REVIEW

Australian Energy Market Commission

TECHNICAL REPORT: OPTIONAL FIRM ACCESS

Transmission Frameworks Review

AEMC Staff Paper

15 August 2012

Reference: EPR0019
Technical Report: Optional Firm Access

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Reference: EPR0019

Citation

AEMC 2012, *Transmission Frameworks Review*, Technical Report: Optional Firm Access, 16 August 2012, Sydney.

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1 Introduction

1.1 Purpose of this Document

This document provides further detail of the proposed Optional Firm Access (OFA) model, building on the description presented in chapter 3 of the Second Interim Report. The *level* of detail provided has been chosen with the objectives of:

- presenting a complete picture of how the OFA model would operate;
- providing confidence that the model contains no irresolvable difficulties or inconsistencies;
- facilitating qualitative and quantitative analysis of the possible impacts of the model on NEM efficiency;
- allowing stakeholders to analyse the potential impacts and implications for their organisations; and
- ensuring that there is opportunity for full consultation on all aspects of the model during the remainder of the transmission frameworks review.

1.2 Acknowledgement

This Technical Report has been prepared by the staff of the Australian Energy Market Commission (AEMC) to facilitate consultation on the Transmission Frameworks Review. It does not necessarily represent the views of the Commission or any individual Commissioner.

The AEMC staff acknowledge the assistance of David Smith of Creative Energy Consulting in preparing this report.

1.3 Structure of this Document

This document is structured as follows:

- Section 2 describes the fundamental concepts of access, firmness and optionality that provide the foundations and rationale for the model design, and introduces the model *elements*: the main building blocks of the model.
- Section 3 provides a top-down view of the model's scope and architecture, describing how the model elements interact with each other and with existing National Electricity Market (NEM) processes.
- Sections 4 to 10 consider each of the main model elements in turn.
- Section 11 considers potential changes to market behaviour that might be induced by the model.
- Section 12 provides technical detail on concepts, algorithms and processes used in the model.

Those sections describing the model design (section 2 and sections 4 to 10) are each subdivided into three subsections:

- The first subsection presents the *what*: a high-level description of the scope and functionality of the particular element.
- The second subsection presents the *how*: a blueprint of the element's design.
- The third subsection presents the *why*: design issues and options arising, and the rationale for selecting the proposed design.

2 Access

2.1 Overview

In the present NEM design, a generator is paid the *regional* market price on its dispatched output, irrespective of its location within a region. That is to say, its *access* to the regional market always equals its *dispatch level*: if the generator is dispatched, it automatically gets access; if it is not dispatched, it gets *no* access.

This linkage – between regional access and dispatch – is so intrinsic to the NEM design that it is easy to forget that it is a design *choice*: a choice that was made for good reasons during the original NEM development but that is neither inevitable nor irrevocable. Indeed, most electricity markets around the world do *not* link regional access to dispatch in this way.

This design choice is being revisited because of the operational and commercial issues that it creates, relating to congestion management and access certainty. The OFA model breaks the linkage and establishes a process for determining access *independently* from dispatch. Generators who require access certainty can procure a new *firm access service* from their local Transmission Network Service Provider (TNSP) and receive preferential access in return. The market's dispatch process is unchanged, with dispatch priority based on offer prices. Just as dispatch does not affect access, access does not affect dispatch.

A generator *without* access receives only a *local* price for its output. A generator *with* access receives the regional price for its output; it is compensated – based on the difference between the regional and local prices – to the extent that its output is below its access level.

Access – like dispatch – is constrained *in aggregate* by the size and reliability of the transmission network. TNSPs are therefore required to plan and operate their networks to a new *firm access standard* which ensures that a guaranteed level of access firmness can be provided to those *firm generators* that have procured firm access.

The costs that this obligation creates for TNSPs are recovered from firm generators in *access charges*. These charges provide new *locational signals* for new generation: in choosing its location and firm access level, a generator will tailor its access cost and firmness to its budget and risk appetite.

2.2 Design Blueprint

2.2.1 Regional and Local Markets

NEM dispatch is conventionally thought of as a *regional* market clearing process operating as follows:[1]

1. Generators submit dispatch offers to the Australian Energy Market Operator (AEMO) which represent the lowest price at which they are willing to be dispatched.
2. The *NEM dispatch engine* (NEMDE) determines the price at which sufficient generation can be dispatched so as to meet regional demand.
3. That price is the *regional price*, (ie the *regional reference price* or RRP), which is paid to all dispatched generators.[2]

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[1] It can also be thought of as merit-order dispatch, with the regional price set at the offer price of the marginal generator.

[2] Transmission losses are ignored in this discussion and in general in this document. They are not pertinent to the OFA model, which doesn't change the way they are calculated and applied. They are discussed in section *12.5 Transmission Losses*.

That is a reasonable description of market clearing when there are no transmission constraints interfering with dispatch: or, conversely, where the dispatch determined through the process above does not overload the transmission network.

However, this is a poor description of NEM dispatch in the common situation where transmission constraints become relevant. In this case, a more accurate description would be:

1. Generators submit dispatch offers to AEMO which NEMDE *interprets* to be the lowest *local* price at which they are willing to be dispatched.
2. NEMDE determines a local price at each node such that:
    a. sufficient generation is dispatched to meet regional demand;
    b. the transmission network is not overloaded; and
    c. subject to the above two conditions, total dispatch costs (as represented in dispatch offers) are minimised.
3. The regional price (RRP) is *defined* to be the local price at the regional reference node (RRN).
4. The RRP is paid to all dispatched generators.

In summary, there is an inconsistency between:

- *NEM dispatch*: which is a *local* market clearing process; and
- *NEM settlement*: which is designed to reflect a *regional* market clearing process.

It is this fundamental inconsistency within the NEM design which lies at the root of problems such as disorderly bidding and access uncertainty. To address these issues, the inconsistency must be addressed.

2.2.2 Dispatch and Network Access

A framework for resolving this inconsistency is to consider that a generator's *access* to the NEM is made up of two components:

1. *Dispatch access*: which gives a generator a right to submit a dispatch offer, be dispatched at its local node in accordance with that offer[3] and be paid the *local price* for its output.
2. *Network access*: which gives the generator the right, notionally, to buy an amount of power at its local node at the local price, transport it over the transmission network and sell it at the regional price.

In this model, the settlement payment to a generator is:

$$\begin{aligned} \text{Pay\$} &= \text{Pay\$}_{\text{dispatch}} + \text{Pay\$}_{\text{network}} \\ &= \text{LMP} \times \text{G} + (\text{RRP} - \text{LMP}) \times \text{A} \qquad (2.1) \end{aligned}$$

where:

G = dispatched output

A = amount of network access

RRP = regional price (regional reference price)

LMP = local price (locational marginal price)

[3] Ie dispatched if the local price exceeds its offer.

In the current NEM design, the level of network access provided is always set equal to the dispatch level (*A*=*G*) and so equation (2.1) resolves to become the more familiar:

$$\text{Pay\$} = \text{RRP} \times \text{G}$$

Dispatch access is a *physical* service: a generator must be connected to the transmission network so that it can be dispatched, and the generator must actually run to receive payment. Network access is a *financial* service: from the generator's perspective, it is simply an additional payment from AEMO, not (explicitly) relying on transmission or generation. Thus it is possible to change arrangements for the provision of network access without making any corresponding changes to the dispatch process.

2.2.3 Firm Access

The OFA model *removes* the existing link between network access and dispatch access. For each generator, the dispatch level is determined as it is currently.[4] The level of network access is set independently of dispatch; instead it is dependent on the following factors:

- the amount of *firm access* agreed with the local TNSP;
- generator availability;
- transmission availability; and
- the firm access level and availability of nearby generators.

Firm access service is a new transmission service in the OFA model, provided by each TNSP to generators in its region.[5] Generators can choose the amount of firm access service that they wish to procure from their TNSP and are charged by the TNSP for this.

The target level of network access for each generator is equal to its availability; a generator will never receive more than this and will sometimes receive less. The reliability with which the network access level is at, or close to, the target level is referred to as the *firmness* of access. A generator that has procured firm access service will receive a firmer level of network access than one who has not.

Because dispatch access is unchanged in the OFA model, it is only referred to in this section of this document. Thus, in other sections, *network access* will generally be referred to simply as *access*.

2.2.4 Settlement Balancing

Equation (2.1) above can be rewritten as follows:

$$\text{Pay\$} = \text{RRP} \times \text{G} + (\text{RRP} - \text{LMP}) \times (\text{A-G}) \qquad (2.2)$$

The first term is exactly the same as the generator settlement payment in the existing NEM design.[6] The second term is a *new* settlement payment introduced in the OFA model and is referred to as *access settlement*. A fundamental principle of the OFA model is that *aggregate* settlement payments are unchanged. To achieve this, access settlement – when aggregated across all generators – *must* net out to zero.

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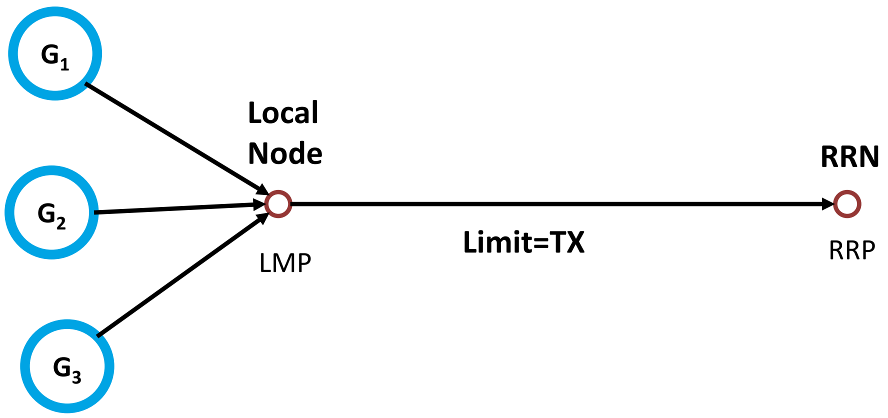
4 There is no change to the dispatch *process*. However, changes to bidding incentives will lead to changes in dispatch *outcomes*.

5 It may be useful to clarify the OFA model terminology at this point, since it can be a little confusing. *Access* always means *network access*, being the MW volume on which RRP is paid in AEMO settlement. *Firmness* means the reliability with which anything (in this case access) is provided. *Firm access* is a service provided by TNSPs. The design of the OFA model ensures that a generator that has procured firm access service *does actually obtain* a firm level of network access. See Glossary for the defined terms used in the OFA model.

6 Again, ignoring transmission losses for simplicity.

The implications of settlement balancing are discussed below for a simple two-node network, shown in Figure 2.1. The more general situation of a meshed, multi-node network is discussed in section *4.2.6 Flowgate Pricing and Settlement Balancing*.

Figure 2.1 Two-node network example



In this example, all generators are connected to the same node, so LMP is the same for each generator.[7] Dispatch and access will vary between generators, so define:

A_i = access for generator i

G_i = dispatch for generator i

Then, from equation (2.2), the access settlement payment to generator i is:

$$\text{Pay\$}_i = (RRP - LMP) \times (A_i - G_i) \qquad (2.3)$$

The total payment across all generators is then:

$$\sum_i \text{Pay\$}_i = (RRP - LMP) \times (\sum_i A_i - \sum_i G_i)$$

If the transmission line connecting the two nodes is uncongested then RRP=LMP and so the access settlement payments are zero: individually and collectively. If the line *is* congested then, for settlement to balance, we must have:

$$\sum_i A_i = \sum_i G_i$$

But, since the line is congested we know that:

$$\sum_i G_i = TX$$

where:

TX = transmission capacity

Therefore, a sufficient condition for settlement balancing is:

$$\sum_i A_i = TX \qquad (2.4)$$

Thus the setting of generator access levels involves sharing, or *allocating*, the available transmission capacity between various generators. A similar result holds in general on a meshed network, as explained below.

[7] There must also be a generator connected to the RRN that sets the RRP but this generator does not participate in access settlement and so is ignored in the analysis below.

2.2.5 Flowgates, Usage and Entitlements

In the OFA model, the locations in the shared network where congestion *may* occur are referred to as flowgates. In the simple network shown in Figure 2.1 there is a single flowgate, lying between the two nodes. In a real, meshed network, there are hundreds of flowgates: congestion can potentially occur on any transmission line. Locations where congestion actually occurs are called *congested flowgates*. In the simple network example, the flowgate is congested. In a real, meshed network, *several* flowgates may be congested at any point in time.[8]

Table 2.1 below lists the variables that are defined in the OFA model for each congested flowgate, and shows the values they take in the simple two-node example.

Table 2.1 Settlement variables and their equivalents in the two-node model

Variable	Acronym	Description	Value in 2-node model
flowgate price	FGP	the value of network access through the flowgate	RRP-LMP
flowgate usage	U	the amount of a generator's output that flows through the flowgate	G
flowgate entitlement	E	the amount of network access that a generator is allocated through the flowgate	A
flowgate capacity*	FGX	the maximum aggregate flowgate usage which the flowgate can accommodate	TX

(*) Flowgate capacity is conceptually different to transmission capacity, as discussed in section *12.2.3 Transmission Capacity versus Flowgate Capacity.*

Using the new terminology, we can rewrite equation (2.3) as:

$$\text{Pay\$}_i = \text{FGP} \times (E_i - U_i) \qquad (2.5)$$

Equation (2.4) can also be rewritten, as:

$$\textstyle\sum_i E_i = \text{FGX} \qquad (2.6)$$

In the OFA model, equations (2.5) and (2.6) apply to *all* congested flowgates in all meshed networks. They are the basic building blocks of access settlement and are discussed further in section *4 Access Settlement*.

2.2.6 Access Allocation

When transmission capacity is allocated, *preferential* access is given to *firm generators*: those who have procured firm access service from the TNSP. Access is only provided to *non-firm generators* (those who have *not* procured firm access) if and when all firm generators have been provided with their target access level. Algorithms for allocating access between firm and non-firm generators are described in section *4 Access Settlement*.

[8] Which may mean a handful of flowgates, and certainly not hundreds. It is only the *weakest* links in the transmission network which constrain dispatch, meaning that the myriad *stronger* links cannot become congested.

2.2.7 Firm Access Standard

Equation (2.6) means that, *overall*, access can only be as firm as the transmission network: at the extreme, if there is no flowgate capacity, there can be no access. In the OFA model, a TNSP is required to ensure that a sufficient level of flowgate capacity is available to provide the necessary access firmness to all firm generators, individually and concurrently. This requirement is called the *firm access standard* (FAS). The FAS ensures that firm generators are provided with at least a specified level of access firmness. The FAS takes no account of non-firm generators, who will therefore receive an inferior level of access firmness.

Even for firm generators, access is required to be *firm* but not *fixed*. That is to say, the FAS allows firm generators' allocated access to be below target under specified circumstances: for example, when there are transmission outages. The FAS is discussed further in section *5 Firm Access Standard*.

2.2.8 Access Charges

Because a TNSP is required to expand and maintain its transmission network so as to comply with the FAS requirement, it incurs costs in providing firm access service to generators.[9] This cost is recovered from firm generators, through an *access charge*. The access charge is determined when new firm access is agreed. It is fixed[10] for the life of the *firm access agreement*, to ensure maximum financial certainty for firm generators. The charge is based on the forecast *incremental cost* associated with the new access.

A TNSP has no obligations in relation to *non-firm* generators and so their presence does not directly create any additional costs. Therefore, non-firm generators do not pay access charges.

Access charges are discussed further in section *6 Access Pricing*.

2.2.9 Flowgate Support

The discussion above considers situations where:

- there is no congestion and so LMP=RRP; or
- there is congestion which causes LMP<RRP.

A third possibility is that congestion causes LMP>RRP. This occurs where a generator's dispatch helps to *relieve* transmission congestion: the premium in the LMP reflects the value to the market of it doing this. In the OFA model, such generators are referred to as *flowgate support* generators. Irrespective of whether they are firm or non-firm, these generators are always paid the RRP. This is done by setting the entitlement level equal to the usage level, so that access settlement payments are zero (from equation 2.5). Usage - and hence entitlement - is based on dispatch so, for flowgate support generators, access and dispatch are *not* delinked. The rationale for this design decision is discussed in section *2.3.9 Flowgate Support and Constrained-on Generators*.

2.2.10 Summary

Setting access levels based on access agreements with TNSPs, rather than on dispatch, is a conceptually simple change, but it addresses many of the outstanding transmission issues in the transmission frameworks review, by simultaneously defining the level of access that generators are *entitled to* and the level of transmission capacity that TNSPs are *obliged to provide*. Clear rights

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[9] Unless there is so much spare capacity, the new access does not affect future transmission expansion.

[10] Except for some defined indexation.

and obligations are the foundation stone of an efficient market. The OFA model builds on this simple premise to construct a new access framework for the NEM.

2.3 Design Issues and Options

2.3.1 Disorderly Bidding

In the current NEM design, disorderly bidding occurs when there is congestion within a region. The driver for this behaviour is that network access is linked to dispatch level: a generator can only maintain its network access by maintaining its dispatch level and, during periods of congestion, it must reduce its offer price to ensure this.

Therefore, *any* NEM design that de-links network access from dispatch level will solve the problem of disorderly bidding.[11] Reform packages 2, 4 and 5 in the First Interim Report all de-link access from dispatch and so all address disorderly bidding. However, in package 4, the delinking is just the first step in addressing several issues, of which disorderly bidding is only one.

2.3.2 Financial Certainty for Generators

A generator's *operating margin* is the difference between its revenue from AEMO settlement and its variable generating costs. If, for simplicity, we assume that a generators has a fixed *marginal cost* of generation, *C*, then its variable generating costs are *G x C*. Using the revenue formula in equation (2.1) its operating margin in the OFA model is:

$$\begin{aligned} \text{Margin\$} &= \{ \text{LMP} \times \text{G} + (\text{RRP} - \text{LMP}) \times \text{A} \} - \text{C} \times \text{G} \qquad (2.7) \\ &= (\text{LMP} - \text{C}) \times \text{G} + (\text{RRP-LMP}) \times \text{A} \\ &\equiv \text{dispatch margin} + \text{access margin} \end{aligned}$$

Note firstly that a generator is dispatched only if *LMP ≥ Offer Price*.[12] Therefore, as long as a generator bids *at cost* (*Offer Price* = *C*) or higher, the dispatch margin is never negative. This result reflects another fundamental principle of the OFA model: that a generator never *regrets* being dispatched, in the sense that it is never financially worse off from being dispatched than it would have been had it *not* been dispatched.[13]

For a generator investor, the margin *certainty* is critical. Leaving aside the uncertainty of RRP itself (which can be hedged through forward contracts, as discussed in the next section), a major determinant of margin certainty is access firmness. In the current NEM design, if a generator is not dispatched, it has zero access. This means it loses its dispatch margin *and* its access margin. In the OFA model, access is independent of dispatch, so only the dispatch margin is lost, not the access margin. Consider a situation where transmission congestion causes – or coincides with – very high regional prices: RRP could be as high as $10,000/MWh, whereas LMP might be as low as $20/MWh.[14] In these circumstances, the loss of dispatch margin is immaterial; a loss of access margin is critical.

Since margin certainty now depends upon access firmness rather than dispatch firmness, firm generators will have more certainty than they do presently. However, non-firm generators will

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[11] Assuming that it is narrowly characterised as bidding -$1000 when there is intra-regional congestion.

[12] As noted in section *2.2.2 Dispatch and Network Access* this is a fundamental right associated with dispatch access, which is provided to all generators.

[13] Clearly, if it is not dispatched, its dispatch margin is zero.

[14] Based on the cost of the generators behind the constraint.

generally have *less* margin certainty, because their access firmness in the OFA model is likely to be *worse* than their dispatch firmness currently.[15]

Another way of describing this feature is that firm access service provides a *hedge* against dispatch risk.

Recall equation (2.2) from above:

$$\text{Pay\$} = \text{RRP} \times \text{G} + (\text{RRP} - \text{LMP}) \times (\text{A-G}) \qquad (2.8)$$

The first term is the current AEMO settlement and the second term is the new access settlement. If dispatch is reduced when regional prices are high, the amount in the first term falls but the amount in the second term rises to offset that fall. Thus, the access settlement payment *hedges* the generator against dispatch risk, similarly to how forward contract payments hedge RRP risk.

In the first interim-report, equation (2.8) was characterised as meaning that firm, constrained-off generators (having *A*>*G*) receive, through settlement, compensation from the non-firm, dispatched generators (having A<G) causing the congestion. That description remains *broadly* true but, in the revised OFA model presented here, terms such as constrained-off and non-firm may be imprecise or misleading. The more precise terms *access-long* (for A>G) and *access-short* (for A<G) are used instead.

2.3.3 Forward Trading

The analysis above demonstrates that firm access reduces the margin risk associated with dispatch uncertainty. However, a major driver of margin risk remains: RRP volatility. Generators hedge this risk currently by selling forward contracts: swaps (or other derivative structures) against the RRP. A generator will receive payments under a forward swap equal to:

$$\text{Pay\$} = \text{F} \times (\text{FP} - \text{RRP})$$

where:

F is the quantity of forward sales

FP is the forward price

When this payment is added to the equation (2.7) the adjusted operating margin becomes:

$$\begin{aligned}\text{Margin\$} &= (\text{LMP} - \text{C}) \times \text{G} + (\text{RRP-LMP}) \times \text{A} + \text{F} \times (\text{FP} - \text{RRP}) \\ &= \text{F} \times (\text{FP} - \text{C}) + (\text{A-F}) \times (\text{RRP-C}) + (\text{G-A}) \times (\text{LMP-C}) \qquad (2.9) \\ &= \text{forward margin} + \text{spot regional margin} + \text{spot local margin}\end{aligned}$$

Exposure to RRP is through the middle term: the spot regional margin.[16] The exposure depends upon the relative levels of access and forward sales and is independent of dispatch.

The middle term in equation (2.9) highlights the concerns that generators have under the existing NEM design and how these are addressed by the OFA model. In the current NEM, A=G, so if a generator is constrained off (ie *not* dispatched, because of congestion), its access is reduced and any high RRP will adversely affect its margin (because A<F). In the OFA model, a generator that procures sufficient firm access can be confident that A will be reliably higher than F under a range of transmission conditions and so risks from congestion coinciding with high RRP are substantially mitigated.

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[15] Put another way, since the overall level of access firmness is dependent on transmission firmness, providing greater access firmness for firm generators inevitably means providing lower access firmness for non-firm generators.

[16] A generator may also have exposure to RRP in the last term, when there is no congestion and so RRP=LMP. This situation is the same as in the current NEM design and the RRP risks are unaffected by the OFA model.

The spot local margin, *(G-A) x (LMP-C)*, will always be non-negative for a generator that bids at cost, because:

- If (LMP-C)>0 then the generator is fully-dispatched and so (G-A)≥0.[17]
- If (LMP-C)<0 then the generator is not dispatched and so (G-A)≤0.
- if LMP=C then the margin equals zero.

2.3.4 LMP rather than Offer Price

The "no regrets" principle discussed above could have been achieved by paying the generator its offer price rather than LMP, so that equation (2.1) becomes instead:

Pay$ = G x Offer Price + (RRP – Offer Price) x A

LMP has been chosen in the design for two reasons: conceptual and pragmatic. Conceptually, LMP is the clearing price in the local market and this is what a generator with dispatch access, but no network access is entitled to. Pragmatically, if generators were paid at offer price, this would create a pay-as-bid market[18] at each generator node; when there was no congestion in a region, this pay-as-bid market would extend across the region. Pay-as-bid markets can be inefficient, because they encourage generators to rebid to earn close to the clearing price, potentially leading to disorderly bidding.[19]

Effective rebidding would in any case see generators bidding at, and earning, close to LMP. It is preferable, therefore, just to pay LMP in the first place and avoid the rebidding problem.

2.3.5 Firm Access, not Fixed Access

Access payments in the OFA model are similar in some ways to payments made under a regime of Fixed Transmission Rights (FTRs), as seen in some electricity markets in the US and elsewhere. A key difference, though, is that FTRs generally provide a *fixed* MW level of network access. Since transmission capacity still varies, but total access is fixed, transmission will at times exceed total access (creating an access settlement *surplus*) and at other times fall short of total access (creating an access settlement deficit). FTR markets absorb these surpluses and deficits by *smearing* settlement payments across settlement periods.

FTR markets typically have highly-meshed transmission systems, meaning that extreme settlement deficits or surpluses are unlikely. In the NEM's much less meshed network, a fixed access approach could give rise to very large deficits in some settlement periods which could not possibly be recovered from surpluses in other periods. Settlement would become untenable.[20] Therefore, a fundamental principle of the OFA model is that access settlement balances in each settlement period.[21] To achieve that principle, a *firm* - rather than *fixed* - access design has been chosen for the OFA model.

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[17] Recalling that access can never exceed availability in the OFA model.

[18] A pay-as-bid market is a market design where each dispatched generator is paid its offer price rather than a common market clearing price.

[19] Although not of the "bid -$1000" variety. Rather, each generator would rebid constantly to *chase* the LMP as it varied up and down.

[20] Unless an uplift charge were levied on customers to fund any unrecoverable deficits

[21] Ie each 30-minute trading interval.

2.3.6 Optionality

Another fundamental principle of the OFA model is its *optionality*: generators are entitled to *choose* the level of firm access that they wish to pay for. An alternative approach would have been to provide firm access as a mandatory service to all generators. That approach would be similar to the Generator Reliability Standards option described in the first interim report.

Optionality is considered an important feature, because it allows generators to reveal and signal the level of access firmness that they require, rather than this being decided for them by a regulator. It means that, in planning a new generation investment, investors have two degrees of freedom: the location and the level of firm access.

2.3.7 Fixed Access Charge

In the OFA model, the access charge is fixed for the life of an access agreement, similar to connection charges currently. An alternative approach would have been for annual access charges to vary according to an annual pricing methodology, similar to demand-side transmission use of system (TUOS) charges. Fixed charges have been chosen for two reasons: to give certainty to generators; and to give certainty to TNSPs.

The certainty provided to generators is obvious, the certainty to TNSPs, less so. If charges were to vary annually, generators would respond by procuring *shorter term* access: generators would be reluctant to sign up to a long-term agreement where prices could be changed annually in an uncertain and unforeseeable way. At the expiry of the shorter term access agreements, generators would only renew their firm access if, in the near term, access prices were low or congestion risks expected to be high. The resulting variations in the level of firm access – and access revenue – would create major risks for TNSPs and also for demand-side users who, under proposed TNSP regulation, would be required to cover any access revenue shortfalls.[22]

Thus, having fixed (or, at least, reasonably stable and foreseeable) access pricing is the preferred design option when there is *optionality* in firm access procurement. Conversely, where transmission pricing varies annually, it is usually in the context of a mandatory (not optional) transmission service: for example, in TUOS pricing in the NEM.

2.3.8 Free Non-firm Access Service

It may appear that non-firm generators are getting something for nothing: network access (albeit at an uncertain level) for no access payment. This might be contrasted with non-firm gas shippers (say) who still pay a transmission charge, albeit lower than firm shippers.

This view is not entirely correct. Non-firm shippers implicitly pay for the cost of transmission losses – whether or not they obtain network access – and losses represent *most* of the variable costs of electricity transmission. Apart from losses, variable transmission operating costs[23] are small and difficult to identify and measure. The OFA model implicitly approximates these costs as being zero: an approximation which is unlikely to have any material impact on generator behaviour or market efficiency.

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[22] Discussed in section *8 TNSP Regulation*.

[23] That is to say, the incremental operating costs associated with a line being loaded compared to it not being loaded.

2.3.9 Flowgate Support and Constrained-on Generators

In the OFA model, a flowgate support generator is allocated an entitlement equal to its usage.[24] This ensures that a generator – whether firm or non-firm – is never paid a price (in settlement overall) higher than the RRP, even if its LMP is higher than RRP.

This approach might appear asymmetric and unfair: a generator without network access is only paid LMP when it is *lower* than RRP, but is not paid LMP when it is *higher* than RRP. It is also potentially inefficient, since a generator that is *constrained on* (ie dispatched despite its offer price exceeding the RRP) will rebid unavailable if it is paid only RRP, but would willingly be dispatched if paid the LMP (which, as always, can be no lower than the offer prices of dispatched generators).

There are several reasons for the approach taken in the OFA model:

- Flowgate support generators are not currently paid LMP and it is not clear that it would be appropriate to do so.
- Where flowgate support generators assist a TNSP in maintaining the FAS, a TNSP could enter into network support agreements with them, just as they do currently in relation to demand-side reliability standards.
- Generators with pricing influence might, if paid LMP, be able to cause very high LMPs. These high LMPs would distort outcomes and would create high risks for access-short generators at associated flowgates.
- Constrained-on situations are dealt with currently through directions and direction compensation and it is not clear that modification to these arrangements is necessary.

In many ways flowgate support is a mirror image of flowgate access. It would be possible to create an *optional firm support* model as a mirror image of the OFA model, in which the *TNSP* procures and pay for flowgate support *from* generators and *firm support generators* are required to make payments *into* settlements if their dispatch is less than their *agreed support level*. Such a model could efficiently address constrained-on problems in the NEM, just as the OFA model addresses constrained-off issues. However, the model would be complex to design and the cost of its implementation would likely be disproportionate to the problems it aims to solve. It is therefore not being proposed at this stage. It could potentially be developed and introduced at a later date.

2.3.10 Interconnectors

The NEM has two different types of interconnectors: regulated interconnectors and market interconnectors (or *MNSPs*). The OFA model provides optional firm access for both types. Regulated interconnectors are discussed in section *10 Inter-Regional Access*.

MNSPs use TNSP shared networks in the two regions that they interconnect. In the region that they draw power from (the *exporting region*) they are a demand-side user and so beyond the scope of the OFA model. In the region they deliver power into (the *importing region*), they are similar to a generator, in the sense that they inject power into the shared network at a specific node. Therefore, access provision to an MNSP in the importing region is exactly the same as for a generator. An MNSP would decide how much firm access to procure, using similar criteria to a generator.[25]

[24] Which will be negative, since its participation factor is negative.

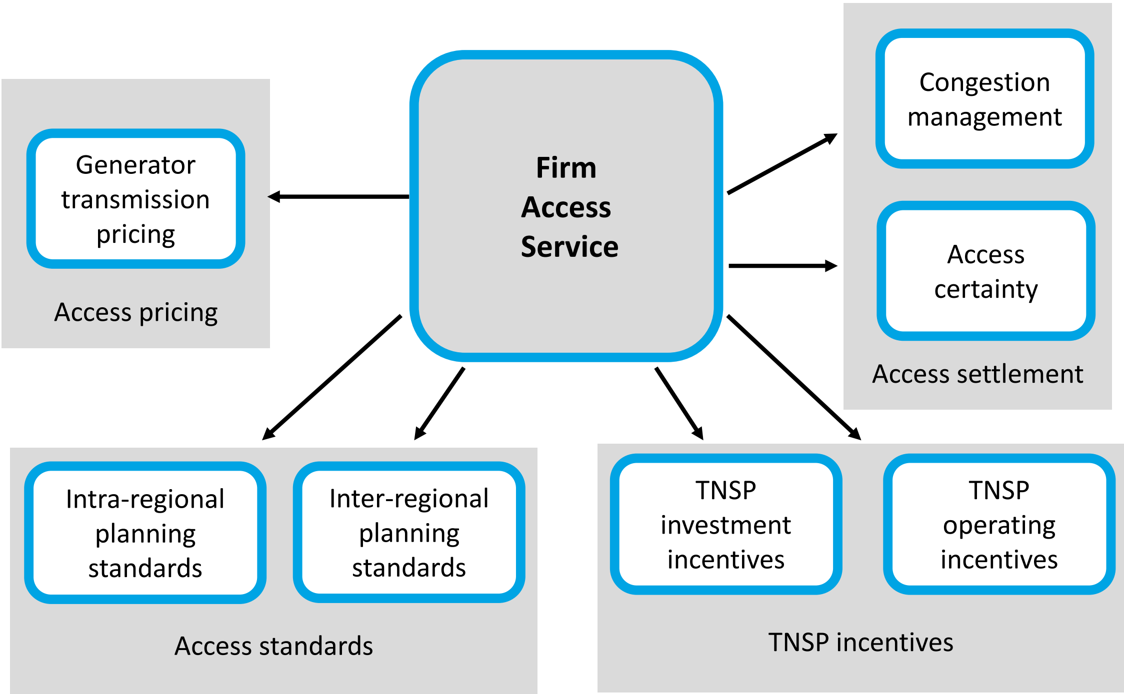
[25] An MNSP can flow power in both directions and so there are potentially two importing regions in which it might seek firm access. However, the only MNSP in the NEM currently is Basslink, which connects to the RRN in Tasmania, and so would only require network access in Victoria.

3 OFA Model Overview

3.1.1 Model Scope

The OFA model is designed to address issues arising on the *generation-side* of the *shared* transmission network. These issues all arise because of the way that network access is provided to generators in the current NEM design, and are addressed in the OFA model by the introduction of the firm access service, and the delinking of network access from dispatch. This scope is illustrated in Figure 3.1, below, which shows how the resolution of all of these issues has a common factor: the introduction of firm access service.

Figure 3.1 Transmission issues addressed by the TFR model

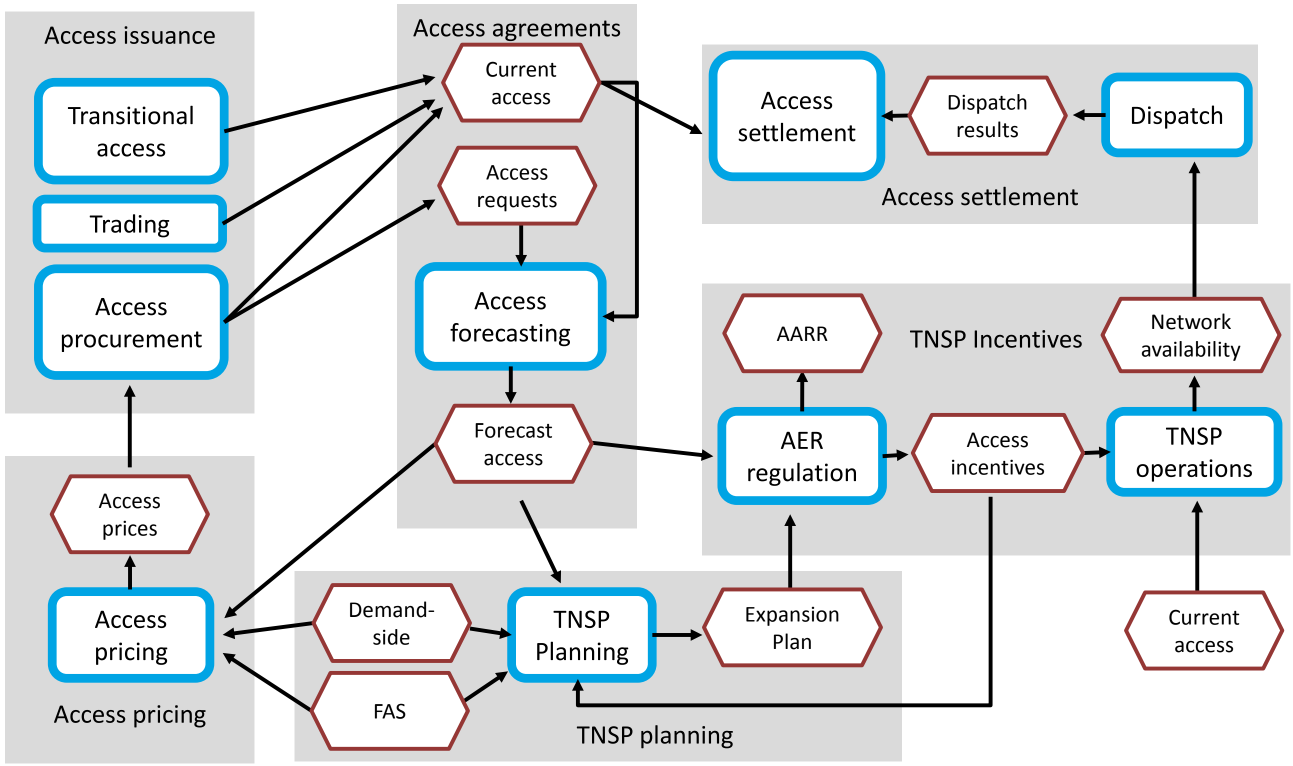


The OFA model does not address, and is not intended to address, transmission issues outside of this scope.

3.1.2 Model Architecture

The architecture of the OFA model is presented in Figure 3.2, below.

Figure 3.2 Optional firm access model architecture



Although many processes associated with transmission provision and use will change under the OFA regime, this document focuses on five key processes – and one new standard - that are either new or substantially augmented from the status quo, as presented in Table 3.1, below.

Table 3.1 Key OFA model processes

Process/Standard	Status	Document Section
Access Settlement	New	4
Firm Access Standard	New	5
Access Pricing	New	6
Access Procurement	New	7
TNSP Regulation	Augmented	8
Transition	New	9
Inter-regional Access	New	10

These processes are considered in turn in the sections below.

4 Access Settlement

4.1 Overview

Access settlement is the process which *effects* the de-linking of network access from dispatch, described in section 2 *Access*. Network access is allocated to generators based on their agreed access level and their availability, taking into account the competing access demands of other generators and the fundamental constraint that, to ensure settlement balancing, aggregate network access cannot exceed flowgate capacities.

Existing AEMO settlement calculations and processes are unchanged.[26] Existing settlement payments provide a level of network access *equal* to dispatch level. Therefore, where the access to be allocated to a generator is higher than its dispatch level, the generator *receives* payments *from* access settlements in order to *increase* its network access. On the other hand, where allocated access is *lower* than its dispatch level, a generator makes payments *into* access settlement in order to *reduce* its network access.

Access settlement occurs around congested *flowgates*: bottlenecks in the transmission network which are represented by binding transmission constraints in NEMDE. Typically, there are no more than a handful of congested flowgates in a region in any particular settlement period, so access settlement, whilst conceptually complex, should be straightforward for AEMO to implement.

