid the LRIC price for firm access. If the access price underestimated the cost, then consumers would pay for the difference. If the access price overestimated the cost, then consumers would receive a benefit in lower network charges. Therefore, provided there is no systematic bias one way in the pricing model, consumers should not be exposed to the costs. While prices may be inefficient in one direction, in principle, the LRIC pricing method should not produce prices that are biased in one direction. See section 6.11.2 for a possible approach were access prices to deviate substantially from expected underlying costs.
Unforeseen changes in load which diminish a generator's access may not be able to be responded to by the TNSP within the short term.	AEMO, First Interim Report submission, pp. 6-10.	While this may be the case in the short-term, the firm access planning standard and firm access operating standard would provide incentives on the TNSPs to respond in a timely manner to such unforeseen changes. The sell-back mechanism should also help with this (see below).

Issues raised	Stakeholder	AEMC response
It is unclear whether investment required to meet firm access planning standard under these changed conditions has been sufficiently valued by the market to justify the cost.	AEMO, First Interim Report submission, pp. 6-10.	Generators would have the right to sell back firm access to TNSP at the long-run decremental cost. If this is more than the value the generator places on continuing to receive firm access, and potentially the augmentation, the generator could exercise this option. See section 7.5.
Greater weight could be placed on incentives and not compulsion. Potentially a buyback mechanism could be used.	DSDBI Victoria, First Interim Report submission, pp. 3, 5.	
The firm access planning standard should cover investments which are favourable to generators without resorting to a regime which provides for, or requires, additional investments beyond the firm access planning standard to resolve congestion.	AEMO, First Interim Report submission, pp. 10-11.	Agreed. See section 5.2.
Planning arrangements should not seek to maintain access levels during force majeure events (as this could lead to a high risk of overinvestment).	AEMO, First Interim Report submission, p. 10.	The exact specification of the level of redundancy in the firm access planning standard would be considered in the implementation of optional firm access.
The firm access planning standard should be a probabilistic standard and not deterministic.	AEMO, First Interim Report submission, p. 11; Stanwell, First Interim Report submission, pp. 4, 15.	As set out in section 5.2, the purchase of firm access would represent a generator's economic assessment on the value of the provision of the firm access. Since generators would fund the development of the network they would take the risk of inefficient investment. On the whole, optional firm access would be expected to lead to a lower system cost for consumers than the current arrangements.
Forcing TNSPs to meet the firm access standard – in order to avoid any associated penalties – may necessitate ongoing investment by TNSPs in assets and infrastructure that are, increasingly, underutilised.	AGL, First Interim Report submission, p. 3; PIAC, First Interim Report submission, p. 5.	
Agree that a generator's decides the quantity of firm access purchased, so the firm access planning standard would be economic.	Grid Australia, First Interim Report submission, p.5.	

Issues raised	Stakeholder	AEMC response
Worst case values for firm access planning standard parameters are likely to be chosen to limit TNSP liabilities under the firm access planning standard. Therefore less network capability will be available under the standard than were a probabilistic approach to defining the firm access planning standard taken. This passes risk to generators, reducing contract market liquidity.	Hydro Tasmania, First Interim Report submission, p. 2.	
A risk of uneconomic overbuild of network capacity as individual generators are not prepared to accept possibility of having capacity they know could get constrained off and hence unable to earn revenue.	AGL, First Interim Report submission, p. 3.	Each generator would make its own assessment of the amount of efficient investment. If the generator is risk averse and purchases firm access, than investing in fully firm access would be the efficient outcome.
Queries whether generators are able to set their own levels of reliability for firm access.	MEU, First Interim Report submission, p. 14.	There would be a single firm access standard to apply to all firm generators in each region. However, each generator would be able to choose its own firm access level. See section 5.2.
Difficult to see how benefits of optional firm access framework can be realised when reliability standards exceeds firm access standard.	Consumer Utilities Action Centre (CUAC), First Interim Report submission, p. 3.	The firm access planning standard and the reliability standard would be met concurrently. Generators would drive some of the transmission investment decisions. See section 5.2.
Before considering options for enforcement of the firm access planning standard, consider that the AEMC should clarify the nature of the relationship between a generator and a TNSP.	Grid Australia, First Interim Report submission, p. 6.	The nature of the relationship between the TNSPs and generators is described in section 7.2. The enforcement mechanism of the firm access planning standard is explained in section 5.5.2.
The firm access planning standard is all but unenforceable due to information asymmetry between TNSP and AER.	Stanwell, First Interim Report submission, pp. 4,16.	

Issues raised	Stakeholder	AEMC response
Support the firm access planning standard being classified as a conduct provision.	Snowy Hydro, First Interim Report submission, p. 9.	
Unclear about mechanisms to allow for expenditure to meet congestion outside of the firm access planning standard condition but which are material.	Stanwell, First Interim Report submission, p. 16.	TNSPs would still be able to undertake a RIT-T assessment. However, it would not include any benefits associated with non-firm generators.
AEMC should publish any empirical studies into the impact of possible definitions of firm access planning standards.	Stanwell, First Interim Report submission, p. 16.	While the AEMC has not undertaken any specific empirical modelling of the firm access planning standards, there are a number of studies that the AEMC has undertaken that may be informative in this regard: • the transactional access runs undertaken by AEMO, and published on the AEMC's website, assumed a firm access planning standard based on peak demand; • the prototype pricing model uses firm access planning standard conditions based on peak demand; and • the simulations of the optional firm access incentive scheme was done in order to inform the development of the firm access planning standard. This can be found in appendix C of Volume 1.
There need to be adequate investment and operational signals on TNSPs as part of the firm access standard.	DSDBI Victoria, First Interim Report submission, p. 2.	Agreed. See chapter 5.

Issues raised	Stakeholder	AEMC response
Firm Access Operating Standard		
Broadly supportive of incentive scheme.	Victorian DSDBI, First Interim Report submission, p. 5.	Noted. See section 5.3.
Generally supportive of measures that aim to provide TNSPs with operational incentives to deliver the level of access agreed. Some operational uncertainty in the level of firm access provided is appropriate.	GDFSAE, First Interim Report submission, p. 2.	Agreed. See section 5.3.
Applying incentives that take account of market conditions is broadly supported.	GDFSAE, First Interim Report submission, p. 3; Grid Australia First Interim Report submission, p. 6.	Agreed. See section 5.3.
Supports incentives for TNSPs, but only where the benefits to consumers exceed the rewards to the TNSPs.	MEU, First Interim Report submission, p. 11.	TNSP rewards and penalties would be based directly on shortfall costs. See section 5.3.1.
Incentive scheme to incentivise TNSPs to operate its network efficiently would be necessary under the optional firm access model.	EnergyAustralia, First Interim Report submission, p. 3.	Agreed. See section 5.3.
Supports financial incentives for TNSP as the best means to deliver efficient operational outcomes.	Grid Australia, First Interim Report submission, p. 3.	
Supports the symmetrical nature of the incentive scheme.	Grid Australia, First Interim Report submission, p. 6.	Agreed. See section 5.3.
Incentive scheme should include rewards and penalties, but penalties should be steeper than rewards.	Snowy Hydro, First Interim Report submission, p. 9.	See section 5.3.3.

Issues raised	Stakeholder	AEMC response
If generators are required to pay a bonus to TNSPs, they may seek to recover this cost through higher pool prices. It is not clear why a generator should pay a reward when customers are the main beneficiaries of efficiency, through lower prices.	Origin, First Interim Report submission, pp. 10, 12.	See section 5.3.
Generators must pay TNSPs even when TNSPs have not delivered the contracted level of service, providing the TNSPs are delivering over the theoretically efficient level of service. This is an unbalanced design.	Stanwell, First Interim Report submission, p. 4.	See section 5.3.3. Further, TNSPs would only be required to provide access during a set of specified conditions.
The incentive scheme does not make the access product fully firm. Generators are still exposed to shortfall costs.	CS Energy, First Interim Report submission, pp. 13-14, 16; CS Energy, Draft Report submission, p. 9.	See chapter 5. Exposing firm generators to efficient shortfall costs would be appropriate. Setting the firm access planning standard such that a TNSP has to plan to provide access under *all* conditions (rather than just under a *set* of conditions), would impose a large cost on the TNSP, which, through the LRIC pricing model, would be reflected in the price for firm access. Instead, in deciding how much firm access to procure, a generator would undertake its own economic assessment of the value of that firmness.
In instances of major outages, customers should fund the shortfall in access settlement (where TNSP payments are capped and hence not fully exposed to the shortfall cost), in order to make the firm access fully firm.	CS Energy, Draft Report submission, pp. 7, 8, 9.	The Commission does not consider that the benefits of providing a fixed service to generators is likely to warrant exposing consumers to these costs.
TNSP rewards under the scheme are not appropriate.	CS Energy, First Interim Report submission, p. 16.	See section 5.3.3.
Incentive scheme does not provide financial certainty for generators.	CS Energy, First Interim Report submission, p. 17.	Noted. See chapter 5 and section B.1.

Issues raised	Stakeholder	AEMC response
It is appropriate for the incentive scheme to more directly reflect the value of access (revealed more accurately by generators) as opposed to the STPIS $10 materiality threshold currently in place.	Grid Australia, First Interim Report submission, p. 6.	Agreed. See section 5.3.1.
AEMC should investigate whether incentive scheme should be based on costs the network monopoly is likely to incur, rather than shortfall costs.	CS Energy, First Interim Report submission, pp. 2, 13, 16.	See section 5.3.1. By being based on shortfall costs, TNSPs would be incentivised to make a trade-off between the cost of improving the network, and the cost of shortfall (subjected to the nested caps). This incentivises TNSPs to deliver capacity at times generators value it most.
An incentive scheme linked to the potential benefits to generators may create incentives for TNSPs to "over-price" access.	EnergyAustralia, First Interim Report submission, p. 3.	AER would be responsible for developing and maintaining the prototype pricing model. The TNSP would not be able to "over-price" access. By balancing the reward gained through improvements with the expenditure required to make improvements, over time the TNSP should reveal the most efficient shortfall cost. See appendix B.
Impact of network performance on notionally firm generators should be considered as part of the optional firm access incentive scheme.	Stanwell, First Interim Report submission, p. 9.	Noted. See section 5.3.1.
Supports an incentive scheme which aligns the interest of TNSPs and generators.	Stanwell, First Interim Report submission, p. 17.	Noted. See section 5.3.1.
Incentive scheme should incentivise delivery of firm access service to rights holders, not the delivery and operation of physical assets.	EnergyAustralia, First Interim Report submission, p. 3.	Agreed. See section 5.3.1. The optional firm access incentive scheme is linked to the value of the shortfall to generators.