A generator's *participation* in a flowgate is the proportion of its output that flows through the flowgate. Participation factors are currently calculated by AEMO for every generator and for every potentially congested flowgate, and appear as coefficients in the corresponding NEMDE constraint equation. A 1000MW generator with a 10% participation in a flowgate, say, would have just 100MW of its output flowing through the flowgate.[27] This 100MW is referred to as its flowgate *usage*.

Correspondingly, if that generator is to have 1000MW of network access, it must have 100MW of access on that flowgate. In the OFA model, access on a flowgate is referred to as an entitlement. A *target entitlement* is the entitlement that would be required to provide a certain level of network access. However, to ensure settlement balances, total entitlements on a flowgate must equal the capacity of the flowgate and so not all target entitlements can be provided. An *entitlement scaling* process takes place in access settlement that gives priority allocation to firm generators so that their targets are met before any entitlements are allocated to non-firm generators.

For each generator at each congested flowgate, the access settlement payment is defined to be the difference between entitlement and usage, multiplied by the *flowgate price*: the value of the corresponding NEMDE constraint. Generators whose entitlement exceeds their usage (typically constrained-off firm generators) will *receive payments* from access settlement. Generators whose usage exceeds their entitlement (typically dispatched non-firm generators) will *make payments into* access settlement.

4.2 Design Blueprint

4.2.1 Architecture

Recall from section *2.2.5 Flowgates, Usage and Entitlements* the basic equations of flowgate settlement:

$$\text{Pay\$}_i = \text{FGP} \times (E_i - U_i) \qquad (4.1)$$

$$\textstyle\sum_i E_i = \text{FGX} \qquad (4.2)$$

Access settlement calculates the amounts payable to or from each generator by applying these equations through three processes, presented in Table 4.1 below.

[26] With the exception of the calculation and allocation of the inter-regional settlements residue, discussed further in section *10 Inter-Regional Access*.

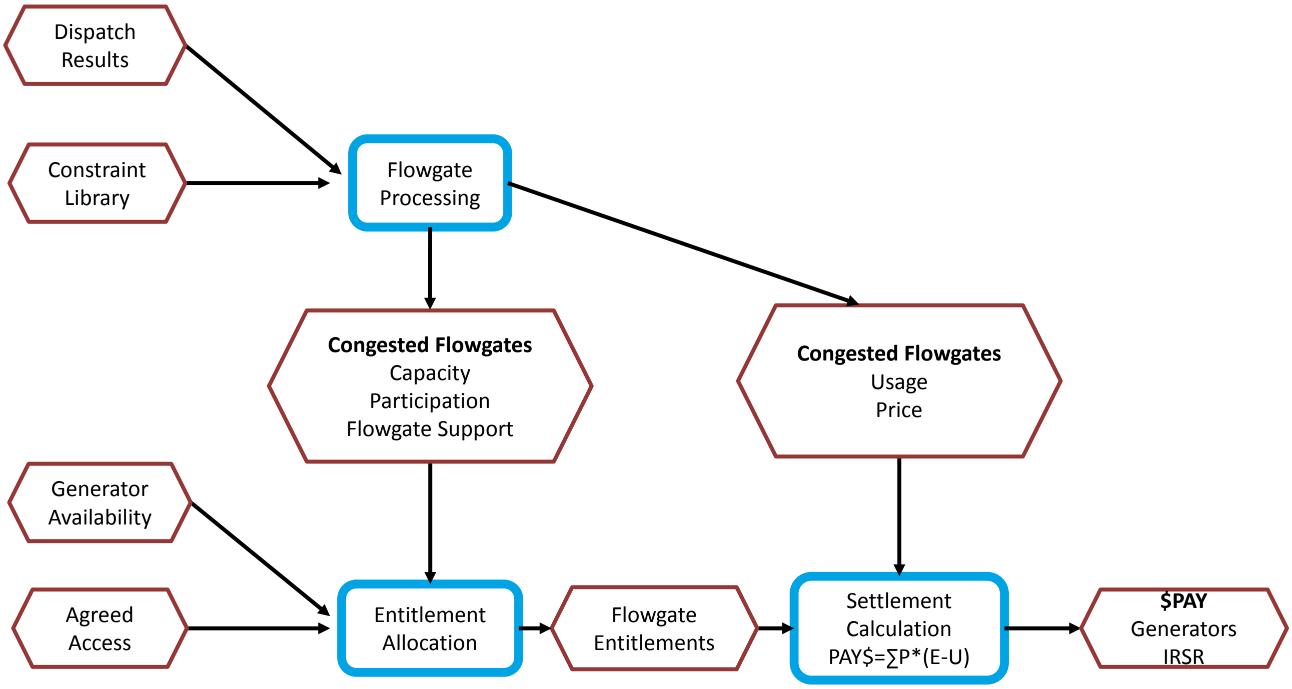
[27] Notionally, of course. It is not possible to *physically* track generator output through a shared network.

Table 4.1 **Access settlement processes**

Process	Description
Flowgate Processing	Determines price, capacity, usage and other relevant variables for each congested flowgate
Entitlement Allocation	Allocates the flowgate capacity between generators, ensuring that total entitlement equals flowgate capacity
Settlement Calculation	Applies the formula Pay$ = FGP x (E-U) to each generator at each congested flowgate

The linkages between these processes and existing NEM databases are shown in Figure 4.1, below.

Figure 4.1 Access settlement processes



4.2.2 Flowgates

Although the term *flowgate* comes originally from gas transmission,[28] in the electricity context it means any bottleneck that potentially constrains dispatch and which is therefore represented by a *transmission constraint* in NEMDE.[29] The generic, linear form of transmission constraints in NEMDE provide us with all of the parameters of a flowgate that we need for access settlement. Thus, a generic NEMDE constraint takes the form: [30]

$$\sum_i(\alpha_{ik} \times G_i) \leq RHS_k \qquad (4.3)$$

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[28] In that context, it is where gas does literally flow through a gate: typically a point of connection between two gas pipelines at a point where gas flow is both commonly constricted and easily measured.

[29] In the AEMC congestion management review, *constraint support price* and *constraint support contract* were terms used to describe flowgate prices and flowgate access, respectively.

[30] Although access settlement does not rely on the constraint being in that form; only that the constraint coefficients, a_i, are clearly defined. This is discussed further in section *4.3.5 Unusual Constraint Formulations*.

where:

i is the generator index and k is the flowgate index

Equation (4.3) provides the following quantities used in access settlement:

a_{ik} is the flowgate *participation factor* for generator i on flowgate k

$U_{ik} \equiv a_{ik} \times G_i$ is the *usage* of flowgate k by generator i

RHS_k is the *flowgate capacity* for flowgate k

Thus, the generic constraint is re-framed in the OFA model as:

total usage ≤ flowgate capacity

Formulating the transmission constraints is a complex process undertaken by AEMO experts using sophisticated power system software. This complexity is transparent to the OFA model: access settlement needs to know *what* the flowgate parameters are, but not *why* they are what they are. Correspondingly, it is not necessary to understand the intricacies of power systems in order to understand the OFA model. Access settlement takes the flowgate parameters as *read*, and moves on from there. An explanation of the physical meaning and derivation of the NEMDE constraints – and their application to the OFA model – is provided in section *12.2.2 Flowgate Participation*.

4.2.3 Target Entitlements

Recall that the existing NEM design provides a generator with a level of network access equal to its dispatch level. If we wished to give generator the same level of access in the OFA model, we would need to ensure that its settlement payments are unchanged; that is to say, that its *access settlement* payments are zero. From equation (4.1) we can see that this is achieved by providing that generator with an entitlement on each flowgate:

$$E_{ik} = U_{ik}$$

where:

E_{ik} = is the *entitlement* of generator i on flowgate k

Using the formula for usage, we have:

$$E_{ik} = \alpha_{ik} \times G_i$$

And, since the network access level A_i is then equal to G_i, we have:

$$E_{ik} = \alpha_{ik} \times A_i \qquad (4.4)$$

Thus, in general, to provide a generator with access level, *A*, it needs to be allocated entitlements on a flowgate equal to $a \times A$ using the relevant participation factor, a.

Equation (4.4) is another fundamental building block for access settlements. It provides values for *target* entitlements: the entitlements that would need to be allocated to deliver a target level of access. These targets are calculated dynamically: as congestion arises at different flowgates, the relevant participation factors are extracted from the corresponding NEMDE constraints and target entitlements are then automatically calculated for each participating generator.

Access settlement calculates three access amounts for each generator, based on the agreed access level and the offered availability, as described in Table 4.2 below.

Table 4.2: Calculation of access amounts

Access Level	Formula
Firm access amount	Lower of agreed access and availability
Non-firm access amount	Amount (if any) by which availability exceeds firm access amount
Super-firm access amount	Amount (if any) by which agreed access exceeds availability

For each access amount, a corresponding target entitlement is determined for each flowgate, being the entitlement amounts that would need to be allocated to deliver that access amount, using equation (4.4). A numerical example demonstrating the calculation of target entitlements is presented in section *12.7.2 Target Entitlements*.

4.2.4 Entitlement Scaling

The aggregate of all target entitlements on a congested flowgate will always *exceed* the flowgate capacity[31] and so not *all* entitlement targets can be met. An entitlement scaling algorithm is used to determine *actual entitlements* from the scaling back of target entitlements, based on the principles that:

- total actual entitlements must equal flowgate capacity;
- a single *firm scaling factor* is applied to all firm and super-firm entitlements, and a single *non-firm scaling factor* is applied to all non-firm entitlements;
- firm entitlements are only scaled back when non-firm actual entitlements have already been scaled back to zero; and
- super-firm actual entitlements are only provided to the extent necessary to offset the scaling back of firm entitlements.

The detailed algebra for determining the scaling factors and entitlements, together with a numerical example, is presented in section *12.7.3 Actual Entitlements*.

Generators can informally be placed into one of four categories according to their relative levels of agreed access and availability, as presented in Table 4.3 below.[32]

Table 4.3 Generator access categories

Generator Type	Description
Super-firm generator	agreed access> availability
Firm generator	agreed access = availability
Part-firm generator	agreed access<availability
Non-firm generator	agreed access = 0

Figure 4.2, below, illustrates the level of entitlements that would be allocated to generators in these four access categories under decreasing levels of flowgate capacity. For simplicity, these generators are assumed to have identical availabilities and participation factors.

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[31] The aggregate of the target entitlements is what the total flowgate usage would be if all of the generators were dispatched at full output. If flowgate capacity exceeded this level the flowgate could not possibly be congested.

[32] The categories are for illustration only and are not considered explicitly in the access settlement algebra.

Figure 4.2 Entitlement scaling for four access categories

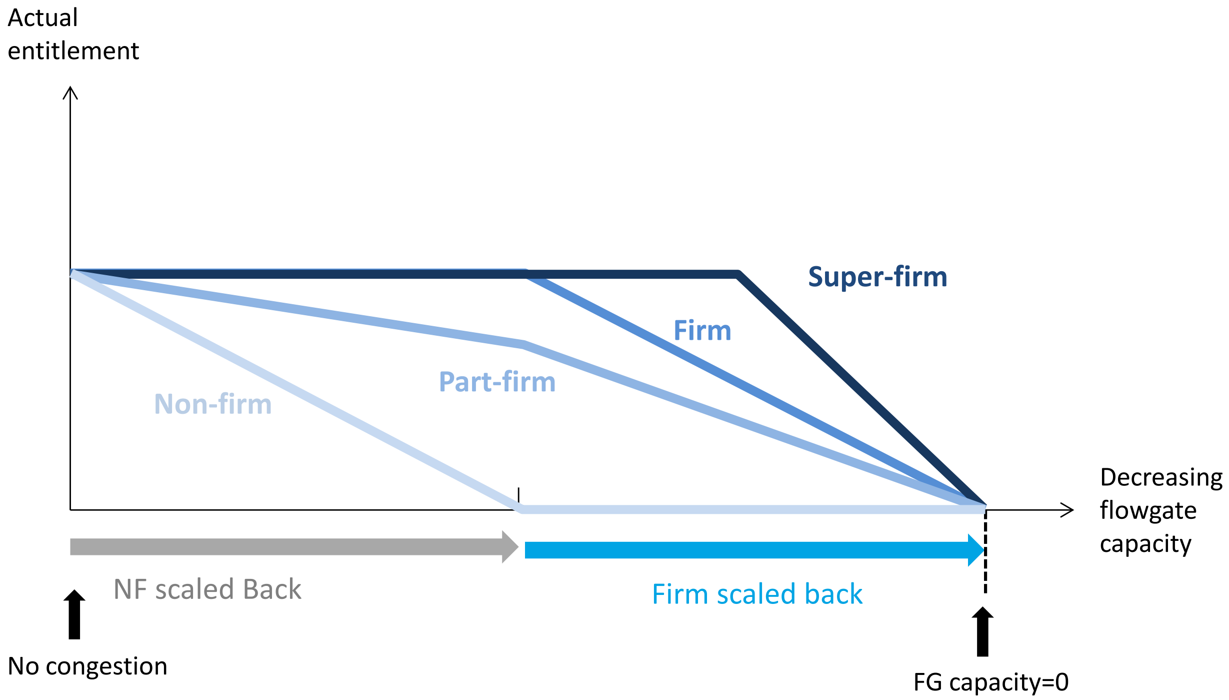
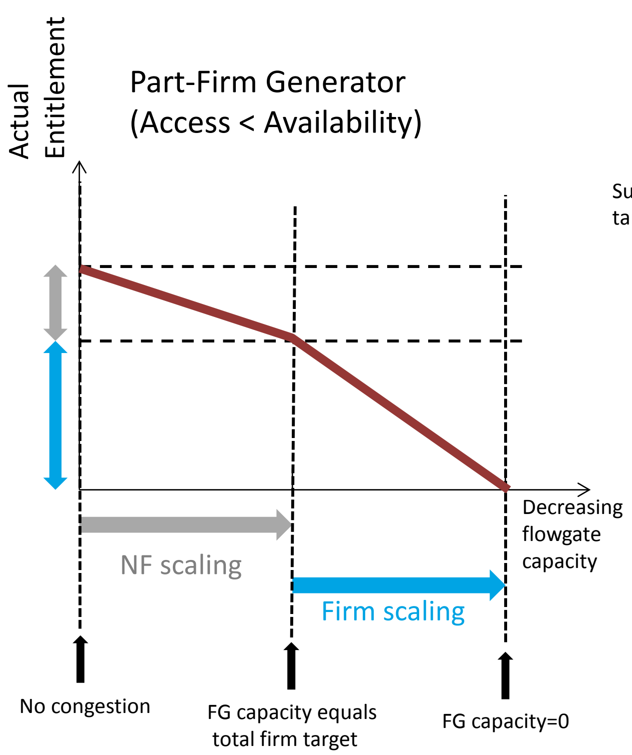
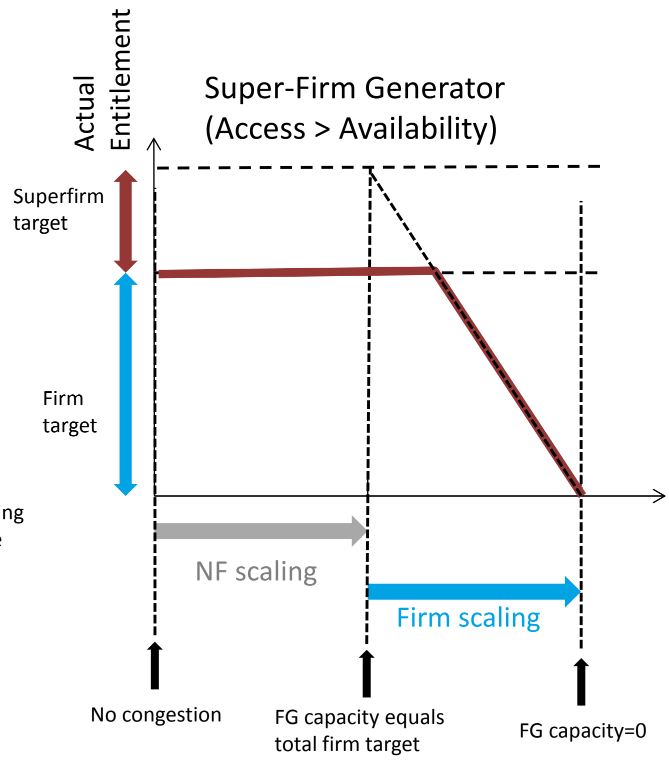


Figure 4.3 shows actual entitlements relative to target entitlements, for a super-firm and a part-firm generator. It will be seen that non-firm targets are only taken into account once firm targets have been fully met.

Figure 4.3 Actual entitlements compared to target entitlements





4.2.5 Flowgate Support Generation

In the description above, it has been implicitly assumed that all participation factors in a flowgate are *positive*. In fact, participation factors can be, and commonly are, *negative*. A generator with a negative participation factor is referred to in the OFA model as a *flowgate support* generator with respect to that particular flowgate. It will be noticed, from the formula for usage, that a dispatched flowgate support generator has *negative* usage, which means its dispatch *relieves* congestion on the flowgate (hence its name).

Flowgate support generators are always provided with (negative) actual entitlements equal to their (negative) flowgate usage.[33] The flowgate *support* amount (a positive number) is the total absolute level of entitlements allocated to flowgate support generators.

Since total actual entitlements must always equal flowgate capacity, flowgate support generators increase the *effective* level of flowgate capacity that is allocated through the entitlement scaling algorithm. For example, if flowgate capacity is 1000MW and flowgate support is 100MW, the entitlement scaling algorithm allocates 1100MW between the remaining generators.

4.2.6 Flowgate Pricing and Settlement Balancing

Access settlement is based on the difference between entitlement and usage on a flowgate, multiplied by the *flowgate price*. The flowgate price is defined to be equal to the value (or shadow price) of the corresponding transmission constraint in the settlement period, as calculated by NEMDE.[34] Thus, for each generator and each congested flowgate:

Payment$ = Flowgate Price x (Actual Flowgate Entitlement – Flowgate Usage)

The sum of all settlement payments for a flowgate is therefore:

Total Payment$ = flowgate price x (Total Flowgate Entitlement – Total Flowgate Usage)

Since the flowgate is congested, *total flowgate usage equals flowgate capacity*. Furthermore, the entitlement scaling algorithm ensures that *total flowgate entitlement equals flowgate capacity*. Thus *total entitlement equals total usage* and so the total payment$ is zero. Access settlement balances for each flowgate in each settlement period and, therefore, always clears in aggregate.

Section *12.2.9 Generator Access Settlement* describes how access payments based on this settlement algebra ensures that generators receive the proper levels of network access and dispatch access, as defined in section *2 Access*.

4.2.7 Settlement Period

The settlement period is a trading interval (30 minute period), the same as for existing NEM settlement processes. However, many of the dispatch variables – such as flowgate prices, usages and capacities – are calculated by NEMDE each dispatch interval (5 minute period). These quantities are converted in access settlement to 30 minute equivalents, generally through simple arithmetic averaging. The approach taken is discussed in section *12.4 Thirty Minute Settlement*.

4.2.8 Grouped Entitlements

Generators are permitted – but not required – to form an *access group*. Grouped generators are able to pool their agreed access and, in doing so, will often receive higher actual entitlements than they

[33] This is to ensure that they have no exposure to access settlement and thus are simply paid, as now, the RRP on their dispatched output. Refer to section *2.3.9 Flowgate Support and Constrained-On Generators* for an explanation of this design decision.

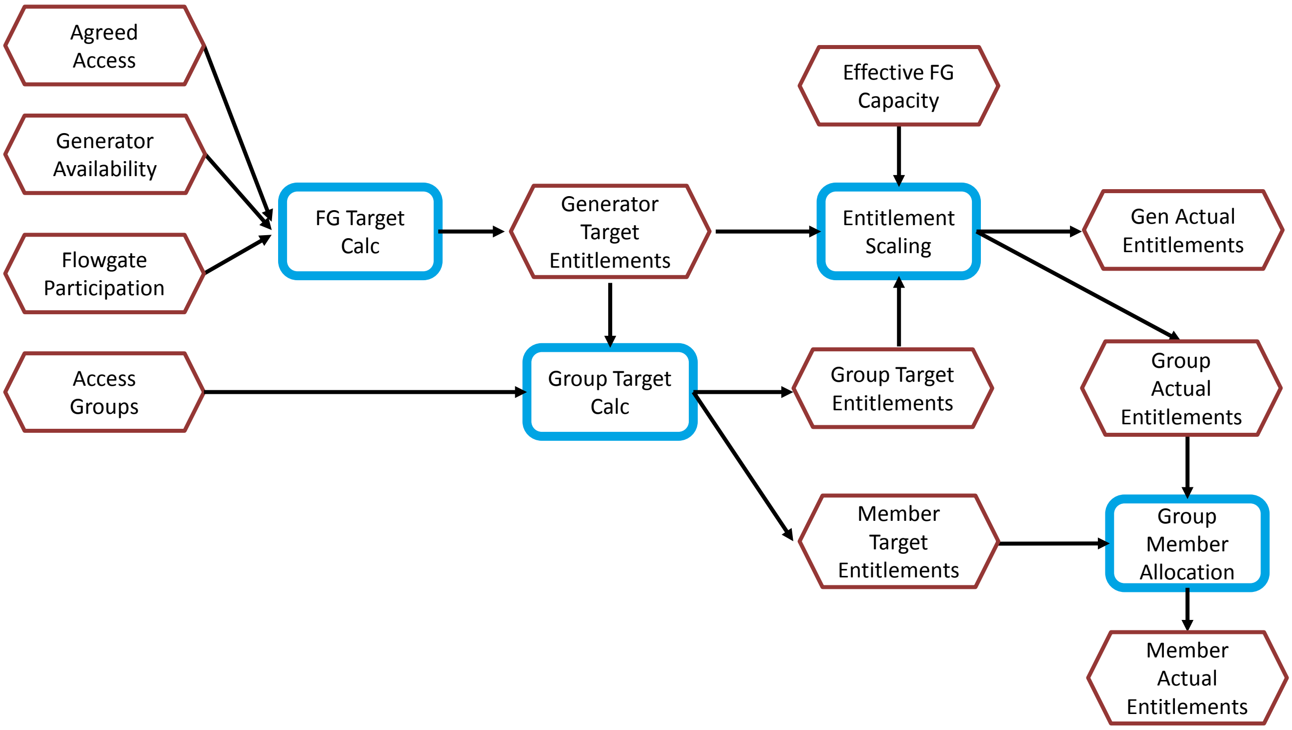
[34] The economic meaning and relevance of flowgate prices is discussed in section *12.2.4 Flowgate Prices*.

would have as non-grouped individuals. Grouping will be most beneficial for generators who share common flowgates and who have low levels of availability, *weakly correlated* with those of fellow group members.

Group target entitlements are calculated in a similar fashion to generator target entitlements, but based on the *aggregate* availability and *aggregate* agreed access amounts of group members, rather than the individual amounts.[35] Actual entitlements are allocated to *groups* by the entitlement scaling algorithm, based on the group target entitlements and *as though* the group was an individual generator. The group actual entitlement is then allocated between group members, based on member target entitlements and again using the same entitlement scaling algorithm.

A process map for determining grouped and ungrouped entitlements is presented in Figure 4.4, below. Algebra for, and numerical examples of, group entitlement scaling and allocation are presented in section *12.7.4 Grouping*.

Figure 4.4 Group access and entitlements



Groups must be notified to AEMO so that it can properly undertake access settlement. Group members will have already procured firm access from their local TNSP(s) and do not require TNSP permission to form the group.[36] A generator[37] cannot belong to more than one group.

Groups would typically need an internal agreement between members to prevent cheating or free riding.[38] If a group were large, involving several major generating companies, such an agreement may require ACCC exemption or authorisation in order to avoid breaching Competition Law.

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[35] In fact, because members are typically located at different nodes, what is aggregated is the product of *participation* and availability or access amount, respectively.

[36] Grouping should not affect TNSP rights or obligations. Each group member must still separately pay its TNSP in accordance with its access agreement. Since the TNSP has agreed to provide firm access levels to each group member individually, it is able to provide a corresponding aggregate level for the group. Grouping does not make the FAS obligations any more onerous.

[37] Or strictly speaking, an individual power station.

[38] For example, a group member not procuring its own firm access but relying on others' agreed access.

4.2.9 Summary

Access settlement undertakes two main tasks. Firstly, it rations access to congested flowgates, giving preferential access to firm generators. Secondly, it provides payments to generators dispatched below their (scaled) access levels and recovers the cost of this from generators dispatched above their (scaled) access levels.

Access settlement is conceptually complex, but it is practically straightforward, for two reasons. Firstly, all of the information required to calculate settlement amounts is either already present in the existing dispatch process (eg the flowgate formulations and prices) or is specified in the access agreements (eg agreed access amounts). Secondly, the nature of transmission congestion is that only a handful of flowgates are likely to be congested at a time in each region. So, the settlement algorithm will never be computationally onerous, and the verification and analysis of settlement statements by generators will be relatively straightforward.[39]

4.3 Design Issues and Options

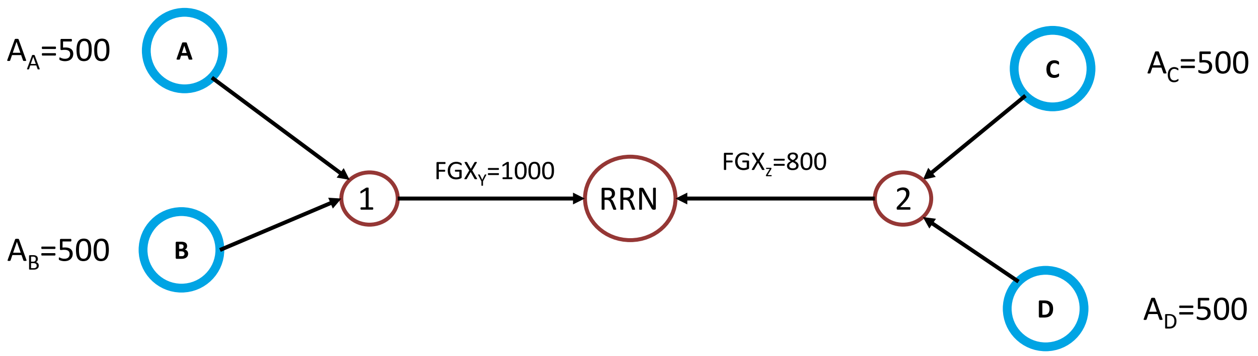
4.3.1 Use of Flowgate Prices rather than Nodal Prices

Section 2 *Access* describes access settlement in terms of the difference between RRP and LMP. However, LMPs are not mentioned at all in the settlement blueprint and, as discussed in section *12.2 Flowgate Pricing and Local Pricing* it is complex to demonstrate that the use of FGPs and LMPs can be financially equivalent. Which raises the question: why not just use LMPs?

The reason for using flowgate pricing lies in the entitlement scaling process. The regional optional firm access model presented in the first interim report (ie package 4) used LMPs and then scaled back access settlements *pro rata* across a region to ensure settlement balance. The latest OFA design is considered to be a substantial improvement on that previous design, for reasons discussed below.

Consider Figure 4.5 below. There are two congested flowgates: flowgate Y between node 1 and the RRN; and flowgate Z between node 2 and the RRN. The capacity of flowgate Y is sufficient to accommodate the firm generation connected to node 1 and using that flowgate. However, the capacity of flowgate Z is insufficient to provide firm access levels to generators connected at node 2.

Figure 4.5 Example three-node radial network



Scaling of entitlements at a flowgate level allows for access levels to be maintained from node 1 but scaled back from node 2, so only generators C and D are impacted by the capacity shortfall on flowgate Z. A regional scaling approach would have required effective access levels of *all* firm generators to be scaled back.

[39] Generator traders are typically already well aware of transmission constraints and their impacts on dispatch.

These characteristics make the flowgate approach not only fairer but also more efficient and transparent. It is more efficient because, in deciding on location and firm access levels, generators will only take account of flowgate capacity and firmness on flowgates affecting their location. Access decisions should not be – and will not be – affected by congestion in other parts of the region.[40]

It is more transparent, because access settlement occurs only on congested flowgates. These will – in any particular settlement period – typically be few in number, and only a subset will affect any individual generator. It is relatively straightforward for a generator to monitor and verify entitlement scaling and flowgate pricing on a few, relevant, flowgates. It would much harder to monitor every single flowgate in the region.

4.3.2 Target Access based on Availability rather than Preferred Output

There is another significant improvement to the OFA model since the first interim report. In the earlier model, target access for firm generators was based on *preferred output*. In the current design it is based on *availability*.

Preferred output is the level at which a generator *would* be dispatched (according to its dispatch offer) in the absence of congestion.[41] Preferred output represents the level at which a generator is seeking access. For example, when the RRP is low, a peaking firm generator is unlikely to wish to be dispatched (ie its preferred output is zero) and so is unlikely to require access.

The practical difficulty with preferred output is that it is dependent on the dispatch offer and so is easily *manipulated* by rebidding. If access were to be based on preferred output, the peaking firm generator mentioned could simply rebid to make it *appear* as though its preferred output was full output.[42] So, whether access is based on preferred output or availability, the outcome will be the same. However, the current approach avoids the problem of rebidding that would have bedevilled the earlier design.

4.3.3 Target Access Limited by Availability

A related design question is why target access should be limited by availability. Why shouldn't a generator be provided with its agreed access amount, even if this exceeds availability?

The answer lies in the discussion of the previous issue. Availability is used as a *proxy* for preferred output, given that rebidding means that a generator never has to reveal its true preferred output. However, it is clear that true preferred output cannot exceed availability, so availability (if lower than agreed access) is always a better estimate of preferred output than agreed access.

4.3.4 Firm Generator may be liable to pay into Access Settlement

In the previous OFA model, a firm generator would *never* make payments *into* access settlement: it was either out-of-merit, dispatched or constrained-off. In these three cases it would receive nothing, RRP and compensation, respectively. That model implied that a firm generator would always receive agreed access if dispatched, even if other, constrained-off, firm generators had their access scaled back. Similarly, a non-firm generator could only receive a level of access that was at or below its dispatch level. In this design, then, there was some residual linkage between access and dispatch, creating the potential for some disorderly bidding to continue.

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[40] For example, a SW Queensland generator should not have to take account of possible congestion in North Queensland.

[41] Assuming no change in the RRP.

[42] It can do this by bidding at a price anywhere between LMP and RRP so that it appears to be constrained off.

In the revised OFA model, access and dispatch are *totally* de-linked. This creates the possibility of two counter-intuitive situations which could not have arisen in the previous OFA model:

- a *firm* generator making payment *into* access settlement; and
- a *non-firm* generator receiving payment *from* access settlement.

The first situation could arise where a firm generator is fully dispatched and (coincidentally) has its entitlements scaled back. For example, suppose a 1000MW generator procures 1000MW of agreed access. In a settlement period, it is fully dispatched to 1000MW but has its firm access scaled back to 800MW. It is access-short by 200MW and must pay *into* access settlement.

The second situation would arise where a non-firm generator is not fully dispatched, but is (coincidentally) allocated some (non-firm) entitlement. For example, a 500MW generator is dispatched to 100MW and receives 150MW of entitlement. It is access-long and so is paid *from* access settlement.

These situations will be relatively uncommon but can (and should) nevertheless occur from time to time. In short, a firm generator does not *get* fixed access; and a non-firm generator does not get *zero* access. Each gets different degrees of access firmness and these are unrelated to dispatch levels.

4.3.5 Unusual Constraint Formulations

Those familiar with NEMDE constraints will point out that these rarely have the simple form expressed in equation (4.3). For example, AEMO often uses *feedback constraints*, taking the form:

change in usage ≤ spare flowgate capacity in prior period + change in flowgate capacity

In a feedback constraint, and other non-standard constraint formulations, the RHS of the constraint does not represent flowgate capacity.

To ensure that access settlement correctly extracts the information it requires from NEMDE constraints, no matter what their form, the following approach is taken:

- participation factors are taken from the coefficients that are applied to generator dispatch variables on the LHS of the NEMDE constraint;
- flowgate capacity is calculated from flowgate usage

Coefficients must exist in all NEMDE constraint forms, because they are necessary for NEMDE to operate. Therefore, usages on a flowgate can always be calculated and aggregated. For a congested flowgate, flowgate capacity *by definition* equals total flowgate usage. It is not necessary to explicitly calculate the constraint RHS.

4.3.6 The Potential Benefits of Grouping for Intermittent Generators

Entitlement grouping provides a mechanism through which generators with low capacity factors that use the same flowgates can share firm access, particularly where their output is uncorrelated. The mechanism is likely to be most useful to intermittent generators who could potentially substantially reduce their cost of firm access; or, conversely, could obtain a much firmer level of access for a given cost. For the mechanism to be effective:

- the generator's average availability[43] must be substantially less than registered capacity;

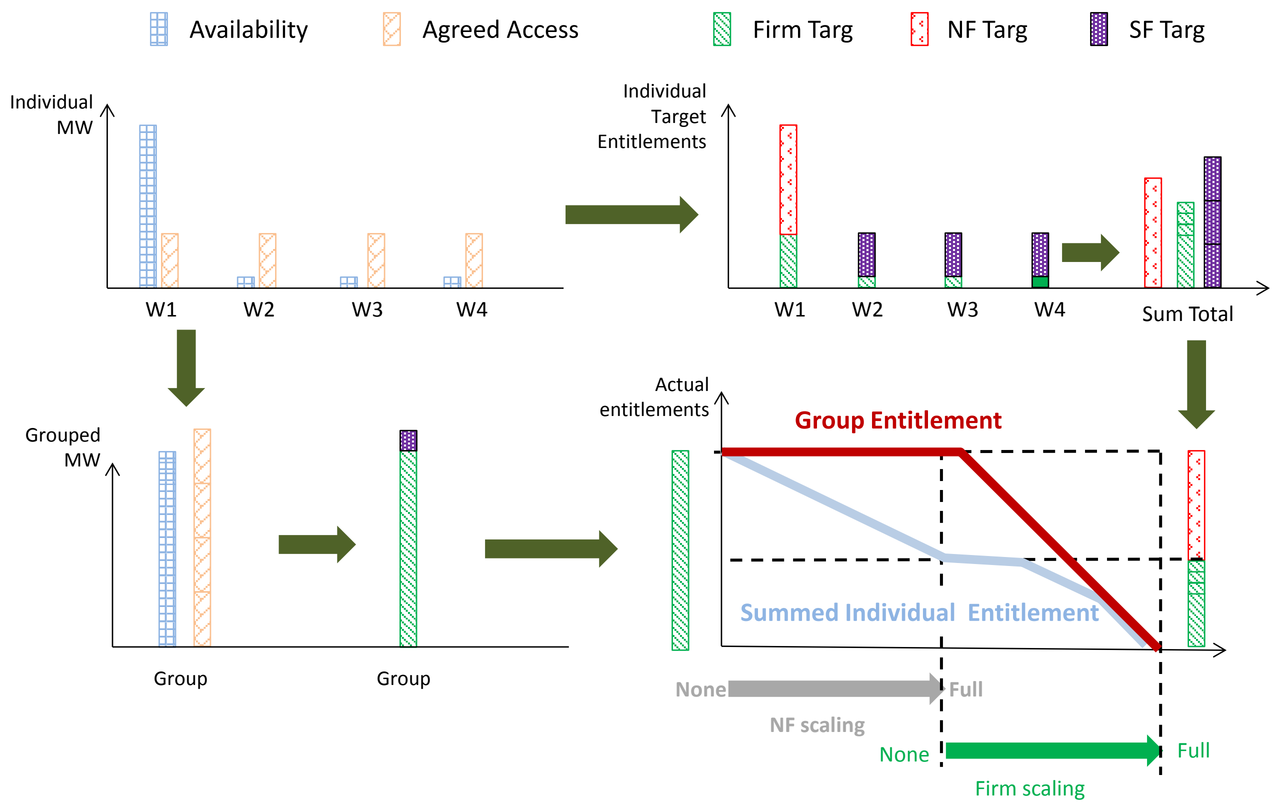
[43] For an intermittent generator, the measure of availability used in the OFA model is the unconstrained intermittent generation forecast (UIGF), which represents the generator's true ability to generate if dispatched, not the offered availability.

- the generator's availability must have low correlation with the availability of other generators in the group; and
- the generators in the group must have common participation in the flowgates that most affect their dispatch.

Wind generators in a local zone might meet those criteria. However, there is an intrinsic trade-off in that, the more proximate the group members, the more closely correlated their availability is likely to be. Quantitative modelling is required to assess to what degree these criteria are met and the consequent benefits realisable from grouping.

Figure 4.6 below illustrates the benefits of grouping. It illustrates aggregate target entitlements for four wind generators, with and without grouping. For simplicity, participation factors are assumed to be 100%, so target entitlements are equal to access amounts. It shows a snapshot in one settlement period, where one generator (W1) has full availability and the other three (W2-W4) have low availability. It is assumed the capacity factor of each group member is around 25% and, correspondingly, each group member agrees firm access for 25% of its output.

Figure 4.6 The benefits of grouping



If ungrouped, the surplus access of W2-W4 gives rise to super-firm target entitlements, which provide only limited firmness benefit. On the other hand, W1 is short of firm access, leading to a non-firm target entitlement which, of course, is the first to be scaled back during congestion. Thus, across the four generators, aggregate entitlements are generally scaled back substantially.

When grouped, aggregate access is compared to aggregate availability in setting entitlement targets. Because these aggregates are (in this snapshot) quite similar, a large firm target entitlement is set and this ensures a lower amount of scaling back in most circumstances.

The diagram does not show the allocation of the group entitlement between the four members. However, recalling that entitlement cannot exceed availability, most of the entitlement will be allocated to W1. To get a similar level of entitlement without grouping, W1 would have had to procure an amount of firm access closer to its capacity: ie 4 times more which would correspondingly cost 4 times as much.

This is only a snapshot in a single settlement period. So long as average availabilities of the W1-W4 were similar, the benefits of grouping would, over the medium term, be shared evenly between them.

5 Firm Access Standard

5.1 Overview

The *quality* (ie the firmness) of the firm access service is predicated on the capacity and reliability of the shared transmission network that underpins it. Thus, two ingredients are required to provide generators with confidence that service quality will be maintained: a *service standard* that specifies the minimum service quality that must be provided to *each user*; and a corresponding *network standard* that specifies the minimum level of transmission capacity that the TNSP must build and maintain to provide the minimum service quality to *all users*. The *Firm Access Standard* (FAS) performs both of these roles. A generator can obtain a service with a higher or lower *effective* firmness than this standard by procuring an *agreed access amount* that is higher or lower, respectively, than its generating capacity.

The agreed access amount specified in each access agreement is a *nominal* amount and is not required to be provided in *every* single settlement period in which the agreement is active. Rather, a minimum amount of access must be provided which is a *specified percentage* of the nominal amount. The percentage, or *FAS scaling factor*, will vary according to transmission conditions prevailing in the particular settlement period.

In planning and operating its network, a TNSP must ensure that it can provide the FAS-defined level of service to every firm generator concurrently: since it is possible that every generator will require access at the same time. Thus, the FAS – in combination with the set of all access agreements – defines a *network standard*: a minimum level of transmission capacity that must be provided under each type of operating condition. A TNSP must also ensure that it continues to maintain existing *demand-side reliability standards*, which still apply alongside the OFA model.

5.2 Design Blueprint

5.2.1 The Role of the FAS

The FAS provides the nexus between access agreements and other transmission processes such as network planning and operations, access pricing, and TNSP incentive regulation. A TNSP must ensure that, in real-time, it always has sufficient *available* transmission capacity to provide at least the minimum level of access that the FAS specifies. That obligation drives operational decisions and also, through the TNSP forecasting future access demand, drives planning decisions.

5.2.2 FAS Definition

The FAS is defined by different, specified tiers of *normal operating conditions* (NOCs) and a *FAS scaling factor* for each tier. The minimum access level that must be provided to each firm generator in each settlement period is then:

minimum access level = agreed access amount x FAS scaling factor for current NOC tier

The FAS will be defined in a FAS table, as illustrated in Table 5.1 below.

Table 5.1: Illustrative FAS table

Operating condition tier	Description	FAS scaling factor
Normal operating condition tier 1	System normal	100%
Normal operating condition tier 2	Minor change from system normal	90%
Normal operating condition tier 3	Moderate change from system normal	80%
Normal operating condition tier 4	Major change from system normal	50%
Abnormal operating conditions	Severe change from system normal	0%

The FAS defined in the table above is generic and illustrative. Defining an actual FAS will be undertaken during OFA implementation and will involve TNSPs, AEMO and generators. In defining the NOC tiers it is important that:

- they are *clearly defined*, such that the correct tier can be unambiguously identified within settlement timescales;[44]
- they do not encourage *perverse* TNSP behaviour: for example, deliberately taking a line out of service so that its FAS obligation is reduced;
- they are *relevant* to generators: for example, if generators are most concerned about congestion during planned outages, these must be covered by a NOC tier which gives a relatively high access level; and
- they reflect a full range of transmission conditions and the likely impact of these conditions on transmission capacity.

Ideally, the FAS scaling factors will be tapered such that, in general, a transmission network designed to maintain the FAS under NOC1 will also *just about* maintain the FAS under NOC2, NOC3 etc,[45] although there would always be exceptions.[46]

Section *12.8 TNSP Planning and Operations under the Firm Access Standard* discusses in more detail how a TNSP might monitor and manage its FAS obligations.

5.2.3 FAS and Access Firmness

The FAS defines the level of firmness of access that a TNSP *must ensure is provided* to a firm generator. If a generator procures an agreed access amount, AQ, then it is entitled to a level of access in a settlement period specified by the formula:

Access = FAS scaling factor x AQ

However, a generator is never provided a level of access in excess of its availability (as discussed in section *4.3.3 Target Access Limited by Availability*) and so the actual level of access that must be provided is:

$$\text{FAS access obligation} = \min(\text{Availability}, \text{FAS scaling factor} \times AQ) \tag{5.1}$$

[44] This is to allow TNSP incentive payments to be cleared through AEMO settlement, discussed further in section *8.2.6 Financial Quality Incentives*.

[45] If it does not, there would be surplus capacity provided under NOC1, simply to maintain the FAS under lower NOC tiers.

[46] Eg in weak parts of the network, capacity reduction under outage conditions would be more than the corresponding FAS scaling factor.

It will be seen from this equation that if a generator procures access equal to its availability, its access will be scaled back under higher tier NOCs. However, for a *super-firm generator* that procures an agreed access amount substantially higher than its availability, the FAS scaling factor may not affect its access, at least for some NOCs. This is discussed further in section 5.3.2 *Effective Access Firmness*.

5.2.4 FAS Implications for Flowgate Capacity

As discussed in section *4.2.3 Target Entitlements*, for a generator to receive some level of access, A, it must be provided with an entitlement on each flowgate equal to the product of the participation factor and that access level:

$$E = \alpha \times A$$

By applying the formula for access obligations in equation (5.1), above, we get:

$$\begin{aligned} \text{FAS entitlement obligation} &= \alpha \times \text{FAS access obligation} \\ &= \alpha \times \min(\text{Availability, FAS scaling factor} \times \text{AQ}) \qquad (5.2) \end{aligned}$$

A TNSP must provide sufficient effective flowgate capacity to provide the FAS access obligation to all firm generators *concurrently*:

$$\text{Effective Flowgate Capacity} \geq \sum(\text{FAS entitlement obligations}) \qquad (5.3)$$

The RHS side of this inequality is referred to as the *target flowgate capacity.* Putting together equations (5.2) and (5.3) gives:

$$\text{Target Flowgate Capacity} = \sum_i \{a_i \, x \, \min(\text{AV}_i, \text{FAS scaling factor x AQ}_i)\} \qquad (5.4)$$

where:

a_i is the participation factor for generator i

AV_i is the availability of generator i

AQ_i is the agreed access level of generator i

Since the TNSP cannot generally forecast when a generator is going to be available it would prudently assume that:

$$AV_i = RC_i$$

where:

RC_i is the registered capacity of generator i

And so aim to deliver flowgate capacity according to the formula:

$$\text{Target Flowgate Capacity} = \sum_i a_i \, x \, \min(\text{RC}_i, \text{FAS scaling factor x AQ}_i) \qquad (5.5)$$

In the situation where there are no super-firm generators (so $AQ \leq RC$), equation (5.4) simplifies to:

$$\begin{aligned} \text{Target Flowgate Capacity} &= \sum_i \{a_i \, x \text{ FAS scaling factor x AQ}_i\} \\ &= \text{FAS scaling factor x } \sum \text{target firm entitlement} \\ &= \text{FAS scaling factor x Target NOC1 Flowgate Capacity} \end{aligned}$$

Thus, where there are no super-firm generators, target flowgate capacity is scaled back by the FAS scaling factor for the prevailing NOC tier. On the other hand, where there are super-firm generators, target flowgate capacity is not scaled back to such an extent:

$$\text{Target Flowgate Capacity} > \text{FAS scaling factor x Target NOC1 Flowgate Capacity}$$

5.2.5 FAS is flowgate specific

It is natural to think of a transmission operating condition applying to the network as a whole. For example, if the condition *system normal* means every transmission element is in service, then a *single* outage means that the network is no longer system normal. In this paradigm, the same NOC tier – and hence the same FAS scaling factors – should, at any point in time, apply to *every flowgate* in a region.

However, because access settlement is flowgate specific, the FAS can and should be applied at the flowgate level. This can be done by requiring AEMO to tag each NEMDE transmission constraint with the relevant NOC tier, as discussed below.

Each NEMDE constraint prepared by AEMO relates to a particular transmission condition. For example, AEMO may prepare several constraints preventing contingent overloads on a line X: a constraint XN for system normal conditions, XY for when line Y is on a planned outage, XZ for when line Z is out, and so on. In the above example, AEMO would label XN as *NOC1* and the other two constraints as *NOC2*, say.

AEMO arranges for prepared constraints to be *applied* in NEMDE only when the prevailing transmission conditions correspond to the conditions assumed when they were formulated. In a system normal, constraint XN would be applied; if line Y was on outage, constraint XY would be applied; and so on. If, during a system normal situation, a forced outage occurred in a zone *remote* from line X, AEMO would leave constraint XN in NEMDE since the remote outage would not affect contingent flows on line X. In other words, although the *network as a whole* is no longer system normal, in the sense of *everything* being in service, the *system normal constraint XN* continues to apply.

If flowgate XN became congested in these conditions, the label on that would indicate that it was a NOC1 constraint and so a 100% FAS scaling factor would apply. The remote outage does not physically affect the capacity of flowgate XN and so it should not affect the FAS obligation, despite the fact that the *network-as-a-whole* is no longer, technically, system normal.

In general, the FAS scaling factor applying to a flowgate is predicated on the NOC tier applicable to that flowgate, and *not* to the condition of the transmission network overall.

5.2.6 Summary

The FAS defines the minimum level of firm access service quality that a firm generator is entitled to and, consequently, drives TNSP network planning and operation. It progressively scales back the service level that must be provided under more severe transmission conditions and so represents a service profile that can realistically be provided by a transmission network and maintained by a TNSP.

5.3 Design Issues and Options

5.3.1 Firmness of FAS

Through the use of NOC tiers and FAS scaling factors, the FAS describes an access standard that is *firm* but not *fixed*. Why was this design choice made?

A fixed access FAS would mean a guaranteed agreed access level in *all* conditions. For settlement to balance, that means, in turn, a *fixed* target flowgate capacity. Achieving this is impractical: there is always the possibility of extreme conditions (multiple outages, extreme weather events etc) where a minimum level of transmission capacity cannot be maintained.

The use of the word "firm" comes from the gas industry, where *firm* transportation (as opposed to *non-firm* transportation) is provided. Firm is not *fixed* in for gas transportation either. Events such as compressor failure will lead to reduced service.

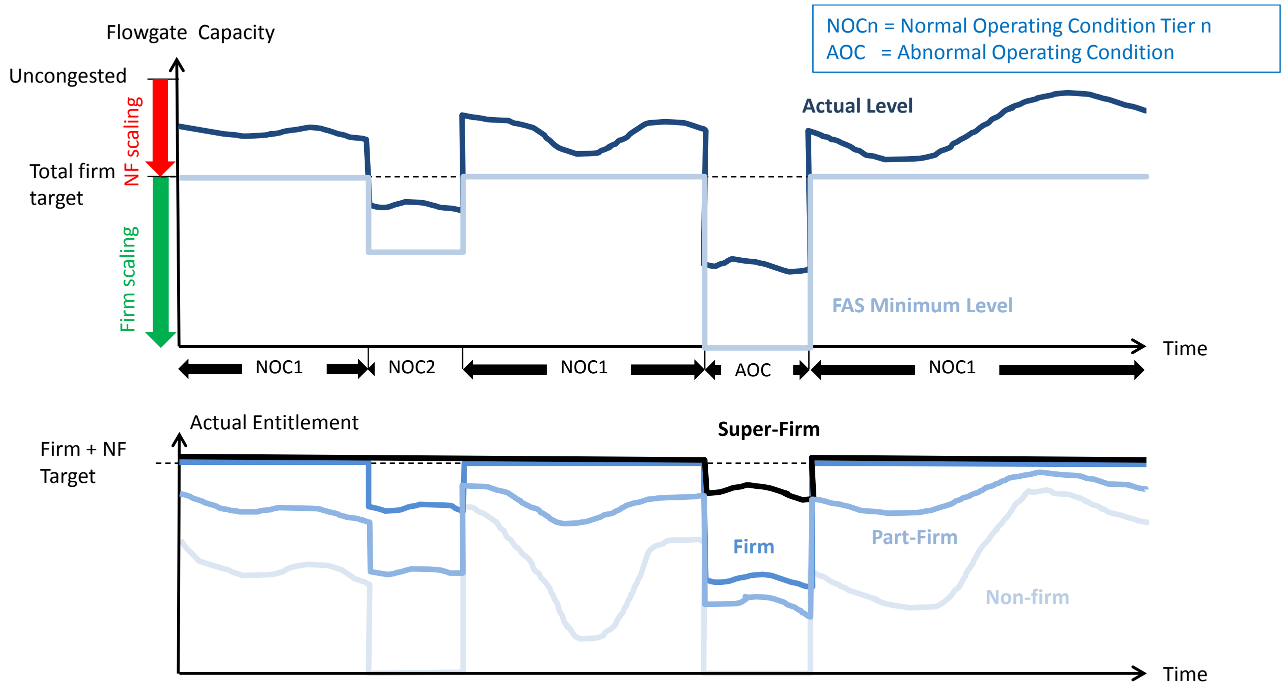
Rather than over-engineer the transmission system to attempt to provide a level of firmness that it cannot inherently provide, it is preferable to set the FAS to a level that reflects transmission characteristics. For example, if the network can typically provide, under NOC3 conditions, 80% of the capacity that it can provide under system normal, then the FAS for the NOC3 tier should be set to 80%. New access of 100MW, say, may then lead to a transmission expansion that provides an additional 100MW in system normal and 80MW under NOC3.

If, instead, the FAS tier 3 factor was set to 100%, this would simply mean that 125MW of system normal transmission capacity would need to be added, with the additional 25MW essentially being wasted during NOC1 and NOC2 conditions.

5.3.2 Effective Access Firmness

Despite there being a single FAS, a generator can choose the *effective* firmness of access that it prefers by varying its agreed access amount, as illustrated in figure 5.1. This shows flowgate capacity varying constantly as demand, generation and transmission conditions vary, and illustrates how the actual entitlements for the four categories of generation will vary correspondingly. Although the maximum level of entitlement is determined by the generator's availability (and its participation), the firmness of the entitlement over time is also dependent on the agreed access. Firmness is highest for a super-firm generator followed, in order of descending firmness, by firm, part-firm and non-firm generators.

Figure 5.1 Effective access firmness



5.3.3 Establishing the FAS

If it is decided to implement the OFA model, the FAS will be developed as part of the implementation process. It is likely that the FAS would be developed in consultation with TNSPs and generators to ensure that it was both practical and useful. The OFA design places no limitations on FAS, except that it must be structured around NOC tiers and that the appropriate NOC tier can be identified for each flowgate (ie NEMDE transmission constraint): if not in advance of dispatch, then at least in time for access settlement.

5.3.4 Changing the FAS

Subsequent changes to the FAS after OFA implementation are somewhat problematic in that they affect the rights of generators with *existing* access agreements. It would be difficult – if not impossible – to grandfather existing access agreements and apply the new FAS only to subsequent agreements. Doing so might, in any case, largely defeat the purpose of the FAS change.

Alternatively, access charges payable on existing access agreements could be adjusted (up or down, as appropriate) to reflect a changed FAS. That may be rather more practical, but is conceptually problematic in that it forces changes on firm generators who may not want them. Finally, it may be possible to adjust the agreed access amount on existing agreements to negate the impact of the FAS change.

In the light of these issues, the FAS would probably only be changed if necessary to address some unexpected – and unwanted – feature: for example, if definitions are ambiguous or able to be manipulated by TNSP decisions. The FAS could be embodied in the rules – or in schedules to the rules – which would mean that it would be changed through the usual rulemaking process.

5.3.5 Abnormal Operating Conditions

The AOC tier is intended to represent operating conditions whose occurrence or impact is not reasonably foreseeable. It is acknowledged that their inclusion creates some moral hazard, whereby TNSPs have no specific responsibility to maintain transmission capacity and mitigate impacts during AOC periods. Nevertheless, they would maintain a general responsibility to act in accordance with good industry practice and would likely be judged by that standard in any subsequent investigations of the AOC event.

Ideally, the NOC tiers would go a *long way down* and cover some fairly severe – albeit foreseeable and manageable – transmission conditions. This would ensure that generators have access certainty under these conditions and can tailor their agreed access levels to their risk appetite.

5.3.6 The FAS cannot be Customised

Ideally, each generator could procure a *customised* access firmness through negotiation with its TNSP: for example, be provided with a 95% factor during tier 2 NOC when the standard factor was 90%. However, introducing such customisation would create complexity in every aspect of the OFA model: especially in settlement, pricing and planning. For example, should such a generator's entitlements be scaled back less than other firm generators during tier 2 conditions and how would the relevant information be transmitted to and applied by AEMO in making the necessary adjustments?

The choice of agreed access amount gives a generator *one degree of freedom* in choosing its access firmness and that is likely to be largely sufficient to cover a wide range of generator preferences.

5.3.7 Region-specific or NEM-wide FAS

The shared networks in the different regions of the NEM have somewhat different characteristics, due both to different planning regimes existing historically and to different geographical characteristics. This raises the question of whether the FAS should be region-specific to reflect these differences.

As discussed in section *5.3.2 Effective Access Firmness*, the FAS does not restrict generators to a single level of access firmness but rather a single firmness spectrum. A generator can choose where it wishes to be on this spectrum: from non-firm to super-firm. If the characteristics of a region make it more expensive to provide a given level of access firmness in that region than in another region then, other things being equal, generators might choose a lower level of access firmness in that region. That is a matter for generators and does not need to be reflected in the FAS.

On the other hand, if the regional differences create different typical capacity profiles (eg meaning tier 2 transmission capacity is typically 80% of tier 1 capacity in one region, but typically 90% of tier 1 capacity in another region), it might be appropriate to reflect those differences in different FAS standards.

Such differences might potentially create difficulties or complexities in relation to inter-regional access, but so long as these can be overcome, a region-specific FAS would be feasible.

Notwithstanding this, the *governance* of these standards would need to remain NEM-wide. This implies that they would be established, monitored and varied through NEM-wide institutions, not by State-based institutions.

5.3.8 Demand-side Reliability Standards will continue

There is a large overlap between the FAS and the existing demand-side reliability standards. The FAS provides for minimum network access for firm generators under specified conditions, whereas demand-side reliability standards (except in Victoria) require sufficient network access under peak-demand conditions that enough generation can be dispatched to meet demand. For example, if peak demand in a region were 10GW and there was at least 10GW of firm access issued across the region, then there should be no generation-side transmission constraints preventing demand from being met.[47]

However, that level of firm access issuance cannot be relied on: it may be that only 8GW of generation wishes to be firm. In that case, if demand-side reliability standards did not continue, there might be a 2GW shortage of generation at peak and consequential load shedding. That would be unacceptable. Therefore, demand-side reliability standards need to continue to apply, acting as a *safety net* to cover the situation where firm access levels alone are insufficient to maintain reliability.

6 Access Pricing

6.1 Overview

When a TNSP agrees to provide new or additional firm access, this automatically increases the network capacity that the TNSP is required to provide under the FAS, thus imposing new costs on the TNSP. A fundamental principle of the OFA model is that the firm generator must pay an amount to the TNSP that covers these *incremental costs*. The purpose of *access pricing* is to estimate what these costs are.

Transmission planning is a long-term process and it is not sufficient to simply calculate the *immediate* cost of the extra expansion required prior to the new access commencing. The new access may cause a *future*, already planned expansion to be *brought forward*. The capital cost remains the same, but the advancement means that, after applying a discount rate, there is an incremental cost in *net present value* (NPV) terms. A methodology in which *all* incremental costs are calculated – present *and* future – is referred to *here* as long run incremental costing (LRIC). LRIC forms the basis for the access pricing approach.[48]

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[47] There may be some demand-side constraints in relation to supplying demand away from the RRN and demand-side reliability standards would need to continue to apply to ensure that these were removed.

[48] Terminology in this area is imprecise and this approach might be referred to as long run marginal cost (LRMC) in other contexts. In this document, LRMC is given a different meaning, so the distinction between LRIC and LRMC is important.

LRIC is defined to be the difference between two costs: the *baseline cost*, which is the NPV of the *baseline expansion plan* which is in place before the access request is received; and the higher *adjusted cost*, which is the NPV of the *adjusted expansion plan*: an amendment to the *baseline expansion plan* to accommodate the new access request:

LRIC = adjusted cost – baseline cost

The expansion plans are derived using a *stylised* methodology which, by assuming away some of the complexity inherent in transmission planning, provides stable and smooth expansion outcomes. The methodology is unlikely to capture every aspect of the network and would involve some judgements about future outcomes, but within these limitations it should be a robust basis for determining access charges.

To ensure that the calculated LRIC is nevertheless realistic and representative of actual expansion costs, critical features that determine LRIC characteristics are included in the methodology. These features include: the measurement of *existing spare capacity*; the *lumpiness* of transmission expansion; the *topology* of the existing transmission system; and the *background growth* of demand and firm generation.

6.2 Design Blueprint

6.2.1 The Element-based Expansion Model

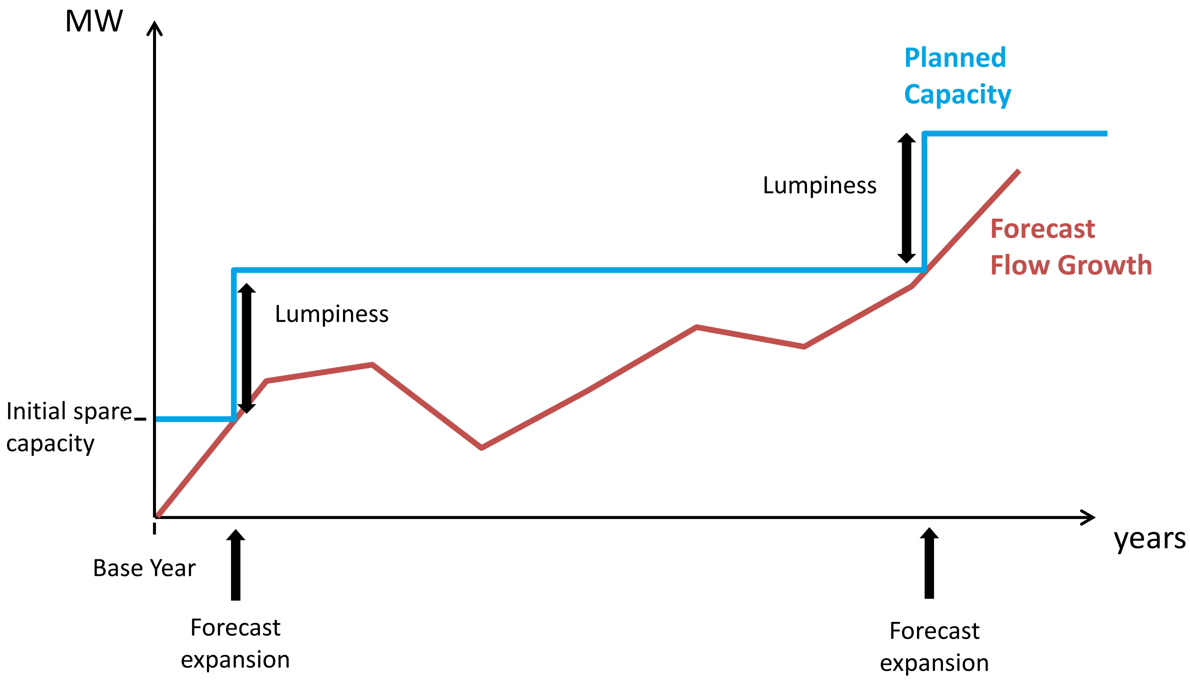
The access pricing methodology establishes a simplified model of transmission planning by assuming that separate, independent expansion plans are developed for each existing *branch element* (such as a transmission line or network transformer) of the shared transmission network. Each element's *baseline* expansion is based on three variables:

- *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 are forecast to increase each year; and
- *lumpiness*: reflecting the size of a practical and economic expansion of that element.

It is assumed that each element is expanded as soon as spare capacity is exhausted.[49] That expansion provides new spare capacity, which will be progressively eroded through subsequent flow growth until, eventually, a second expansion is required, and so on. This expansion model is illustrated in Figure 6.1 below.

[49] By assuming a piecewise linear demand growth each year, the time of expansion is estimated to a fraction of a year which, while unrealistic in practice, avoids the jerkiness associated with rounding to the nearest whole year.

Figure 6.1 Element baseline expansion model

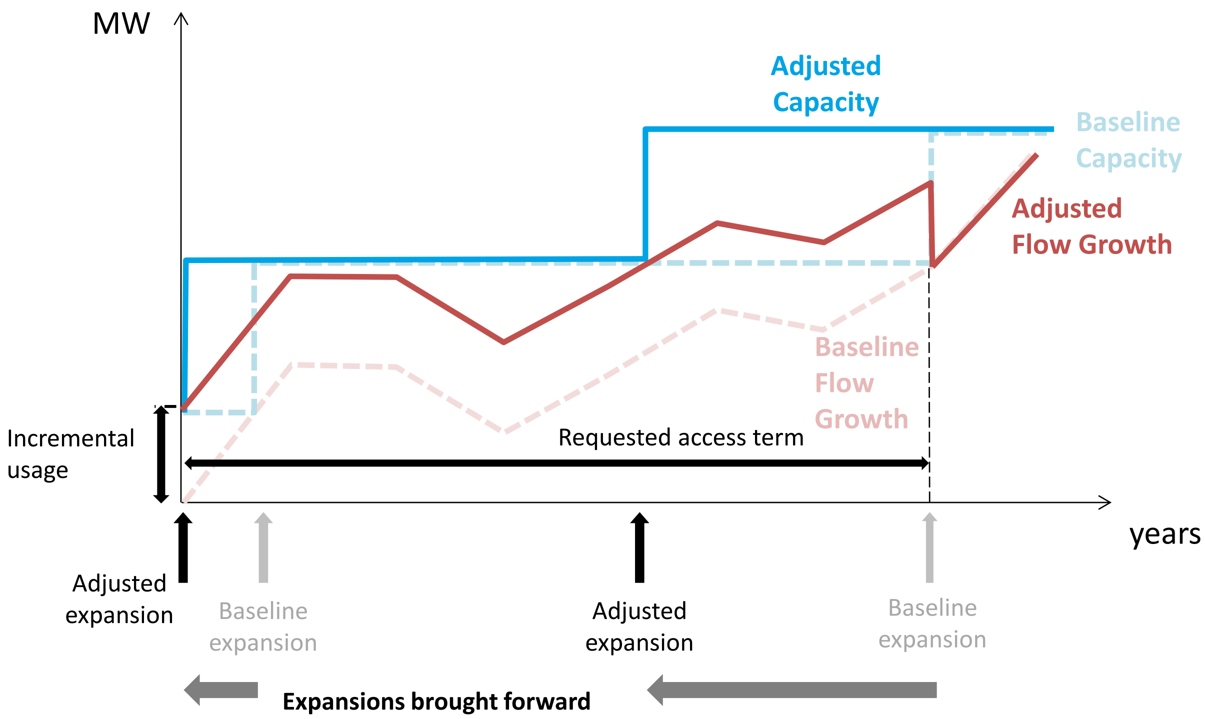


To model the *adjusted* expansion, the impact of the new access request is included, which is represented by two further variables:

- *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.

This incremental usage simply adds to the baseline flow growth and will cause the expansions in the baseline plan to be *brought forward* by varying amounts, as illustrated in Figure 6.2, below.

Figure 6.2 Element adjusted expansion model



The NPVs of baseline cost and adjusted cost are then calculated by applying an appropriate discount rate to the capital costs implied by the corresponding expansion plans. The access charge is the difference between these two NPVs, summed over all transmission elements in the network.[50]

The model is not a complete or realistic description of actual transmission planning and is not intended to be. In particular, new elements and changing connectivities are often introduced in expansion plans and these practices are not represented in the stylised model. On the other hand, it will be seen that the LRIC calculated by the model is smooth and proportionate: small changes in access request will generally give rise to small changes in LRIC. As discussed below, below, it also has characteristics which are similar to what one would expect of a *true* LRIC.

6.2.2 Estimating the Model Variables

Methods for determining the necessary model variables are described below.

Initial spare capacity
Various planning studies would be carried out, based on transmission, access and TUOS conditions expected in the *base year*: the first year of the access request In each study, generators would be dispatched at a proportion of their agreed access level using the FAS scaling factor applicable to the transmission condition. The *study spare capacity* on an element would be the difference between the study flow and the secure flow limit.[51] The *initial spare capacity* is the lowest value of all the study spare capacities.[52]

Annual flow growth
This will be based on end-user demand forecasts and firm generation forecasts for each node and each year of the pricing analysis. In the short-term, firm generation forecasts would be based on current access agreements and requests. In the longer-term, they would be based on generation forecasts produced in the National Transmission Network Development Plan (NTNDP). A standard load flow analysis would be used to convert these nodal forecasts into flow forecasts for each element in each study year.

Lumpiness
The lumpiness of an element is set equal to its expansion size *divided* by its *meshedness,* for reasons discussed briefly below and in more detail in section *12.9 Meshedness in Access Pricing*. The expansion size would be chosen, from the practical engineering alternatives available, based on minimising the NPV cost of current and future expansions[53].

Meshedness
Meshedness is a measure of how many elements run in parallel to the studied element[54]. If four, identical lines operate in parallel, an expansion of one line by 1000MW (say) is equivalent to a 250MW expansion across all four lines. This situation is best approximated in the model by

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[50] In practice, incremental usage will only be material on a subset of elements, generally those elements lying between the new access node and the RRN and so LRIC on only these elements needs to be calculated and summed.

[51] Ie maximum flow level consistent with secure dispatch.

[52] Or, so that it is not too dependent upon a single study, it might be set at, say, the average of the lowest five study spare capacities.

[53] This would be based on average flow growth and discount rate. Where flow growth was fast a relatively larger expansion size would be more efficient.

[54] In practice, lines do not run exactly in parallel. Meshedness is defined more precisely by modelling a load flow between the two nodes at each end of an element and calculating the factor by which the total flow from node to node exceeds the flow on the element itself.

assuming that each line can be expanded, independently, by 250MW at a time, not 1000MW at a time, which gives the reason for the lumpiness formula, above.

Incremental usage
Incremental usage is equal to the amount by which flow on the element increases when the amount of the access request is dispatched across the transmission network to supply the incremental demand at the RRN.

Access term
The access term is based on the access request.

Expansion cost
The expansion cost is based on the capital cost of the expansion, divided by the meshedness.

Discount rate
The discount rate would be based on an estimate of the TNSP's regulated cost of capital.

6.2.3 Special Situations

Some special situations which need to be managed in the LRIC pricing model are discussed below.

Counterflow incremental usage
An access request in a demand-rich location may create incremental usage which is in the *opposite* direction to baseline flows on many elements. This would have the effect of increasing spare capacity and potentially *deferring* future expansion and so creating a *negative* LRIC. However, spare capacity is only increased in practice if the associated power station is actually *available and dispatched* in the critical peak period. The TNSP is unable to rely on this on the basis of the access agreement alone.[55] Therefore, the element LRIC would be *zero* (rather than negative) in this situation.

Inter-regional effects
New access in one region may create incremental usage – and so LRIC – on some elements in a neighbouring *remote* region. Conversely, nodal demand or firm access changes in the remote region may cause changes to flows on elements in the local region. Thus, the access pricing model needs to include these remote elements and nodes to the extent there are material inter-regional impacts. Where the access request generates material LRICs on remote elements, corresponding payments should be made to the remote TNSP.

Reliability-driven expansion
Obligations on TNSPs to maintain jurisdictional *reliability standards* will continue in the OFA model. Possible future reliability expansion – expansion needed to maintain reliability standards – would need to be modelled and included in the baseline expansion plan. That would be done by including suitable *reliability generation* (ie any non-firm generation for which peak-period access must be provided in order to maintain reliability) in the relevant pricing studies.[56] If a reliability generator sought access, the *calculated* access price would then be zero, because the generator appears equally in the baseline studies and the adjusted studies. To avoid this anomaly, that particular generator would be removed from the baseline plan in that situation.[57]

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[55] However, the TNSP could enter into a separate network support agreement with the generator, under which the generator commits to be available and dispatched as needed and receives a payment from the TNSP in return. Similar agreements are made in the present NEM design.

[56] The TNSP would need to decide which generators would be reliability generators, typically those non-firm generators to whom transmission access can be provided most cheaply.

[57] In fact, similar issues arise in relation to all access requests, as discussed in section *6.3.5 Including Pending Access Requests in Forecast.*

6.2.4 Payment Profiling Algorithm

The access pricing methodology calculates a lump sum cost which would be recovered through annual payments[58] over the life of the access agreement. The payment profiling algorithm determines these annual payments.

There are a number of considerations relevant to payment profiling:

- the preference of the generator and the ability of the generator to negotiate variations from the standard payment profile;
- the cashflow and borrowing implications for a TNSP of timing mismatches between expansion costs incurred and access revenue received;[59] and
- the regulatory implications of revenues and costs varying within and between regulatory control periods.[60]

These considerations make payment profiling potentially complex. They are discussed further in section *12.10 Annual Payment Profiling*. However, it should be noted here that the profiling and payments are likely to depend on indices such as the consumer price index (CPI) and regulatory weighted average cost of capital (WACC). Therefore, annual access charges may vary as these indices vary, creating some modest uncertainty for the generator.

6.2.5 Summary

The access charge for an access request is based on the estimated long-run incremental cost incurred by the TNSP in expanding its network to accommodate the new access, in accordance with the FAS. That charge is calculated and agreed during the access procurement process and cannot be subsequently amended, apart from agreed future indexation based on CPI, regulated WACC or similar indices.

The access pricing methodology is based on a highly stylised model of transmission expansion which, nevertheless, is expected to broadly reflect the characteristics and levels of a true LRIC forecast. It is designed to provide smooth, transparent and robust prices which guide efficient generator behaviour whilst covering the cost to TNSPs of providing firm access services.

6.3 Design Issues and Options

6.3.1 Why not use LRMC or deep connection?

The OFA model uses an LRIC-based methodology as described above. However, there are two alternative approaches, referred to here as long run marginal cost (LRMC) and deep connection, which are used in other electricity markets.[61] These were considered for the OFA model, but were rejected for the reasons discussed below.

6.3.1.1 LRMC

An LRMC approach is similar to LRIC, with the essential differences that expansion lumpiness is ignored: it is assumed that, if an additional 233MW, say, of transmission capacity is required, exactly 233MW will be built. The access charge for 233MW will reflect that and will be set at 233 times the average $/MW cost of transmission expansion.

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58 Perhaps broken down into twelve monthly payments.

59 Recognising that, in NPV terms, the revenues and costs should be similar.

60 These are discussed further in section *8.2.4 Revenue Regulation*.

61 These terms can be used in various ways, but a specific meaning is applied here, as described below.

LRMC is a much simpler methodology than LRIC, because there is no need to take account of existing spare capacity or future planned expansions: capacity is expanded only as needed and so tracks the flow growth rather than occurring in steps. However, this simplification is also its flaw. Other things being equal, the access charge at a node where there is plentiful spare capacity will be the same as the charge where there is no spare capacity, despite the incremental cost of transmission being much higher at the latter location. Generators will choose locations that are best for them (in terms of land and fuel availability), rather than those where access can be provided more cheaply by the TNSP, due to existing spare capacity.

The materiality of this pricing inaccuracy is unclear and it may be that LRMC is actually quite a good proxy for LRIC. That will be revealed during more detailed examination of LRIC during the OFA implementation process and a decision whether to switch to an LRMC approach (perhaps driven by the relatively greater complexity of the LRIC methodology) could be made at that stage.

6.3.1.2 Deep Connection Charge

A deep connection charging approach levies only the *immediate* costs of transmission expansion through the access charge and takes no account of *future* costs as a result of future expansions being advanced. Rather than using a stylised methodology, a deep connection approach would rely on the TNSP (or other institution) determining *exactly* what needs to be built immediately to provide the new access and charging for the cost of that: analogous to what occurs currently for connection charging.

As with the LRMC approach, the fundamental problem with this approach is that the deep connection costs do not reflect the true incremental cost of access provision. Unlike with LRMC, however, it is clear in this case that the costing could be highly inaccurate. Consider a generator seeking access where there is limited spare capacity but an upgrade is planned in two years' time. The new generator would prompt immediate expansion and be charged the full cost of the expansion, even though it had simply caused the expansion to be brought forward by two years.

Another difficulty with deep connection is that the generator paying the cost is likely to demand the smallest possible (and hence cheapest in absolute terms) expansion, despite this being uneconomic in the longer term. There may be ways to help correct this inefficiency (eg by giving the generator some form of marketing rights on a larger expansion) but these introduce substantial additional complexity.

6.3.2 Comparison of LRIC, LRMC and Deep Connection

Notwithstanding the disadvantages of the LRMC and deep connection methodologies, as discussed above, LRIC pricing may give similar outcomes to one or other of these models in certain circumstances. Such situations are discussed below.

6.3.2.1 Elements where LRIC will be similar to LRMC

As noted, LRMC assumes there is no lumpiness. In that case, expansion of an element notionally occurs annually, with each annual expansion exactly matching annual flow growth.

In the LRIC model, because there *is* lumpiness, expansion occurs in cycles rather than annually. For example, if lumpiness is 1000MW and annual flow growth is 200MW per year, expansions will occur every 5 years. If the investment cycle is fairly short,[62] lumpiness is less material and LRIC will be broadly similar to LRMC.

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[62] The cycle length is measured relative to the discount rate. At a 5% discount rate, net present value is discounted by 21% over 5 years, meaning broadly that LRIC might vary by 21% depending upon the point in the investment cycle at which the new access commences: whether it is just prior to or just after a baseline expansion.

These conditions are most likely to apply in the *core grid*: the main high voltage backbone of the transmission network. Here, large expansion lumps are offset by high meshedness,[63] and there is likely to be relatively high flow growth. Therefore, LRIC pricing of some elements in the core grid may be broadly similar to LRMC.

6.3.2.2 Elements where LRIC will be similar to Deep Connection

The opposite situation to the one described above is where the investment cycle is long: lumpiness is *high* relative to annual flow growth. At the extreme, where flow growth is zero, the investment cycle is infinite: ie there are no planned expansions of the element in the baseline expansion plan. In the adjusted expansion plan there will simply be:

- *no expansion*: if there is sufficient initial spare capacity to accommodate the incremental usage from the new access request; or
- *immediate lumpy expansion*: otherwise.