Issues raised	Stakeholder	AEMC response
There should be no exclusions from the firm access operating standard.	MEU, First Interim Report submission, p. 14.	Agreed. See section 5.3.2.
Incentive scheme should apply at all times.	Victorian DSDBI, First Interim Report submission, p. 5; EnergyAustralia, First Interim Report submission, p. 3; Snowy Hydro, First Interim Report submission, p. 9.	Agreed. See section 5.3.2.
Nested caps should apply at all times, and be higher at system abnormal conditions.	Snowy Hydro, First Interim Report submission, p. 9.	See section 5.3.4. Nested caps would apply at all times (as the incentive scheme as a whole would apply at all times). Differently structured penalties apply to the different conditions, because the shortfalls during these different conditions have different intrinsic characteristics which interact with the scheme in different ways – see section B.2.
The firm access operating standard should have some carve outs where generator assumes the risk of the asset being unavailable.	CS Energy, First Interim Report submission, p. 12.	The firm access operating standard (and incentive scheme) would apply at all times. Risks to the TNSPs of extreme events would be managed through the use of nested caps. See sections 5.3 and B.2.
For extreme rare catastrophic events, Stanwell supports a force majeure clause in the incentive scheme.	Stanwell, First Interim Report submission, p. 18.	A force majeure clause would be unnecessary due to the design of the nested caps. See section 5.3.4 and appendix B.
When caps are reached, the incentives of the scheme will not be in place, potentially leading to inefficient outcomes. Risk through the scheme is disproportionately placed on the TNSPs. Incentive scheme too weak.	Origin, First Interim Report submission, pp. 7-9; Stanwell, First Interim Report submission, pp. 4, 18.	See section 5.3.4.
Caps could provide incentives for TNSPs to game (for example, provide as much maintenance activity as	Stanwell, First Interim Report submission, p. 18.	Agreed. The design, and specific parameters, of the caps would need to avoid the possibility of such

Issues raised	Stakeholder	AEMC response
possible on a single day, or bring forward scheduled work between years if the annual cap is met).		gaming. See section 5.3.5 and appendix B.
Nested caps not supported. Otherwise, there would be a situation where penalties are capped, but later, rewards are earned to reduce penalties payable.	Stanwell, First Interim Report submission, p. 20.	See section 5.3.3.
MIC component of STPIS appears to be functioning well.	Origin, First Interim Report submission, p. 5.	Noted. See section 5.3. The incentive scheme would replace (and would represent an evolution of) the market impact component of the STPIS as it applies to TNSPs.
The introduction of the incentive scheme would require the removal of the MIC component of the STIPIS scheme and changes to Network Capability Incentive Parameter Action Plan (NCIPAP) to ensure consumers are not paying rewards for acts that are also rewarded through the incentive scheme.	MEU, First Interim Report submission, pp. 12, 14.	With regard to the MIC, see section 5.3. With regard to NCIPAP, were the optional firm access model to be implemented, the Commission agrees that care would need to be taken to ensure that there are not double payments to TNSPs.
Payments that have been made to TNSPs from the MIC component of the STPIS scheme are probably higher than the benefits to consumers.	CS Energy, First Interim Report submission, p. 14.	Noted. The optional firm access incentive scheme would be based on shortfall costs, and hence directly on the costs to firm generators of network constraints.
MIC component of the STPIS scheme currently may create perverse incentives.	CS Energy, First Interim Report submission, p. 15.	Noted. See appendix B.
Replacing MIC component of STPIS scheme with new incentive scheme could be problematic if only small amounts of firm access are procured. This would mean that the TNSP only has an incentive to operate efficiently on a small part of its network. Also unclear whether reliability upgrades will be subject to the TNSP incentive scheme.	Stanwell, First Interim Report submission, p. 18.	It would be appropriate that TNSPs would not be incentivised to maintain network performance for non-firm generators, as these generators would have not signalled, through their firm access procurement decisions, that they sufficiently value access. The incentive scheme would only replace the MIC component of STPIS. Other components of STPIS

Issues raised	Stakeholder	AEMC response
		would remain unaffected, and so TNSPs would still have incentives (and obligations) for consumer reliability.
Incentive scheme should be supported by a obligation for the TNSP to operate in an efficient manner.	Victorian DSDBI, First Interim Report submission, p. 5.	Agreed. See section 5.3.
TNSPs should not be penalised for events outside of their control.	GDFSAE, First Interim Report submission, p. 3; Grid Australia, First Interim Report submission, p. 4.	Noted. See sections 5.3.4 and B.2. Nested caps would limit risk exposure and provide incentives for TNSPs to rectify events quickly, even if initial cause of event was out of the TNSP's control.
Use of nested caps supported.	MEU, First Interim Report submission, p. 14; Grid Australia, First Interim Report submission, p. 7; Victorian DSDBI, First Interim Report submission, p. 5.	
Nested caps should be structured all the way down to trading intervals, in order to maintain the incentive properties of the scheme.	Grid Australia, First Interim Report submission, p. 8.	Noted. The AER would set the incentive scheme parameters. See sections 5.3.4 and B.2.
Incentive scheme option 1 (T-factor scheme) from the First Interim Report has a number of flaws.	MEU, First Interim Report submission, p. 14; Grid Australia First Interim Report submission, p. 7; Stanwell, First Interim Report submission, p. 19.	Agreed. See section 5.3.
TNSP incentive scheme option 2 from First Interim Report supported over option 1.		
Total annual cap per TNSP could facilitate unnecessary wealth transfer between generators.	Stanwell, First Interim Report submission, p. 18.	Agreed. See section 5.3.6.
Under incentive scheme, payments to/from TNSPs should only be to/from the affected generator and the relevant TNSP.	MEU, First Interim Report submission, pp. 13-14.	Agreed. See section 5.3.6.

Issues raised	Stakeholder	AEMC response
Incentive scheme must be designed to avoid unintended consequences (including risk exposure to consumers).	MEU, First Interim Report submission, p. 14.	Noted. See sections 5.3.5 and B.1.
Incentive schemes are inherently complex. Multiple iterations are often required for schemes to work as planned. Rules should therefore include high level principles (allowing for flexibility rather than prescription), allowing the AER to design and refine the scheme over time.	AEMO, First Interim Report submission, p. 12.	Agreed. See section 5.3.
Incentive scheme shares risks between TNSPs and generators. This may result in reduced contract market liquidity which would reduce competition in the market.	Hydro Tasmania, First Interim Report submission, p. 2.	Noted, see section 5.3.4. The current design of STPIS also shares the risk of TNSP operations. The Commission considers that if optional firm access was to be implemented, then the optional firm access incentive scheme would represent an improvement to the current STPIS.
Incentive scheme should be low powered.	EnergyAustralia, First Interim Report submission, p. 3.	See section 5.3.4.
Incentive scheme is too weak and low powered to sufficiently align TNSP and generator incentives.	Stanwell, Request for comment submission, First Interim Report submission, p. 3.	
There may be incentives for generators to create congestion to receive payments (either from TNSPs or non-firm generators). This may be easier if the generator has pre-warning of TNSP planned outages. The optional firm access model may *create* incentives for disorderly bidding.	Stanwell, First Interim Report submission, pp. 20-21.	Noted. In theory, there could be incentives for generators to try and create congestion in order to receive incentive scheme payments. However, in practice, the Commission considers that it may be difficult for generators to bid in a manner which would create high shortfall costs. Furthermore, TNSPs would be partially protected from this behaviour by the nested caps.

Issues raised	Stakeholder	AEMC response
AEMC proposed benefit of option 2 of reduced disputes in the allocation of payments between generators is alarming, as there should be no disputes (the incentive scheme is mechanical, no judgement required).	Stanwell, First Interim Report submission, p. 20.	Agreed. The supposed benefits of reducing disputes was not taken into account when designing the optional firm access incentive scheme.
Shortfall costs should not be included in the RIT-T assessment.	Stanwell, First Interim Report submission, p. 21.	Noted. The Commission considers that shortfall costs associated with firm generators should be taken into account in the RIT-T assessment, as discussed in section 8.3.
Frequently resetting the incentive scheme parameters could make evaluating the cost effectiveness of firm access for generators over the long-term difficult.	Stanwell, First Interim Report submission, p. 18.	Noted. However, resetting the incentive scheme parameters more frequently could result in a scheme that better reflects the efficient provision of access. Ultimately, this would be a matter for the AER, since it would have responsibility for developing the scheme, if optional firm access were to be implemented. See section B.1.
Setting the initial level of service may be challenging for the AER.	MEU, First Interim Report submission, p. 14.	Noted. See section 5.3.5 and B.1.
Unclear how the annual cap would be set. Unclear whether the network would need to be "fully sold".	Stanwell, First Interim Report submission, p. 20.	See section B.1. The network would be "fully sold" (through the short-term auction) for the incentive scheme to operate effectively, so that, were historical performance to be the basis of setting the annual shortfall cost benchmark, historical performance was being compared on a consistent basis.
It is unclear whether the incentive scheme will apply for inter-regional access.	Stanwell, First Interim Report submission, p. 26.	See section 5.3.1.
Incentive scheme should apply to both short-term and	Stanwell, First Interim Report submission, p.	Agreed. See section 5.3.2.