Recall that LRIC is based on the difference between the adjusted and baseline expansion cost, so in this case LRIC either charges *nothing* if no immediate investment is required, or the full expansion cost if it is. This is the same as the deep connection charge. More generally, if the investment cycle is long (relative to the discount rate), LRIC will be broadly similar to deep connection.

These conditions are most likely to apply in the *local grid*: lower voltage lines either serving specific power stations or local load.[64]

6.3.2.3 General Situation

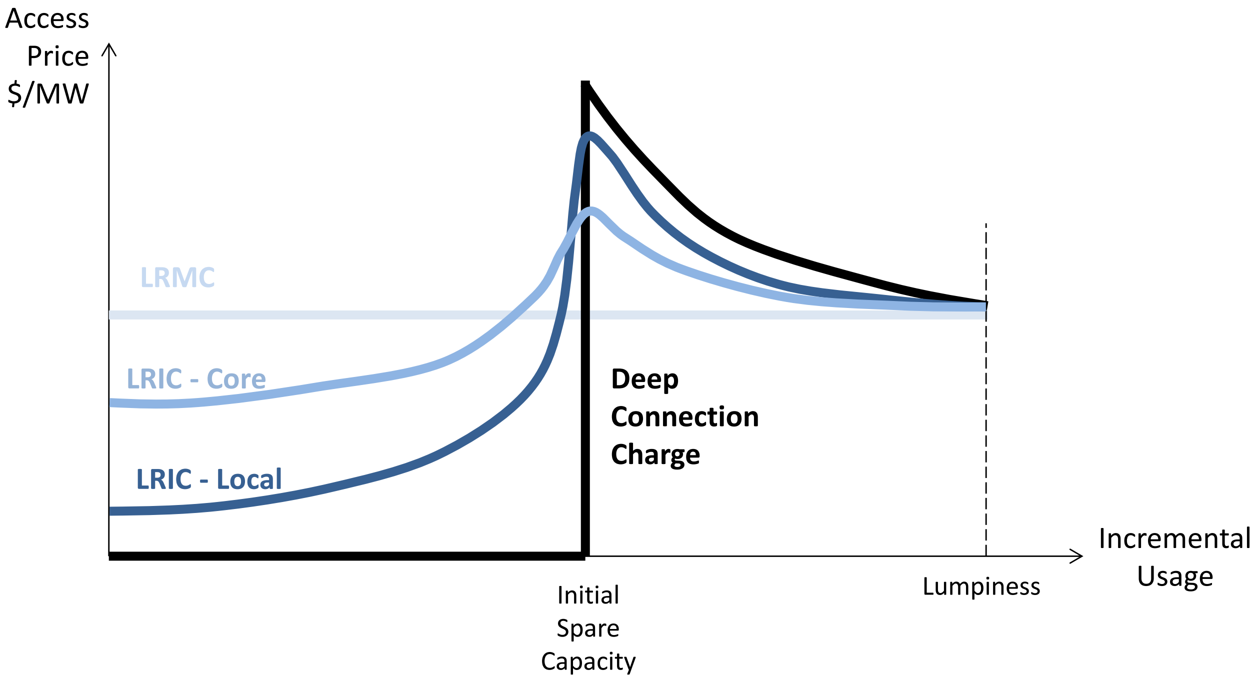
Figure 6.3 illustrates how the incremental price (the incremental cost divided by the incremental usage) on an element varies by incremental usage, for the three methodologies. It will be seen from the figure that:

- if the incremental usage equals the expansion size, the three methodologies give identical outcomes, reflecting the cost of an immediate lumpy expansion;
- the LRMC price is constant, because the LRMC cost is proportional to the incremental usage;
- the Deep Connection charge is either zero or the full expansion cost: note that the incremental price is the cost divided by the incremental usage and so – given a fixed cost – decreases as usage increases;
- LRIC is closer to Deep Connection where there is a long investment cycle: low flow growth relative to lumpiness; and
- LRIC is closer to LRMC where there is a short investment cycle: high flow growth relative to lumpiness.

[63] Recalling that in the LRIC model meshedness is defined as the expansion lump divided by the meshedness.

[64] In the latter case, flow growth may even be negative, but since LRIC can never be negative, this is equivalent to the zero growth case.

Figure 6.3 Comparison of LRMC, LRIC and Deep Connection



The access charge is the aggregate of LRIC across all elements. The overall outcome, then, will depend upon the mix of long-investment-cycle and short-investment-cycle elements used to provide the requested access.

6.3.3 What if the Expansion Cost is much higher than Modelled?

There is a risk that the access price could underestimate the true incremental cost of access provision, occasionally or systematically. Any pricing errors could cause inefficiency, to the extent they fail to signal the efficient location for new generation. However, any future inaccuracies must be compared to the status quo where there is no transmission price for generators to signal efficient locations.

Systematic errors should be able to be identified in the implementation process, using detailed analysis of access pricing under various generation scenarios and comparing those with actual expansion costs. The pricing model can then be recalibrated as necessary to ensure that costs are correct on average. To the extent under-pricing remains, the shortfall in costs will be recovered from demand-side users through higher TUOS charges: which, again, is likely to be no *worse* than what happens at present.

6.3.4 How to Ensure Forecasts are Objective and Transparent

The access prices calculated by the LRIC method are highly dependent on forecasts of flow growth on elements which, in turn, are dependent on forecasts of end-user demand and firm generation. For pricing and procurement efficiency, these forecasts must be accurate, objective and transparent.

To help to ensure this, it may be appropriate for the forecasts to be developed by an independent institution such as the National Transmission Planner (NTP). This would also help to ensure consistency of forecasting across regions.

6.3.5 Including Pending Access Requests in Forecast

There is an interaction between access requests and access prices, since a TNSP is bound to take some notice of pending access requests in producing a baseline forecast. For example, a TNSP might make the assumption that 30% of requests currently being processed will proceed through to completion. Therefore, when any request is priced, 30% of the request will already be in the baseline and so the adjusted forecast would only add the remainder 70%. Obviously, costing only the extra 70% would significantly understate the true incremental cost.

Thus, there would be a need to create a special baseline scenario for each request, which would remove the request from the baseline, but leave all other pending requests.

6.3.6 Different Network Conditions in Adjusted Scenario

As described here, incremental usage on an element is a treated as a *single number* for each access request. It would be calculated through a load flow analysis. But the load flow outcome would depend upon what transmission conditions were assumed: incremental usage would be higher under some outage conditions (that might *funnel* the additional access through the particular element) than under system normal.

However, this effect will be offset by the FAS scaling factors, under which the incremental capacity requirement would be lower under outage conditions (eg NOC2 or NOC3 etc) than under system normal (NOC1).[65] Thus, modelling different conditions might not materially affect pricing outcomes. These issues would need to be investigated further prior to OFA implementation.

6.3.7 Who Undertakes Pricing

It has been noted above that inter-regional impacts mean that a cross-regional (although not necessarily NEM-wide) pricing model is required, to accurately estimate incremental costs and allocate these appropriately across different TNSPs. In that context, it would arguably be preferable for pricing of access requests to be undertaken by a NEM-wide institution which had a NEM-wide transmission model and demand and generation forecasts.

On the other hand, as discussed in section *7 Access Procurement*, access pricing is an intrinsic part of the access procurement process, which is undertaken between a generator and its local TNSP. Requiring a third party to undertake pricing in this process has the potential to make it much less effective and timely.

7 Access Procurement

7.1 Overview

Access procurement is the process through which generators can procure new or additional *firm access service*, by entering into a *firm access agreement* with the TNSP in its region (the *local TNSP*).

Default access service terms and prices are regulated. These terms can be *customised* by mutual agreement, but only to the extent that this does not impact adversely on other transmission users. Primarily, though, the procurement process involves information exchange rather than commercial negotiation. Specifically, the generator seeks the combination of access level, location and term that best meets its needs

Access pricing and procurement interact, since prices depend upon existing and prospective access agreements. Therefore each access request or agreement may affect the pricing of other,

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[65] For example, if the relevant FAS scaling factor were 80%, then only 80% of the incremental usage would have to be accommodated by existing or expanded transmission capacity.

concurrent requests. The procurement process must be structured to manage these interactions so as to avoid placing undue risk and uncertainty on generators or TNSPs. A possible process is described below, but other processes, which could be developed by TNSPs in consultation with generators, are not ruled out.

The access agreement specifies the *access charge* and *service parameters:* the latter covering aspects such as term, amount and location. It may also include some standard terms such as prudential requirements, termination and assignment: given that, in procuring access, a generator is committing to pay a potentially large sum of money over a long period, effective prudential requirements may be paramount. However, most terms of service – such as service standard and liability – will lie outside the agreement, in rules and regulations.

There is no obligation on generators to procure firm access. Generators who do not do so will not be required to make any payment to the TNSP, but will receive a lower level of access firmness and so will receive fewer payments from – and make larger payments into – in access settlement.

7.2 Design Blueprint

7.2.1 Service Parameters

Through the procurement process, a generator decides upon a set of *service parameters* which best meet its access needs and for which it is prepared to pay the associated access charge.[66] The process will typically be iterative, with the generator submitting a request, the TNSP pricing that request and the generator then amending its request in response. The list of service parameters – and associated restrictions on them – is presented in Table 7.1 below.

Table 7.1 Firm Access Service Parameters

Parameter	Description	Restrictions
Amount (MW)	Nominal level of service	Not limited: eg by power station capacity
Power Station(s)	Generating units to which the service applies	Must be connected to the shared network at a common point[67] (node)
Node	Transmission node from which access applies	Must be the point at which the power station(s) connects to the shared transmission network
Term	Service commencement date and expiry date	Commencement may be delayed until transmission expansion can occur.
Profile	Variation of the nominal service level with time	Peak and/or off-peak, following forward energy contract convention
Payments	Payment dates, amounts and indexation	Discussed in section *6 Access Pricing*
Custom	Agreed variations from the default service terms	If these can be settled by AEMO, and do not adversely affect other users

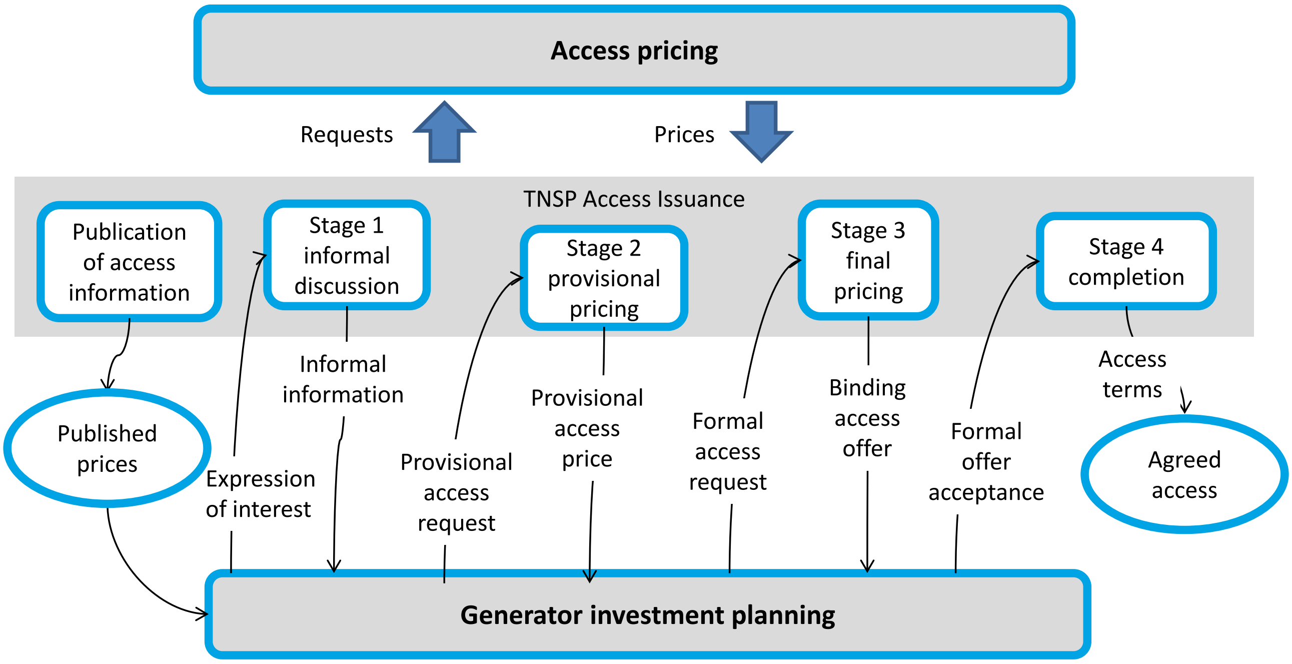
However, the role of the TNSP will be not simply to *provide a price* for the requests made, but also to advise the generator on the characteristics of the access pricing methodology and on possible service parameters that might best meet the generator's needs. An illustrative example of this is presented in section *7.3.1 A Procurement Example*.

[66] See section *6 Access Pricing.*

[67] For an embedded generator, this would be the point at which the relevant distribution network connects to the transmission network, discussed further in section *7.3.7 Firm Access Procurement for Embedded Generation.*

7.2.2 Procurement Stages

Figure 7.1 Illustrative access procurement process



A possible staged procurement process is presented in Figure 7.1, above. This is intended to illustrate one way in which procurement objectives may be met, but other and better ways may be developed by, or in consultation with, TNSPs and generators. The stages are described in Table 7.2, below.

Table 7.2 Access procurement stages

Stage	Info provided by G to TNSP	Info provided by TNSP to G	Obligations[68]	Queuing
Publication of Access Information	None	Publication of indicative prices at all nodes for standard terms and amounts	TNSP to update information annually[69]	none
Stage 1: Informal Discussion	Indicative location(s) and access level	Indicative prices, key breakpoints in price for amounts, times, locations	TNSP to provide timely information in good faith	none
Stage 2: Provisional Pricing	Specific provisional access request	Provisional price for request	G to pay TNSP for costs incurred.	First-come-first-served queue
Stage 3: Final Pricing	Formal access request	Binding, time-limited, price offer	G to provide refundable deposit.	One request at a time admitted in stage 2 queue order

68 TNSP obligations will be set out in regulation, as discussed in section *8 TNSP Regulation*.

69 And perhaps published in the annual NTNDP.

Stage	Info provided by G to TNSP	Info provided by TNSP to G	Obligations[68]	Queuing
Stage 4: Completion	Binding acceptance of stage 3 offer	Signed access agreement	G to provide non-refundable deposit (deducted from access charge)	none

A generator may withdraw from the procurement process at any stage, until the agreement is finalised in stage 4. Once completed, prudential arrangements would come into effect, but firm access would only be provided from the specified commencement date which – where a new power station or transmission expansion is being constructed – may be several years after procurement completion.

7.2.3 Confidentiality

The details of any generation project are commercially sensitive in its early stages, but nevertheless its details are published in AEMO's Statement of Opportunities once it reaches a certain stage. Similarly, Stage 1 access requests would be confidential, but progress in later stages will be published to ensure transparency of the queuing and pricing processes. Once agreed, service parameters will be published. The question of whether details of access charges, payment arrangements and any customisations of service parameters should be published needs to be considered further.

7.2.4 Summary

Deciding on the appropriate set of service parameters will be complex, especially for a new entrant generator who would be, in parallel, arranging to construct and fuel a new power station. Access pricing will be regulated and transparent, but its complexity nevertheless means there may be several iterations before a generator discovers its preferred service. The procurement process must ensure that a TNSP provides useful and timely information and advice to assist the generator with this discovery.

7.3 Issues and Options

7.3.1 A Procurement Example

An illustrative example of the procurement process is presented below.

An investor is planning to build a gas-fired power station. It has decided on the field from which it will buy the gas, and the pipeline on which it will be transported. However, it has a choice of pipeline off-take points and could potentially build a dedicated lateral to a site away from the pipeline.

Correspondingly, the investor has a choice of connection points to the transmission system, could commission a new connection point on an existing line, or could potentially build a dedicated transmission extension to a site remote from existing transmission lines.

Notwithstanding these options, the power station is likely to lie within a given *zone of interest*. The investor would review prices published in the TNSP access information report for relevant nodes and this might narrow down the choice somewhat. It would then, in stage 1, go to its TNSP to discuss access pricing as well as connection and extension practicalities and pricing.

The TNSP may highlight a number of relevant issues:

- *pending access requests* in the zone of interest which may affect access prices, depending upon whether or not they proceed;

- *transmission expansion plans*, which might also affect prices: since they affect the level of initial spare capacity;
- *elements with limited capacity in the zone of interest*: typically, it will be these local elements which will cause the biggest *variations* in access prices between different nodes in the zone of interest; and
- *breakpoints associated with this limited capacity*: eg up to 500MW could be accommodated without expansion; anything higher would prompt lumpy expansion which would increase access prices (obviously, this is most relevant where forecast flow growth on the element is low).

These issues – and the associated access price variations – will feed into the investor's decision-making, which will of course also be affected by site-specific costs and consents, gas supply costs and transmission connection and extension costs. Marginal loss factors may also be relevant.

Extensions to a node will generally be radial and not affect flows on the transmission network (compared to a direct connection to the node) and therefore not affect access pricing. On the other hand, a new connection point on an existing line would need to be explicitly modelled in the access pricing model at some point. However, the price difference from existing nearby connection points on the same line might be low and so not material: at least until stage 2 or 3.

Following the stage 1 discussions, the generator may settle on a proposed site for the power station and would then enter stage 2 to get a provisional access price(s) for the node(s) associated with that site, perhaps for different levels of agreed access.

Stage 3 would then probably not be entered until the site had been purchased, consents received or well advanced, and the project approaching financial close. That is because the firm offer made by the TNSP in stage 3 is time-limited and the generator would not be in a position to accept it and commit to it unless well advanced on all other stages of the project.

Stage 4 completion would occur at the same time as completion of other key components of the project (construction contract, gas supply contract etc). The TNSP would then commence undertaking the necessary expansion in parallel with the investor constructing the power station. Firm access would typically be scheduled to commence at the same time as power station commercial operation, although commencement might be delayed in some cases where there is a long lead time for the necessary transmission expansion.

7.3.2 Form of Agreement

It is proposed that the basic terms of the agreement are as follows:

- the TNSP agrees to provide the agreed amount of firm access service; and
- the generator agrees to make the annual access payments.

The first term means in practice that the TNSP agrees that it will *notify* the agreed access amount (and the relevant generator node) to AEMO for each settlement period over the agreement term. AEMO will then use this notified amount in determining access settlement amounts in accordance with access settlement formulae which are described in the rules. In this respect, the role that AEMO plays is similar to its role in reallocation transactions[70] although more complex. It is not AEMO's role to question or verify the notified amounts.[71]

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[70] Where market participants notify the amount to be reallocated and AEMO adjusts settlements accordingly.

[71] A generator could dispute the notified amount, through the normal settlement dispute process. In resolving the dispute, AEMO would need to refer to the firm access agreement to confirm the agreed access amount. To facilitate dispute resolution, agreed access amounts should be recorded in the agreement in standardised form which is lodged with AEMO in advance of access commencement.

In making this notification, the TNSP discharges its explicit obligations to the generator. The consequential obligations to maintain service quality (through the FAS) are with the AER, not the generator and so the firm access agreement should not refer to FAS.[72]

The nature (as opposed to the volume) of the firm access service is predicated on the rules and on AER regulation. These may change from time to time and such changes are outside the control of the TNSP. Therefore, the agreement *cannot* contain any obligation on the TNSP to maintain service definitions or standards over the term of the agreement.

Prudential obligations of generators (firm and non-firm) in *access settlement* will be managed by AEMO, through a continuing AEMO obligation to manage prudential requirements across the whole of NEM settlements.[73] Therefore, the firm access agreement does not need to address this.[74]

Provisions of the firm access agreement associated with making annual access payments are likely to be similar to corresponding provisions in connection agreements where, similarly, annual payments must be made over the life of the agreement. Where there is a default on payment obligations, a TNSP would probably be relieved of its obligation to make continuing notifications of agreed access amounts to AEMO and of its corresponding FAS obligations.

7.3.3 Changes to standard forward contract peak/off-peak times

It is anticipated that the standard peak and off-peak periods which would apply to firm access agreements would be aligned with the convention used in forward contracts. These are agreed between market participants under the aegis of AFMA, which is beyond the jurisdiction of both TNSPs and the AEMC.[75] Although the rules, or firm access agreements, could easily reference this convention, this could create a governance issue in the future, where AFMA proposed to change the convention and this impacted adversely (through its link to firm access) on TNSPs or the NEM in general.

Therefore, it is proposed that peak period definitions are contained in the firm access agreement and then reflected in AEMO settlement procedures. Should the AFMA convention change and a generator wish to change the period definitions in existing access agreements, it would need to negotiate a change to the agreement with its TNSP. TNSPs may also decide to change (or may be required by the AER to change) the default period definitions for future agreements to align with the new AFMA standard.

7.3.4 Agreed access not limited to registered capacity

The concept of super-firm access is discussed in section *4 Access Settlement* and section *5 Firm Access Standard* and relies on a generator procuring an access amount greater than its generation capacity. The concept is a logical and straightforward way for a generator to obtain access that is firmer than the FAS standards. However, it does raise possible competition issues around hoarding capacity.

There is a potential scenario whereby a generator might deliberately buy up existing *spare* capacity, above its current needs, so as to pre-empt the use of that capacity by a future competitor. The

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72 To avoid a double jeopardy situation, where a breach of the FAS leads to a breach both of the regulations and the agreement.

73 Although access-short generators will be making payments into access settlement, taking into account other AEMO payments to generators, generators will continue to receive, net, monies *from* settlement.

74 Nor could it, because non-firm generators – whose prudential obligations must also be managed – do not *have* an access agreement.

75 Strictly speaking, AFMA only recommends non-binding standards but, in practice, all companies use the AFMA standards when agreeing forward contracts.

future entrant would therefore be required to pay for transmission capacity to be expanded and this may create a barrier to entry.

However, this scenario is mitigated in a number of ways. Firstly, the LRIC methodology takes a long-term view of the level of spare capacity and its value. Spare capacity may not be substantially discounted in price compared to new capacity: unlike, say, under a deep connection charging approach, where the former has zero price attached.

Furthermore, and most importantly, whilst a generator can hoard *firm* access it cannot hoard access, *per se*. If the firm generator does not actually use the spare transmission capacity (and it obviously cannot generate above its generation capacity) the relevant flowgates will either remain uncongested or will have sufficient capacity for non-firm entitlements to be allocated. Therefore, a generator seeking to hoard firm access may simply be encouraging future entrants to free-ride by relying on non-firm access. Thus, hoarding is unlikely to be a tenable strategy, except perhaps for a short period: eg where a generator is planning to build a new power stations and wishes to "get in first". That would be a legitimate strategy, which regulations should not seek to prohibit.

In summary, our current view is that there seem unlikely to be any competition concerns in relation to super-firm access or access hoarding.

7.3.5 Customisation

Customisation of access terms would be permitted, subject to this customisation not impacting adversely on other users.[76] For example, the TNSP agreeing to a heavily-discounted access charge would imply correspondingly higher TUOS prices to recover the revenue shortfall and so would not be permitted.[77] On the other hand, a discounted access charge might be allowable in some situations, similar to discounting of TUOS charges.[78] The regulation of customisation to ensure the TNSP complies with this principle is discussed in section *8.2.2 Issuance Regulation*.

Since the agreement refers to only two matters (the TNSP notifying agreed access amounts to AEMO and the generator making annual access payments) only terms associated with these two matters can logically be customised.[79]

Customisation of agreed access amount might include variations such as:

- non-standard peak-period definitions;
- a call option structure: where access was only provided where RRP exceeded a threshold amount;
- scheduled outage windows: the agreed access amount could be set to zero for a period agreed each year between TNSP and generator; and
- future agreed access amounts being contingent on transmission expansion being completed.

Since some of these variations could make it more complex and expensive for AEMO to undertake access settlement, the TNSP would need to ensure that these variations did not adversely affect other users. Similarly, where a non-standard access price accompanied these variations, the TNSP

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[76] Meaning *all* users of transmission services, not just firm generators. However, non-firm generators are not considered to be users as they do not have any agreement with the TNSP. And, of course, many new firm access agreements will – quite appropriately – impact adversely on some non-firm generators.

[77] See section *8 TNSP Regulation*.

[78] TUOS price discounting is currently permitted where this discounting provides benefits to users as a whole: eg by discouraging transmission bypass.

[79] A TNSP would not be permitted to include terms *not* relating to these matters. For example, if a generator agreed to provide network support to the TNSP, this should be recorded in a separate agreement, not in the firm access agreement.

would need to ensure that this reflected real changes to the cost of service provision, to ensure that it did not lead to costs being loaded onto other users.

Variations to annual access payments could include:

- discounts or premiums to the default access price to reflect a lower or higher service level;
- an upfront *capital contribution*;
- a change to the annual payment profile;
- a change to the indexation of the annual amounts; and
- different approaches to prudential management: eg parent company guarantees.

Again, the principle of *no adverse impact on other users* applies.

Customisation relating to anything apart from these two matters would not be permitted: for example (without limitation):

- options to renew or extend the agreement term;
- variations to the FAS;
- performance incentives or risk sharing;
- grouping (eg the generator committing not to group the access with other agreements); and
- bundling with other services (eg network support or network control ancillary services).

7.3.6 Recognising Transmission Expansion Lead Time

Transmission expansion will commonly be required prior to new firm access commencement to ensure no breach of the FAS. Expansion often has a long lead time and this needs to be reflected in the access procurement process: a generator whose access requirements necessitate expansion will need to provide the requisite time between procurement completion and access commencement.

On the other hand, a TNSP is not permitted to refuse or delay access because lumpy expansion may be underutilised in the medium-term: for example, where a 250MW access request prompts a 500MW expansion and the TNSP seeks to delay access until a second 250MW access request is received. This underutilisation is reflected in the access price and the TNSP can expect to recover the full cost of the expansion over time.

7.3.7 Firm Access Procurement for Embedded Generation

A generator procures access from its local transmission node: the connection point at which its power station connects to the shared transmission network. This raises the question of where an embedded generator (a generator connected to a distribution network) would buy access from.[80]

AEMO does not typically model distribution network constraints in NEMDE. If there were such constraints, they would be agreed between the generator and the distribution network service provider (DNSP) and reflected in the generator's dispatch offer.[81] If the generator required certainty on how it would be affected by distribution constraints it would need to enter into some arrangement with the DNSP, which is beyond the scope of the OFA model.

Where the output of an embedded generator materially affects *transmission* congestion, AEMO would include its output on the LHS of a transmission constraint and so it would have flowgate

[80] Only *scheduled* embedded generators would need to consider procuring access, because non-scheduled generators are not dispatched by AEMO and so cannot be constrained off by transmission congestion.

[81] For example, if the constraint meant that a 50MW generator could temporarily only generate at a maximum of 30MW, the generator would reduce its offered availability to 30MW.

participation and usage, just like a transmission-connected generator. In formulating the constraint, AEMO would need to know the node at which the embedded generator's output entered the transmission network. So long as this node did not change over time, an embedded generator could procure firm access at this node and it would receive the necessary network access to the RRN, just like a transmission-connected generator.

If the node did change – or if AEMO assumed that the entry of the embedded generator output was shared across multiple nodes – procuring firm access would be more complex. The embedded generator would need to enter into discussions with its DNSP, AEMO and the local TNSP to resolve this issue.

7.3.8 Access Trading and Rescindment

There may be occasions where a generator wishes to transfer existing agreed access to another power station: whether one from within its portfolio or one belonging to another generating company. There are then three potential changes to the agreement:

- a change to the *power station* that the firm access applies to;
- a change to the *node* from which firm access applies, with possibly different participation in congested flowgates;
- a change to the *generating company* who is the agreement counterparty and is obliged to make annual access payments

These issues are considered in turn below.

If the transfer is simply to a different *power station* connected at the same transmission node and owned by the same company, the impact on the TNSP is unlikely to be material (since the FAS obligations would remain the same) and granting permission should generally be straightforward.

If the transfer were to a different *node*, the TNSP would need to examine the FAS implications: the required capacity might increase at some flowgates and decrease at others. One possible approach the TNSP could take would be to calculate the access price at the two nodes and only approve the transfer if the price at the new node was lower than that at the old node. If the price was higher, the amount of agreed access provided at the new node could be scaled back as needed to equate the two charges.

Taken to its logical extreme, that approach would suggest that a generator could offer to rescind its agreed access, on payment of the calculated *current* applicable access price *by* the TNSP *to* the generator. However, the payment of monies *by* the TNSP is rather problematic from a regulatory perspective, since it may ultimately be the demand-side user who picks up the cost of any resultant revenue shortfalls. Generators might find a way to *game* the pricing methodology by judiciously buying and selling back access: like a day-trader buying and then selling shares.

If the transfer were to a different *generating company*, that company would acquire the obligation to make any *future* access payments specified in the access agreement. The TNSP would need to establish prudential arrangements to ensure that these payments are made. Given the possibly different credit profile of the new counterparty, the new prudential arrangements may differ from those applying previously.

Therefore, it is proposed that transfers of access are approved subject to TNSP approval and *no net reduction* in access charges occurring. Rescindments of access involving payments *by* the TNSP should *not* be permitted.

Any payments between the new generator and the old generator would be a purely bilateral matter and not relevant to the TNSP or subject to any rules or regulations.

8 TNSP Regulation

8.1 Overview

Firm access service is provided by the shared network, the operation of which is a natural and regulated monopoly. Since TNSPs are therefore monopoly providers of firm access service, the service is treated as a *prescribed service*. Regulation covers four areas: *issuance*, *pricing*, *revenue*, and *quality*. These are considered in turn.

Issuance regulation requires that, through the access procurement process, TNSPs offer the default service at a default price (determined by the access pricing methodology), provide timely and relevant information to allow a generator seeking firm access to choose its preferred service parameters, and negotiate and agree customised variations from the default in good faith, to the extent that these variations do not adversely affect other users. Where expansion is necessary prior to access commencement, TNSPs will be permitted to *reasonably* delay access commencement to give time for such expansion.

Pricing regulation requires that default prices for firm access should be calculated using the approved pricing methodology, consistent with LRIC pricing principles and requirements set out in the rules. The pricing methodology would be developed during implementation, should the OFA model proceed.

Revenue regulation will require that the *combined* revenue from TUOS services and firm access services are not forecast to exceed a revenue cap determined by the AER, based on the efficient cost of building and maintaining the shared network to provide those services in accordance with the relevant service standards. Revenue regulation must reflect the fact that access revenue is essentially fixed once firm access is agreed, meaning that any variations in cost or revenue from forecast must be borne by either TUOS users or the TNSP itself. The AER will be responsible for defining mechanisms for managing and sharing these forecasting risks.

Quality regulation provides incentives for TNSPs to maintain access service quality at or above the minimum standard specified in the FAS. Incentives would initially be through transparent publication of information on breaches but will increasingly be through financial penalties on the TNSP where breaches occur. Penalties will be based on – and not exceed - the cost to firm generators of shortfalls of flowgate capacity below the FAS standard. Through access settlement, payments by the TNSP will be allocated directly to the generators affected.

8.2 Design Blueprint

8.2.1 Firm Access Service Regulation

Firm access is a service provided by a TNSP using its shared network. Because the shared network is a natural and regulated monopoly, TNSPs are monopoly providers of firm access; the service cannot be provided on a competitive basis. For that reason, the service is treated as a *prescribed service* for the purposes of regulation, similar to TUOS service.

Regulation will apply to four areas:

- issuance;
- pricing;
- revenue; and
- quality.

As with TUOS service, regulatory principles and processes will be defined in the rules and these will be applied and operated by the AER.

These areas are discussed in turn below.

8.2.2 Issuance Regulation

Regulation will require that TNSPs develop and operate an access procurement process similar to that described in section *7 Access Procurement*. TNSPs will be required to provide access seekers with timely and useful advice and information on access procurement.

As discussed in section *7.3.5 Customisation*, TNSPs are permitted to agree variations from default firm access terms and prices, so long as these are in the interests of all users and relate to agreed access amounts or to access payments.

This requirement will be overseen and enforced by the AER through:

- the AER specifying customisation principles, in accordance with high-level principles in the rules;
- TNSPs being required to develop an approved customisation policy and offering and agreeing variations in accordance with that policy; and
- the AER reviewing and approving the policy based on its compliance with the customisation principles.

The envisaged process is similar to that which applies to discounting of TUOS charges in relation to the TUOS service to demand-side users.

TNSPs would be required to operate a dispute resolution mechanism and those procuring access would refer disputes to this forum if they felt the TNSP was not meeting its obligations under its procurement procedure or customisation policy.[82]

8.2.3 Pricing Regulation

A TNSP will offer default prices for firm access which must be calculated using the access pricing methodology (see section *6 Access Pricing*). As proposed in that section, there will be a *single, common* pricing methodology for all NEM regions.

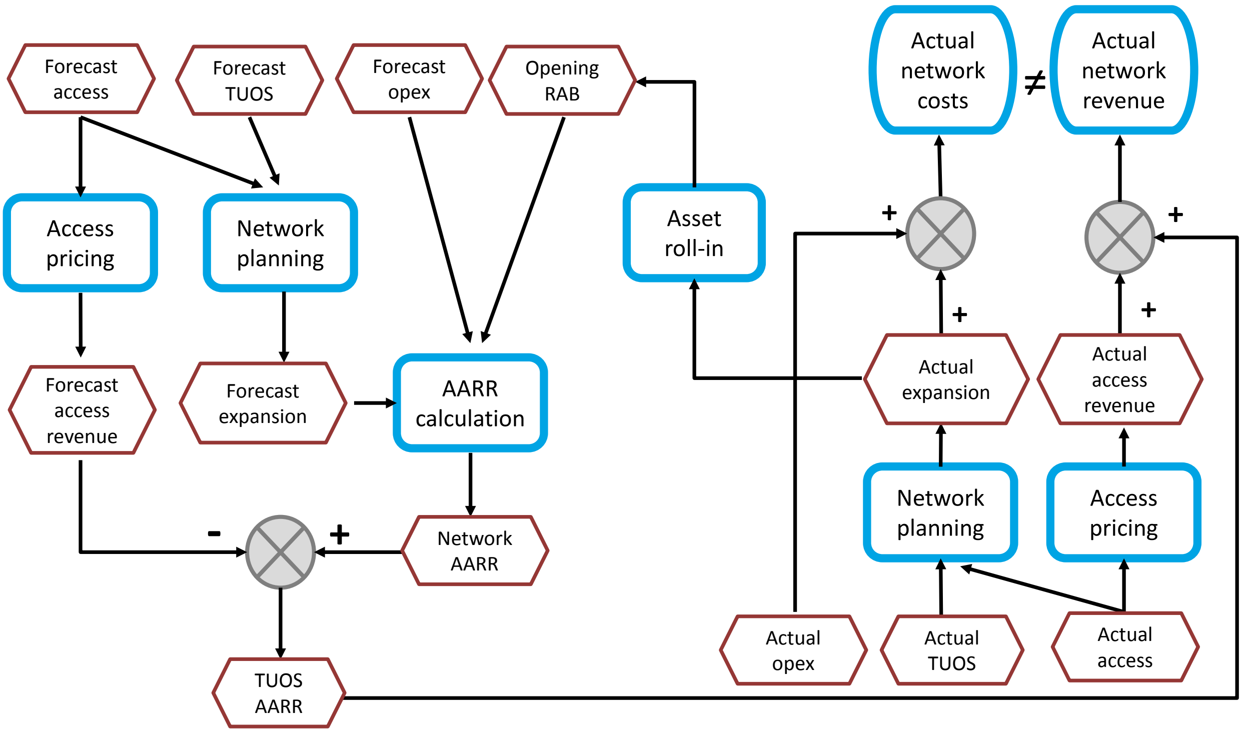
In accordance with customisation principles, discounts are permitted where the TNSP is able to demonstrate that these are in the interests of all users.

8.2.4 Revenue Regulation

There will be a single regulatory framework for revenue from firm access service and TUOS service (which, collectively, will be referred to as *shared network services*). The regulatory framework for share network service revenue is presented in Figure 8.1 below.

[82] This could be an existing mechanism or one especially created for access procurement.

Figure 8.1 Revenue regulation processes



The AER will determine, on each *regulatory reset*, an *aggregate annual revenue requirement* (*AARR*) for *shared network services* over a *regulatory period*. The AARR would be based on the efficient cost of building, owning and operating a shared network capable of providing shared network services to the relevant standards[83] based on current and forecast levels of these services.

Firm access revenue for the period will then be estimated, based on current and anticipated access agreements, and *deducted* from the network AARR to determine a revenue cap for TUOS. TUOS prices will then be determined as they are at present, and subsequently adjusted as necessary to ensure that the *TUOS revenue cap* is not breached. On the other hand, access revenue is not explicitly regulated through this mechanism: a TNSP may earn higher revenue than forecast if additional, unanticipated, access issuance occurs.[84]

Variations of actual firm access levels from forecast may lead to changes in transmission costs where expansion is triggered. Access pricing is designed to ensure that incremental access revenue and costs are *broadly* matched, but they will not *exactly* match and some risk will be borne by the TNSP. The AER may include regulatory mechanisms that mitigate this risk for a TNSP: for example, applying a *contingent projects* mechanism, similar to the current mechanism for TUOS, where network AARR could be reopened to cover the cost of a major expansion project which had been anticipated as *possible* in the prior regulatory reset but not included in the AARR. This issue is discussed further in section *8.3.2 TNSP Risk from Lumpy Access-Driven Expansion Costs*.

On the other hand, there will typically be no additional transmission costs associated with sales of short-term firm access where a TNSP has sufficient spare transmission capacity to do this without incurring expansion costs or breaching the FAS. Since such sales do not impact on other firm access or TUOS users, discounts from the default access price could generally be offered[85], and a TNSP is incentivised to maximise revenue from such sales.

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[83] Ie for TUOS and firm access services, the reliability standard and the FAS, respectively.