Issues raised	Stakeholder	AEMC response
long-term access.	28.	
Payment of the incentive scheme should occur through access settlement, rather than after the event.	CS Energy, First Interim Report submission, p. 16.	See section 5.3.3 and 5.3.6.
Annual payments will not provide more certainty (in advance of purchasing access) to generators of incentive scheme outcomes.	Stanwell, First Interim Report submission, p. 19.	See section 5.3.3 and 5.3.6. Any payments made by generators would be as a result of, and offset by, improvements in settlement outcomes for the firm generator as a result of reduced shortfall costs.
Pricing		
An imperfect pricing mechanism is likely to be more efficient than a regime which does not attempt to provide pricing signals. Perfectly costly reflective price signals are unrealistic.	AEMO, Supplementary Report on Pricing submission, pp. 1, 3.	Agreed. See section 6.1.
LRIC supported as the best pricing method (with caveats).	Alinta, Supplementary Report on Pricing submission, p. 2; GDFSAE, Supplementary Report on Pricing submission, p. 1; AEMO, Supplementary Report on Pricing submission, p. 1; Grid Australia, Supplementary Report on Pricing submission, pp.1-2; Energy Networks Association, Supplementary Report on Pricing submission, p. 1.	See sections 6.6.1 and 6.5.2. See section 6.11.2 for a possible approach were access prices to deviate substantially from expected underlying costs.
Theoretically, the LRIC method will produce efficient prices. However, this is unachievable in practice. Prices do not reflect costs, and could therefore result in inefficient investment decisions by generators.	CS Energy, Supplementary Report on Pricing submission, pp. 2-4.	

Issues raised	Stakeholder	AEMC response
The model could not be materially improved by changes to the model inputs or assumptions – it is the stylised nature of the model which is the issue.	Origin, Supplementary Report on Pricing submission, p. 1.	
LRIC method reliant on forecasts which may be inaccurate.	AGL, Supplementary Report on Pricing submission, p. 2; SADSD, Supplementary Report on Pricing submission, p. 2.	
The DCC approach may be more appropriate in some circumstances.	SADSD, Supplementary Report on Pricing submission, p. 2; AEMO, Supplementary Report on Pricing submission, p. 2.	
Many deficiencies and limitations in the prototype pricing model can be overcome.	DIgSILENT, Supplementary Report on Pricing submission, pp. 1, 26.	Noted. See section 6.10.3.
Prototype pricing model appears to be able to demonstrate relativities in pricing due to spare capacity and locations.	DIgSILENT, Supplementary Report on Pricing submission, p. 6.	Noted. See section 6.10.4.
The prototype pricing model provides quite weak locational signals.	Stanwell, Supplementary Report on Pricing submission, pp. 3, 5.	
More confidence is required in the pricing model before a decision can be made to proceed with the optional firm access model.	AGL, Supplementary Report on Pricing submission, p. 4.	The Commission acknowledges limitations with the prototype pricing model (see section 6.10.3), and considers that many of these could be improved with more time, resources and data availability. See section 6.11.2 for a possible approach were access prices to deviate substantially from expected underlying costs.
Stylised approach will systematically overstate prices.	EnergyAustralia, Supplementary Report on Pricing submission, p. 1; AGL, Supplementary Report on Pricing submission, p. 1; Snowy Hydro, Supplementary Report on Pricing	See sections 6.6.1 and 6.11.

Issues raised	Stakeholder	AEMC response
	submission, p. 1; Origin, p. 6; CS Energy, Supplementary Report on Pricing submission, pp. 2-3; Stanwell, Supplementary Report on Pricing submission, p. 7..	
Argument that prices will be broadly reflective over time, with under- and over-predictions of costs averaging out, requires high volume of argumentation expenditure, which is currently not the case.	TasNetworks, Supplementary Report on Pricing submission, p. 3.	
Stylised approach will not produce accurate pricing signals.	Frontier Economics, Draft Report submission, p. 22.	
Systematic overpricing will result in windfall gains for TNSPs.	Stanwell, Supplementary Report on Pricing submission, p. 4.	
Inaccuracies in pricing may result in costs being passed to consumers or generators.	SADSD, Supplementary Report on Pricing submission, p. 2; Grid Australia, Supplementary Report on Pricing submission, 2.	See section 6.11.2 for a possible approach were access prices to deviate substantially from expected underlying costs.
By locking in net present cost of future transmission investment, without considering alternative expansion plans, the LRIC is likely to result in less efficient pricing outcomes.	Origin, Supplementary Report on Pricing submission, p. 1; Origin, Request for comment submission, p. 3.	Generators will pay a fixed price, set when the firm access is registered. This promotes financial certainty for generators. See section 6.4.
Certainty in prices, stability in prices and avoiding one-on-one negotiations are not sufficient to justify the proposed approach.	EnergyAustralia, Supplementary Report on Pricing submission, p. 1.	
Supports access prices being fixed at time of access procurement.	GDFSAE, Supplementary Report on Pricing submission, p. 1.	

Issues raised	Stakeholder	AEMC response
Stylised pricing model results in financial uncertainty for generators.	Origin, p. 6.	
Before committing to purchasing access, generator would want to be able to reconcile the access cost (through the pricing model) with the access value (through settlement).	CS Energy, Supplementary Report on Pricing submission, pp. 4-5.	Upon a generator purchasing firm access, the TNSP would be required to meet the firm access planning and operating standards. The Commission acknowledges that the access provided would not be fully firm. See chapter 4. Given the requirements on the TNSP, a generator may be able to estimate the likely value derived through access settlement and compare this to the fixed cost, provided through the pricing methodology.
Various input and methodological limitations in the current pricing prototype model, which could result in inefficiencies and/or systematic over-pricing, including: • no replacement capital expenditure, or simplistic possible replacement capital expenditure profiles; • no operational expenditure; • inappropriate security adjustments; • simplistic large-scale network replication expansion plans; • inter-regional access prices and inter-regional flow not included; • inappropriate access growth / generator entry assumptions and transitional access sculpting, which indicate that central planning remains a	SADSD, Supplementary Report on Pricing submission, p. 1; EnergyAustralia, Supplementary Report on Pricing submission, p. 2; AGL, Supplementary Report on Pricing submission, pp. 2-3; Grid Australia, Supplementary Report on Pricing submission, pp. 2-4; Snowy Hydro, Supplementary Report on Pricing submission, pp. 1-2; Alina, Supplementary Report on Pricing submission, pp. 2-3; Origin, Supplementary Report on Pricing submission, pp. 2-3; AEMO, Supplementary Report on Pricing submission, pp. 1-2; TasNetworks, Supplementary Report on Pricing submission, p. 2; Stanwell, Supplementary Report on Pricing submission, pp. 3-4, 6-8, 10-11; Stanwell, First Interim Report submission, p. 24; CS Energy, Supplementary Report on Pricing submission, pp. 2-4, 14; DIgSILENT, Supplementary Report on Pricing submission, pp. 5-6, 12-24, 26; Dr Col Parker, Supplementary Report on	The Commission acknowledges limitations with the prototype pricing model (see section 6.10.3), and considers that many of these could be improved with more time, resources and data availability. See section 6.11.2 for a possible approach were access prices to deviate substantially from expected underlying costs.

Issues raised	Stakeholder	AEMC response
feature of the optional firm access model; • lumpiness and costing assumption; • inappropriate forecasts of peak demand at nodes; • exclusion of stability constraints from the model, which may become increasingly prevalent in the future of the NEM; • errors in network characteristics; • treatment of losses; • inappropriate exclusion of committed TNSP work; • the use of direct current load flow calculations (rather than alternating current); • discrepancies versus real NEM operations.	Pricing submission, pp. 3, 6, 8, 12, 26-30; Snowy Hydro, Draft Report submission, pp. 5-6; Clean Energy Council, Draft Report submission, pp. 1, 3; Frontier Economics, Draft Report submission, pp. 20-22; Hydro Tasmania, Draft Report submission, p. 3.	
Agrees that the pricing element of optional firm access needs more work if it is to be implemented.	Grid Australia, Draft Report submission, p. 2.	
The ability to sell-back access at the current long run decremental cost may allow generators to inter-temporally arbitrage errors in the access prices that arise over time to the detriment of consumers.	Frontier Economics, Draft Report submission, pp. 20-21.	To the extent that the pricing model would produce prices that were not fully cost-reflective, generators could be able to arbitrage. The Commission acknowledges limitations with the prototype pricing model (see section 6.10.3), but considers that many of these could be improved with more time, resources and data availability.

Issues raised	Stakeholder	AEMC response
		See section 6.11.2 for a possible approach were access prices to deviate substantially from expected underlying costs.
The pricing model will not be correlated to the NTNDP or TNSP annual planning processes.	EnergyAustralia, Supplementary Report on Pricing submission, p. 2.	The pricing model would use assumptions that are consistent with the assumptions and outputs of the NTNDP and TNSP annual planning processes.
In an environment of mature and stable technologies, to the extent that inaccuracies in the pricing model are present in both the base line and adjusted expansion plans, the incremental costs between them (upon which the LRIC is based) should be relatively accurate. But, if technologies change over time, this assessment might not hold true.	Grid Australia, Supplementary Report on Pricing submission, p. 2.	Transmission costs in the pricing model could be based on projections of future costs, allowing the LRIC to more accurately take account of the possible changes in cost (over time) to alleviate the same constraint.
Forecasts of generator entry have changed considerably in recent years. This could create pricing volatility if these forecasts are updated into the pricing model.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	To the extent that any input assumption changes, this would need to be updated in the pricing model, with the potential for changes in prices. During any implementation process for optional firm access, a process (with public consultation) for updating the pricing model would need to be developed. The Commission agrees that updating the pricing model frequently could create volatility in prices. Therefore, this would need to be balanced against not updating the model, which would result in allowing known inaccuracy to prices to remain in place.
Effort to manually determine interconnector costs (for the purpose of pricing) would be high.	Stanwell, First Interim Report submission, pp. 24-25.	Noted. LRIC model would price costs associated with thermal constraints. Manual modelling would only be used for those inter-regional costs which would be incurred immediately to address stability constraints (due to the use of the DCC method to address inter-regional stability constraints). The Commission

Issues raised	Stakeholder	AEMC response
		understands that currently TNSPs undertake similar modelling in deciding whether or not to undertake a RIT-T assessment on an interconnector, so this approach would likely not impose substantially more costs than at the moment. See section 6.7.
High cost to upkeep pricing model.	EnergyAustralia, Supplementary Report on Pricing submission, p. 4.	See section 6.6.
Frequent review of the inputs and model assumptions are necessary.	Stanwell, Supplementary Report on Pricing submission, p. 14; DIgSILENT, Supplementary Report on Pricing submission, p. 27.	
Unclear how commercially sensitive information on industrial demand can be incorporated in a publicly available model. The pricing model must be transparent.	TasNetworks, Supplementary Report on Pricing submission, p. 3; Stanwell, Supplementary Report on Pricing submission, pp. 13-14; DIgSILENT, Supplementary Report on Pricing submission, p. 27.	Noted. The pricing model would be publicly available to the extent that commercial-in-confidence issues could be resolved. Alternatively, if such issues were not resolved, only some elements could be publicly available.
The pricing model must be easy to use.	Stanwell, Supplementary Report on Pricing submission, p. 13.	Agreed. The AER would be responsible for developing the pricing model, were optional firm access to be implemented.
In general, the model is easy to operate.	DIgSILENT, Supplementary Report on Pricing submission, p. 26.	Noted. Further changes have been made to improve the usability of the model. See section 6.10.2.
Better references of sources inputs should be given.	DIgSILENT, Supplementary Report on Pricing submission, p. 27.	Noted. See section 6.10.3. While efforts have been made to detail the inputs used, some inputs have required judgements to be made by AEMC staff, owing to data limitations. Were optional firm access to be implemented, all inputs, sources and judgements would be documented by the AER.