[84] Of course, it cannot increase prices on pre-existing agreed access, since prices are fixed prior to access commencement.

[85] Although typically a low access price would be calculated for such sales anyway.

8.2.5 Non-Financial Quality Incentives

As discussed in section *5.2 Firm Access Standard Design*, the FAS defines a level of target flowgate capacity that a TNSP must meet or exceed on every congested flowgate in every settlement period. The target flowgate capacity will be calculated by AEMO and any *capacity shortfalls* will be *identified* and *reported on*.

A capacity shortfall causes firm generators' entitlements to be scaled back by more than the FAS permits and consequently their settlement payments will be reduced by an amount that – in aggregate – equals the product of the capacity shortfall and the flowgate price: the *shortfall value*. Capacity shortfalls, and their associated values, will be published by AEMO. This might trigger investigations where shortfall amounts or values exceeded specified thresholds. Investigations would seek to determine whether a TNSP's planning, operational or access issuance processes were at fault and, if so, what remedial action would be appropriate.

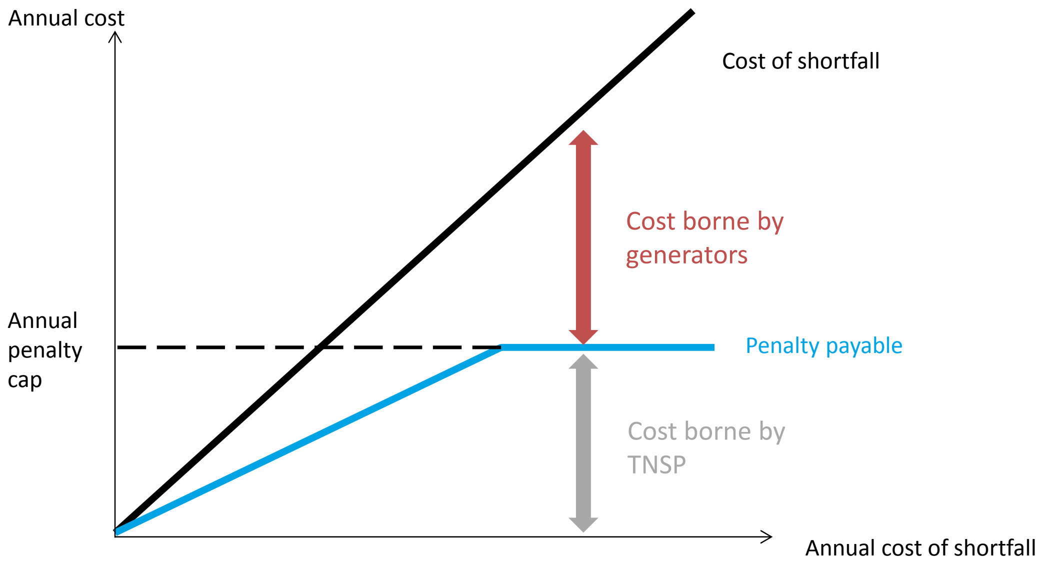
8.2.6 Financial Quality Incentives

The design and timing of any financial incentive scheme for FAS breaches would be decided by the AER. Any scheme would be required to set TNSP penalties according to the formula:

TNSP penalty = incentive sharing factor x shortfall value

with the AER deciding on the appropriate mechanism for setting a sharing factor between 0% and 100%. If it followed the design of similar quality incentive schemes elsewhere, the AER would set a fixed sharing factor that applies until aggregate penalties over a period reach a preset limit, after which the sharing factor is set to zero and so no further penalties apply, as illustrated in Figure 8.2 below. However, other designs are possible.

Figure 8.2 An illustrative quality incentive regime



The penalty would be calculated and applied in access settlement whenever a capacity shortfall occurred, by calculating a TNSP support amount on the relevant flowgate based on the formula:

TNSP support = incentive sharing factor x capacity shortfall

The TNSP would then be obliged to pay a penalty amount into access settlement based on the formula:

TNSP penalty$ = flowgate price x TNSP support

The TNSP support *adds* to the *effective* flowgate capacity, meaning that the total effective flowgate capacity is:

Effective Flowgate Capacity = Actual Flowgate Capacity + Flowgate Support + TNSP Support

As described in section *4.2.4 Entitlement Scaling*, the effective flowgate capacity is allocated between generators using the entitlement scaling algorithm. Thus, actual entitlements to firm generators are *enhanced* by the TNSP support and the TNSP penalty payment is automatically allocated between firm generators affected by the capacity shortfall.[86]

So long as the incentive sharing factor is less than 100%, the FAS *obligations* on a TNSP to maintain flowgate capacity must remain. However, if at any time a 100% sharing factor were applied,[87] firm generators would be indifferent to any capacity shortfalls, as they would be fully compensated. It could then be left to a TNSP to decide whether to maintain the FAS level of capacity or to pay the shortfall penalties.

8.2.7 Summary

Regulation will be designed to ensure that TNSPs, being monopoly providers of firm access service, will provide and price firm access in a way that promotes generator choice and market efficiency.

8.3 Design Issues and Options

8.3.1 Regulated or Negotiated Service

The firm access service has some similarities to negotiated services such as connection services, particularly in the procurement process: ie the service is agreed through bilateral discussions between TNSP and user, and agreed terms are enshrined in a long-term agreement between the two.

However, the firm access service, like the TUOS service, is provided by the shared network and these can only be provided by the TNSP.[88] It is impractical to differentiate between assets providing the firm access service and those providing the TUOS service. Therefore, the firm access should be treated as a prescribed service, as the TUOS service is.

8.3.2 TNSP Risk from Lumpy Access-Driven Expansion Costs

8.3.2.1 Capital Costs and Carrying Costs

As discussed above, errors in forecasting firm access levels, coupled with lumpy expansion requirements, could lead to a TNSP undertaking significantly more capital expenditure than anticipated in the regulatory reset process. Some of this will be recoverable through revenue from new access agreements; some of it may be borne by the TNSP, as discussed below.

It is an existing recognised feature of TNSP regulation (of TUOS revenue) that TNSPs bear the *capital* cost of transmission expansion and hold the network assets on their balance sheets, financed by equity and debt. The revenue framework then allows TNSPs to recover a *carrying cost*: a return on this asset base plus a recovery of the asset cost over time through a specified depreciation

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[86] Since access settlement always balances.

[87] At this point in time, this would appear likely to create unacceptable risk for a TNSP but, in time, TNSPs may find ways to manage such risk.

[88] In the sense of planning and operating the shared network assets collectively. A third party might construct individual assets, but that party does not provide the shared network.

schedule and allowance. Over the life of an asset, its total recoverable carrying cost (in NPV terms) equals its capital cost, meaning the TNSP *gets its money back* in NPV terms.[89]

This feature would continue under the regulation of network services revenue, described above. Therefore, the risk to the TNSP from lumpy investment is not from the capital cost, *per se*, but rather from any mismatches between the carrying cost of the new investment and the incremental revenue from the new firm access provided.

8.3.2.2 Variances and Impacts

A mismatch may potentially arise from two sources:

1. a difference between the *actual* capital cost of expansion triggered by the new access and the cost *estimated* by the access pricing methodology;[90] and
2. a *timing* difference in the *recovery* of the expansion cost, between the regulated carrying cost and the annual access payment profile.

The capital cost difference arises from a combination of two components: modelling errors or simplifications in the pricing methodology; and inefficiencies in the TNSP expansion process.

For example, if the pricing methodology estimates an expansion cost of $100m and the TNSP ends up spending $180m, the discrepancy could be due to:

- *pricing errors alone*: ie the true efficient expansion cost is $180m;
- *TNSP inefficiency alone*: ie the efficient expansion cost is $100m; or
- *a combination of both*: the efficient expansion cost is somewhere between the two.

It is not possible in practice to distinguish these components, which means that any regulatory mechanism to remove risks due to pricing errors would also remove incentives for capital efficiency, which is undesirable. Therefore it is not practically possible to mitigate pricing risk: except, of course, by carefully designing the pricing methodology so that such errors are minimised.

The *timing* discrepancy between actual costs and revenue recovery is similarly due to a combination of two factors:

- a timing discrepancy between actual and estimated costs; and
- a timing discrepancy between estimated costs and revenue recovery.

The first timing discrepancy is a function of the differences between *actual* expansion planning and the *stylised* expansion planning assumed in the access pricing methodology. The second discrepancy arises because it is not always possible to match the profile of access payments to the profile of estimated costs. This issue is discussed further in section *12.10 Annual Payment Profiling*.

A TNSP is exposed to these discrepancies only within the regulatory period in which the new access commences: the *first period*. In subsequent periods, the new physical assets from the access-driven expansion will be *rolled-in* to the TNSP's *regulatory asset base (RAB)* and remaining carrying costs will be recoverable under the network services AARR. To the extent there is a mismatch between remaining carrying costs and remaining access payments, this mismatch will then be borne by demand-side users, through TUOS charges, rather than the TNSP.

[89] One can think of the carrying costs as repayments on a loan. The NPV of loan repayments must always equal the loan value, using the loan interest rate as the discounting value for the NPV.

[90] It should be recalled that the capital cost being talked about here is actually an *incremental* cost and may be associated with planned expansions being *advanced*, as well as *new* expansions.

These risk drivers – and their impacts on TNSPs, firm generators and TUOS users – are summarised in Table 8.1, below: *positive* means reduced prices or improved profit; *negative* means increased prices or reduced profit; *none* means no effect.

Table 8.1 Transmission cost drivers and their impacts

Driver	TNSP impact (first period)	TUOS impact (subsequent periods)	Firm generator impact
TNSP expands inefficiently	negative	negative	none
TNSP expands super-efficiently[1]	positive	positive	none
Access price understates efficient expansion cost	negative	negative	positive
Access price overstates efficient expansion cost	positive	positive	negative
Expansion costs front-ended[2]	negative	positive	none[4]
expansion costs back-ended[3]	positive	negative	none[4]

(1) Actual expansion costs are *lower* than would be expected from an efficient TNSP.
(2) Expansion carrying costs exceed access payments in the first regulatory period.
(3) Access payments exceed expansion carrying costs in the first regulatory period.
(4) Assuming that the generator is indifferent to the *timing* of access payments.

The table reveals the following. Firstly, as one would expect, TNSP capital efficiency affects *total* costs which feed through to the TNSP and to TUOS users. It does not affect generators, whose charges are based on stylised, rather than actual, expansion costs. The other drivers do not affect *total* costs but rather how they are *shared*: so the impacts are *zero sum.*

Secondly, all of the drivers are *symmetrical*: they can operate in either direction and so associated impacts may be positive or negative, for each affected party. Ideally, the design of regulation (AARR forecasting and access pricing) should ensure these risks are *unbiased*, so that the positive and the negative average out over the longer term. Nevertheless, risk will remain and cannot be eliminated.

8.3.2.3 Numerical Example

Table 8.2 below provides an example to illustrate these different risks. For simplicity, the amounts in this table are all NPV in the year prior to new access commencement, using the regulatory WACC as the discounting factor, meaning that total carrying cost equals capital cost.

Table 8.2 Example illustrating TNSP costs and revenues

($m)	Total revenue or cost	First period revenue or carrying cost	subsequent periods revenue or carrying cost
actual new costs	60	12	48
access payments	50	5	45
Adverse Impact on TUOS users	*+3*	*0*	*+3*
Adverse Impact on TNSP	*+7*	*+7*	*0*

In this example, it is assumed that the new access that commences in the first period was not forecast *at all* during the previous regulatory reset and so had not been included in the AARR.

Therefore the *full* impact of incremental costs and incremental revenues are felt. More commonly, in practice, the new access would be forecast, but the associated forecasts of incremental costs and revenue may be inaccurate. In that context, the figures in Table 8.2 for costs and revenue would represent forecast *errors* rather than total amounts.

As discussed above, there are two drivers which affect prices or profits. Firstly, the access pricing methodology *under*-estimates the new expansion costs: $50m estimated versus $60m actual. That is due to a combination of pricing error and TNSP capital inefficiency.[91] As a result, there is a $10m shortfall between the incremental expansion costs and the incremental access revenue. The $10m burden is shared between the TNSP and TUOS users.

Secondly, there is a discrepancy between the timing of costs incurred and the timing of access payments. The table shows that only $12m of the total $60m (or 20%) of carrying costs is borne in the first period, compared to recovery of just $5m (10%), of estimated expansion costs. This leads to a $7m shortfall of revenue in that period, which is borne by the TNSP.[92]

After the first period, there are $48m of expansion costs remaining and just $45m of further access payments. The $3m shortfall will be recovered from TUOS users in subsequent periods.

In summary, the total $60m cost of the expansion caused by the new access is shared as follows:

- $50m borne by the new firm generator through access charges;
- $7m borne by the TNSP in the first regulatory period; and
- $3m borne by TUOS users in subsequent regulatory periods.

These numbers are purely illustrative. Actual cost-sharing will depend upon the details of the access pricing methodology and the specific characteristics of the new access and associated expansion. As noted above, the risks are symmetric and (ideally) unbiased, so for every case like the example, where the generator is undercharged and the TNSP and/or TUOS users negatively impacted, there will be another case where the reverse applies.

8.3.3 Mechanisms to Mitigate TNSP Risk

The example above can also be used to illustrate three possible mechanisms for mitigating TNSP risk arising from discrepancies between estimated carrying cost and access revenue:

- *Access agreement front-ending*: the first-period access charges are increased and the second-period access charges are correspondingly reduced.
- *Contingent project reopener*: the TUOS revenue cap in the current period is reopened; it is increased to cover the cost discrepancy.
- *Shortfall roll-up*: part of the shortfall in the first period is capitalised, included in the RAB and so recoverable in future periods.

It will be seen that all of these options transfer costs from the TNSP to demand-side users. It is not possible to transfer additional costs to firm generators[93] since these costs are fixed by the access pricing methodology.

The difficulty for the AER in designing such mechanisms is to prevent cost shortfalls that are caused by TNSP capital inefficiency from being passed through to demand-side users. It is

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91 These components cannot be broken down in practice and so are not shown separately in Table 8.2 above.

92 Note that even if the pricing methodology had *correctly* estimated the expansion cost (of $60m) the same payment profiling (10% in the first period) would mean only $6m of access revenue would be received in the first period, leading to a $6m ($12m - $6m) shortfall being borne by the TNSP.

93 Except by changing the pricing methodology.

possible that this could be addressed through basing the pass-through amount on modelled costs rather than actual costs.

8.3.4 Sharing of Congestion Risks

The incentive sharing factor can *conceptually* be anywhere between 0% and 100%, although there may be *practical* limits as to how high the factor could be commensurate with existing TNSP regulation and risk tolerance. However, the incentive sharing factor does not represent the percentage of *total* congestion costs that the TNSP would bear, which would be substantially lower than this, because:

- The FAS explicitly recognises (in the FAS scaling factors) that transmission capacity reduces under certain conditions. A TNSP is only exposed where capacity falls *more* than the FAS anticipates.
- Conditions which are genuinely unmanageable and unforeseeable would be classed as Abnormal Operating Conditions under the FAS, under which TNSP has no exposure.
- A TNSP is entitled to withhold provision of new firm access until the necessary transmission expansion is completed.
- The risks of extreme NEM market conditions are already mitigated through administered pricing and market suspension.
- There would likely be an aggregate annual cap on TNSP payments under any incentive regime.

These factors mean that the TNSP risk is substantially lower – and more manageable – than if the TNSP had to bear *all* congestion costs. Most congestion costs will continue to be borne by firm and non-firm generators.

In any case, the AER is likely to take a cautious and prudent approach to revising the incentive regime on each regulatory reset, taking into account actual congestion and transmission conditions experienced in the previous regulatory period. For example, the AER might *back-cast* the new scheme, calculating the payments that the TNSP would have made had the revised regime applied in the previous regulatory period.

8.3.5 TNSPs are Rewarded for Providing More Transmission than FAS Requires

As described, the incentive scheme appears *asymmetric*: the TNSP is *penalised* for a *shortfall* in transmission but not *rewarded* for a *surplus* of transmission.

It would be possible to design a symmetric regime, where a TNSP received a bonus for providing transmission capacity in excess of the FAS standard. The question that then arises is who should pay for these bonuses. The cost should not be borne by demand-side users, who would gain little benefit from the surplus transmission capacity. The beneficiaries are generators, who will receive a higher level of network access than they are entitled to. But generators already have the option of procuring additional firm access if they value it. Why should generators then also be charged for network access that they *have* not requested?

Herein lies the resolution of this issue. If a TNSP finds that it has some surplus transmission capacity, it is entitled to *market* that capacity to generators, by offering new firm access. It will be entitled to retain any additional access revenue within the regulatory period and so this creates a bonus for the TNSP to the extent access sales are made.

In summary, then, the regulatory regime as described *does* provide for symmetrical incentives on transmission provision. This occurs without any generator being charged for access that it has not requested.

8.3.6 Treatment of Market Benefits in the RIT-T

Under the current RIT-T, *economic expansion* of transmission is permitted. That is to say, TNSPs are permitted to expand transmission, even where this is not necessary to meet demand-side reliability standards, so long as the *market benefits* (for example, reduced congestion costs) exceed the expansion cost. More generally, where an expansion is required for reliability reasons, market benefits can be included in the net benefit calculation and this may affect the ranking of project options.

The philosophy of the OFA regime is that generators, rather than TNSPs, decide on the economic benefits associated with expansion: or, more specifically, the benefits associated with the firm access service that prompts expansion. TNSPs then expand as necessary purely to maintain the FAS, not (explicitly) because of the economic benefits associated with the firm access service.

Were the TNSP to continue to undertake economic expansion in the OFA regime, the TNSP would be making decisions to expand the network to provide additional access despite generators not requiring or valuing that additional access. Because there is no firm generator that is paying for the expansion, the expansion costs pass to demand-side users, despite the fact that these users will typically gain limited benefit from the expansion.[94]

For these reasons, economic expansion will *not* be permitted in the OFA model. All expansion must be justified, through the RIT-T, as being the cheapest way of meeting current and anticipated demand-side reliability standards and FAS obligations. The assessment will therefore not include many of the market benefits currently included in the RIT-T.

9 Transition

9.1 Overview

Transition processes will apply prior to, and in the early years following, implementation of the OFA model, with the objectives of mitigating the impact of its introduction and ensuring that affected parties have time to develop their capabilities for operating in the new regime without being exposed to undue risks in the initial period.

The main transition mechanism will be the allocation of *transitional access* (TA) to existing generators. TA acts identically to other firm access, except that it does not need to be procured from a TNSP and no access charges apply.

The transitional allocation process will have four stages. Firstly, generators' access *requirements* – the level of firm access they would need to have unfettered access to the RRN – are estimated, based on historical generation patterns. Secondly, these access requirements are *scaled back* to the extent necessary to ensure that the *existing shared network is FAS compliant*. Thirdly, this scaled access level is *sculpted* back over time, so that transitional access reduces over a number of years and eventually expires. Finally, an *auction* will be established to allow generators to sell some of their transitional access or buy additional transitional access from other generators.

The other transition mechanism is that no *financial* quality incentives will apply to TNSPs in relation to FAS breaches in the early years of OFA operation. This would be at least until each TNSP's next regulatory reset.

[94] Note the similarity with the issue in the previous section: in each case, the TNSP is seeking to get paid as a result of expanding transmission capacity beyond the FAS level.

9.2 Design Blueprint

9.2.1 Transition Objectives

The objectives of the transition process are:

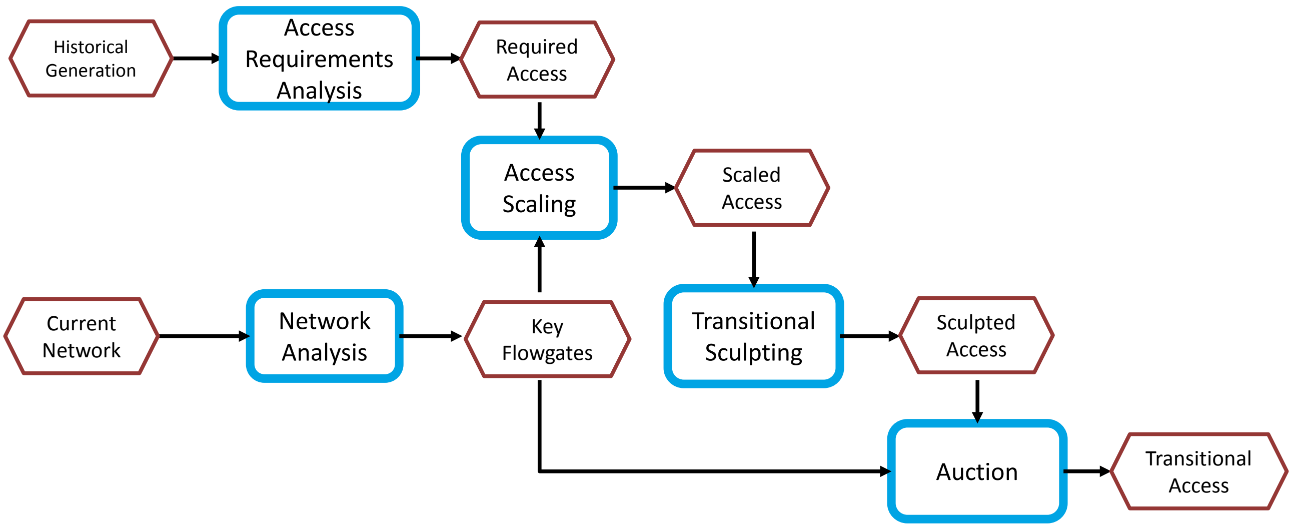
- to mitigate any sudden changes to prices or margins for market participants (generators and retailers) on commencement of the OFA regime;
- to encourage and permit generators – existing and new – to acquire and hold the levels of firm access that they would choose to pay for;
- to give time for generators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

Importantly, the transition process will *not* delay or dilute the efficiency benefits that the OFA model is designed to promote.

9.2.2 Transitional Access Allocation

The process for determining levels of transitional access consists of four stages, as illustrated in Figure 9.1, below. These are described in turn.

Figure 9.1 Transitional access allocation processes



9.2.2.1 Stage 1: Access Requirements

A generator's access requirement is the maximum level of access that a generator needs to give it full access to the RRN. As noted earlier, access agreements will be based on the peak and off-peak periods used in forward trading. Generator access requirements will therefore be expressed in terms of these periods, as summarised in Table 9.1 below.

Table 9.1 Generator access requirements

Gen Type	Peak Access Requirement[1]	Off-peak Access Requirement[1]
Baseload	Generator capacity	Generator capacity
Mid-merit	Generator capacity	Zero or minimum generation[2]

Gen Type	Peak Access Requirement[1]	Off-peak Access Requirement[1]
Peaking	Generator capacity	Zero
Intermittent	Generator capacity	Generator capacity
MNSP	Capacity in peak flow direction	Capacity in off-peak flow direction
Interconnector	Zero[3] access in each direction	Zero[3] access in each direction

(1) *Peak* and *off-peak* times are aligned with forward contract convention.
(2) Depending on whether the generator historically shuts down off-peak or runs at minimum generation level.
(3) *Zero* access means that IRSR is compensated for any counterprice flows (see section *10 Inter-regional Access*).

Therefore, this stage of the transition process aims to determine generator types – and hence their access requirements – by analysing historical output and bidding data.

9.2.2.2 Stage 2: Access Scaling

In this stage, access requirements will be scaled back as necessary to ensure that they do not lead to FAS breaches, given the capacity of the existing shared network. Scaling will be based on the following principles:

- Transitional access should be *maximised*, subject to *not* causing FAS breaches.
- Scaling should be *robust:* small changes in flowgate formulations should not cause large changes in scaling.
- Scaling should also be *efficient*: extra access should not be granted to one generator if this disproportionately restricts the access that can be provided to other generators.

The algorithm for the scaling process will be conceptually similar to a dispatch algorithm: with access level analogous to dispatch level and a common requirement that aggregate access/dispatch must not cause transmission/flowgate constraints to be violated. In this context, the relative level of access will be determined by the *quasi-bids* which are entered into the scaling process.[95]

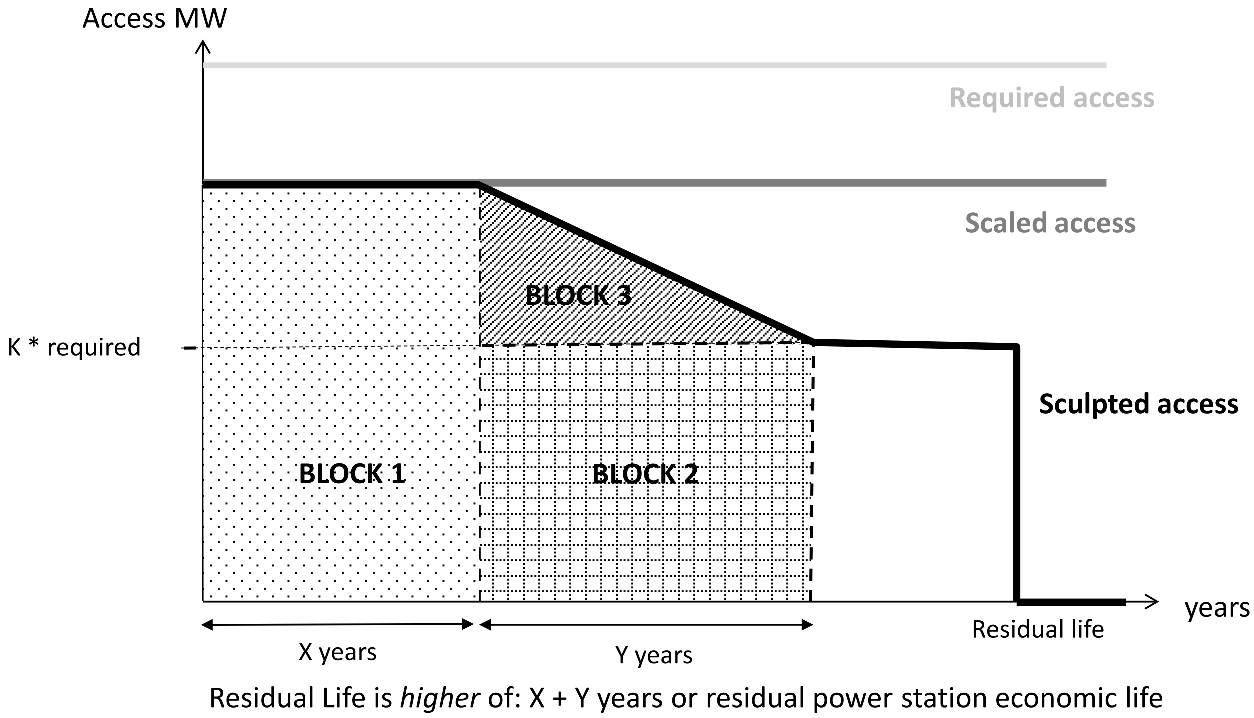
The access scaling process is described further in section *12.6.2 Transitional Access Scaling*.

9.2.2.3 Stage 3: Access Sculpting

The transitional access levels determined by stage 2 will set the level of access provided in year one: the year of OFA commencement. These levels will be sculpted back over time, following a profile illustrated in Figure 9.2 below.

[95] Sufficient additional notional load would be added at the RRN to ensure that generators were "dispatched" as high as the transmission capacity permitted.

Figure 9.2 Sculpting of transitional access for a Power Station



Thus, older power stations (those with less than X+Y years of remaining life on OFA commencement) will be provided with the minimum X+Y years of access; younger power stations will be provided with longer terms. The values of K, X and Y would be determined during OFA implementation.

9.2.2.4 Stage 4: Access Auction

An *auction* will be established that permits generators to bid to *top-up* their TA level, by buying from other generators who choose to offer to *sell* some of their TA. Auction participation will be voluntary and bids and offers unregulated, except that a generator is not permitted to offer more TA than it has been allocated.

The only constraint placed on the clearing of bids and offers[96] is that the final, post-auction allocation is *FAS-compliant*. So long as compliance is based on the same set of flowgate constraints as in the stage 3 scaling process, auction settlement will clear.[97]

Auctioned products would be based on three blocks, shown in figure 9.2:

- Block 1 is an X year block of constant volume;
- Block 2 is a Y year block of constant volume; and
- Block 3 is a Y year triangular block of declining volume.[98]

These three blocks are the generic components of all generator TA allocations for the first X+Y years. The auction design is described further in section *12.6.3 Auction Process*.

Settlement of the auction would be through AEMO acting as a clearing agent: thus buyers would pay AEMO, who would pass payments onto sellers. Potentially, settlement could take place

[96] Apart from the ones that apply to all auctions: that bids and offers are only cleared if the clearing price is below or above the bid or offer price, respectively.

[97] See section *12.6.3 Auction Process* for an explanation of this.

[98] Ie 100% of nominal volume in year one, (1-1/Y)x100% in year two, (1-2/Y)x100% in year three etc.

progressively over the term of the TAs, so in this case appropriate prudential arrangements would need to be established and applied.

9.2.3 Summary

The transition process will help to ensure that, from day one of the OFA regime, existing generators will hold agreed access amounts that provide them with firmness of access to the RRN similar to the *de facto* access they enjoy currently. Aggregate access holdings will initially be commensurate with transmission capacity but, as these are sculpted back over a number of years, transmission capacity will be freed up to support new access issuance: to existing or new entrant generators.

9.3 Design Issues and Options

9.3.1 Implications for Competition and Contestability

It has been argued that transitional access for existing generators creates a barrier to entry of new generators and so will lessen the degree of future generation competition in the NEM. This argument rests on two premises:

- that new generators must pay access charges to obtain firm access, whereas existing generators do not, placing the new generators at a competitive disadvantage; and
- that existing transmission capacity is allocated to transitional access, meaning that new generators must rely on transmission expansion.

It is true that having to bear costs that your competitors do not creates a competitive disadvantage. But such inequalities will always exist in competitive markets: for example, new generators must incur the capital cost of building a power station, whereas for existing generators, the costs are sunk; some generators may have higher debt or a higher cost of capital than others; and so on. Other things being equal, lower cost generators will be more profitable than higher cost generators, but this by itself does not disrupt competition. New generators will enter when market prices cover their entry and operating costs. Market prices will have to rise somewhat to cover the cost of access charges but, for consumers, this higher price will be offset – over time – by lower TUOS charges, as firm generators bear more of the costs of the shared network.[99]

It is true also that new generators may have to rely on transmission expansion. But, although in some parts of the network, further transmission expansion may be impractical and so new generators might effectively be prevented from locating there, there will be plenty of other locations where new generators can and will locate.

In any case, over time, as TA is sculpted back, existing generators will increasingly bear the cost of access charges and spare capacity on the existing transmission network is likely to become available.

9.3.2 Choosing the Sculpting parameters

The sculpting approach used in stage 3 of the transition process is likely to be refined and changed during the OFA implementation process, with more specific parameters being defined.

Nevertheless, it is an important principle of the transition process that the same sculpting parameters are applied to each existing generator. This principle has the benefits of simplifying the process, avoiding debates about how one generator might be *slightly* different to another, and allowing for an auction process in which just the three standard blocks are auctioned.

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[99] As transitional access is sculpted back.

10 Inter-regional Access

10.1 Overview

The descriptions of OFA processes in the preceding section relate entirely to *intra*-regional access: access from a generator node to the *local* RRN. However, the OFA model also establishes a framework for *inter*-regional access: access from the RRN of one region to the RRN of a neighbouring region.

Inter-regional access is included in the OFA model for two reasons. Firstly, many transmission elements provide a combination of inter- and intra-regional access and this combination is reflected in NEMDE by *hybrid* transmission constraints which include both generator and *interconnector* terms. To ensure that access settlement balances on *hybrid* flowgates, interconnector usage and entitlements must be defined, and interconnector access payment paid into or from access settlement. So long as there are hybrid flowgates, the inclusion of inter-regional access is unavoidable.

Interconnectors could play a purely passive role in the OFA model: accepting access on existing transmission capacity, but not seeking the additional access that would drive transmission expansion. However, just as there are efficiency benefits in allowing *generators* to decide their levels of *intra*-regional access, there are potential efficiencies from allowing interconnector stakeholders to decide *inter-regional* access.

Because the benefits of inter-regional access are potentially dispersed across a number of sectors, representatives of all of these sectors should – to the extent practical – be involved in that decision process. This is achieved through a bidding process in which these beneficiaries promise to contribute to the cost of inter-regional expansion, which then proceeds when the aggregate bids equals or exceeds the cost of expansion. Market participants funding an inter-regional expansion will receive some inter-regional access in return.

Transitional inter-regional access may be allocated in the transition process, but only to the extent that this can be done without causing any additional scaling back of generator TA. Settlement payments arising from this TA will be paid into the inter-regional settlement residue, which will then be passed onto market participants through a process similar to existing Settlement Residue Auctions.

10.2 Design Blueprint

10.2.1 Inter-regional Terminology

Inter-regional access is similar to intra-regional access, but not the same. Interconnectors are like generators, but different in some important respects. Some additional terminology is needed to reflect these differences.

Interconnectors are conceptual entities in the NEMDE, corresponding to regulated interconnections between regions.[100] They do not submit dispatch offers (they are assumed implicitly always to have zero offer price) but are dispatched by NEMDE in an analogous way to generators.

For DC interconnectors (ie Murraylink and Directlink), the dispatch target is received by the relevant TNSP, who operates the interconnector so as to comply with the dispatch target. On the

[100] Market interconnectors, or MNSPs, are treated like generators in the dispatch model, as discussed in section *2.3.10 Interconnectors*.

other hand, AC interconnectors are free-flowing: the interconnector dispatch will automatically reflect the imbalance between generation and demand in a region.[101]

There is just one AC interconnector between each pair of neighbouring regions in the NEM, notwithstanding the fact that there may be several *physical* inter-regional transmission paths.

A *directed interconnector* is a conceptual component of an interconnector. If the QNI interconnector is dispatched to flow into NSW, this is considered to be a dispatch of the *southerly interconnector*.[102] Thus, each interconnector is composed of a pair of directed interconnectors.

In section *2.2.2 Dispatch and Network Access*, the financial benefit to a generator of being paid the RRP, rather than its local price, is referred to as *network access* and it is this *access* that is provided to generators (on a firm or non-firm basis) in the OFA model. For interconnectors, network access means being paid the RRP of the destination (or *importing*) region, rather than that of the source (or *exporting*) region.[103] To distinguish these different forms of access, access provided to generators may be referred to as *intra-regional access* and access provided to interconnectors as *inter-regional access*.

Settlement payments associated with intra-regional access are made directly to generators. Payments associated with inter-regional access are paid into a fund known as the *inter-regional settlement residue* (*IRSR)* which is held *in trust* by AEMO.[104] Separate IRSR funds are maintained for each directed interconnector.

Interconnector dispatch may be constrained in dispatch by NEMDE transmission constraints. The associated flowgates are referred to as *inter-regional flowgates*, if they are used only by interconnectors, or as *hybrid flowgates,* if they are used by both generators and interconnectors.[105] For contrast, flowgates that are *not* used by interconnectors may be referred to as *intra-regional* flowgates.

Unlike with generators, there is no intrinsic limit on the level of interconnector dispatch and so no corresponding concepts of registered capacity or offered availability. In practice, of course, there is always some flowgate that binds when interconnector dispatch is high, so interconnector dispatch is not unlimited. However, there is no value, independent of NEMDE transmission constraints, which can be used as a proxy for availability.

10.2.2 Inter-regional Access

Recall the description in section *2.2.2 Dispatch and Network Access* of network access as a payment to a generator based on the difference between the regional price and the local price. In the current NEM design, network access is linked to dispatch, so that a generator is paid this price difference on its dispatched output. The OFA model de-links access from dispatch and pays the price difference on the access level, irrespective of dispatch.

Similarly, in the current NEM design, network access for an *interconnector* is based on *interconnector* dispatch. However, for interconnectors, *network access* means being paid the *inter-regional price difference*: the difference between the RRPs in the importing and exporting regions. This slightly different form of access is referred to as *inter-regional access*.

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[101] So, for example, if generation exceeds demand by 1000MW in Queensland and 100MW is exported through Directlink to NSW, QNI will be dispatched for 900MW south and this amount is automatically exported on QNI to NSW.

[102] Although in some circumstances it might also, or alternatively, be considered to be a negative dispatch of the *northerly interconnector*. Such *mixed constraint* situations are discussed further in section *12.3.3 Mixed Interconnector Constraints*.

[103] To extend the analogy with generator access, one can think of the RRN of the exporting region as being the *local node* for the directed interconnector and the RRN of the importing region as being the *regional node.*

[104] AEMO's management of these funds is discussed in section *10.2.4 Firm Interconnector Rights*.

[105] Inter-regional flowgates are relatively rare and so it will be assumed that all flowgates relevant to interconnectors are hybrid flowgates.

Leaving aside losses, in the current NEM design, an interconnector is paid an amount into the IRSR defined as:

$$Pay\$ = (RRP_M - RRP_X) \times IC \qquad (10.1)$$

where:

RRP_M is the RRP in the importing region

RRP_X is the RRP in the exporting region

IC is the level of interconnectors dispatch

Importing and *Exporting* are predicated on the flow direction of the directed interconnector

In the OFA model, inter-regional access is set at a level, A, independent of dispatch, meaning that:

$$Pay\$ = (RRP_M - RRP_X) \times A \qquad (10.2)$$

Equation (10.2) can alternatively be written as:

$$Pay\$ = (RRP_M - RRP_X) \times IC + (RRP_M - RRP_X) \times (A - IC) \qquad (10.3)$$

The first term on the RHS of equation (10.3) is the existing payment into the IRSR. The second term is the access settlement payment, introduced in the OFA model, also paid into the IRSR. Combining the two gives the term on the RHS of (10.2).

In the current NEM design, the payments defined in (10.1) are received by those market participants who purchase, through the Settlement Residue Auction (SRA) the rights to receive a share of the IRSR.[106] The SRA rights might be purchased purely for their intrinsic monetary value, but more generally they are purchased for their value as *inter-regional hedges* (IRHs): hedges against exposure to inter-regional price differences that the purchaser has in its trading portfolio.