Issues raised	Stakeholder	AEMC response
There could be inefficiencies if network investment is negotiated between a TNSP and generator, but prices for firm access are set by the AER.	Origin, First Interim Report submission, p. 2.	Network investments would not be negotiated. Generators would agree to pay a price based on a regulated model (determined through the methods described in chapter 6). Investment would then made by the TNSP, subject to the RIT-T process as appropriate (see section 8.3).
Pricing model is inconsistent with the Optional Firm Access, Design and Testing Review Terms of Reference, in that it does not include inter-regional access.	Stanwell, Supplementary Report on Pricing submission, pp. 4, 8.	The pricing prototype has been updated to allow for estimates of inter-regional access prices.
How can generators be more involved in the process of determining upgrade requirements? What changes need to be made to the RIT-T process?	DIgSILENT, Supplementary Report on Pricing submission, pp. 7, 24.	See section 6.6.1. The stylised expansion plans on which access prices are predicated would not be the actual plans that the TNSP would follow in augmenting the network (which would continue to require RIT-Ts were materiality thresholds met, as is currently the case). Also see section 8.3.
Stylised method may result in network augmentations different to that actually undertaken by the TNSP.	Dr Col Parker, Supplementary Report on Pricing submission, p 1.	
The stylised assumptions and methodology of the pricing model could 'leak' into RIT-Ts and revenue proposals.	EnergyAustralia, Supplementary Report on Pricing submission, pp. 1-2.	
LRIC approach to network planning could constrain the ability of the market to respond to changing market conditions, compared to the current RIT-T arrangements.	Origin, Supplementary Report on Pricing submission, p. 2.	
Commission should consider mechanisms to align prices with actually incurred costs if material discrepancies arise.	Grid Australia, Supplementary Report on Pricing submission, p. 2; AGL, Supplementary Report on Pricing submission, p. 3.	See section 6.11.2.
LRIC prices should be allowed to be negative.	CS Energy, Supplementary Report on Pricing	See section A.1.1.

Issues raised	Stakeholder	AEMC response
	submission, p. 12; EnergyAustralia, Supplementary Report on Pricing submission, p. 4; AGL, Supplementary Report on Pricing submission, p. 4; CS Energy, Draft Report submission, p. 8.	
Modelled forecasts of generator access should not be included in stylised model.	GDFSAE, Supplementary Report on Pricing submission, pp. 1-2.	See section C.2.
Assumptions regarding renewal of access may cause inaccuracy in pricing and may also cause a divergence from the forecasting information sourced from the NTNDP.	AGL, Supplementary Report on Pricing submission, p. 3.	
Requests that the Commission considers the extent to which forecast generator retirements would be included in the pricing model baseline.	Grid Australia, Supplementary Report on Pricing submission, pp. 3-4.	
Assumption that all generation is balanced at the regional reference node could distort pricing accuracy.	Origin, Supplementary Report on Pricing submission, pp. 1-2; Dr Col Parker, Supplementary Report on Pricing submission, p 6.	See table D.2. Also note that the assumption that all major industrial demand is added to the regional reference node is made in the *prototype* pricing model (for reasons of data confidentiality), and would not be made were the optional firm access model to be implemented.
Pricing model is inflexible to customisation of access.	EnergyAustralia, Supplementary Report on Pricing submission, p. 4.	See section 7.2.3.
Scope for strategic procurement (with regard to access term), to avoid costs associated with lumpy investment.	AGL, Supplementary Report on Pricing submission, p. 3.	See section C.6.4.

Issues raised	Stakeholder	AEMC response
Unclear from prototype pricing model what the LRIC pricing outcomes should be in the situation where: • existing network capacity is sufficient to accommodate firm access request; and • no additional network maintenance expenditure is required beyond that required to meet reliability obligations.	AGL, Supplementary Report on Pricing submission, pp. 3-4.	See section C.1. The LRIC pricing method takes into account the value of spare capacity. In the special case that there is zero projected growth on an element, then the long run incremental costing access price would be the same as the DCC curve. Therefore, if the access request does not prompt an immediate expansion then the access request would be zero, subject to any additional network maintenance expenditure required beyond that required to meet reliability obligations. If there was no additional maintenance expenditure, the total price would be zero.
Anomalies between theoretical access prices produced by LRIC, LRMC and DCC approaches (as detailed in figure C.1) and the indicative prices produced by prototype pricing model.	AGL, Supplementary Report on Pricing submission, p. 4; Frontier Economics, response to First Interim Report, pp. 72-81.	Figure C.1 shows the theoretical prices relating to *one network element.* Prices produced by the prototype pricing model for each of the three methodologies are the summation of LRIC, LRMC and DCC costs respectively, *across all network elements.* For example, the DCC method would only produce prices of $0 if no network elements are immediately expanded as a result of the access request. DCC prices are typically above zero because some network elements are immediately expanded, but others are not. See section C.1 for a detailed discussion of the relationship between LRIC, LRMC and DCC for one network element.

Issues raised	Stakeholder	AEMC response
Pricing model currently not applicable to the specific features of Tasmania.	Grid Australia, Supplementary Report on Pricing submission, p. 3; Alinta, Supplementary Report on Pricing submission, p. 3; TasNetworks, Draft Report submission, p. 2.	Agreed. See section C.4 and chapter 11 of Volume 1. These issue would have to be resolved as part of the implementation of the optional firm access model, were it to be implemented in Tasmania.
For the pricing of inter-regional access using the LRIC model, what conditions will be being modelled for the network? For instance, under firm access planning standard conditions, the 'from' region will typically be unconstrained (as concurrent intra-regional access is counter to the inter-regional flow). However, firm access planning standard conditions may not be the typical conditions when price separation between regions occurs.	Stanwell, First Interim Report submission, p. 26.	Noted. The design of the firm access planning standard conditions, and hence the pricing model, may need to take this issue into account.
The only reason that the LRIC model would need to be included in the optional firm access model is to provide a pricing signal for *new entrant* investors. Otherwise, access should be traded between generators on a secondary market.	CS Energy, Supplementary Report on Pricing submission, p. 2.	Noted. While generators may trade their access (see chapter 7), regulated prices would be needed for the procurement of firm access for new generator entry, increases to the level of firm access for existing generators, and once transitional access is sculpted for existing generators.
Reliability access distorts pricing for existing generators.	CS Energy, Supplementary Report on Pricing submission, pp. 5-11.	See section 5.2.6 of the Transmission Frameworks Review.
Sell-back mechanism may be more appropriate than including replacement expenditure in the LRIC model.	CS Energy, Supplementary Report on Pricing submission, p. 12.	Both the sell-back mechanism and inclusion of replacement expenditure in the pricing model would be appropriate. However, these elements are not reflected in the prototype model. It is expected they would be included in the pricing model if optional firm access were to be implemented.

Issues raised	Stakeholder	AEMC response
Prototype pricing model cannot handle multiple access requests at different locations.	DIgSILENT, Supplementary Report on Pricing submission, pp. 6, 23; AGL, Supplementary Report on Pricing submission, p. 3; Grid Australia, Supplementary Report on Pricing submission, p. 3.	See section 7.2. TNSPs would be able to give informal information to generators regarding access prices at any time. To the extent that a generator wishes to make multiple access purchases, the TNSP would be able to indicate the impact of a particular access request on the price of other access requests (were they to be made subsequently).
Impact of generator dispatch influences load flows.	Dr Col Parker, Supplementary Report on Pricing submission, pp 6-12.	Notwithstanding a number of improvements that could be made to the model as suggested, the model does not include *generator dispatch* as part of the load flow calculations. Instead, it includes *firm access*, which is analogous to dispatch for the purpose of load flow calculations. The inputs to the model should take account of the total and projected level of firm access, because under the firm access planning standard, the TNSP would have to plan to provide this level of access to the regional reference node (under the specified conditions).
How long-term line flows are calculated is misreported in the Supplementary Report on Pricing.	DIgSILENT, Supplementary Report on Pricing submission, p. 15.	Noted. Long-term line flow calculations now accurately reported in the Final Report.
Dupe parameter has no bearing on direct current loadflow calculations.	DIgSILENT, Supplementary Report on Pricing submission, pp. 16-18.	The dupe parameter is not used directly in the direct current loadflow calculation. Parallel lines must have the admittance parameter updated to reflect the new parallel admittance, which is representative of total admittance rather than per individual line.
Contingency analysis in prototype pricing model may be departing from theoretically derived results.	DIgSILENT, Supplementary Report on Pricing submission, pp. 19-20.	The Commission, using the input numbers published by DIgSILENT, was unable to replicate the results that diverged from the theoretically correct results. The Commission notes that the short-term rating (st rating)

Issues raised	Stakeholder	AEMC response
		is used in the evaluation of post contingent capacity rather than the continuous rating (ct rating) values that DIgSILENT have published.
DCC calculations in prototype pricing model may be departing from theoretically derived results.	DIgSILENT, Supplementary Report on Pricing submission, pp. 20-21.	The DCC calculation takes into account the weighted average cost of capital ('wacc' parameter). Setting this parameter to zero appears to gives the results expected by DIgSILENT.
Generators may pay substantially more or less than one another at the same node, due to first- or second-move advantages.	AGL, Supplementary Report on Pricing submission, p. 3; CS Energy, Supplementary Report on Pricing submission, pp. 12-13.	See section 7.2.2.
Queuing mechanism may be an effective way to price the renewal of transitional access that expires concurrently.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	
Randomisation of queuing order not appropriate.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	
Prices being distorted as a result of access requests being withdrawn from the queue.	AGL, Supplementary Report on Pricing submission, p. 3.	
Over course of access request negotiation, prices could change as a result of other access requests.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	
Credit support arrangements will be required to avoid a generator prompting an expansion through the procurement of firm access and subsequently pulling out of the agreement, with the risk that customers bear the cost of shortfalls in revenue.	Victorian DSDBI, First Interim Report submission, pp. 4-5.	Noted. See section 7.5.2 for a discussion of how the LRDC may guide the level of credit support required.