The *firmness* of the inter-regional hedging provided by current SRA rights is predicated on the firmness of interconnector dispatch. As for generators, interconnectors may be constrained off by NEMDE, due to the presence of generators competing with the interconnector for scarce transmission capacity.[107]

In the OFA model, the firmness of the IRHs that can be provided by the IRSR is predicated on the firmness of access, not the firmness of dispatch, as can be seen from equation (10.2). The firmness of access in turn, will depend how much *firm inter-regional access* the interconnector *procures* from TNSPs. Inter-regional procurement processes are discussed in sections *10.2.5 Inter-regional Expansion* and *10.2.6 Transitional Inter-regional Access*, below.

10.2.3 Inter-regional Access Settlement

Interconnectors make use of the same shared network capacity as generators. Therefore, they need to be included in access settlement on the same basis as generators. That means that access settlement for interconnectors occurs on every binding *hybrid* flowgate. If an interconnector's flowgate use is higher, or lower, than their flowgate entitlement then they will pay into, or receive from, access settlement, respectively.

However, there are some special considerations required for interconnectors, as discussed below.

10.2.3.1 Hybrid Flowgates and Directed Interconnectors

The transmission constraint corresponding to a *hybrid flowgate* will include both generator terms and interconnector terms on the LHS: for example

$$\alpha_1 \times G_1 + \alpha_2 \times G_2 + \alpha_{IC} \times IC < FGX$$

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[106] In fact, anybody can participate in the SRA auction, but typically it will be a generator or retailer.

[107] In fact, interconnectors are worse off in this respect than generators, because they are not able to rebid to -$1000 when congestion occurs and so will typically be constrained off before generators.

where:

G_1 = dispatched output of generator 1

G_2 = dispatched output of generator 2

IC = dispatched flow of interconnector

a_1 and a_2 are the participation factors for the generators

a_{IC} is the participation factor for the interconnector

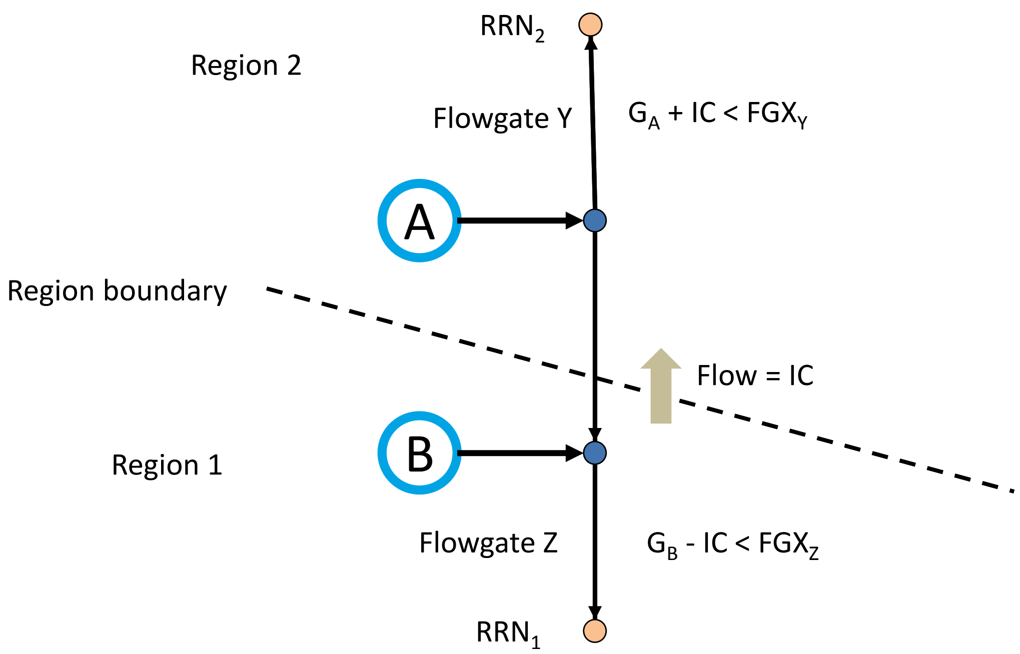
FGX is the flowgate capacity.

In NEMDE, α_{IC} may be positive or negative, indicating whether the constraint limits the amount of inter-regional flow *north* or *south*, respectively.[108] For the purposes of the OFA model, a directed interconnector participates in a flowgate only where it has a *positive* participation, based on the sign of the interconnector constraint efficient, a_{IC}. This means that:

- if $\alpha_{IC}>0$, the *northerly interconnector* participates in the corresponding flowgate, with participation α_{IC} and flowgate usage α_{IC} x IC; and
- if $\alpha_{IC}<0$, the *southerly interconnector* participates in the corresponding flowgate, with participation $-\alpha_{IC}$ and flowgate usage $-\alpha_{IC}$ x IC.

An example of northerly and southerly constraints on an interconnector is illustrated in Figure 10.1, below. The northerly interconnector participates in flowgate Y and the southerly interconnector participates in flowgate Z.

Figure 10.1 Northerly and southerly interconnector constraints



The two interconnector entities are settled separately, based on the entitlements and usages for the respective flowgates that they participate in, and payments are made into separate IRSR funds.[109]

[108] It is an AEMO convention that IC>0 implies a northerly interconnector flow and this convention is used here.

[109] Separate IRSR funds exist for directed interconnectors in the current NEM design. However, the basis for allocating settlement payments between the funds is somewhat different to that proposed in the OFA model and some changes

10.2.3.2 Entitlements

Like generators, interconnectors may have some agreed access.[110] Because there is no concept of interconnector availability:

- interconnector firm target entitlement is based solely on agreed access and participation factor; and
- interconnector non-firm and super-firm target entitlements are defined to be zero.

Firm actual entitlements for each interconnector group are then calculated in the same way as for generators, with hybrid flowgate capacity allocated between interconnectors and generators. Because of the interconnector's zero non-firm target entitlement, it is possible that there will be some *residual* flowgate capacity even after all firm and non-firm targets have been fully met. This residual is allocated to the relevant interconnector as a *non-firm actual entitlement*.

For example, consider a radial hybrid flowgate (ie participation factors equal 1) shared between a 1000MW firm generator and a non-firm interconnector. The generator simply has a firm target entitlement of 1000MW; the interconnector has zero target entitlements. If the flowgate capacity is 1200MW, say, all target entitlements can be fully met and 200MW of flowgate capacity remains. This 200MW is allocated to the interconnector as a non-firm actual entitlement.

10.2.3.3 Access Settlement

Access settlement for interconnectors uses the same formula as for generators: *FGP x (E-U)*. The access settlement payment is paid into – or out of – the relevant IRSR.

An amount equal to IC x (RRP_X - RRP_M) is already paid into the IRSR. This amount is equivalent to the aggregate arising from an amount FGP x U being paid to the IRSR on each hybrid flowgate (see section *12.2.10 IRSR Allocation*). Thus, the total amount paid into the IRSR for each flowgate is

$$\text{IRSR pay\$} = \text{FGP} \times \text{E} \qquad (10.3)$$

This is a generalisation of equation (10.2) above.

10.2.4 Firm Interconnector Rights

In the current NEM design, AEMO regularly auctions the rights to receive the IRSR through Settlement Residue Auctions (SRAs). Each purchaser of an *SRA right* for a particular directed interconnector receives a corresponding share of the IRSR in each settlement period. Fees paid to AEMO in the SRA are passed onto TNSPs, who return this money to demand-side users through reduced TUOS prices.

In the OFA model, SRA rights are replaced by similar financial instruments, called *firm interconnector rights* (FIRs). FIRs are issued to market participants in two ways:

- in relation to *existing* inter-regional capacity: through an AEMO-operated auction process, similar to the existing SRAs; and
- in relation to *new* inter-regional capacity: issued to market participants who help to fund inter-regional expansion.

These issuance processes are discussed further in section *10.2.6 Transitional Inter-regional Access* and section *10.2.5 Inter-regional Expansion*, respectively.

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may need to be made to *existing* settlements in this respect to align the two. This is discussed further in section *12.2.10 IRSR Allocation*.

[110] Access procurement for interconnectors is discussed further in sections below.

In each settlement period, a FIR holder is paid, for each flowgate that the relevant directed interconnector participates in:

$$\text{FIR Payment\$} = \text{FGP} \times \alpha_{IC} \times \text{FIR amount} \times k_F \qquad (10.4)$$

where:

FIR amount is the MW amount of the FIR holding

a_{IC} is the participation factor of the directed interconnector in the flowgate

k_F is the firm scaling factor for the flowgate: the ratio of actual to target firm entitlements

Payments are made from the IRSR of the relevant directed interconnector.

This payment formula is designed to achieve two objectives:

- the FIR provides a firm inter-regional hedge for the holder; and
- the total FIR payments never exceed the IRSR in a settlement period.

These two features are discussed in section *10.3.4 Inter-regional Hedging using FIRs* and section *10.3.3 Revenue Adequacy of the IRSR*, respectively.

Any *residual* IRSR remaining after FIR payments are made are paid to the TNSP in the importing region, who also receives the FIR auction proceeds.[111]

10.2.5 Inter-regional Expansion

Generators procure intra-regional access. Analogously, interconnectors should procure *inter-*regional access. However, in the NEM design, as we have seen, interconnectors are notional entities. A notional entity cannot undertake real-world activities such as agreeing access levels with a TNSP and making corresponding payments. Thus, a different procurement model is required for inter-regional access and is presented below.

10.2.5.1 Inter-regional Planning and Cost-benefit analysis

In the current NEM design, the National Transmission Planner (NTP) and TNSPs are tasked with identifying inter-regional expansion projects. Under the RIT-T, projects may proceed if the estimated benefits exceed the costs: ie there is a *net benefit*. A similar approach is taken in the OFA model, except that the benefits associated with the expansion are estimated by the beneficiaries themselves rather than the planners.

Inter-regional expansions may provide benefits to multiple parties. Benefits may flow to:

- *market participants* where they can obtain FIRs associated with the expansion;
- *TNSP(s) in the importing region(s)* who are able to use the additional inter-regional transmission capacity to maintain their reliability standards more cheaply than through intra-regional expansion;
- *TNSPs* for whom the expansion also helps in maintaining intra-regional FAS requirements; and
- the *market as a whole*, through benefits such as increased regional or inter-regional competition and increased liquidity from (effectively) larger forward markets.[112]

Each of these beneficiaries participates in the expansion decision, as discussed below.

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[111] The residual IRSR will come from two sources: any non-firm interconnector entitlements; and the effect of inter-regional losses.

[112] Where the removal of basis risk between two regional markets effectively allows them to operate as a single, combined, forward market.

10.2.5.2 Bidding Process

To ensure *efficient* inter-regional expansion, each of the beneficiaries can promise to contribute to expansion costs by making separate *bids* into a central agent. The relevant TNSPs would jointly submit bids on behalf of the *market as a whole*.

Since TNSPs are regulated, any bids made by them would have to be justified through a RIT-T, or similar cost-benefit analysis, that would demonstrate that the bid level was no higher than the forecast benefits. It is important that these parallel tests do not double-count benefits: discussed further in section *10.3.6 Avoiding the Double-counting of Benefits*. To ensure this, the RIT-T analysis could be subject to review by the NTP.

10.2.5.3 Clearing Process

In the event that bids were sufficient to fund the expansion, the project would proceed.[113] Contributions would be collected from the various successful bidders and passed to the TNSP(s) incurring the expansion costs. Payments associated with the market-as-a-whole benefits would be recovered from demand-side users - either in the relevant regions or, possibly, across the entire NEM - via the TNSPs through a levy on TUOS charges.

As discussed above, the aggregate amount of FIRs issued should not exceed the level of agreed inter-regional access, to ensure that FIR payments can be fully-funded out of the IRSR. For that reason, the *additional* FIRs issued in the procurement process must not exceed the *new* inter-regional access provided by the TNSPs through the inter-regional expansion, to ensure that existing SRA rights holders are not adversely affected. The relationships between the expansion, the agreed access and the FIRs are established as follows:

1. The planners who identified the inter-regional expansion project would specify the additional MW level of firm inter-regional access that would be provided by the expansion.
2. In the access procurement process, the central agent would seek bids, in aggregate, for a corresponding amount of FIRs.[114]
3. In the event that aggregate bids are sufficient and the inter-regional expansion proceeds, AEMO would receive (and hold in trust) an access agreement, specifying the amount of new inter-regional firm access, from the relevant TNSPs, and would issue a corresponding amount of FIRs to the successful market participant bidders.
4. The increased settlement payments into the IRSR, arising due to the inter-regional expansion and the new firm access, would fund the new FIR payments.

The issued FIRs would be long term, corresponding to the economic life of the new inter-regional assets.

10.2.6 Transitional Inter-regional Access

The scaling stage of the transition process (described in section *9.2.2 Transitional Access*) will assume that there is zero inter-regional TA. Once that stage is complete, the maximum possible level of FAS-compliant inter-regional TA will be calculated through a similar process.[115] That level of transitional inter-regional access will be allocated in year one.[116] Unlike generator TA, inter-regional TA will *not* be sculpted back, but will instead remain at its initial level *indefinitely*.

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[113] If total bids exceeded expansion costs, the bids from TNSPs would be scaled back, so that demand-side users would receive the benefit from any *surplus value.*

[114] If the aggregate bid quantity exceeded this level, the central agent would clear only the highest-priced bids.

[115] Discussed in further detail in section *12.6.2 Transitional Access Scaling*.

[116] Which might be zero, if hybrid flowgate capacity has been fully allocated to generator TA.

Just as AEMO looks after the IRSR currently, it would be trustee for the inter-regional TA. Settlement payments associated with the TA will feed into the IRSR and would support the issuance (through the AEMO auction process) of FIRs whose quantity, in aggregate, equals the TA amount.

For example, suppose that on a directed interconnector:

- transitional access is 500MW; and
- an additional 100MW of inter-regional access is provided through a subsequent inter-regional expansion.

AEMO would receive payments *into* the IRSR associated with the *600MW* of firm inter-regional access, plus any payments from non-firm access and losses residue. 100MW of FIRs would be issued to those market participants funding the expansion. AEMO would periodically auction 500MW of FIRs, similarly to (although not necessarily identically to) the existing periodic SRAs. Thus, at any point in time, 600MW of FIRs would be issued in aggregate.

Since aggregate FIR issuance equals the agreed access amount, the IRSR would always be sufficient to fund payments to the holders of the issued FIRs. Any residual IRSR (from losses residue and non-firm access) would be paid to the importing region TNSP.

10.2.7 Inter-regional FAS

TNSPs are required to maintain capacity on hybrid flowgates at or above the product of the firm target entitlements and the FAS scaling factor. Since the former includes interconnector entitlements, the issuance of inter-regional access (whether in transition or through future inter-regional expansion), will mean that inter-regional transmission capacity must be maintained and may not be cannibalised through TNSPs using the capacity to provide new intra-regional firm access to generators connecting on inter-regional transmission paths.[117]

Although inter-regional expansion would commonly be a joint project between two TNSPs, FAS obligations would nevertheless fall solely on the TNSP in whose region the congested flowgate is located.[118]

10.2.8 Impact on Intra-regional Access Pricing

Inter-regional access would be included in the baseline flows in the access pricing methodology in the same way as intra-regional access is. Element flows associated with this access would be based on a load flow from one RRN to the other. Generally, flows on an element will be increased by interconnector flows in one direction and decreased by opposite flows, so only the former flow need be modelled.

10.2.9 Summary

The OFA model places market participants in the driving seat in relation to inter-regional expansions, just as it does for generators in relation to intra-regional expansions. However, it also recognises that there may be significant externalities associated with inter-regional expansion: benefits accruing to parties other than those who receive the settlement payments associated with inter-regional flows. The inter-regional procurement process allows these externalities to be factored into the expansion process.

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[117] If a new firm generator did connect on an inter-regional transmission path, the TNSP would be required to expand transmission so that the interconnector firm access was not affected.

[118] Where the location is unclear – for example in the case of stability constraints – the FAS obligation would need to be allocated and managed through some agreement between the two TNSPs.

10.3 Design Issues and Options

10.3.1 Non-firm Target Entitlement for Interconnectors

Because there is no inter-regional equivalent of offered availability for interconnectors, their non-firm target entitlement is set to zero. An alternative approach would be to base the non-firm target entitlement on some *nominal* interconnector capacity which could be determined by AEMO, TNSPs or the NTP.

There are conceptual and pragmatic reasons for rejecting this alternative approach. Pragmatically, it is not clear on what basis the nominal interconnector capacity would be set: inter-regional capacity is varying continually, driven by changing transmission, generation and demand conditions.

Conceptually, it is not clear what benefit a non-zero non-firm target entitlement would create. It does not affect settlement payments to holders of firm interconnector rights (since these are based on firm entitlements) and would just feed some extra payments into the residual IRSR paid to TNSPs, which will nevertheless remain highly non-firm and be of little benefit to TNSPs or demand-side users. At the same time, the change would reduce non-firm entitlements for *generators*, which would impose some additional costs and risks on those generators.

For these reasons, the preferred approach is to have zero target non-firm entitlements for interconnectors.

10.3.2 Counterprice Flows and Negative IRSR

Recall that, in the current NEM design, the settlement payment into the IRSR for an interconnector is:

$$Pay\$ = (RRP_N - RRP_S) \times IC$$

where:

IC is the interconnector dispatch in a northerly direction (negative if southerly)

RRP_N is the RRP at the northern end of the interconnector

RRP_S is the RRP at the southern end of the interconnector

Generally, interconnector flow direction is from the lower price to the higher price region, ensuring a positive settlement payment. However, it is possible for the interconnector to flow in the opposite direction, called a *counterprice flow*, leading to a negative IRSR. To offset this settlement deficit, the TNSP in the importing region is required to make a corresponding payment *into* AEMO settlement.

AEMO is required to *clamp* interconnectors[119] during periods of counterprice flow to prevent the negative residues from growing too large and materially affecting TNSPs and, ultimately, demand-side users.

In the OFA model, the payment into the IRSR, for each congested hybrid flowgate is:

$$Payment = FGP \times E$$

The entitlement, E, can *never* be negative, even if the interconnector has zero firm access. Therefore, negative IRSR can never occur and, correspondingly, there is never a need for AEMO to clamp interconnectors or for TNSPs to make good the shortfall. This will improve dispatch efficiency and increase financial certainty for TNSPs and demand-side users.

[119] Ie introduce additional, fictitious inter-regional constraints into NEMDE so as to prevent the counterprice interconnector dispatch.

10.3.3 Revenue Adequacy of the IRSR

The total payment into the IRSR in relation to a congested hybrid flowgate is given by the formula:

$$\text{IRSR pay\$} = \text{FGP} \times \text{E} \qquad (10.5)$$

The entitlement is the sum of firm and non-firm entitlements[120] meaning that:

$$\text{E} \geq \text{firm actual entitlement} = k_F \times \text{firm target entitlement} \qquad (10.6)$$

where:

k_F is the firm scaling factor

Recall from section *4.2.3 Target Entitlements* that:

$$\text{firm target entitlement} = \alpha \times \text{AQ} \qquad (10.7)$$

where:

α is the participation of the directed interconnector in the flowgate

AQ is the agreed access amount for the directed interconnector

From equations (10.5), (10.6) and (10.7):

$$\text{IRSR pay\$} \geq \text{FGP} \times k_F \times \alpha \times \text{AQ} \qquad (10.8)$$

Now, recall from section *10.2.4 Firm Interconnector Rights* that the FIR payment on a flowgate is:

$$\text{FIR Payment\$} = \text{FGP} \times \alpha \times \text{FIR amount} \times k_F \qquad (10.9)$$

Summing this payment across *all* issued FIRs:

$$\begin{aligned}\text{Total FIR payment\$} &= \sum(\text{FGP} \times \alpha \times \text{FIR amount} \times k_F) \\ &= \text{FGP} \times k_F \times \alpha \times \sum \text{FIR amount} \qquad (10.10)\end{aligned}$$

It will be seen by comparing equations (10.8) and (10.10) that:

$$\sum \text{FIR amount} \leq \text{AQ}$$

is a sufficient condition for ensuring that:

$$\text{IRSR pay\$} > \text{Total FIR payments}$$

on each congested flowgate and, therefore, in aggregate.

10.3.4 Inter-regional Hedging using FIRs

Recall that the payment to an FIR holder in respect of a flowgate is:

$$\text{FIR Payment\$} = \text{FGP} \times \alpha \times \text{FIR amount} \times k_F \qquad (10.11)$$

Summing this over all congested flowgates and assuming, for simplicity, that k_F is the same on every flowgate:

$$\text{Total FIR payment} = \text{FIR amount} \times k_F \times (\textstyle\sum_j \text{FGP}_j \times \alpha_j)$$

where:

FGP_j is the flowgate price on flowgate j

[120] Because an interconnector has no availability, it can have no super-firm entitlement.

α_j is the participation of the interconnector in flowgate j

Assuming that *all* congested flowgates on the interconnector are binding in the direction of the directed interconnector being considered:[121]

$$\sum_j FGP_j \times \alpha_j = RRP_M - RRP_X \qquad (10.12)$$

where:

RRP_M is the RRP in the importing region

RRP_X is the RRP in the exporting region

The result in equation (10.12) is demonstrated in section *12.2.8 Inter-regional Price Difference*.

Therefore, the total FIR payment is:

Total FIR payment = FIR amount x k_F x (RRP_M - RRP_X)

This means that the FIR provides the holder with an inter-regional hedge (IRH) with volume:

Hedging Volume = FIR amount x k_F

In the more general case where the firm scaling factors are different on each flowgate:

Hedging Volume = FIR amount x average(k_F)

where:

average(k_F) is a weighted-average of the k_Fs on each flowgate

The firm scaling factors are governed by the FAS: the TNSP(s) responsible for the inter-regional capacity used by the interconnector must ensure that the firm scaling factor is no lower than the FAS scaling factor for the current operating conditions. Thus, the FAS ensures a minimum level of hedging firmness of the FIR.

By comparison, the hedging volume provided by an SRA right in the current NEM design is proportional to the interconnector flow and goes to zero when the flow is counterprice. Thus, the hedging firmness of an FIR will be far superior to the hedging firmness of an SRA right.

10.3.5 Pricing of Inter-regional access

Pricing of new FIRs is established through the bidding process and will reflect the actual cost of inter-regional expansion, less any contributions from TNSPs. This is different to pricing of intra-regional access, which is based on a regulated pricing methodology. A design alternative would be to also price new FIRs using the access pricing methodology.

The design choice is based on two intrinsic differences between inter-regional and intra-regional access. Firstly, unlike with intra-regional access, there is no *obligation* on TNSPs to offer inter-regional access in the OFA model. It will only be offered when TNSPs have identified a potentially-economic inter-regional expansion project. Thus, the issue of frequent pricing of small amounts of access does not arise and it is not necessary to introduce practical simplifications into the pricing process.

Secondly, the distances between RRNs – and the associated length and size of interconnector assets – will at times make inter-regional expansion very lumpy. This increases the risk associated with the access pricing methodology not accurately estimating expansion costs: on multiple intra-

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[121] The situation of mixed constraints where this is not true is discussed in section *12.3.3 Mixed Interconnector Constraints*.

regional expansions, any errors are likely to cancel out; on infrequent, large inter-regional expansions, errors are likely to remain material.

For these reasons, the OFA model is designed to ensure that TNSPs are guaranteed to recover the costs associated with providing new inter-regional access from the beneficiaries of that access.

10.3.6 Avoiding the Double-counting of Benefits

The current RIT-T allows for all market benefits associated with transmission expansion to be include in the *net benefit* calculation. Depending upon the method of analysis, different categories of benefit might be separately identified or might be bundled into a single aggregate.

The inter-regional expansion process requires that the different categories of benefit are separately enumerated, to ensure there is no double-counting of benefits between bidders. Market participants bidding for firm interconnector rights will estimate their private benefits: ie the benefits that would accrue to them from holding the FIRs that they would not receive otherwise. Such benefits would typically comprise of both the expected amount of settlement payments they would receive and the hedging value of that revenue in the context of their trading portfolio.

In a conventional RIT-T, similar benefits would be counted, but these would be expressed in terms of lower dispatch costs (through the substitution of local generation with cheaper remote generation). In the RIT-T used by TNSPs in setting their bids for inter-regional access procurement, such benefits would have to be excluded.

10.3.7 Rationale for FIR Allocation

In the inter-regional access procurement process, successful market participant bidders receive FIRs, but TNSP bidders do not. This asymmetry may require some explanation.

The benefits to market participants from the inter-regional expansion will come primarily from the value of the FIRs issued to them. It is true that there are some benefits that may accrue to market participants, even without FIRs: for example, generators in the exporting region may receive a higher and more stable RRP as a result of the expansion. But since bidding is optional, there would be a free-rider problem if generators were expected to bid solely on the basis of receiving those non-FIR benefits: since they would accrue equally to bidders and non-bidders. Thus, it is necessary to allocate FIRs to successful market participant bidders in order to solicit bids that reflect the value to them of the proposed expansion.

On the other hand, TNSPs gain benefits from inter-regional expansion that do not rely on acquiring FIRs. Furthermore, since the TNSPs are monopolies, free-riding is not going to be a problem.

For example, consider a situation where a TNSP must provide an additional 100MW of *reliability access* in order to maintain demand-side reliability standards. Previously, it has been assumed that this access would be provided as unsolicited intra-regional access to generators in the local region. However, the 100MW of additional access could instead be provided to generators in a remote region, supplied to the local region through an expanded interconnector.[122] If the TNSP had calculated that providing the *intra*-regional reliability access would cost $50m, it could bid $50m into the inter-regional access procurement process, knowing that – if the bid was accepted and the expansion project built – it would spend no more than $50m, and possibly less.[123]

These reliability benefits are unaffected by FIRs, which are purely *financial* rights and so cannot contribute to the maintenance of the reliability standards. The TNSP simply needs to be assured

[122] Assuming that there is sufficient generation capacity in the remote region and that it has access to the remote RRN.

[123] In the event that total bids exceeded the expansion cost.

that the additional 100MW of inter-regional capacity is firm and will be maintained for the long-term. This is ensured by AEMO receiving – in trust – the firm inter-regional access, placing FAS obligations on the relevant TNSPs to maintain the inter-regional capacity.

In summary, the benefits accruing to TNSPs are associated with the increase in *physical* transmission capacity resulting from the expansion, and so predicated solely on AEMO receiving the firm inter-regional access; whereas the benefits accruing to market participant bidders are purely *financial* and so predicated on acquiring FIRs. That is the reason for the asymmetry.

10.3.8 Supply-driven or Demand-driven Expansion

In the context of intra-regional access, it is clear that, in the OFA model, transmission expansion is demand-driven: generators decide how much firm access they require, procure it from their TNSP who, in turn, must expand their network so that the FAS is maintained. Indeed, the change in intra-regional expansion from supply-driven to a demand-driven process is considered to be one of the fundamental elements of the OFA model.

For inter-regional access, the expansion driver is less clear. *Demand* for FIRs might come from market participants whose regional market is small with volatile prices.[124] FIRs give those participants effective access to a large, more stable, regional market. However, it is not clear how that latent demand might be communicated to TNSPs. A formal mechanism – such as standing bids for FIRs – might do this, but standing bids are problematic in the context of interconnectors, since as soon as there is prospect of a large expansion, congestion concerns are relieved and the perceived value of FIRs falls.

On the other hand, expansion could be supply driven. TNSPs and the NTP currently investigate potential inter-regional expansion projects, assessing their practicability and likely economic viability. However, in the OFA model, the economics may largely depend upon the level of demand, which may not be apparent until a formal project proposal – and associated marketing process - is established.

The OFA model blueprint does not resolve these issues. However, it at least provides a framework for investigating and promoting inter-regional expansion and for thinking further about how inter-regional roles and responsibilities might be developed in the future.

10.3.9 Priority of Transitional Access Allocation

It is proposed to give priority to existing generators in the TA scaling process and only to provide inter-regional TA in the event it is possible to do that, and remain FAS compliant, without clawing back TA from generators.

This approach is not predicated on any policy priority of inter- versus intra-regional access, but intended simply to reflect the *de facto* situation in the status quo. Currently, when there is congestion on hybrid flowgates, the affected generators can maximise dispatch by bidding -$1000. Since interconnectors are unable to bid in this way, generators are always dispatched at the expense of interconnectors. AEMO intervenes to prevent material counterprice flows, which guarantees interconnectors *zero* dispatch but no more.

Thus, in the status quo, where access is restricted, generators receive a priority allocation and interconnectors are guaranteed only a non-negative allocation. The TA allocation design reflects the reality of this situation, irrespective of its merits.

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[124] For example South Australia.

10.3.10 Sculpting of Inter-regional Transitional Access

It is proposed that, unlike with generator TA, inter-regional TA is *not* sculpted back over time but remains at its year one level in perpetuity. This approach is based on the fact that the reasons for sculpting of generator TA do not apply to interconnectors. Those reasons were:

- to reflect the future closure of power stations – and associated ending of de facto access – in the continuing status quo counterfactual; providing finite-life power stations with perpetual access would give them an unjustified windfall gain; and
- to prevent access hoarding creating a barrier to new entry or prompting unnecessary expansion.

The first reason does not apply to interconnectors, since they have no closure date. The second reason does not apply because the FIRs associated with the inter-regional TA are periodically auctioned and so cannot be hoarded over the longer-term.

11 Behaviour and Outcomes

11.1 Overview

The OFA model relies on changes in the market design and regulations to encourage changes to generator behaviour that promote market efficiency. Generator behaviour is driven by many factors, including the behaviour of other, competing generators. Poorly designed markets can easily encourage - unintentionally – *perverse* behaviours that diminish market efficiency. Even when efficient behaviour is expected under *competitive* market conditions, perverse behaviour may arise if the market is less-than-competitive.

This section examines, qualitatively, the drivers for generator behaviour in three areas:

- forward contracting;
- access procurement; and
- generator bidding.

11.2 Forward Contracting and Access Procurement

11.2.1 Overview

Access procurement is a form of forward contracting. In the current NEM design, a generator sells forward contracts in order to provide a stable revenue stream, hedged against the volatility of RRP. Similarly, an access agreement hedges a generator against the volatility of congestion prices: ie differences between RRP and LMP.

It is useful to draw analogies between forward contracting (RRP hedging) and access procurement (LMP hedging). The next section reviews drivers for forward contracting in the current NEM design, and the following section draws analogies between this and access procurement.

11.2.2 Forward Contracting in the current NEM Design

There are several drivers for a generator's forward contracting level:

- *Hedging value*: the forward price is much more stable than the RRP;
- *Forward premium*: since a forward contract also provides hedging value to risk-averse retailers, forward prices may be set at a premium to fair value;

- *Limiting downside risk*: a generator who is unable to generate (due to unit outages or congestion) during periods of high RRP may be *short* and so exposed to large financial losses;

The first two factors encourage a generator to be *highly* contracted in order to maximise the hedging and premium value. However, these drivers are tempered by the last factor, which encourages a generator to choose a *lower* contracting level. Empirically, generators typically contract to a high percentage of generation capacity, but leave some uncontracted capacity in order to manage *short risks*.

11.2.3 Generator Margins under OFA Model

When a generator, under the OFA model has both *sold* forward contracts and *procured* access, its short-term operating profit, or margin, will be determined according to the formula below:

Margin = forward revenue + spot revenue + access revenue – access charge - generation costs

= F x (FP – RRP) + G x RRP + (A-G) x (RRP-LMP) – AC - G x C

where:

FP = forward price

F = forward level (MW amount of forward contracts sold)

A = access level

G = dispatched output

C = marginal generating cost

AC = access charge

This equation can be arranged to:

Margin = F x (FP- C) + (A-F) x (RRP -C) + (G-A) x (LMP-C) – AC (11.1)

In periods when there is no congestion, RRP=LMP and so equation (11.1) reduces to:

Margin = F x (FP – C) + (G-F) x (RRP-C) - AC

During periods of congestion, the downside risks associated with high RRP are driven by the middle term in equation (11.1), and are managed by ensuring that A≥F over these periods. When there is no congestion, the risk is managed by ensuring that G≥F, as in the current NEM design.

Recall that a generator's access level varies according to the formula:

A = min(availability, agreed access x firm scaling factor)

Therefore, unit outages (through reducing availability and hence access) will have a similar effect on a generator's short risk as they do in the current NEM design. The FAS requires that a TNSP ensures that the firm scaling factor is no lower than the FAS scaling factor for the prevailing NOC tier. To ensure that short risk is covered during more severe transmission conditions, a generator will have to procure *more* agreed access, ensuring that the scaled back access level remains nevertheless higher than the forward position.[125] For example, if the NOC3 is 80%, a generator would have to procure access equal to 125% x F in order to ensure that the scaled back access (80% x 125% x F) is no lower than F during NOC3 conditions.

[125] While, at the same time, ensuring that sufficient availability is maintained.

In summary, a generator will decide on its forward contracting based on similar considerations to now. It will then procure agreed access commensurate with its risk appetite. The more risk averse it is, the higher level of agreed access, in order to ensure that it has enough access during higher tier NOC conditions.

11.2.4 Relying on Non-firm Access

In principle, a generator could rely on non-firm access to cover its short risk during congestion which is similar to what a generator must do currently. However, in the current NEM design, many generators will be able to rely on some level of *de facto* access (through being dispatched) which is proportionate to their availability, through the mechanism of disorderly bidding. In the OFA model, if *all* generators using a congested flowgate are *non-firm*, there is a similar *pro rata* outcome: since they will all receive non-firm entitlements proportionate to availability.[126] On the other hand, if all other generators around it are *firm*, a lone non-firm generator may get little or no access during congestion.

On this basis, one can then envisage two possible equilibrium scenarios:

- if all generators are *non-firm*, each might consider contracting forward without procuring access and thus taking the risk of *pro rata* non-firm access during congestion;
- if most generators are *firm*, a non-firm generator is unlikely to take the risk of congestion and will procure access to cover its forward position.

So, two alternative *equilibria* are that:

- all generators are firm and new generators choose to be firm; or
- all generators are non-firm and new generators choose to be non-firm.

Games where optimal strategies are to do the same as everyone else are referred to as *coordination games*.[127]

In fact, there are two factors reducing the chances of a *non-firm* equilibrium:

- transition arrangements mean that most generators will start with high levels of agreed access and these levels will only be sculpted back slowly; and
- in a non-firm scenario, access prices will be low,[128] and so access procurement will be encouraged.

Therefore, it seems more likely that generators will procure access to cover their forward positions.

11.2.5 Intermittent Generation

An intermittent generator is unlikely to sell forward because that would expose it to high short risks when it is unavailable. In the situation where F=0, equation (11.1) simplifies to:

Margin = A x (RRP-C) + (G-A) x (LMP-C) - AC

= [A x (RRP-LMP) – AC] + G x (LMP – C)

= access premium + dispatch margin

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[126] The difference is that in the status quo the pro rata access relies on the generator being dispatched, but in the OFA model it does not.

[127] One example of a coordination game is deciding which side of the road to drive on.

[128] Because the access pricing methodology will see a lot of spare transmission capacity and so substantially discount the costs of any future expansion caused by new access.

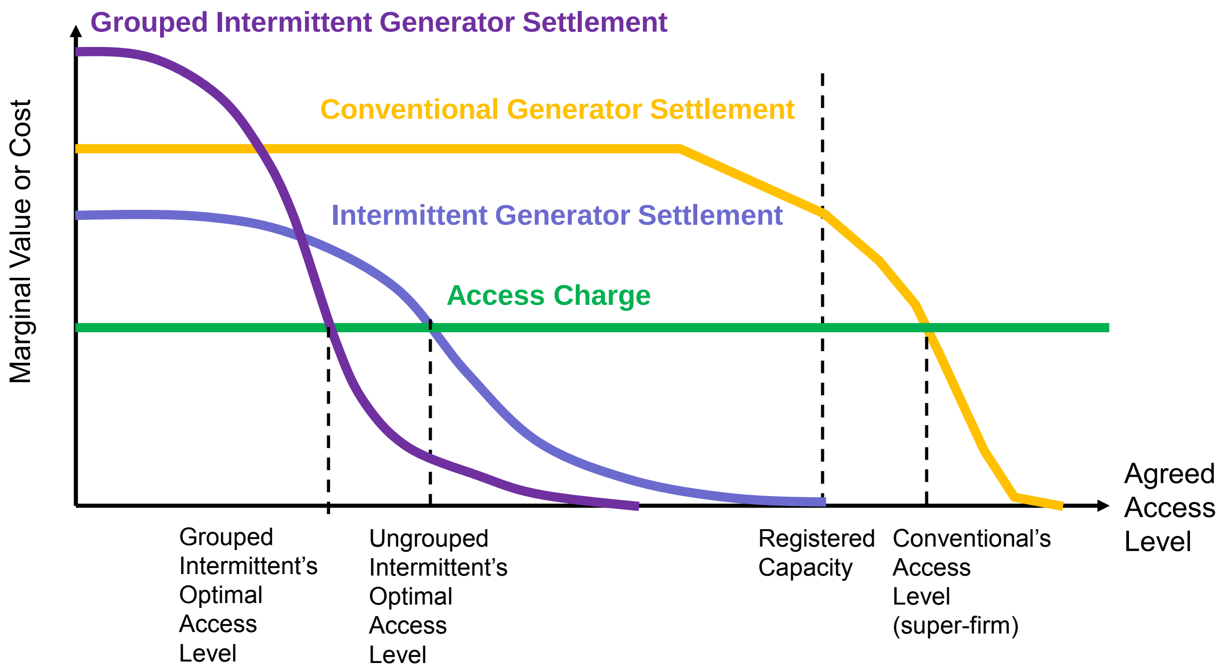
Since access now has limited hedging value,[129] an intermittent generator would typically only procure access to the extent that the access premium is positive: ie the additional income from access settlements exceeds the access charge. It will apply this criterion at the margin: ie purchasing an additional 1MW of agreed access if the incremental settlement income exceeds the incremental access charge.

Now, recall that:

A = min(availability, agreed access x firm scaling factor)

A generator will only earn incremental income during periods when availability exceeds the scaled access. Thus, incremental income will be lower – and fall more quickly – for an intermittent generator than for a conventional generator, as illustrated in Figure 11.1, below.[130]

Figure 11.1 Marginal value of access settlements



Access premium is maximised at the point where the incremental settlement income equals the incremental access charge. This point will be relatively low for an intermittent compared to a conventional generator.

11.2.6 Access Grouping

Suppose that an intermittent generator belongs to an access group, where each member agrees to procure the same agreed access amount, relative to its generation capacity. In this case, the incremental access premium is likely to be higher – than the ungrouped alternative - at low levels of agreed access, due to the multiplier effect of all group members procuring incremental agreed access. However, the level of the incremental access premium is also likely to reduce more quickly and cross the x-axis earlier, because the entitlement grouping gives each group member a higher effective level of access than without grouping – other things being equal.[131]

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[129] It just converts one volatile price, LMP, into another, RRP.

[130] This graph - and the optimal access levels it shows - is illustrative only. It will be seen that, if the access price were higher, optimal access levels would be lower.

[131] This is an intuitive expectation and has not been verified quantitatively.

Thus, grouping may mean that intermittents are more likely to procure access (since the incremental access premium will initially be higher and so more likely to be positive), but are likely to procure a relatively low amount.

11.2.7 Summary

In the current NEM design, a generator's preferred forward level is limited by a concern not to be short – as a result of unit outages or being constrained-off – during periods of high RRP. In the OFA model, the congestion risk is removed, so long as the agreed access level equals the forward level. Thus, other things being equal, there will typically be increased forward contracting under the OFA model.

Intermittents do not need access to protect their forward position during high-RRP periods. They will procure access only if the benefit from access settlement payments exceeds the cost from access charges. The net benefit will be increased by grouping although, paradoxically, grouping might actually lead to lower levels of procured access in some cases.

11.3 Free Riding

11.3.1 Overview

The discussion on forward contracting in the previous section is predicated on there being congestion risks that a generator needs to protect itself against. However, if congestion risks are low, a generator need not procure access. In effect, the generator can obtain the benefits of the transmission network (in removing congestion and ensuring that it receives RRP for its dispatch) without having to pay for it: it is *free riding* on transmission capacity that others have paid for.[132]

In the OFA model, transmission is expanded as necessary to meet both FAS and demand-side reliability standard obligations. Therefore, spare transmission capacity (ie over and above that required by firm generators) will be available only due to:

- *legacy*: transmission capacity built prior to OFA commencement;
- *lumpiness*: spare transmission capacity created during FAS-driven expansion; and
- *reliability*: transmission capacity provided to meet demand-side reliability standard obligations.

These possibilities are discussed in turn below

11.3.2 Legacy

There is some congestion in the NEM currently, but it is unclear whether that congestion risk would be material enough to deter free-riders. In any case, the transition arrangements mean that existing generators will obtain free access initially and will not be making access procurement decisions for a number of years.

A new generator is likely to make access procurement decisions on a timeframe commensurate with its asset life: eg 30 years. Whilst legacy transmission capacity may be important in the early years of that timeframe, it becomes increasingly irrelevant further ahead.

In summary, the driver for free-riding will not be congestion materiality on OFA commencement but rather anticipated congestion 10 or 15 years out.

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[132] This free riding strategy is subtly different to the non-firm strategy discussed above. The non-firm strategy relies on obtaining non-firm access to congested flowgates, whereas free riding relies on flowgates being generally uncongested.

11.3.3 Lumpiness

Lumpiness of expansion applies at an *element* level, not at a *nodal* level. Thus, a generator seeking new access may cause a lumpy expansion of some transmission elements between that generator and the RRN but, at the same time, spare capacity on other elements that are *not* expanded will be reduced.

For example, consider a simplified scenario of a generator using three transmission elements *in series*.[133] Suppose that:

- each element has a lumpiness of 500MW;
- a new generator seeks 200MW of access; and
- initial spare element capacities are as shown in Table 11.1 below.

Table 11.1 Impact of lumpy expansion on spare access

Element	Spare capacity prior to new Access	Expansion?	Spare capacity after new access
A	130	Yes	430
B	260	No	60
C	390	No	190
Node	130		60

The access request exhausts spare capacity on element A, prompting expansion and creating additional spare capacity. However, spare capacity is eroded on elements B and C but no expansion is prompted. The spare nodal capacity - the minimum of the spare capacities on the three elements - has actually decreased rather than increased, despite the lumpy expansion on element A.

Therefore, apart from special cases where a generator node is close to the RRN, it may not be the case that additional spare access would be created as the result of a lumpy expansion. Thus, it appears plausible at least that lumpiness of transmission expansion will not create significant opportunities for free-riding.

11.3.4 Reliability

A TNSP will be obliged – in order to maintain demand-side reliability standards – to provide *reliability access* to some non-firm generators if aggregate agreed access is less than peak demand. If a non-firm generator were confident that it would be provided with reliability access it may choose to free ride.

However, whenever there is some generation *capacity margin* - aggregate peak generation capacity exceeds peak demand - not *all* non-firm generators will need to be provided with reliability access. For example, suppose that:

- peak demand is 10GW;
- firm generation capacity is 9GW; and
- non-firm generation capacity is 3GW.

---

[133] Meaning that the path from the local node to the RRN is made up of the three elements, end to end.

Total generation capacity is 12GW, giving a 2GW capacity margin. Reliability access must be provided to 1GW of non-firm generators; so each non-firm generator has, broadly, just a one-in-three chance of successfully free riding.

A TNSP is required to meet reliability standards at least cost. In the context of reliability access, that would mean choosing the non-firm generator which has the lowest expansion cost associated with reliability access. Typically, this would be a generator located closest to the RRN. Thus, a generator remote from the RRN may be ill-advised to take the free-riding gamble.

Is it plausible that there will be a substantial "capacity margin" of generation capacity over peak demand? Where the development of peak generation capacity (eg open cycle gas turbines) is primarily driven by peak RRPs, the answer might be no, since as soon as there is a significant capacity margin, peak RRPs will collapse. However, in the context of carbon pricing and the growth of intermittent renewables, it is possible that generation investment will be driven by factors (REC or carbon prices) other than peak RRPs and so a large capacity margin is plausible, at least.

11.3.5 Access Pricing and Congestion

The access pricing methodology takes account of spare transmission capacity and trends in demand for firm access and TUOS. Where there is limited congestion and significant free riding, these factors will both lead to *lower* access prices. Thus, free riding will be *self-regulating*, in the sense that high free riding will reduce access prices and so encourage more access procurement

11.3.6 Summary

It is possible that low levels of congestion will promote free riding, as generators choose to bear modest congestion risks rather than pay for access. However, this scenario relies on there being an enduring surplus of transmission capacity over the FAS requirement across the long time frame over which generators' access decisions are likely to be made. The most plausible source for this surplus would be the demand-side reliability standards. However, an individual non-firm generator can rely on being provided with reliability access only if the generation capacity margin remains low (meaning that TNSPs are required to provide reliability access to *all* non-firm generators) or if its advantageous location means the cost of providing it with reliability access is low compared to other non-firm generators.

Generators might delay procuring access until congestion becomes more material. However, a trend of growing congestion and access procurement will lead to growing access prices. Therefore, that strategy might mean a generator taking increased risks for no financial gain: it simply pays a higher access price later rather than a lower access price earlier.

In summary, a qualitative analysis suggests that the risk of substantial and enduring free riding is modest. However, that conclusion would need to be confirmed through quantitative modelling to determine the relative levels of congestion costs and access charges, which will be the main driver of free riding behaviour.

11.4 Generator Bidding

11.4.1 Bidding Terminology

In the NEM, generators *bid* (ie submit dispatch offers) in a way that maximises their profitability. In this section, such bidding is referred to as *optimal bidding*.

Generator profitability depends upon its output and on the spot price received and so a change in output affects profitability in two ways:

- *directly*: because of the change in output; and

- *indirectly*: due to the change in the market price caused by the change in output.

For many generators, the *indirect* impact will not be material. These generators will bid *at cost*: that is to say, bid in a way that ensures that they will be dispatched whenever the market price is sufficiently high to cover their variable generating costs.[134] Other generators, for whom the indirect profitability impact *is* material, will bid *away-from-cost*. Away-from-cost bids may be higher or lower than cost, depending upon the circumstances, as discussed further below.

The materiality of the indirect impact will depend upon many factors and so commonly a generator will bid at cost under some conditions and away-from-cost in other conditions. The analysis below considers this bidding choice further.

In the current NEM design, there is only one market price relevant to a generator: its local RRP. Therefore, optimal bidding is designed in terms of its impact on the RRP. Such bidding is referred to here as *optimal regional bidding*. In the OFA model, generator profitability may also depend upon the level of the local price (LMP) at their node.[135] Bidding designed in terms of its impact on LMP is referred to as *optimal local bidding*. Of course, a generator submits only one bid, so in the OFA model this bid may take into account both regional and local price effects.

11.4.2 Regional Bidding

Before considering possible bidding behaviour under the OFA model, it is useful to think about optimal regional bidding in the current NEM design. Such bidding is well understood both theoretically and empirically. Furthermore, there are strong analogies between regional and local bidding, so describing the former helps in understanding the latter.

Operating margin for a generator in the current NEM design is:

$$\begin{aligned} \text{margin} &= \text{forward contract revenue} + \text{NEM revenue} - \text{generating costs} \\ &= F \times (FP - RRP) + G \times RRP - G \times C \\ &= F \times (FP - C) + (G - F) \times (RRP - C) \\ &= \text{forward margin} + \text{regional margin} \qquad (11.2) \end{aligned}$$

where:

FP = forward price

F = forward level (MW amount of forward contracts sold)

G = dispatched output

C = marginal generating cost

Note that the forward margin is independent of output or RRP and so optimal bidding aims simply to maximise the regional margin.

Regional bidding behaviour depends primarily on three factors:

- marginal generating costs;
- forward level; and
- the sensitivity of RRP to generator output changes (other things being equal).

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[134] It may not always be practical for a generator to bid at *exactly* its variable cost: because of the limitations imposed by the bid structure (eg only 10 offer bands can be used); because costs are non-convex (not increasing with output); or because costs are not known precisely. Therefore, *at-cost* bidding refers to the situation where a generator bids *as close as practical* to variable cost.

[135] Strictly speaking, it depends upon the flowgate prices of all flowgates that they participate in. For simplicity, we will consider the LMP, which generally reflects the overall impact of these flowgate prices on a generator.

The relationship between bidding and these variables is illustrated in Figure 11.2.

Figure 11.2 Illustration of regional bidding

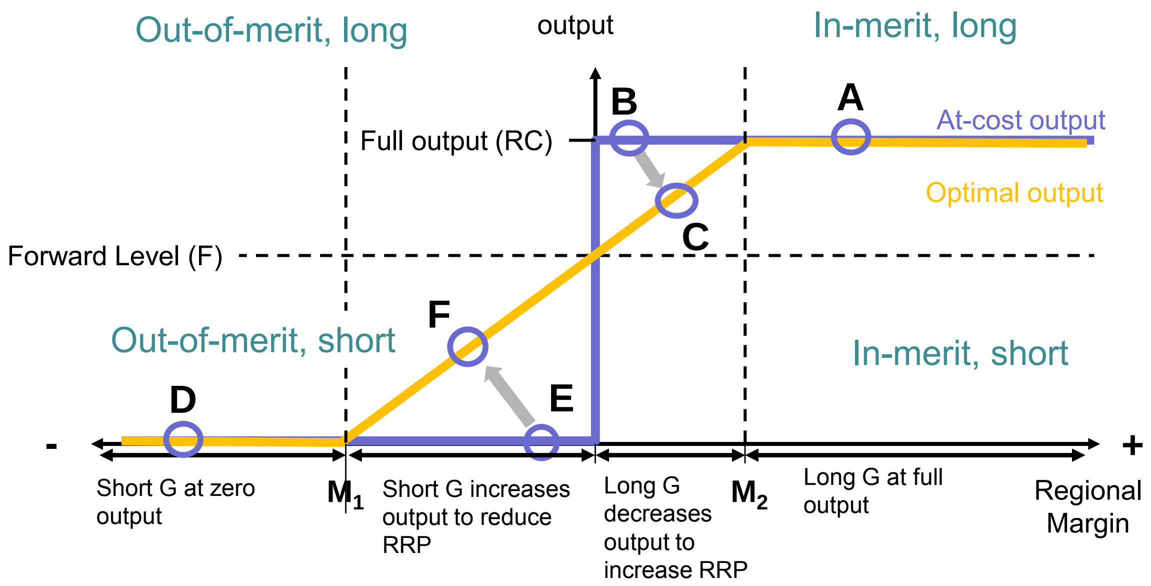

Figure 11.2 plots output (on the y-axis) against *regional margin* (on the x-axis). Regional margin is defined as the difference between RRP and marginal generating cost, C. If the margin is positive, or negative, the generator is said to be *in-merit*, or *out-of-merit*, respectively. If the margin is zero, the generator is said to be *at-the-margin*

On the graph, output is compared to the forward contract position or *forward level*. If output is greater than, or less than, the forward level, the generator is referred to as *long*, or *short*, respectively. It will be seen from equation (11.2) that a *long* generator benefits if RRP *increases*, Similarly, a *short* generator benefits if RRP *decreases*.

There are two curves on the graph. The *at-cost output* curve is the output of a generator that bids at cost. Such a generator simply generates at full output if it is in-merit and doesn't generate if it is out-of-merit.[136]

The *optimal output* curve is the output level under optimal bidding. The optimal output level shown in Figure 11.2 has the following characteristics:

- *Away* from the margin – where the generator is either substantially in-merit or substantially out-of-merit – the optimal output is the same as the at-cost output.
- *Close* to the margin, the optimal output slopes gradually from zero output to full output as the margin changes, in contrast to the step change seen in the at-cost output.

The reasons for these characteristics can be understood by examining a generator who initially bids at cost and then considers whether its profitability could be increased by changing its output. Consider a generator that:

- has a generation capacity = RC (in MW);
- has a regional margin = M (in $/MWh);
- has a forward position = F (in MW) which is less than its capacity (F<RC); and
- is bidding at cost.

[136] The simplifying assumptions here will quickly be seen: dynamic and minimum output constraints are ignored.

Suppose that RRP has a *pricing sensitivity*, P, meaning that a 1MW increase in output by a generator (through rebidding), leads to a price reduction of $P/MWh, other things being equal. In practice, RRP will not respond *smoothly* to small output changes: it would typically not respond at all until there is a sufficient change to cause NEMDE to dispatch a different offer band or to cause other generators to rebid. However, for the sake of the analysis, the RRP impacts are assumed to be smooth and proportionate to output change.

Pricing sensitivity is inversely related to *supply elasticity*. If supply is perfectly elastic, then P=0. The *lower* the supply elasticity is, the *higher* the value of P will be, other things being equal.[137]

There are two situations to consider:

- *positive margin*: M>0 and so the at-cost output is equal to RC and the generator is long (since RC>F); and
- *negative margin*: M<0 and so the at-cost output is zero and the generator is short (since F>0).

These are considered in turn.

In the *positive margin* case, if the generator (initially at full output) reduces its output by 1MW:

- the direct impact on profitability is the loss of 1MW of margin, costing $M per hour; and
- the indirect impact is to *increase* RRP by $P/MWh, benefiting *P x (RC-F)* per hour, since the generator is long and so benefits from higher RRP.

Therefore, the overall impact is beneficial if:

$$M < P \times (RC-F) \qquad (11.3)$$

There is therefore a breakpoint in behaviour when the margin is:

$$M_2 = P \times (RC-F). \qquad (11.4)$$

If the margin is *greater* than M_2 (illustrated on the graph by point A), then any reduction in output will be costly to the generator and its optimal output is full output, the same as *at-cost* output. If the margin is *less* than M_2 (point B on the graph) then there is some benefit from reducing output,

The decrease in output leads to higher RRP (and hence higher M) and lower output, G. Thus, the direct cost of a *further* reduction in 1MW has increased and the indirect gain has decreased. Eventually, at the point at which:

$$M = P \times (G-F) \qquad (11.5)$$

no further gains are possible and so the output level, G, is optimal (point C on the graph). The transition from at-cost output to optimal output is shown in the graph by a grey arrow.

Now consider the *negative margin* case, which is the opposite of the positive margin case. If the generator (originally bidding at cost and so at zero output) *increases* its output by 1MW:

- the direct impact on profitability is the addition of 1MW of negative margin, costing -M per hour (recalling that M is negative); and
- the indirect impact is to *reduce* RRP by $P/MWh, benefiting P x F, since the generator is short and so benefits from lower RRP

Therefore, the overall impact is beneficial if:

$$-M < P \times F$$

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[137] However note that elasticity is typically expressed in relation to percentage changes, whereas P relates to absolute changes.

ie if:

$$M > - P \times F \qquad (11.6)$$

There is a breakpoint in behaviour at margin:

$$M_1 = -P \times F \qquad (11.7)$$

If the margin is less (more negative) than M_1, shown on the graph as point D, then any increase in output will be costly to the generator and its optimal output is zero, the same as its at-cost output. If the margin is greater (less negative) than M_1 then there is some benefit from reducing output (point E on the graph).

The increase in output leads to lower RRP (and hence lower, more negative M) and higher output, G leading to a reduced short position F-G. Thus, the direct cost of a *further* reduction in 1MW has increased and the indirect gain has decreased. Eventually, at the point at which:

$$M = P \times (G-F) \qquad (11.8)$$

no further gains are possible and so the output level, G, is optimal (point F on the graph). The transition from at-cost output to optimal output is shown in the graph by a grey arrow.

If, for simplicity, it is assumed that the RRP sensitivity, *P*, is constant, the optimal output curve between M_2 and M_1, given by equations (11.5) and (11.8), is a straight line given by equation:

$$G = M/P + F$$

This line has slope equal to *1/P*: the lower that *P* is, the steeper the slope. If price sensitivity is low (*P* is small) the optimal output curve will be very similar to the at-cost output.

Thus, regional optimal bidding – in this highly simplified model - can be summarised as follows:

- generators that are *away from the margin* will bid at cost;
- bidding of generators *close to the margin* will depend upon the impact that their output level has on RRP;
- optimal bidding moves a close-to-the-margin generator's output closer to its forward level, compared to at-cost bidding; and
- the higher the RRP sensitivity (ie the more *inelastic* the supply curve), the greater the likelihood and impact of away-from-cost bidding.

At any point in time, there will be:

- *possibly some short generators slightly out-of-merit*: bidding below cost to *reduce* RRP;
- *possibly some long generators slightly in-merit:* bidding above cost to *increase* RRP; and
- all remaining generators bidding at cost.

The impact on RRP of generators bidding away from cost will depend upon the relative influences of the below-cost and above-cost bidding. RRP cannot go both up *and* down. It is like a tug of war, with long, close-to-the-margin generators trying to pull the price up and short, close-to-the-margin generators trying to pull it down. Therefore, the RRP under optimal bidding might be *higher* or *lower* than it would be if all generators simply bid at cost, depending upon the margins and influences of the long and short generators.

11.4.3 Local Bidding

Local bidding in the OFA model closely resembles – at least qualitatively – regional bidding in the current NEM design.

Recall the operating margin of a generator under OFA, as discussed in section *2 Access*:

Margin = dispatch margin + access margin

= G x (LMP-C) + A x (RRP – LMP)

= A x (RRP – C) + (G-A) x (LMP – C)

= regional margin + local margin (11.9)

where:

G = output level

A = access level

C = marginal generating cost

The structure of equations (11.2) and (11.9) is very similar. If we assume that the generator is behind a constraint, and so cannot affect RRP through its bidding,[138] then the regional margin is fixed[139] and so local optimal bidding aims to maximise the local margin. We see that local margin in (11.9) has the same structure as regional margin in (11.2), with LMP replacing RRP and access level replacing forward level.

Therefore, similar to regional bidding, local optimal bidding depends upon three factors:

- marginal generating costs;
- *access* position; and
- the sensitivity of *LMP* to generator output changes (other things being equal).

Correspondingly, for the purposes of local bidding, we say that the generator is long, or short, if output exceeds access.[140]

Because the margin drivers between the regional and local situations are very similar, optimal bidding is also very similar. Local optimal bidding is presented in Figure 11.3.

The optimal output is again plotted against margin, but now it is the *local* margin, LMP-C, rather than the regional margin. The reasons for the shape of the curves is exactly analogous to the regional situation and do not need to be explained a second time.

Given the similarity of the graphs, we can draw very similar conclusions about local optimal bidding:

- generators that are **locally** *away from the margin* will bid at cost;
- bidding of generator **locally** *close to the margin* will depend upon the influence of output on **local** price;
- optimal **local** bidding moves a generator's output closer to its **access** level compared to at-cost bidding; and
- the higher the **LMP** sensitivity (ie the more *inelastic* the **local** supply curve), the greater the likelihood and impact of away-from-cost bidding.

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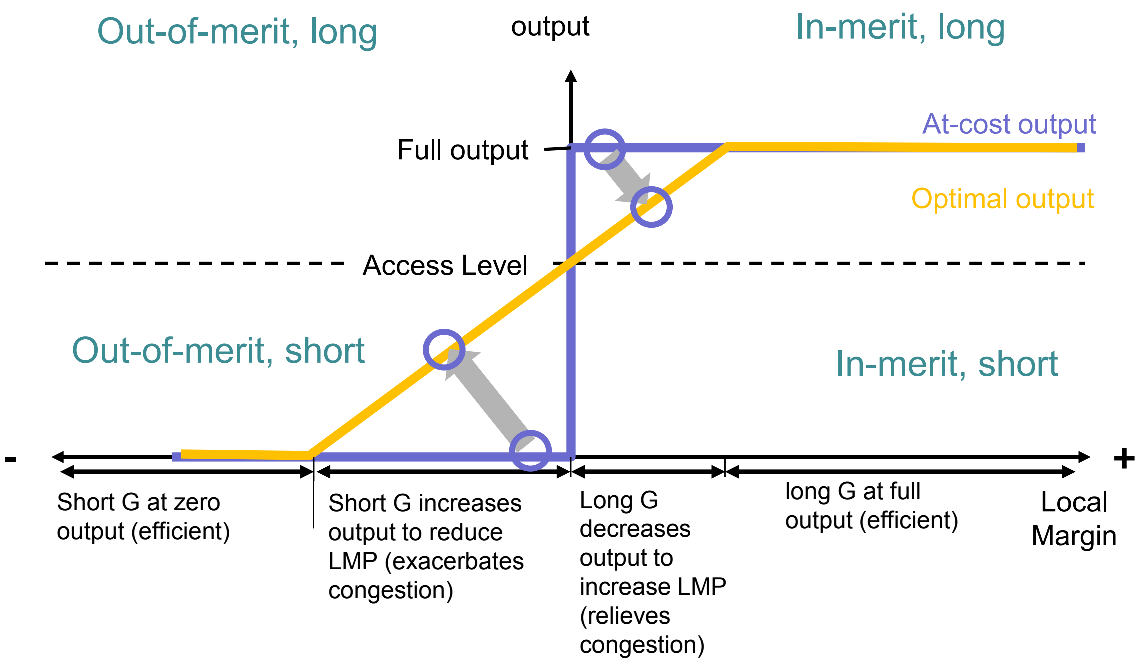
[138] That assumption will be true if the constraint is on a radial part of the network, but only an approximation if the constraint is on a network loop.

[139] That is to say, it is unaffected by the generator's bidding. Of course, it will be volatile over time as RRP goes up and down.

[140]This is the opposite of the terminology used previously in the document, where an access-long generator has access level higher than its output. So an access-long generator is actually short against the LMP and an access-short generator is actually long. The difference is because previously we were considering the price difference, RRP-LMP, but now we are just focused on LMP.

The differences from the regional conclusions are highlighted in **bold** font.

Figure 11.3 Illustration of local bidding



Similarly, we can think of a tug of war metaphor where long close-to-the-margin generators seek to increase the LMP and short close-to-the-margin generators seek to decrease the LMP, recalling that:

- short means output < access: eg firm, constrained-off generators; and
- long means output > access: eg non-firm, dispatched generators.

Increasing the LMP is equivalent to *reducing* flowgate prices: ie seeking to relieve congestion. Similarly, decreasing the LMP is equivalent to increasing the flowgate prices: ie seeking to exacerbate congestion.

11.4.4 Impact of Optimal Local Bidding

The influence of optimal regional bidding on RRP – compared to the hypothetical *perfect competition* counterfactual of all generators bidding at cost – under the current NEM design is well understood, both conceptually (as described in section *11.4.2 Regional Bidding*) and empirically. It is expected and (generally) accepted that:

- when demand levels are low (and so RRP sensitivity is also low), bidding will generally be at cost and so RRP will reflect system marginal cost: the cost of the marginal generator;
- when demand levels are high (and so RRP sensitivity may be high), some away-from-cost bidding will take place and there will be transitory increases in RRP above the system marginal cost.

Indeed, such pricing outcomes allow peaking generators to recover their fixed costs and so help in maintaining supply reliability.[141]

The question for this report is whether optimal local bidding will have similarly modest and beneficial (or, at least, not adverse) impacts on market outcomes. That question will ultimately

[141] If there were never any above-cost bidding, peaking generators would only recover their fixed costs during periods of load shedding, when RRP is set to the market price cap.

only be answered through quantitative analysis. However, the conceptual analysis above may provide some qualitative indicators. Recall that a generator will only bid away from cost where its margin against the market price is in the range:

$$M_1 < M < M_2$$

The values of M_1 and M_2 were presented for the regional context in equations (11.4) and (11.7) above. The corresponding equations for local optimal bidding are:

$$M_1 = -P \times A \qquad (11.10)$$

$$M_2 = P \times (RC - A) \qquad (11.11)$$

where:

P is the local price sensitivity

A is the level of access

RC is the registered capacity

The size of the range between M_1 and M_2 is:

$$M_2 - M_1 = P \times RC \qquad (11.12)$$

Assuming, still, for simplicity that P is a constant value, the RHS of equation (11.12) is equivalent to the impact that a generator can have on the *local* price by increasing from zero output to full output. A similar result would be obtained for the regional case. In practice, P is not a constant value, but qualitatively this result is likely to be broadly true: that the price range of a generator's away-from-cost bidding will be proportionate to the generator's pricing influence: the extent to which it can influence local or regional prices.

Intuitively, one might expect that local pricing influence is greater than regional pricing influence, in the sense that a generator might be a "small fish in a small pool" as compared to a "small fish in a large pool". However, if the region as a whole has a concentrated generation sector, this might not necessarily be the case: eg there might be four generators each with 25% market share in the region and, equally, those four generators might have 25% market share in a local market.[142]

The overall pricing impact depends upon whether short or long close-to-the-margin generators have more *pull* in the tug of war. The design of the OFA model ensures that long and short generators are broadly matched since – for a radial congested flowgate at least - total access equals total generation equals flowgate capacity.[143] So:

$$\begin{aligned} 0 &= \text{total generation} - \text{total access} \\ &= \textstyle\sum_i G_i - \sum_i A_i \\ &= \textstyle\sum_i (G_i - A_i) \end{aligned}$$

meaning that individual generator long and short positions exactly offset each other.[144] However, that does not mean that the short and long positions of close-to-the-margin generators exactly offset each other.

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142 For these purposes, the local market is not a single node, but the *zone* that is affected by a transmission constraint. So, for example, the Latrobe Valley might be a local market and may have similar generation concentration to Victoria as a whole.

143 Since entitlement equals access.

144 This result does not necessarily apply in the regional market, where total forward contracts only equal total generation, if retailers – the buyers of those forward contracts – are 100% hedged.

An important feature of local pricing impacts are that they do not affect customers, who continue to pay regional prices in the OFA model.[145] Therefore, optimal bidding is a zero sum game between local generators. One important consequence of this is that a generator with a local monopoly has no game to win, because there is no other generator for it to take money off. It is indifferent to the local price.

11.4.5 Differences between the OFA Model and Nodal Pricing

In a nodal pricing market design, all generators are paid LMP and all customers pay LMP. Although *theoretically* efficient,[146] nodally priced markets have a number of shortcomings:

- generators with local market power can increase prices to customers and increase the market price of congestion hedges;[147]
- retailers and generators find it difficult to contract forward, since each faces a different spot price;
- congestion hedges may be unavailable or may not be effective in managing congestion risk;
- as a result, generators and retailers typically vertically integrate along zonal lines in order to naturally hedge congestion, leading to reduced retail competition.

Although LMPs are implicitly used in the OFA model, as discussed, the OFA model is very different to a nodal pricing design. Specifically:

- customers pay regional prices, not local prices;
- generators *never* get paid higher than the regional price, which limits their pricing influence;
- generators can obtain firm access to the regional price by agreeing access with TNSPs;
- TNSPs are obliged to offer firm access at regulated prices;
- TNSPs must expand the network to accommodate firm access; and
- increased severity of congestion is likely to prompt additional access procurement, leading to network expansion and thus a reduction in congestion: ie congestion levels are self-regulating.

As a result:

- optimal bidding is as likely to cause LMPs to *reduce* as increase;
- optimal local bidding is a zero sum game between generators, with customers largely unaffected; and
- firm access will give generators increased confidence to locate remotely from their customers.

In summary, there are fundamental differences between the OFA model and a conventional, nodally priced market design. Generator behaviour under the OFA model should not be inferred from analysis or experience of nodal markets, but rather by specific analysis of the elements and drivers present in the OFA model.

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145 Although in some cases loop flows effects could mean that local bidding will distort regional prices to some extent.

146 Under strict assumptions such as perfect competition and generator and customer risk neutrality.

147 Financial contracts that hedge LMP price differentials.

11.4.6 Summary

Optimal local bidding in the OFA model will be *qualitatively* similar to optimal regional bidding in the current NEM design. *Quantitatively*, they will differ, due to differences in pricing influence and in the balance of long and short positions in a zone. Furthermore, local pricing impacts are, in general, a zero sum game between generators; they do not affect customers, who continue to pay regional prices in the OFA model.

12 Technical Detail

12.1 Overview

This section provides some additional design detail for the OFA model. This detail is not really necessary for understanding the OFA model design. However, it helps in explaining how the model achieves its goals and objectives, how it is applied in unusual situations, or how the design would be implemented in practice.

12.2 Flowgate Pricing and Local Pricing

12.2.1 Overview

As noted in section *4.3.1 Use of Flowgate Prices rather than Nodal Prices*, there is something of a disconnect between the high level description of the OFA model (see section *2 Access*) and the more detailed design (as described in section *4 Access Settlements*). The former description is based on local prices (LMPs) and the latter description uses flowgate prices. It is noted that, in the absence of any scaling back of entitlements, the two approaches are mathematically equivalent.

However, that assertion is far from obvious or intuitive. This section explains the relationship between flowgate prices and local prices and demonstrates that the two approaches can be equivalent. Most importantly, it demonstrates that the settlement algebra successfully ensures the *no regrets* principle: that all generators[148] are paid, net, at least their offer price irrespective of their level of access or entitlements.

12.2.2 Flowgate Participation

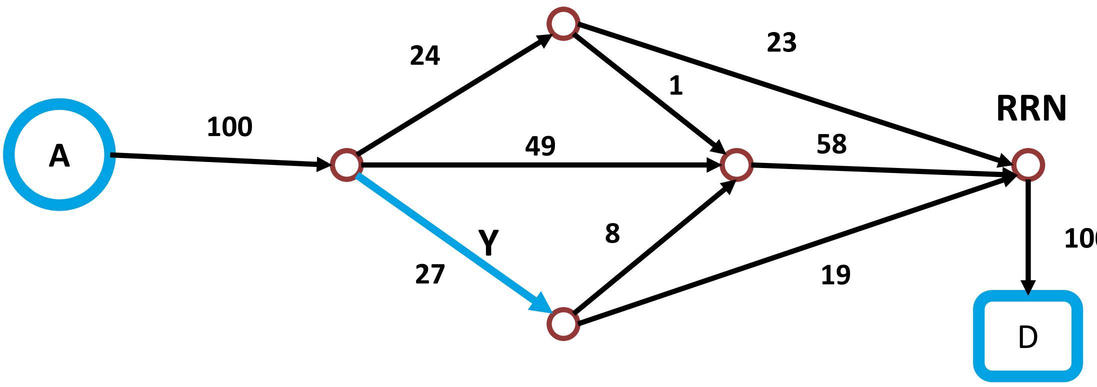
Load flow analysis on a meshed AC power system is extremely complex. It can be considerably simplified by making two approximations:

- *DC approximation*: MVAr flows and variations in voltage magnitudes are ignored.
- *Lossless approximation*: transmission losses are zero.

With these approximations – which are not material for the purposes of this discussion – AC load flow is similar to the electricity flow through a DC circuit or a fluid flow through a network of pipes. Figure 12.1, below, illustrates a transfer of power through a network, from a generator node to the RRN, based on the lossless DC approximation:

[148] With the exception of flowgate support generators.

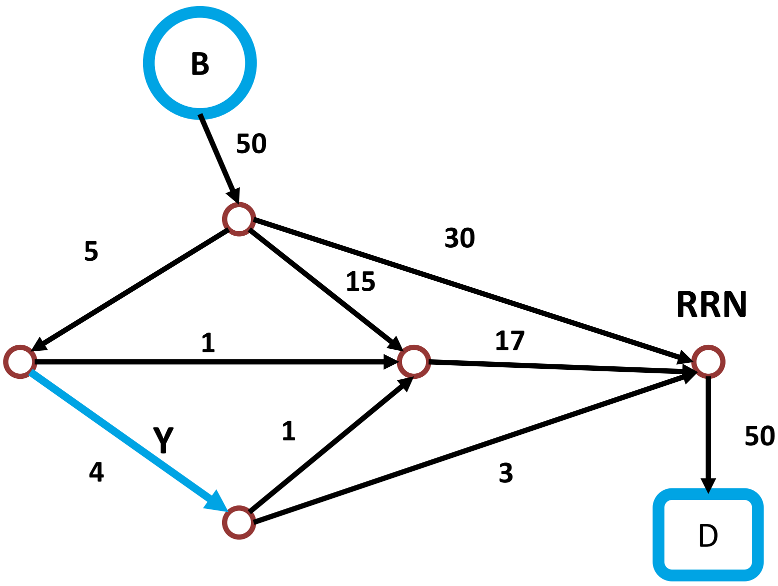
Figure 12.1 Load flow example 1



Each branch in the network has the *potential* to become congested – where the flow on the line reaches the line's maximum rating - and so can be regarded as a *flowgate*, in the terminology of the OFA model. One flowgate, labelled *flowgate Y*, is marked on the figure. Of the 100MW injected by Generator A, 27MW flows through flowgate Y. The *participation* of generator A in flowgate Y is therefore 27%. Note that both the flowgate and the flow have a specified direction. Because they are in the same direction, the participation factor is positive; if they were in opposite directions the participation factor would be negative. Every branch can potentially be congested in either direction, meaning there are two (directed) flowgates on each line.

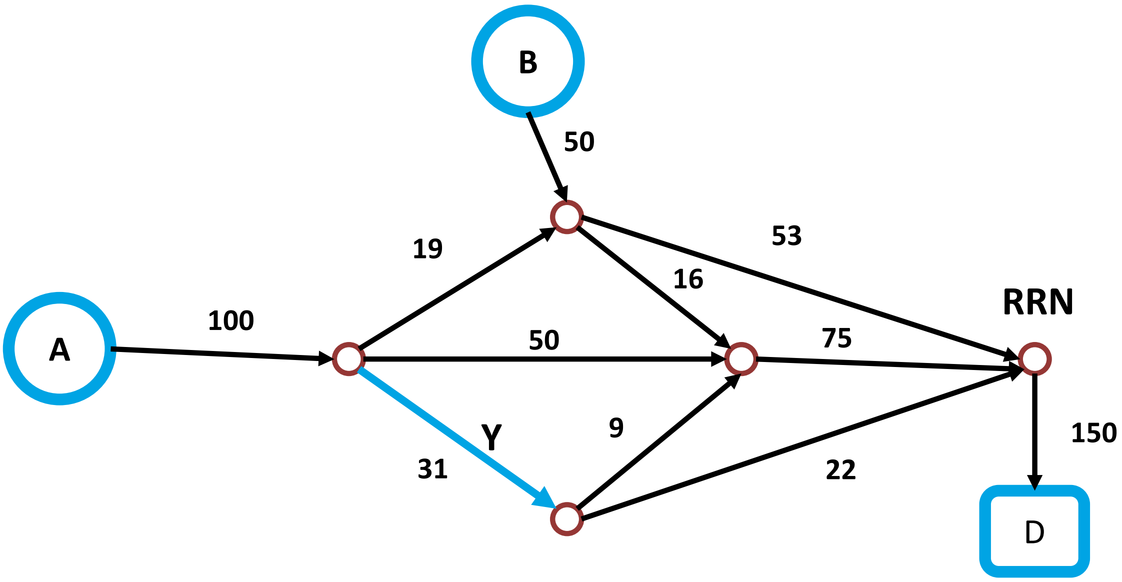
A similar load flow for generator B is presented in Figure 12.2, below. Because the generator connects at a different node, it has a different participation factor. The participation of generator B in flowgate Y is 4MW divided by 50MW, or 8%.

Figure 12.2 Load flow example 2



Our simple model of load flow is *linear*: flows are proportional to injections so if the injection is doubled, say, the flow on each branch would double. Linear systems permit *superposition*: adding together two load flows creates a third load flow. If the load flows presented in Figures 12.1 and 12.2 are superimposed, a third load flow is created as shown in Figure 12.3.