Issues raised	Stakeholder	AEMC response
Access prices under optional firm access will reflect TNSPs' expectations regarding patterns of generation investment.	Snowy Hydro, Draft Report submission, pp. 5-6.	See sections 6.3 and 6.9. The AER would be responsible for developing and maintaining the pricing model, with input from the TNSPs and AEMO. Neither TNSPs nor AEMO would determine the regulated prices.
Optional firm access increases centralised planning due to LRIC prices being based on a pricing model determined by TNSPs and AEMO, and subsequently governed by AER.	AGL, Draft Report submission, p. 3.	
Perhaps there needs to be an undertaking (such as a bank guarantee) provided by the generator to protect the TNSP from any residual risk of a generator failure to pay.	Major Energy Users, Draft Report submission, p. 3.	Agreed. See sections 7.2.7 and 7.5.2.
Non-equivalence of the price produced by the prototype pricing model for incumbent versus generic (non-incumbent) access. That is, one would expect that a generic access request of 400 MW [at a particular node] would produce the same LRIC result as an increase of the assumed [transitional] firm access level of 200 MW [at that node] plus a firm access request for 200 MW [at that node]. However, this is not the case.	Frontier Economics, response to First Interim Report, pp. 81-82.	The results produced by Frontier Economics are as theoretically expected. The LRIC is calculated as the difference between the baseline network development scenario and the adjusted network development scenario. While the adjusted scenario is the same between the two cases described, the baseline scenario is different. One would therefore expect the differences between the baseline and adjusted scenarios, and hence the price, to be different in each case.
With low or no demand growth, one would expect LRIC and DCC estimates to be lower than would otherwise be the case, and often to be zero.	Frontier Economics, response to First Interim Report, p. 83.	LRIC is a function of forecast spare capacity over time (on each element), existing spare capacity (on each element) and the size of the access request. Adjusting the spare capacity over time (as per Frontier's change to demand) has no impact on the other two factors listed above. If there is zero change in spare capacity over time, then LRIC (on each

Issues raised	Stakeholder	AEMC response
		element) must either be: • equal to zero (where the access request is less than the existing spare capacity); or • greater than zero and equal to the DCC (on each element), where the access request is greater than the existing spare capacity, and hence an expansion to an element is made in the first year. Under Frontier Economics' assumptions, for the total LRIC at the node to equal zero, then the LRIC at each element must also be zero (that is, no expansions on *any* elements in year 1). See section C.1.
A number of access prices rise when transitional access within the model is reduced (for example, to zero).	Frontier Economics, response to First Interim Report, pp. 83-84.	When total firm access on the network falls below the level of peak demand, TNSPs would be required to provide some "reliability access" to non-firm generators in order to meet the reliability standard. This is the case when the transitional access within the model is reduced to zero. See section 5.2.6 of the Transmission Frameworks Review Final Report for a more detailed discussion of this rationale. The baseline expansion plan is a function of the total access provided: firm access plus reliability access. It represents the costs that the TNSP would otherwise have to incur were there to be no firm access request (that is, costs to meet reliability access plus firm access). For each marginal increase of reliability access, the

Issues raised	Stakeholder	AEMC response
		total level of access will not change (as each unit of reliability access added should replace, on a one-for-one basis, each unit of transitional access removed). The fact that the LRIC has been observed to be higher as a result of lowering transitional access below the level of peak demand can be explained by the reliability access not being added at an appropriate location on the network. This could be improved by better assumptions as to placement of reliability access in the prototype pricing model.
The pricing model conflicts with results from Frontier Economic's congestion modelling. Victorian results from the pricing model are too low.	Frontier Economics, response to First Interim Report, p. 84.	The Commission would not expect the pricing model and Frontier Economic's congestion modelling to provide the same answers: • The two approaches are measuring different things - Frontier Economics' modelling is a snapshot of current congestion, whereas the pricing model results are based on likely congestion now and in the future. • LRIC modelling is the cost of augmenting the transmission network, whereas congestion costs are based on outcomes from the wholesale market.
The LRIC pricing model utilises assumptions that do not appear to be open to stakeholder input.	Frontier Economics, Draft Report submission, p. 20.	Subject to confidentiality concerns, the assumptions and inputs into the pricing model would be subject to public consultation. See section 6.9.
Generators are subject to a stylised access price with potentially severe commercial implications while this access price is forecast by a central party (the AER) who bears no risk of forecasting error and is highly dependent on long-term inputs from third parties that have a conflict of interest in the level of access prices	Frontier Economics, Draft Report submission, p. 22.	

Issues raised	Stakeholder	AEMC response
offered to generators (AEMO and the TNSPs).		
The most pertinent pricing model assumptions are not necessarily re-examined immediately prior to or following an existing or prospective generator's access request.	Frontier Economics, Draft Report submission, p. 20.	See section 6.11.2.
The LRIC process is far less open than the RIT-T process: under the LRIC process, the volume of firm access and price paid is likely to be commercial-in-confidence, and so will be difficult for other generators to scrutinise or learn from. Where a high LRIC-based price causes a project to not proceed, other potential investors' (including new entrants') ability to scrutinise access price offers would be even more difficult and opaque.	Frontier Economics, Draft Report submission, p. 20.	Subject to confidentiality concerns, the pricing model described would be available for prospective firm generators to use independently, albeit informally, to help in deciding on their location and access level. See section 6.9. Upon a generator purchasing access, details of registered access, including the price paid, would be made public. See section 7.2.5.
Were stakeholder input sought for inputs into the pricing model, stakeholders are unlikely to be as focused or engaged in any such abstract-seeming or remote consultation exercise compared to a RIT-T.	Frontier Economics, Draft Report submission, p. 20.	The Commission considers it unlikely that stakeholders would be poorly engaged with the development and maintenance of the pricing model, given its likely materiality to stakeholders.
Under optional firm access, it is unclear how generator cost uncertainty will be reflected in LRIC prices.	Frontier Economics, Draft Report submission, p. 25.	Generator costs are not reflected in the LRIC, which instead reflects incremental transmission costs.
To the extent LRIC prices are inaccurate, the responsibility will be split between TNSPs, the AER, the AEMC and AEMO, potentially resulting in a 'blame game' between institutions.	Frontier Economics, Draft Report submission, p. 29.	See section 6.9.

Issues raised	Stakeholder	AEMC response
Inter-regional access		
Auction (including secondary trading) is likely to be the most efficient manner of offering inter-regional firm access.	GDFSA, First Interim Report submission, p. 3; Lumo, First Interim Report submission, pp. 2-3.	Agreed. See section 7.3.
Support the aggregation of bids through an auction in order to expose the maximum market value of such rights.	Stanwell, First Interim Report submission, p. 26.	Agreed. See section 7.3.1.
An auction alone may not reveal the value of a long-lived investment.	Grid Australia, First Interim Report submission, p. 8.	Noted. The Commission considers that the inter-regional auction alone is the appropriate mechanism for long-term, inter-regional procurement. See section 7.3.
Auction method of procuring inter-regional access may be unnecessary.	CS Energy, First Interim Report submission, pp. 2, 20; CS Energy, Draft Report submission, p. 9.	See section 7.3.
A generator that wants inter-regional access should be able to buy it outside of the auction process.	CS Energy, First Interim Report submission, p. 20	An auction is preferred to other procurement methods for the reasons discussed in section 7.3.1.
Parties should be able to acquire access on interconnectors for longer than one year.	MEU, First Interim Report submission, pp. 10, 15.	Agreed. See chapter 7 of the Technical Report.
Concerns regarding the governance of the inter-regional auction, particularly TNSP involvement.	CS Energy, First Interim Report submission, p. 20.	See section 6.9.
Complexity of procurement for inter-regional access compared to intra-regional access will discourage purchasing of inter-regional access.	Stanwell, First Interim Report submission, pp. 5, 24.	Noted. The Commission considers that the auction procurement method for inter-regional access is preferable to other procurement methods for the reasons discussed in section 7.3.1.

Issues raised	Stakeholder	AEMC response
Parties other than market participants should be able to acquire firm inter-regional access.	MEU, First Interim Report submission, p. 10.	Agreed. See section 7.3.1.
Unclear why the access planning standard definition is annual, but that firm interconnector rights could be auctioned in quarterly blocks.	Stanwell, First Interim Report submission, p. 24.	Noted. See section 7.3.2. The Commission has not determined all the specifics of the auction design.
Unclear as to the restrictions that would need to be placed on inter-regional access procurement.	Stanwell, First Interim Report submission, p. 24.	
It would be consistent with the concept of the optional firm access model that augmentation would be pursued if generators were willing to pay, even if the augmentation is bigger than a more "optimal" solution.	Stanwell, First Interim Report submission, p. 25.	
Consumers should not be underwriting costs if the beneficiaries are generators and retailers who have bid into the auction.	MEU, First Interim Report submission, p. 15.	See section 7.3.1. The revenue from the sale of firm interconnector rights should cover the estimated cost associated with providing new firm interconnector rights.
Increase in inter-regional access in one direction is likely to lead to an increase in capacity in the other direction. The auction should take this into account.	Stanwell, First Interim Report submission, p. 26.	Noted. See section 7.3.2. The Commission has not determined all the specifics of the auction design. However, the auction design should take this into account.
Inter-regional access based on the incorrect premise that there are discrete limitations of the interconnector assets themselves, rather than deeper on the meshed network.	CS Energy, First Interim Report submission, p. 19; MEU, First Interim Report submission, p. 10.	Under the firm access planning standard, TNSPs would be obliged to provide access. This could be achieved either through upgrading the particular interconnector asset, or other assets in the meshed network, depending on which was the cost effective way of alleviating a constraint.
How would the revised the RIT-T process allow the	MEU, First Interim Report submission, p. 15.	See section 8.3. Through its procurement decisions, a

Issues raised	Stakeholder	AEMC response
costs to exceed the benefits for inter-regional access?		generator would indicate that firm access purchased has a positive net benefit.
Concern that a TNSP factoring in intra-regional considerations into decision to expand interconnectors may (unnecessarily) favour inter-connectors.	Stanwell, First Interim Report submission, p. 25.	
What will happen to SRAs under the optional firm access model?	Lumo, First Interim Report submission, p. 3; AGL, First Interim Report submission, p. 3.	Under the optional firm access model, firm access rights will replace SRAs. A proposed phase-out of the current SRA arrangements is discussed in AEMO's Optional Firm Access Final Report.
A dominant market player may purchase all access on an interconnector to prevent other parties having access.	MEU, First Interim Report submission, p. 7.	The Commission acknowledges that the inter-regional auction would need to be well designed, to avoid this potential issue. Note that inter-regional capacity is not limited in the long-term, as additional capacity can be constructed (if signalled through the auction). See the Technical Report for possible approaches to the auction design.
Is there an interaction between the inter-regional access product and the inter-regional TUOS product that is due to commence in 2015?	MEU, First Interim Report submission, p. 15.	Any interactions between the two processes would be considered during any implementation phase for optional firm access.
How are TNSPs obliged to provide inter-regional firm access, despite the auction being run by AEMO?	MEU, First Interim Report submission, p. 15.	Inter-regional firm access that is procured through the auction would create firm access planning and operating standard obligations on the TNSP, in an identical manner to intra-regional firm access. See chapter 7.
Potentially there could be no interconnector product. Instead, generators in the exporting region could	CS Energy, First Interim Report submission,	The design of option firm access is that generators are either able to purchase access between a node in a

Issues raised	Stakeholder	AEMC response
purchase firm access in the importing region.	p. 19.	region and the local regional reference node (intra-regional access), or between regional reference nodes (inter-regional access). Therefore, under the current design, generators could not purchase firm access in the importing region as contemplated by CS Energy.
Supports the concept of short- and long-term inter-regional access.	Stanwell, First Interim Report submission, pp. 25-26.	Agreed.
Supports the market operator running the auctions with pricing input from the TNSPs.	Stanwell, First Interim Report submission, p. 26.	Agreed. See sections 7.3.3 and 6.9.
Short-term firm access		
Supports incentives to maximise utilisation of the existing network.	Hydro Tasmania, First Interim Report submission, p. 2.	Noted. See sections 7.4.4 and 7.4.5.
Short-term access issuance highly complex, although an auction is probably appropriate.	Stanwell, First Interim Report submission, p. 27.	Noted. See section 7.4 for the rationale for the short-term access procurement process.
Short-term access should be bought or sold between existing holders bilaterally. The auction process is unnecessarily complex.	CS Energy, First Interim Report submission, p. 22.	An auction is preferred for the procurement of short-term access for the reasons discussed in section 7.4. Given that an auction is preferred, it is appropriate that generators may participate in this auction to sell their existing access.
Not supportive of TNSPs being able to sell excess capacity.	CS Energy, First Interim Report submission, pp. 21-22.	Revenue from the sale of excess capacity would be allocated to TUOS customers. See section 7.4.5.
Revenue from the short-term auction should go to the party that funded the original augmentation that resulted in the spare capacity.	MEU, First Interim Report submission, pp. 15-16.	See section 7.4.5.

Issues raised	Stakeholder	AEMC response
Revenue recovered by TNSPs from short-term auction sale should be kept to a minimum.	Lumo, First Interim Report submission, pp, 3-4.	
Allocation of sales revenue from the auction depends on the provenance of the access.	Stanwell, First Interim Report submission, p. 29.	
Allocation of revenue from short-term auction needs to be defined.	Stanwell, First Interim Report submission, p. 5.	
Defining the access to be sold in the short-term auction, or using financial incentives for TNSP to reveal how much access should be sold in the short-term auction, could be problematic.	Stanwell, First Interim Report submission, p. 30.	Noted. See section 7.4.4.
The short-term firm access product may create incentives for the TNSP to down-play transmission capability to allow revenue to be earned on short-term issuance.	Snowy Hydro, First Interim Report submission, p. 10.	See sections 7.4.4 and 7.4.5.
Financial incentives are a better means to ensure TNSPs look for opportunities to increase network capacity, rather than strict obligations to sell all capacity.	Grid Australia, First Interim Report submission, p. 9.	See sections 7.4.4 and 7.4.5.
Source of access (that is, how much access is released in the short-term access) needs to be defined.	Stanwell, First Interim Report submission, p. 5.	See section 7.4.4.
Why is the short-term product limited to quarterly auctions?	MEU, First Interim Report submission, p. 15.	See section 7.4 for why auctions would be an appropriate method for procuring short-term access. The auctions would be run quarterly, although this frequency may be changed after more consideration during implementation.
Supports quarterly blocks for short-term access.	Lumo, First Interim Report submission, p. 2; Stanwell, First Interim Report submission, p. 27.	

Issues raised	Stakeholder	AEMC response
Supportive of secondary trading functionality of short-term auction.	Lumo, First Interim Report submission, p. 2.	Agreed. See section 7.4.6.
Short-term horizon should be clearly defined.	MEU, First Interim Report submission, p. 15.	Agreed. See section 7.4.2.
The distinction between long- and short-term access is artificial and undesirable for generators.	EnergyAustralia, First Interim Report submission, p. 4.	Noted. The short-term and long-term products differ in their procurement method, but the settlement outcomes for generators would be identical between short-term and long-term access. In part the distinction is driven by the lead time of development for new transmission capacity.
TNSPs should be able to hold unsold long-term access created from customer funded augmentation as an asset thus reducing their cost of capital (and hence cost to consumers).	EnergyAustralia, First Interim Report submission, p. 4.	If the creation of spare capacity due to investment to meet reliability standards is considered a problem, one possible solution is discussed with regard to reliability access in the Technical Report.
Reserve price of zero prohibits the TNSP from efficiently releasing additional capacity into the auction at a price to cover any associated cost.	Grid Australia, First Interim Report submission, p. 9.	Noted. See section 7.4.3.
Auction reserve price should apply for TNSPs offering additional firm access above that required, and for generators selling their existing access. This may create additional complexity to the auction design.	Stanwell, First Interim Report submission, p. 28.	
Reserve price of zero for access arising from existing network.	Stanwell, First Interim Report submission, p. 28.	
Short-term access dilutes long-term access. Short-term access should not have the same level of firmness as long-term access. Some short-term sales revenue should go to long-term access holders as	Stanwell, First Interim Report submission, p. 5; CS Energy, First Interim Report submission, pp. 2, 21.	See section 7.3.1 of the First Interim Report. Furthermore, TNSPs will be required to meet the firm access planning standard obligations regardless of the amount of short-term access sold.

Issues raised	Stakeholder	AEMC response
compensation. Excess capacity would be created by long-term access purchase.		Excess capacity has not been paid for, in full, by generators procuring long-term access – access is discounted to represent the spare capacity created.
Appropriate that short-term intra- and inter-regional access are issued through the same process.	Stanwell, First Interim Report submission, p. 27.	Agreed. See section 7.4.1.
Firm interconnector rights should not be aggregated before clearing in the short-term auction.	Stanwell, First Interim Report submission, p. 27.	Noted. See section 7.4.3 and the Technical Report for a description of the short-term auction design.
Concept of short-term horizon is necessary. It may be simpler to define it with reference to the current SRA forward sale period.	Stanwell, First Interim Report submission, p. 27.	See section 7.4.2.
What happens if circumstances change such that a TNSP's network no longer provides access during the firm access planning standard specified conditions, but there is not enough time to augment the network?	Stanwell, First Interim Report submission, p. 27.	See section 5.2. The obligation on TNSPs would be a planning obligation only.
Transitional access		
Generator investments were made on the basis of current implicit access design and transitional access should reflect this implicit access.	GDF Suez, First Interim Report submission, p. 4; Stanwell, First Interim Report submission, p. 36; EnergyAustralia, First Interim Report submission, p. 4.	Agreed. As described in section 9.2.1 the provision of transitional access would include some recognition of the implicit access regime that currently exists for existing generators.
Appropriate for sunk investments to be protected from significant regulatory shock.	Stanwell, First Interim Report submission, p. 36; CUAC, First Interim Report submission, p. 1; EnergyAustralia, First Interim Report submission, p. 4.	
Original sale price of formerly state owned generators likely included some consideration of costs of access.	GDF Suez, First Interim Report submission, p. 4;	Any consideration of access during the sale of a generator is a confidential, contractual matter between

Issues raised	Stakeholder	AEMC response
		the current and former owners.
TNSPs could be required to undertake consumer funded augmentations to meet generator's allocated transitional access.	Hydro Tasmania, First Interim Report submission, p. 3; CEEM, First Interim Report submission, pp. 2-3; Grid Australia, First Interim Report submission, p. 10; AEMO, First Interim Report submission, pp. 6-7.	See section 9.4.3.
The Commission should consider transitional access arrangements in the context of a scenario of low or declining demand.	Grid Australia, First Interim Report submission, p. 10.	The length of the initial X period would be considered in more detail at the implementation stage of optional firm access.
Market conditions indicate that not many new entrants are expected during the transitional period.	CS Energy, First Interim Report submission, p. 26.	
Significant time would elapse before the introduction of optional firm access, so existing generators would be able to prepare. This should be taken into account when determining transitional access allocations.	Victorian DSDBI, First Interim Report submission, p. 5.	
Increasing costs for new entrants could increase the costs relating to reductions in carbon emissions.	CEEM, First Interim Report submission, pp. 13-15.	
Any transitional access must be designed with consideration of balance sheet impacts.	EnergyAustralia, First Interim Report submission, p. 4.	Agreed. See section 9.2.1.
Allocating access to existing generators will help new investments as investors will have confidence in market design.	EnergyAustralia, First Interim Report submission, p. 4.	
Gifting of transitional access would create wealth transfer from consumers to existing generators.	PIAC, First Interim Report submission, p. 6.	Provision of transitional access through the Option iii hybrid model, along with sculpting of this transitional access, should minimise wealth transfers compared to

Issues raised	Stakeholder	AEMC response
		a direct allocation.
Transitional access allocation would be a barrier to entry for new entrants.	PIAC, First Interim Report submission, p. 6; CEEM, First Interim Report submission, pp 6-7.	As described in section 9.3.6, there would be a secondary market for transitional access. Therefore, a new entrant would be able to purchase transitional access from another generator, or firm access directly from the TNSP.
Transitional access could operate a market distortion if existing generators could raise prices due to increase costs for new entrants.	PIAC, First Interim Report submission, p. 6; CEEM, First Interim Report submission, pp. 7-9.	
Transitional access could be allocated through an auction.	CS Energy, First Interim Report submission, p. 25; PIAC, First Interim Report submission, p. 6; Snowy Hydro, First Interim Report submission, p. 12; CEEM,First Interim Report submission, p. 15-16; CS Energy, Draft Report submission, p. 11.	See section 9.3.3.
Transitional access could be allocated to new entrants when they enter during the transitional period. When a generator enters there should be enough time for any impacted existing generator to procure access up to the level they need.	CEEM, First Interim Report submission, pp. 16-17.	As discussed in section 9.3.6, it is difficult to reserve such transitional access for new generators. In addition, this would lower the location signal for new entrants and reduce the benefits of the optional firm access model.
The impact of all transitional allocation methods on wholesale prices and investment should be modelled before a choice is made on transitional access policy.	CEEM, First Interim Report submission, p. 20.	The Commission has not undertaken such modelling on the provision of transitional access since it considers that such modelling is complex, and would not be informative, since the outcomes from transitional access may be different when optional firm access is implemented.
Some transitional access would be necessary to minimise perceptions of regulatory risks to investors in generation. This should be the minimum required to maintain capital costs at low level, while minimising	CEEM, First Interim Report submission, p. 3.	See section 9.2.1.

Issues raised	Stakeholder	AEMC response
wealth transfers from consumers.		
Transitional access limits allocation to firm interconnector rights, which could restrict inter-regional trade.	Victorian DSDBI, First Interim Report submission,, p. 5; Alinta, First Interim Report submission, p. 5; Origin, First Interim Report submission, p.8.	Under Option iii participants would be able to purchase an efficient level of transitional firm interconnector rights in the initial auction, or through secondary trading. See section 9.3.6.
As new entrant plant would have the ability to decide whether to enter the market in the knowledge of firm access, the price paid for access by its competitors is immaterial.	Stanwell, First Interim Report submission, p. 34.	See section 9.3.6.
Increasing costs for new entrants while allocating free access to existing generators could delay efficient market exit by existing generators.	CEEM, First Interim Report submission, pp 11-12.	The usage of Option iii as described in section 9.3.4 would minimise this concern as existing generators considering becoming fully firm would be required to purchase transitional access. Furthermore, the X period would be for a short period such as five years.
Initial allocation of transitional access should allow TNSPs to be firm access standard compliant.	Stanwell, First Interim Report submission, p. 36.	Agreed, see section 9.3.
Any determination of initial allocation will require the cooperation of generators. There could be rent seeking behaviour, thus resulting in an excess of transitional access allocations.	CEEM, First Interim Report submission, p. 4.	The initial allocation of transitional access would be determined through a network model prepared by the TNSPs and AEMO. The potential for generator gaming would be minimal.
Sculpting is not the way to ensure consumers do not pay for an augmentation to retain transitional access for a generator. Rather, TNSPs should ask generators their willingness to pay for the retention of this access.	GDF Suez, First Interim Report submission, p. 4.	If generators are willing to pay to retain firm access, this could be done through exercising the renewal right as transitional access is sculpted back.
Agree, in principle, with the use of renewal rights and the use of the LRDC to price them.	CS Energy, Draft Report submission, p. 12.	Agreed. See section 9.4.5.

Issues raised	Stakeholder	AEMC response
Peaking plants should not be sculpted as they rely on rare critical price events for all their revenue. However, if alone among generators peaking plant were not sculpted this would overstate their required capacity at most times.	ERM Power, First Interim Report submission, p. 5.	All generation types are to be treated identically in the provision and sculpting of transitional access.
The majority of new entrants will be peaking plants and renewable generators and so only the investors in these technologies need be protected. Indeed, protecting existing generators may increase the cost of capital for new entrants if it signals a government view to protect existing generators from competition.	CEEM, First Interim Report submission, p. 4.	
Intermittent generator bids in transitional allocation should be based on analysis of their historical generation patterns relative to the peak periods, rather than their capacity.	Stanwell, First Interim Report submission, p. 48.	
As baseload generators operate closer to their capacity than peaking plant, they are more likely to be access short. May create incentives on peaking plants to cause constraints to receive access payments. Consequently baseload generation should receive a higher allocation than peaking plant.	CS Energy, First Interim Report submission, p. 29.	
Transitional access should not be allocated to existing generators as it will discourage investment in renewables.	ACF, First Interim Report submission, p. 4.	
Do not support sculpting of transitional access.	Stanwell, First Interim Report submission, p. 5; GDF Suez, First Interim Report submission, p. 4	See section 9.4.

Issues raised	Stakeholder	AEMC response
There should be a rapid and complete scaling back of transitional access.	Victorian DSDBI, First Interim Report submission, p. 5.	
There should be a liquid secondary market for transitional access which would allow new entrants to easily purchase the firm access they require, rather than sculpting of transitional access.	GDF Suez, First Interim Report submission, p. 4; Stanwell, First Interim Report submission, p. 37; EnergyAustralia, First Interim Report submission, p. 5.	
Sculpting of transitional access is likely to create an abrupt change in aggregate levels of access.	Stanwell, First Interim Report submission, p. 37.	
The potential for degradation of the transmission network is the only reason to sculpt transitional access.	EnergyAustralia, First Interim Report submission, p. 5.	
Many of the potential benefits of the optional firm access model only occur if generators are holding firm access. Sculpting of transitional access would not work towards meeting these benefits	Stanwell, First Interim Report submission, pp. 36-37.	
Transitional access should not be sculpted before generators have had a learning period, have gone through a procurement timeframe, have had time to adjust their forward contracting, and all the regulatory arrangements are fully adjusted.	Stanwell, First Interim Report submission, p. 38.	All of the identified elements are important in determining sculpting length, see section 9.4.3.
Setting residual life for transitional access with generators nominating lengths opens the way for rent seeking behaviour.	CEEM, First Interim Report submission, p.4.	The Commission considers that the process of determining generator's economic life would be difficult. See section 9.4.5.
NTNDP and similar documents are conservative about generator closures and not likely to provide rigorous foundation for determining economic life of generators.	CEEM, First Interim Report submission, p.4.	

Issues raised	Stakeholder	AEMC response
Residual amount of firm access should not be allocated to existing generators on the basis of projected plant life as projected plant life is largely arbitrary, and it will allow generators who no longer need it to monetise their access.	Victorian DSDBI, First Interim Report submission, p. 6.	
Transitional access should be allocated for an individually determined life of generator.	Stanwell, First Interim Report submission, p. 38.	
In the model used for Option i increasing demand only at the regional reference node is not reflective of constraint conditions under the firm access planning standard or reality.	Hydro Tasmania, First Interim Report submission, p. 3; Stanwell, First Interim Report submission, p. 48.	The additional load is not to represent network topography, but to allow the model to balance. The simulated load is best located at the regional reference node. See section B.5.2 of the First Interim Report.
Support allocating transitional access to generators then interconnectors.	Stanwell, First Interim Report submission, p 46; CS Energy, First Interim Report submission, p. 18.	See section 9.3.2.
Urges that caution be used when attempting to aim to maximise the allocation of access as it may result in less equitable allocations.	Stanwell, First Interim Report submission, p. 48.	Under Option iii described in section 9.3.4 all generators within a region would receive the same allocation in terms of percentage of their existing capacity.
Method proposed could potentially create a dead weight cost on generators located near interconnectors - because of the erroneous assumption that sent out energy must be consumed at the regional reference node under conditions of a non-existent constraint.	Origin, First Interim Report submission, pp. 11-12.	
Transitional access sanctions a competitive advantage to incumbent generators for 5 to 15 years.	Clean Energy Council, Draft Report submission, p. 3.	See section 9.2 for the rationale for providing transitional access.
Overall duration of transitional access of 15 years is excessive.	Major Energy Users, Draft Report submission, pp. 3-4.	

Issues raised	Stakeholder	AEMC response
In light of delay to possible implementation of optional firm access, the transitional period should commence now, allowing optional firm access to be implemented in full as early as possible, while existing generators would be aware that their transitional access would expire.	Major Energy Users, Draft Report submission, pp. 3-4.	See sections 9.1 and 9.2.
Transitional access and proposed monitoring regime will result in incentives for incumbent generators to extend their operations.	Clean Energy Council, Draft Report submission, pp. 2, 4-7.	See sections 9.1 and 9.2.
Supports the Draft Report's recommendation transitional access allocation methodology and scaling methodology. Supports that transitional access should be limited to existing capacity.	CS Energy, Draft Report submission, pp. 3, 10.	Agreed.
Sell-back of transitional access should be allowed. Consumers should be indifferent as to whether they pay for transmission replacement or sell-back.	CS Energy, Draft Report submission, p. 10.	See section 9.3.6.
Agrees that incumbent generators should be able to sell short-term access to other generators.	CS Energy, Draft Report submission, p. 10.	See section 9.3.6.
Agrees that transitional access allocation method Option iii (hybrid option) is the most suitable. Any spare capacity above the free and auctioned transitional access should be made available short-term access auctions.	CS Energy, Draft Report submission, p. 13; Major Energy Users, Draft Report Submission, p. 3.	Noted. Also note that there would be no spare capacity after the transitional access auction that could be auctioned in the short-term auction. All initial spare capacity on the network would be auctioned to generators or interconnectors, because the reserve price for that auction will be zero.

Issues raised	Stakeholder	AEMC response
Other		
Consumers should be permitted to buy firm access between two nodes on the network, in order to avoid paying network charges for assets and services that it does not use.	Major Energy Users, Draft Report submission, pp. 4-6.	MEU's proposals appear to address perceived inefficiencies with TUOS charging, rather than the issue of generator (or consumer) access to the network. The Commission does not consider that the proposed changes fall within the remit of the Optional Firm Access, Design and Testing Review.
Further development of the optional firm access model will be required to insure that its implementation would be practical and workable.	Grid Australia, Draft Report submission, p. 2.	Agreed. The Commission has flagged throughout Volumes 1 and 2 those areas of the model which it considers requires specific additional work were optional firm access to be implemented. However, as noted in Volume 1, the Commission is satisfied that the optional firm access model can be functionally implemented.
Excluding the benefits (and costs) to generators from RIT-T assessments would revert them to a cost minimisation test, rather than a test of net economic benefit maximisation. The contingent auction process as part of the RIT-T (described as a non-core element of the OFA model in the First Interim Report) would result in investment decisions that fail to take account of the detrimental impact to generators of transmission investment.	Frontier Economics, response to First Interim Report, pp. 68-71.	While benefits to generators would not be included in the RIT-T under the optional firm access model, all other benefits (that is, to networks and to consumers) would still be included. Therefore, the RIT-T would still represent a net benefit test. Generator benefits can be signalled by generators directly through their access purchase decisions. Further, in practice currently, RIT-T investments to meet the reliability standard can be undertaken as a cost minimisation exercise. Investments to meet the firm access standard could be considered similarly.

F Glossary

Defined Term	Meaning
Access	The amount of power for which a generator or directed interconnector is paid the difference between the regional reference price and local price in AEMO settlement
Access charge	The amount payable, in total, to a TNSP for procured firm access
Access price	A regulated price for some specified firm access which reflects the long-run incremental cost to a TNSP of providing that access.
Access procurement	A process through which a market participant purchases firm access from a TNSP or another firm participant
Access request	A formal request for new firm access, made to a TNSP, with specified service parameters
Access settlement	A new AEMO settlement process in the optional firm access model through which makes payments based on the difference between access and dispatch
Access unit	The generator entity that participates in access settlement. A dispatch unit or a group of dispatch units whose output is measured by a common revenue meter.
Access unit identifier	A grouping of one or more dispatchable units and auxiliary loads for use in access settlement
Adjusted cost	The present cost of the adjusted expansion plan
Adjusted expansion plan	A set of stylised expansions that are projected to be required in order to maintain firm access planning standard under an adjusted scenario
Adjusted scenario	A scenario in which an access request has been added to the baseline scenario
Auxiliary load	Load that is related to power station operation
Baseline cost	The present cost of the baseline expansion plan
Baseline expansion plan	A set of stylised expansions that are projected to be required in order to maintain the firm access planning standard under a baseline scenario
Baseline projection	A sequence of annual firm access planning standard snapshots, together with projected registered access, over a number of consecutive years, used for access pricing
Baseline scenario	A scenario in which the baseline projected eventuates
Benchmark shortfall cost	An annual dollar amount, set by the AER, which is used in the operational incentive scheme.
Capped shortfall cost	The shortfall cost after the nested caps specified in the incentive scheme have been applied. Forms the basis for the TNSP penalties and rewards payable under the incentive scheme

Defined Term	Meaning
Congested flowgate	A flowgate whose capacity is fully utilised in dispatch and which is causing dispatch to be constrained
Congestion	A dispatch condition in which one or more flowgates are congested
Congestion price	The component of the difference between the regional price and the local price that is unrelated to losses
Constrained off	A generator dispatched below its preferred output; a firm, constrained-off generator will typically be so entitled to payment from access settlements
Constrained on	A generator dispatched above its preferred output
Constraint equation	A linear inequality representing a NEMDE constraint
Counterprice flow	A flow on an interconnector which is directed towards the regional reference node with the lower regional reference price and which helps to relieve congestion
Deep connection cost	The immediate (but not future) incremental costs to a TNSP associated with providing additional firm access: that is, only including those costs that must be incurred prior to access commencement.
Directed interconnector	An interconnector in a specified direction: that is, northerly or southerly. A conceptual, inter-regional entity that participates in AEMO settlement.
Dispatchable unit	Either an individual generating unit or logically grouped generating units that are connected to the same node
Effective flowgate capacity	The flowgate capacity plus the flowgate support
Embedded generator	A distribution-connected generator
Entitlement	A flowgate entitlement
Exporting region	The region from which a directed interconnector withdraws power
Firm access planning standard conditions	The network and market conditions to which the firm access planning condition refers, for which the TNSP must plan to provide target flowgate capacity
Firm access (service)	A transmission service provided by TNSPs to generators and directed interconnectors
Firm access certificate	Proof of firm access purchase, issued by a TNSP to the purchaser
Firm access operating standard	The operating component of the firm access standard
Firm access planning standard	The planning component of the firm access standard

Defined Term	Meaning
Firm access standard	The service standard for firm access, which is the lowest level of service quality that the TNSP is permitted to provide
Firm generator	A generator with registered access equal to its capacity
Firm interconnector right	The right to receive a portion of the settlement payments made to a specified directed interconnector.
Flowgate	A point of potential congestion on the transmission network; the notional location on a transmission network represented in NEMDE by a transmission constraint
Flowgate capacity	The maximum aggregate usage of a flowgate allowed in dispatch. The right-hand side of the corresponding NEMDE transmission constraint
Flowgate entitlement	The amount of flowgate to which a generator (or directed interconnector) is entitled. When usage exceeds the entitlement, the generator must make payments into access settlement.
Flowgate participation factor	The proportion of a generator's output that uses a flowgate; the coefficient applied to that generator's dispatch variable in the left-hand side of the corresponding NEMDE constraint equation.
Flowgate price	The marginal value of flowgate capacity in dispatch: the amount by which the total cost of dispatch would increase if flowgate capacity were reduced by 1MW; calculated in NEMDE as the dual value of the corresponding transmission constraint. The rate at which a generator pays into access settlement when its usage exceeds its entitlement.
Flowgate shortfall	Any amount by which effective flowgate capacity is below target flowgate capacity.
Flowgate support generator	A generator with a participation factor less than zero in a flowgate. Its output relieves congestion on a flowgate
Flowgate usage	The amount of a generator's output notionally flowing through the flowgate; the product of the generator's output and its flowgate participation
Generator capacity	The maximum possible output for a generator. Measured empirically by identifying the highest actual output over recent history. the transmission or distribution node at which a generator, connects to the shared transmission network
Generator node	The transmission or distribution node at which a generator, connects to the shared transmission network
Importing region	The region into which a directed interconnector injects power
Interconnector	A notional entity that is dispatched by NEMDE to transfer power between two regional reference node, across a regulated interconnector
Inter-regional access	Network access provided to a directed interconnector, from the regional reference node in the exporting region to the regional reference node in the importing region

Defined Term	Meaning
Inter-regional hedge	A security which pays out an amount proportional to the inter-regional price difference in a settlement period, used by market participants to hedge inter-regional price risk
Inter-regional price difference	The difference in regional reference price between two neighbouring regions
Inter-regional settlement residue	The surplus from regional settlements that is attributed to directed interconnectors. The sum of the congestion rent and the losses residue.
Intra-regional access	Network access provided to a generator, from its generator node to the regional reference node in its local region
Local node	The location at which a generator is connected to the shared network
Local price	The amount that a generator is paid under optional firm access for a marginal increase in dispatch output. For flowgate access generators, under normal conditions, this equals the locational marginal price
Local region	The region in which the generator is connected
Long-run	In the context of access procurement, the period in which flowgate expansion is likely to be feasible; beyond the transmission expansion lead time
Long-run incremental cost	The immediate and future incremental costs to a TNSP associated with providing additional firm access
Long-run marginal cost	The long-run incremental cost calculated assuming no lumpiness of transmission expansion and no spare transmission capacity
Meshedness	Attribute of a network element which reflects the number of alternative paths between the end nodes. If the meshedness equals one then the element is radial and removing it would divide the network into two islands
NEMDE	National Electricity Market Dispatch Engine: The computer application through which AEMO calculates dispatch targets for scheduled plant in the NEM and calculates dispatch prices.
Network topology	The network model used for access pricing. Defines, for each network element, the end nodes and the admittance.
Non-firm access	The access received by a non-firm generator
Non-firm generator	A generator with no registered access.
Operational incentive scheme	A requirement of firm access operating standard, under which a TNSP is incentivised to efficiently manage the market cost of flowgate shortfalls.
Part-firm generator	A generator with some registered access that is less than its capacity
Payment profile	The schedule of access payments associated with an access charge.
Radial (constraint	A flowgate in which all participation factors are either unity or zero.

Defined Term	Meaning
or flowgate)	Typically, a thermal limit on a radial element: one whose removal would split the network into two islands.
Regional reference node	A specified node in each region which is used in setting the regional reference price
Regional reference price	The price paid to a dispatched generator in regional settlement. This is normally set equal to the regional original price, but is administered under certain conditions.
Regional settlement	The existing settlement arrangements in which generators are paid the loss-adjusted regional price for their output
Reliability access	Access provided to non-firm generators as a result of a TNSP expanding transmission to meet a reliability standard
Reliability standard	The minimum service requirement for TNSP supply to consumers
Remote region	A region other than the local region
Renewal right	The financial benefit associated with including an anticipated renewal request in the baseline projection. The renewal request is then priced at LRDC rather than LRIC
Sell-back	The process under which a TNSP cancels a firm access registration and the associated generator receives a corresponding payment from the TNSP, based on the current LRDC of that registered access
Sell-back right	The right of a generator to request a sell-back to a TNSP, which the TNSP is obliged to undertake.
Settlement Residue Auction rights	The right to receive a specified proportion of the inter-regional settlement residue for a specified directed interconnector
Shortfall costs	The flowgate shortfall multiplied by the flowgate price
Short-run	In the context of access procurement, the period in which flowgate expansion is likely to be infeasible; within the transmission expansion lead time
Stability flowgate	A flowgate that is not a thermal flowgate
Stylised expansion	A network expansion which is defined within the access pricing model
Target firm access	The lower of a generator’s registered access and capacity
Target firm entitlement	The product of the target firm access and the participation factor
Target flowgate capacity	The amount of flowgate capacity required to provide all generators and directed interconnectors with their target firm access. It equals the aggregate of the target firm entitlements. The amount of effective flowgate capacity that a TNSP must provide under firm access planning standard conditions.

Defined Term	Meaning
Thermal flowgate	A flowgate that relates to a constraint ensuring that a thermal limit is not exceeded
Transitional access	A level of firm access service that is allocated to existing generators at the commencement of the optional firm access regime and for which no access charge is payable
Transmission constraint	A constraint included in NEMDE that arises as a result of limitations on a shared transmission or distribution network and for which a constrained generator is not compensated under current arrangements