Figure 12.3 Superimposed load flows



It is seen that the flow through flowgate Y is the sum of the flows in the previous two load flows, ie:

Flowgate Y flow = 31 = 27 + 4 = 27% x 100 + 8% x 50

In general, the flow on the flowgate is:

Flowgate Y Flow = 27% x G_A + 8% x G_B (12.1)

where:

G_A is the output of generator A

G_B is the output of generator B

27% is the participation of generator A in flowgate Y

8% is the participation of generator B in flowgate Y

If the limit on the line associated with Flowgate Y is TX_Y then, for any dispatch of generators A and B, we must have:

Flowgate Y flow = 27% x G_A + 8% x $G_B \leq TX_Y$ (12.2)

where:

TX_Y is the transmission capacity of the line of flowgate Y

This inequality has the familiar form of the transmission constraints used in NEMDE. The general version of this inequality is:

$\sum_i \alpha_{ik} \times G_i \leq TX_k$

where:

α_{ik} is the participation of a generator i in flowgate k

G_i is the output of generator i

TX_k is the transmission capacity of flowgate k

12.2.3 Transmission Capacity versus Flowgate Capacity

Suppose that there is some local demand at nodes A and B. For our simplified model, the impact of demand on network flows is exactly the same as negative generation: ie it is the *net injection, G-D,* at each node that determines flows; generation of 100MW will create the same flow as generation of 130MW and local demand of 30MW (since 130 - 30 = 100).

When local demand is included, inequality (12.2) becomes:

$$27\% \times (G_A - D_A) + 8\% \times (G_B - D_B) \leq TX_Y \qquad (12.3)$$

where:

D_A is the local demand at node A

D_B is the local demand at node B

Demand is not dispatched by NEMDE and so it is treated as a constant and moved to the RHS of the inequality. Therefore, equation (12.3) becomes:

$$27\% \times G_A + 8\% \times G_B \leq TX_Y + 27\% \times D_A + 8\% \times D_B \equiv FGX_Y$$

where:

$$FGX_Y = TX_Y + 27\% \times D_A + 8\% \times D_B \qquad (12.4)$$

FGX_Y is the *flowgate capacity* for flowgate Y. It is seen that flowgate capacity is a combination of the transmission capacity and local demand. The general form of equation (12.4) is:

$$FGX_k = TX_k + \sum_i \alpha_{ik} \times D_i$$

where:

FGX_k is the capacity of flowgate k

TX_k is the transmission capacity of flowgate k

α_{ik} is the participation of node i in flowgate k

D_i is the local demand at node i

It is seen from the above formula that flowgate capacity will vary as local demand varies. When TNSPs are managing their networks so as to maintain FAS, they must take account of local demand as well as transmission availability.

12.2.4 Flowgate Prices

In the OFA model, the *flowgate price* is defined as *the marginal value of flowgate capacity for economic dispatch.*

Economic dispatch is the dispatch of generation that meets demand, complies with transmission constraints and minimises generation costs, as these are specified in dispatch offer prices.

The marginal value of flowgate capacity is the *increase* in economic dispatch cost caused by a 1MW *decrease* in flowgate capacity.[149] Therefore

$$FGP = c(ED_2) - c(ED_1)$$

where:

ED_1 is the original economic dispatch

[149] Or, alternatively, the *decrease* in economic dispatch cost allowed by a 1MW increase in flowgate capacity. These two values are generally the same, and the situations where they are different are not important to this discussion.

ED_2 is the revised dispatch when the flowgate capacity is reduced by 1MW

$c(ED)$ is the cost of an economic dispatch

Characteristics of flowgate prices are:

- *A flowgate price can never be negative*: $c(ED_2)$ cannot be less than $c(ED_1)$. If it were, ED_2 would have been chosen originally and so ED_1 would not be economic.
- If *a flowgate is uncongested, its price is zero*: since there is already some unused capacity on the flowgate, removing 1MW of this unused capacity is not going to affect dispatch: ie ED_2 is the same as ED_1.
- Usually, but not always, *if a flowgate is congested then its price is greater than zero.*

12.2.5 Local Prices

The local price[150] at a node is defined as *the marginal value of generation at a node*. As discussed previously, the impact of +1MW of generation is identical to -1MW of demand. Therefore, the local price is also the *marginal cost of supplying demand at a node*.

Using the same definition of marginal value as above, this means it is the amount by which the cost of economic dispatch *reduces* if a zero cost generator, at the node, and not included in the original economic dispatch, injects 1MW.

Suppose that the local price at a node A is P_A. If the extra 1MW generated at node A is zero cost, the dispatch cost saving is P_A, by definition. More generally, if the 1MW generation costs C_A, the dispatch cost saving is P_A-C_A. If the generator at node A is available for dispatch and submits a dispatch offer price C_A then:

- If $C_A<P_A$, dispatching that generator by 1MW *reduces* the cost of dispatch: hence that 1MW will be *included* in an economic dispatch.
- If $C_A>P_A$, dispatching that generator by 1MW *increases* the cost of dispatch: hence that 1MW will *not* be included in an economic dispatch.

Thus, the local price defined above is a *clearing price*: the generator is dispatched if its offer price is below the local price and not dispatched if its offer price is above it.

12.2.6 Marginal Generators

Suppose that in an economic dispatch there is a *part-loaded* generator B at node B with offer price C_B. What happens to dispatch costs if another, zero-cost generator injects 1MW into node B. An obvious change to make is simply to reduce the output of generator B by 1MW. Since the total injection at node B – and hence the load flow - is the same as before, the dispatch must be feasible and the cost saving is C_B. Is this dispatch now *economic*, or is there a way of changing the dispatch so that the cost saving is more than C_B? Well, if there were, that alternative dispatch would have been used originally, together with a 1MW increase in the output of generator B.

So, the cost saving in *economic* dispatch is C_B, meaning that the local price is:

$$P_B = C_B$$

In general, whenever there is a part-loaded generator,[151] the generator's offer price sets the local price. Such a generator is referred to as *marginal*.

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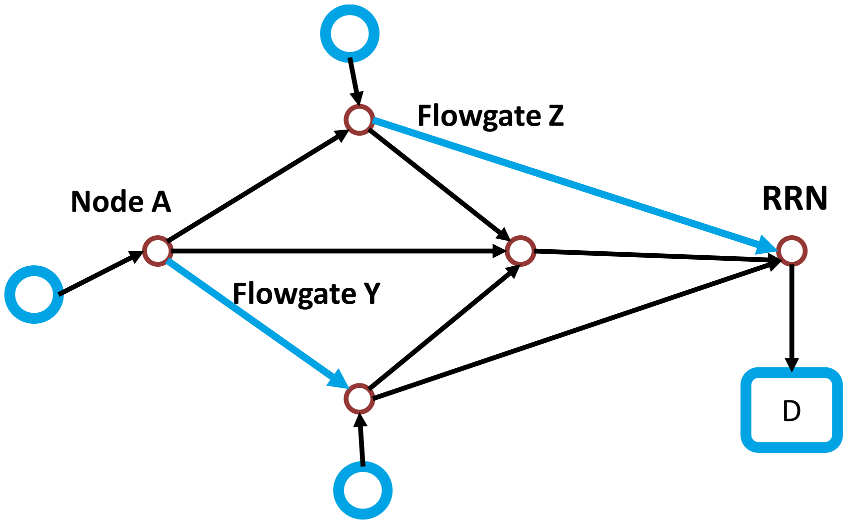
[150] Also referred to as locational marginal price, LMP or nodal price.

[151] Or strictly a generator that is part-loaded within a dispatch offer band.

12.2.7 Relationship between Local and Flowgate Prices

Consider now the economic dispatch shown in Figure 12.4, below. Flowgates Y and Z are both congested and have corresponding flowgate prices FGP_Y and FGP_Z.

Figure 12.4 Economic Dispatch Example



What is the local price at node A? The marginal value of generation at node A can be examined by considering that the economic dispatch in Figure 12.4 above is changed through a zero-cost generator producing 1MW at node A and supplying an additional 1MW of demand at the RRN, with dispatch otherwise unchanged.

The superposition principle means that this is equivalent to *superimposing* on the original load flow a new load flow corresponding to 1MW from node A flowing to the RRN. The incremental output would flow through the two flowgates based on the node A participation factor. This would add to the flow already on the flowgates. Thus:

$$Flow_Y = FGX_Y + \alpha_{AY}$$

$$Flow_Z = FGX_Z + \alpha_{AZ}$$

where:

α_{AY} is the participation of a generator at node A in flowgate Y

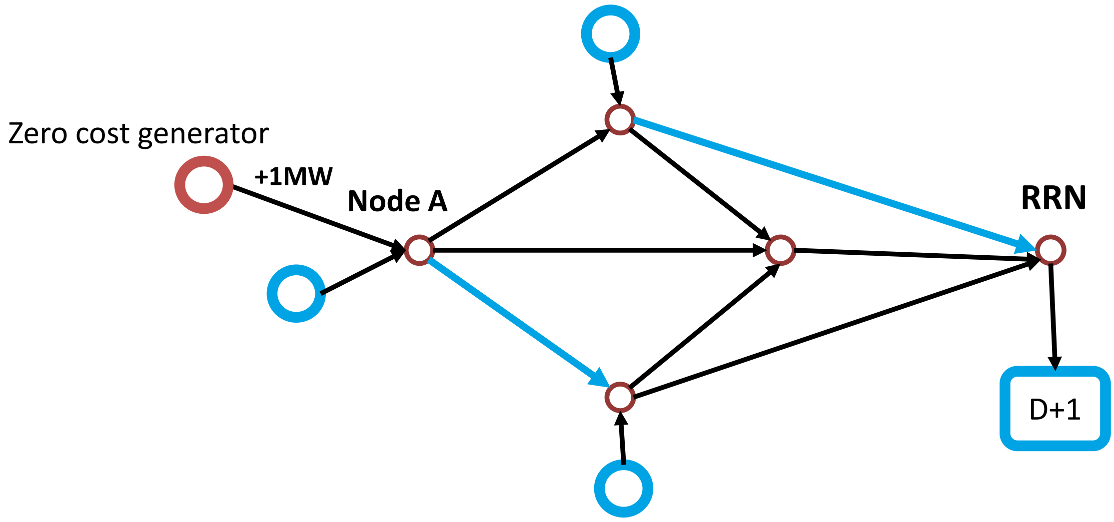
α_{AZ} is the participation of a generator at node A in flowgate Z

$Flow_Y$ is the flow through flowgate Y in the adjusted dispatch

$Flow_Z$ is the flow through flowgate Z in the adjusted dispatch

The adjusted dispatch and load flow is shown in Figure 12.5:

Figure 12.5 Adjusted Dispatch (Infeasible)



This dispatch is *not feasible*, since the flowgate flows on Y and Z now exceed the flowgate capacity.[152] The dispatch must be changed: firstly, to reduce the flow on flowgate Y by α_{AY} and secondly to reduce the flow on flowgate Z by α_{AZ}. We know by the definition of the flowgate prices that the cost of doing these two redispatches is $\alpha_{AY} \times FGP_Y$ and $\alpha_{AZ} \times FGP_Z$, respectively.

However, based on our definitions of local price:

- The extra 1MW of generation at node A *decreases* dispatch costs by P_A.
- The extra 1MW of demand at node R *increases* the dispatch cost by P_{RRN}.

P_{RRN} is the local price at the regional reference node which, by definition, equals RRP.

Therefore, from the definition of flowgate prices:

$$\text{Net increase in dispatch costs} = \alpha_{AY} \times FGP_Y + \alpha_{AZ} \times FGP_Z$$

And from the definition of nodal prices:

$$\text{Net increase in dispatch costs} = RRP - P_A$$

So, putting the last two equations together:

$$RRP - P_A = \alpha_{AY} \times FGP_Y + \alpha_{AZ} \times FGP_Z \qquad (12.5)$$

Rearranging this equation, P_A is defined by the formula:

$$P_A = RRP - \alpha_{AY} \times FGP_Y - \alpha_{AZ} \times FGP_Z \qquad (12.6)$$

The example considers the situation of two congested flowgates, but the analysis applies irrespective of the number of congested flowgates. In general, then, the local price is defined by the formula:

$$P_i = RRP - \sum_k \alpha_{ik} \times FGP_k \qquad (12.7)$$

where:

P_i is the local price at node i

α_{ik} is the participation of node i in flowgate k

[152] Assuming that the participation factors are positive. If they are negative, the dispatch is no longer economic, because the valuable flowgate capacity is being underutilised.

FGP_k is the price of flowgate k

The summation can be over all congested flowgates or, equally, over all flowgates, recalling that the price of uncongested flowgates is zero.

12.2.8 Inter-regional Price Difference

Suppose that, in the above example, the RRN was the reference node for region 2 and that node A was the reference node for region 1. Then equation (12.5) becomes:

$$RRP_2 - RRP_1 = \alpha_Y \times FGP_Y + \alpha_Z \times FGP_Z \qquad (12.8)$$

The participation factors α_Y and α_Z represent the amount of flow through flowgates Y and Z for a flow from RRN_1 to RRN_2. Such a flow is referred to in the OFA model as the *directed interconnector* from region 1 to region 2. Generalising equation (12.8) gives:

$$RRP_N - RRP_S = \sum_k \alpha_k \times FGP_k \qquad (12.9)$$

where:

RRP_N is the RRP in the northerly region

RRP_S is the RRP in the southerly region

α_k is the participation of the northerly interconnector in flowgate k

12.2.9 Generator Access Settlement

Suppose that a non-firm generator at node i with *zero entitlement* on every congested flowgate is dispatched to a level G. In normal settlement it is paid RRP x G. In access settlement it will *pay* an amount on flowgate k equal to:

$$\text{Access Pay\$}_k = U_k \times FGP_k$$

where:

U_k = the generator's usage of flowgate k

Recall that usage is defined by:

$$U_k = \alpha_{ik} \times G$$

Therefore, the total payment is:

$$\text{Total access pay\$} = \sum_k \text{Pay\$}_k$$

$$= \sum_k \{(\alpha_{ik} \times G) \times FGP_k\} = G \times \sum_k (\alpha_{ik} \times FGP_k)$$

The generator's net payment in settlements is then:

$$\text{Net Pay\$} = G \times RRP - G \times \sum_k (\alpha_{ik} \times FGP_k)$$

$$= G \times \{RRP - \sum_k (\alpha_{ik} \times FGP_k)\}$$

$$= G \times P_i \qquad \text{(from equation (12.7))}$$

So, a generator with zero entitlement gets paid its *local price*. Since the generator is dispatched, the local price must be higher than its offer price, so the generator does not regret being dispatched.[153]

In general, generators – even non-firm ones – will have *some* entitlements on congested flowgates and will receive a price higher than the local price.

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[153] Assuming that its offer price is no lower than its generating cost.

Now suppose instead that the generator has an agreed access level A and receives its firm target entitlement on each congested flowgate:

$$E_k = \alpha_{ik} \text{ x } A$$

Its total payment is:

$$\begin{aligned} Pay\$ &= RRP \text{ x } G + \textstyle\sum_k\{(E_k\text{-}U_k) \text{ x } FGP_k\} \\ &= RRP \text{ x } G + \textstyle\sum_k\{(\alpha_{ik} \text{ x } A - \alpha_{ik} \text{ x } G_k) \text{ x } FGP_k\} \\ &= RRP \text{ x } G + (A\text{-}G) \text{ x } \textstyle\sum_k(\alpha_{ik} \text{ x } FGP_k) \\ &= RRP \text{ x } G + (A\text{-}G) \text{ x } (RRP - P_i) \qquad \text{(from equation (12.7))} \\ &= P_i \text{ x } G + A \text{ x } (RRP - P_i) \end{aligned}$$

which is the formula for access presented in equation (2.1) in section *2 Access*.

Thus, access settlement correctly implements the principles set out in section *2 Access*.

12.2.10 IRSR Allocation

Ignoring losses as usual, the IRSR accruing on an interconnector is:

$$IRSR = IC \text{ x } (RRP_N\text{-}RRP_S)$$

where:

IC is the interconnector flow in the northerly direction.

RRP_N is the RRP in the northern region

RRP_S is the RRP in the southern region

Substituting for the inter-regional price difference from equation (12.9), we get

$$\begin{aligned} IRSR &= IC \text{ x } \textstyle\sum_k (\alpha_k \text{ x } FGP_k) \\ &= \textstyle\sum_k \{(\alpha_k \text{ x } IC) \text{ x } FGP_k\} \qquad (12.10) \end{aligned}$$

Now, recall from section *10.2.3 Inter-regional Access Settlement* that:

- the northerly interconnector is considered to participate in flowgates where the participation factor is positive; and
- the southerly interconnector is considered to participate in flowgates where the participation factor is negative.

We will refer to these two subsets of flowgates as *N* and *S* respectively. Equation (12.10) can be rewritten as:

$$\begin{aligned} IRSR &= \textstyle\sum_{k\epsilon N} \{(\alpha_k \text{ x } IC) \text{ x } FGP_k\} + \textstyle\sum_{k\epsilon S} \{(-\alpha_k \text{ x } -IC) \text{ x } FGP_k\} \\ &= IRSR_N + IRSR_S \end{aligned}$$

where:

$$IRSR_N \equiv \textstyle\sum_{k\epsilon N} \{(\alpha_k \text{ x } IC) \text{ x } FGP_k\} = \textstyle\sum_{k\epsilon N} (U_k \text{ x } FGP_k) \qquad (12.11A)$$

$$IRSR_S \equiv \textstyle\sum_{k\epsilon S} \{(-\alpha_k \text{ x } -IC) \text{ x } FGP_k\} = \textstyle\sum_{k\epsilon S} (U_k \text{ x } FGP_k) \qquad (12.11B)$$

and:

U_k is the usage of flowgate k by the relevant directed interconnector.[154]

[154] Note that, for the southerly interconnector, the dispatch level is –IC and the participation factor is - α_k.

Note that this allocation of the IRSR between the two directed interconnectors is *not* the same as in the *current* NEM design, which allocates *all* of the IRSR to the directed interconnector which flows into the higher-priced region. There will need to be a change to existing NEM settlements to change the allocation to the one defined in equations (12.11) above.

The general formula for access settlement for an interconnector is:

$$\text{Access Pay\$}_N = \textstyle\sum_{k\epsilon N} \{(E_k - U_k) \text{x } FGP_k\} \qquad (12.12A)$$

$$\text{Access Pay\$}_S = \textstyle\sum_{k\epsilon S} \{(E_k - U_k) \text{x } FGP_k\} \qquad (12.12B)$$

where:

E_k = is the entitlement on flowgate k for the relevant directed interconnector.

In the OFA model, the existing settlement payments into the IRSRs are supplemented by the access payments shown in equations (12.12), meaning that total IRSR is:

$$\begin{aligned} \text{IRSR\$}_N &= \text{existing pay\$ + access pay \$} \\ &= \textstyle\sum_{k\epsilon N} (U_k \text{ x } FGP_k) + \sum_{k\epsilon N} [(E_k - U_k) \text{x } FGP_k] \\ &= \textstyle\sum_{k\epsilon N} (E_k \text{ x } FGP_k) \qquad (12.13A) \end{aligned}$$

And similarly:

$$\text{IRSR\$}_S = \textstyle\sum_{k\epsilon S} (E_k \text{ x } FGP_k) \qquad (12.13B)$$

We can consider equations (12.13) under two special situations. Firstly, if an interconnector has zero entitlement on all flowgates, the corresponding IRSR will be zero. This is the worst case scenario for IRSR: it can never be *less* than zero.

Secondly, consider a northerly interconnector, with agreed access, A, that receives its firm target entitlement, and no non-firm entitlement, on each flowgate, ie:

$$E_k = \alpha_k \text{ x } A$$

Then from equation (12.13):

$$\begin{aligned} \text{Net Pay \$} &= \textstyle\sum_{k\epsilon N} (\alpha_k \text{ x } A \text{ x } FGP_k) \\ &= A \text{ x } \textstyle\sum_{k\epsilon N} (\alpha_k \text{ x } FGP_k) \end{aligned}$$

A corresponding result holds for a southerly interconnector.

In the common case where all binding hybrid constraints on an interconnector are in the same direction (northerly say)

$$\begin{aligned} \text{Net Pay \$} &= \textstyle\sum_{k} (\alpha_k \text{ x } FGP_k) \\ &= A \text{ x } (RRP_N\text{-}RRP_S) \qquad \text{(from equation (12.9))} \end{aligned}$$

Thus, in this case, the access settlement payment converts the *existing IRSR*, which is proportionate to the interconnector *flow*, *IC*, and the inter-regional price difference, into an IRSR which is proportionate to the interconnector *access* level, *A* and the inter-regional price difference. A similar result again holds for the southerly interconnector, which may have a different agreed access level to the northerly interconnector. In general, the firm IRSR will be allocated to the directed interconnector in the direction of the binding constraints: ie which is *directed towards the higher price region*. The allocation does not depend upon the direction of interconnector *flow*.[155]

[155] Recalling that the interconnector flow is defined as the flow across the regional boundary, not the flow through the hybrid flowgates.

The more complex case where there is mixed congestion on the interconnector (both northerly and southerly binding flowgates) is discussed in section *12.3.3 Mixed Interconnector Constraints* below.

12.3 Mixed Constraints

12.3.1 Overview

For generators and interconnectors, OFA access settlement treats flowgates differently depending upon whether the party has a positive or negative participation in the flowgate. It is possible for a party to concurrently have negative and positive participation in different binding flowgates.

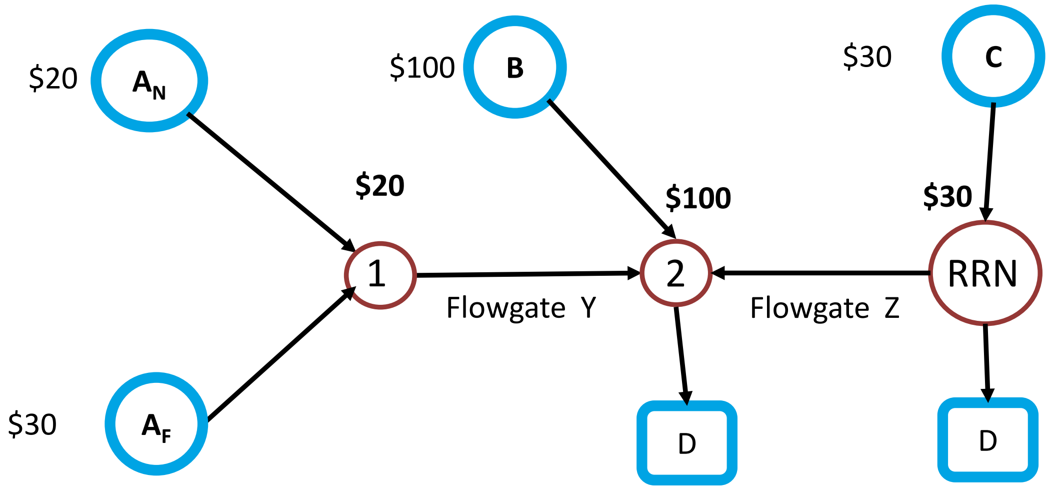
For generators, this scenario may be a largely theoretical situation which never, or rarely, occurs in practice. However, if quantitative modelling were to show that it could occur frequently, some changes may be needed to the OFA model design to address the issues arising.[156]

Issues arising under mixed constraint situations are discussed further below.

12.3.2 Generator Situation

Figure 12.6, below, presents a simple scenario where a generator participates in two binding flowgates.[157] Generators A_N and A_F each have positive participation in flowgate Y and a negative participation in flowgate Z, both of which are binding.

Figure 12.6 Mixed generator constraints



Assume that generator A_N is non-firm, and receives zero entitlement on flowgate Y. It is therefore charged the flowgate price on its output.[158] However, because it is a flowgate support generator for flowgate Z, it receives a negative entitlement and so has zero access settlement on the flowgate. Therefore, payments to generator A_N are:

$$\text{Pay\$}_N = \text{RRN settlement\$} + \text{Flowgate Y settlement\$} + \text{Flowgate Z Settlement\$}$$

$$= \$30 \times G - (\$100 - \$20) \times G + 0\$ = -\$50 \times G$$

Generator A_F receives an entitlement on flowgate Y which (since the generator is not dispatched) pays \$80 (FGP_Y) multiplied by the access amount. Generator A_F is not dispatched and so receives

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[156] Which would be along the lines discussed in section *2.3.9 Flowgate Support and Constrained-on Generators*.

[157] This simple example may appear unrealistic because it relies on a generator, B, being constrained on. However, a similar mixed constraint combination could arise on a looped network without requiring constrained-on generation. The radial example is used because it is simpler to explain and understand.

[158] Since the flowgate is radial, usage equals output.

no negative entitlement on flowgate Z. Therefore, generator A_F is compensated at $*80* for being constrained off, despite its opportunity costs being only $10.

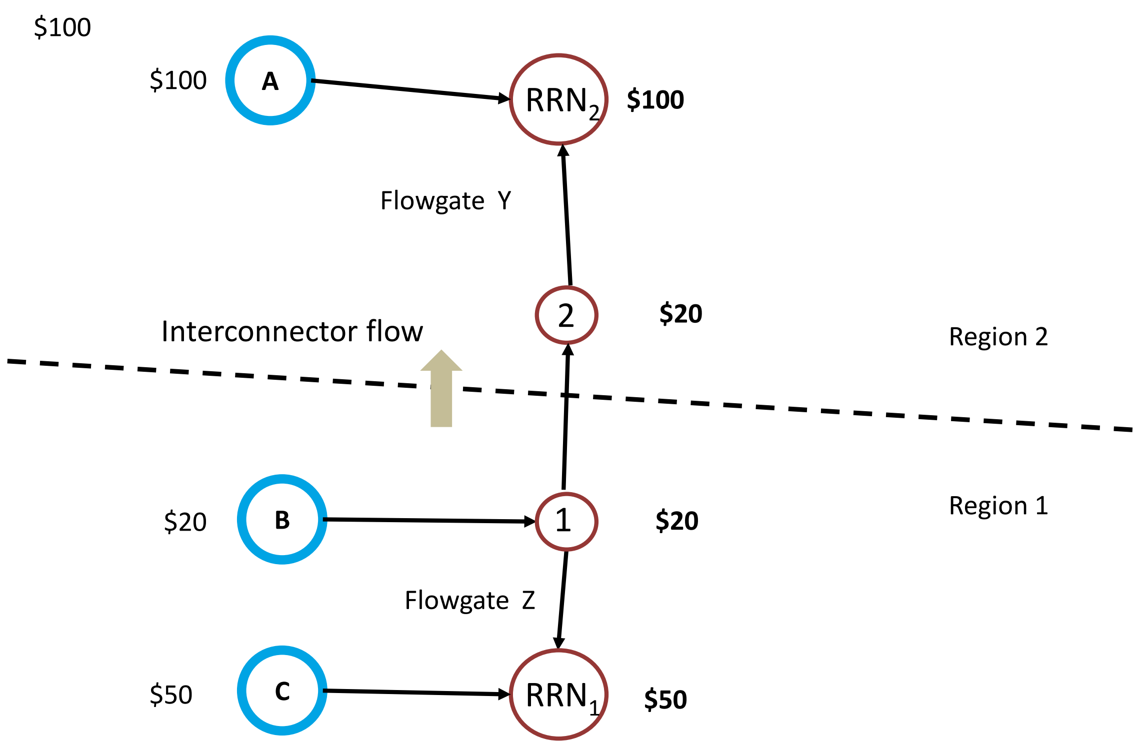
So, in this example, a non-firm generator is not just paid less than its *offer price*, it is paid less than *zero*. A firm generator, on the other hand, receives substantially more compensation for being constrained off than is justified. The root of the problem is not in the OFA model, *per se*, but in the treatment of flowgate support generators in the current NEM design,[159] where the *no regrets* principle does not apply for constrained-on generation.

Generator A_N in this example would clearly reduce its offered quantity until either flowgate Y was no longer binding, which would mean the generator would be paid RRP, or its output reduced to zero. That should not materially affect system security: the flow on flowgate Y only needs to reduce by 1MW to remove the congestion. If, in a more complex example, generator A's backing off *did* create a security problem, AEMO could *direct* it and compensate it as necessary for any out-of-merit costs.

12.3.3 Mixed Interconnector Constraints

Figure 12.7, below, presents an example of an interconnector facing mixed flowgates.

Figure 12.7 Mixed interconnector constraints



Recall that directed interconnectors never have negative participation in flowgates, because each directed interconnector is deemed to participate only in positive-participation flowgates. Therefore, in the example, the northerly interconnector participates in flowgate Y and the southerly interconnector participates in flowgate Z.

[159] Which the OFA model retains.

As explained in section *12.2.10 IRSR Allocation*, the addition of access settlement to existing IRSR provides a firm revenue stream on each flowgate. In the example, suppose that agreed inter-regional access is as follows:

- 100MW for the northerly interconnector
- 200MW for the southerly interconnector

and assume also that firm entitlement targets are met and that there are no non-firm entitlements. In this situation, IRSR allocation is as follows:

$$IRSR\$_N = A_N * FGP_Y = 100MW \text{ x } (\$100\text{-}\$20)$$

$$IRSR\$_S = A_S * FGP_Z = 200MW \text{ x } (\$50\text{-}\$20)$$

where:

A is the agreed access

FGP is the flowgate price

suffixes N and S refer to northerly and southerly, respectively

suffixes Y and Z refer to flowgates Y and Z respectively

The IRSR payouts are based on price differences of \$80 and \$30, respectively, neither of which matches the inter-regional price difference of \$50. That might suggest that these IRSR payouts – and the associated SRA and FIR instruments – do not act as effective inter-regional hedges.

However, hedging is most critical when inter-regional price differences are extreme. Suppose that the price in the northerly region, RRP_2, increases to \$10,000. Other things being equal, FGP_Y will increase to \$9,980 which is (proportionately) very similar to the inter-regional price difference of \$9,950. Therefore the northerly IRSR acts as a very effective northerly inter-regional hedge under these severe conditions. On the other hand, if RRP_2 remains at \$100 but now RRP_1 increases to \$10,000, FGP_Z will increase to \$9,980 – similar to the inter-regional price difference of \$9,900 – so, similarly, the southerly IRSR will provide an effective southerly inter-regional hedge at such times.

Recall that, under the OFA model, IRSR allocation and amount do not depend upon the direction of interconnector *flow*.[160] In the situations described above the flow could remain northerly or turn southerly; it would not affect the IRSR and so would not diminish the hedging effectiveness of the IRSRs. That compares to the status quo, where a change in interconnector flow direction (to a counterprice flow) would *completely remove* any hedging benefit from holding an SRA right.

12.4 Thirty-Minute Settlement

12.4.1 Overview

Access settlement uses trading intervals (TIs), which are 30-minute periods, for settlement. However, the settlement calculation is based on dispatch information which is defined by dispatch interval (DI): a 5-minute period. There is therefore a need to define settlement algebra that reconciles these two bases.

This is not a new problem: current NEM settlement addresses similar issues. Indeed, it is important to ensure that, as far as possible, access settlement adopts the same approach to addressing the issue, so as not introduce new basis risks resulting from DI-TI discrepancies.

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[160] The flow across the regional boundary.

12.4.2 Access Settlement Approach

Table 12.1 below shows the dispatch data used by access settlement and how this is converted from 5-minute dispatch information to 30-minute settlement inputs.[161]

Table 12.1 Conversion of DI data to TI data

TI Settlement data	Processing of dispatch data
Flowgate applied in NEMDE	if transmission constraint applied in one or more DIs
Congested Flowgate	if applied constraint is binding in one or more DIs
Flowgate Participation	from static data in constraint library
Generation Dispatch	average of DI dispatch across TI
Flowgate Usage	participation x TI dispatch
Flowgate Support	negative of TI flowgate usage, for flowgate support generators
Flowgate Capacity	aggregate of TI flowgate usages
Flowgate Price	average of DI flowgate prices*
Availability	average of the DI offered availabilities or UIGFs
TNSP Support	discussed in next section below

(*) flowgate price is taken to be zero in any DIs where the corresponding transmission constraint is not applied in NEMDE

Averages will be simple, unweighted, arithmetic means. Each average is on a TI basis, meaning that it is the average of six DI-based values. This averaging is consistent with the approach currently taken in settlements: eg half-hourly spot prices are based on the average of dispatch prices.

The major complexity in converting from DI to TI is that transmission constraints may be applied in NEMDE – or be binding in NEMDE – only for a subset of DIs in a TI. This issue is addressed by using the calculated *LHS* of the constraint (ie aggregate usage) as a proxy for the *RHS* (flowgate capacity).

A flowgate is considered to be congested in a TI if the corresponding transmission constraint is binding in a single DI. In other DIs within the same TI, the constraint may not actually be binding. In fact, it may not even be applied in NEMDE.[162] In these situations:

- *aggregate usage*<*flowgate capacity* in DIs where a constraint is not binding;
- possibly, *aggregate usage*>*flowgate capacity* in DIs where a constraint is not applied in NEMDE.

Given these possibilities, a constraint could be binding in a TI, but have aggregate usage either higher or lower than the *true* flowgate capacity.

This is not a problem for settlement balancing: since flowgate capacity is *defined* to be equal to aggregate flowgate usage for congested flowgates, settlement must balance. It may affect generators somewhat, since their entitlements will be affected. However, it is accepted in the current NEM design that there will be some basis risks arising from the 5-30 discrepancy. It is not expected that the issue above will significantly exacerbate those risks.

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161 Note that this processing calculates MW rather than MWh values, so 30-minute settlement amounts need to be divided by two: Pay$ = price ($/MWh) x volume (MW) / 2.

162 Ie where transmission conditions change midway through a TI, causing new constraints to be introduced into NEMDE and other constraints to be removed from NEMDE.

On the other hand, this issue c*ould* materially affect TNSPs, since it might cause FAS breaches to be flagged (and possibly penalised) even when there was no actual breach: or vice versa. Therefore, a different measure of flowgate capacity will be used in that context, as discussed in the next section.

12.4.3 FAS Monitoring Approach

FAS monitoring requires flowgate capacity to be compared to target capacity. The calculation of target capacity has previously been discussed in section *5.2.4 FAS Implications for Flowgate Capacity*. This section considers the calculation of flowgate capacity. As discussed above, the measure of flowgate capacity used in access settlement would not be appropriate for use in FAS monitoring.

The materiality of a FAS breach is proportionate to the flowgate price. Therefore, DIs in which the flowgate price is high should contribute most to the estimation of flowgate capacity for the TI. For this reason, for the purposes of FAS monitoring, the TI flowgate capacity is defined as the FGP-weighted-average of the DI-based FGXs:

$$FGX_{TI} = \sum_{DI} (FGP_{DI} \times FGX_{DI}) / \sum_{DI} FGP_{DI}$$

where:

FGP_{DI} is the flowgate price in a DI

FGX_{DI} is the flowgate capacity in a DI, calculated from the constraint LHS as above

FGX_{TI} is the measure of flowgate capacity in a TI, used in FAS monitoring

The summation is over all DIs in the TI

Since a flowgate that is congested in the TI must be congested in at least one DI, the sum of the FGPs must be greater than zero and so the weighted-average is well-defined. The weighting ensures that DIs in which the flowgate is either not binding or not applied in NEMDE are ignored in the TI measure, since FGP_{DI} equals zero in these DIs. Thus the issues discussed in the previous section do not arise.

12.5 Transmission Losses

12.5.1 Overview

Transmission losses have been ignored in the description of the OFA model and, in particular, in access settlements. That is because the OFA model deals only with congestion and the impact that it has on access. Nevertheless, it is worthwhile considering the impact that losses have under the OFA model and ensuring that they do not affect the principles and objectives underlying the OFA model.

12.5.2 Marginal Loss Factors

In the current NEM design, intra-regional transmission losses are represented through static marginal loss factors or *MLFs*, which are defined for each node in a region. The nodal MLF represents the additional generation that must be dispatched by NEMDE to supply an extra 1MW of demand at the node:

$$\text{Incremental Dispatched Generation in NEMDE} = \text{Incremental Local D} \times \text{MLF}$$

The incremental generation is the amount extra dispatched by NEMDE. However, MLFs similarly apply to generation at a node:

$$\text{Aggregate Dispatched Generation in NEMDE} = \sum_i G_i \times MLF_i$$

where:

G_i is the amount of generation dispatched at node i

MLF_i is the MLF at node i

For example, if the aggregate generation target in NEMDE was 1000MW this could be met by 1000MW of generation dispatched at the RRN (which, by definition, has an MLF of one) or by 990MW of generation at a node with an MLF of 1.01 (990MW x 1.01 = 1000MW).

Because 990MW of generation at the latter node is worth the same as 1000MW of generation at the RRN, offer prices are adjusted accordingly: if both generators in the example offered at the same price, NEMDE would dispatch the generator at the local node since a lower quantity is required. In general, the cost assumed by NEMDE for dispatching a generator is:

Assumed Cost = Offer Price/MLF

NEMDE then dispatches generators in ascending order of *assumed cost*, not offer price.

Finally, to reflect their value in the market, generator payments are adjusted by MLF

Pay$ = RRP x Dispatch Output x MLF

Thus, if the RRP is $20, then the generator at the RRN would be paid:

Pay$ = $20 x 1000MW x 1 = $20,000

A generator dispatched at the local node to meet the same demand would be paid:

Pay$ = $20 x 990MW x 1.01 = $20.2 x 990MW = $20,000 (12.14)

The payments are the same, since each generator makes the same contribution to meeting demand.

MLFs can be greater or less than one and output, offer price and RRP may be scaled up or scaled down accordingly.

12.5.3 Local Prices in the Absence of Congestion

It is seen from equation (12.14) that the value to dispatch of a generator at a local node is RRP x MLF. Thus, in the absence of congestion, the *local price* is RRP x MLF, not RRP.

If a generator's offer price is C, the cost assumed by NEMDE is C/MLF and so it will be dispatched if:

$C/MLF < RRP$

Or, equivalently, if

$C < RRP \times MLF$

Thus, in the absence of congestion, the local price RRP x MLF is a *clearing price*: a generator will be dispatched if its offer price is below this and not dispatched if its offer price is higher.

12.5.4 Local Prices during Congestion

In section *12.2.7 Relationship between Local and Flowgate Pricing* an expression was derived for the local price in terms of RRP and flowgate prices:

$$P_i = RRP - \sum_k \alpha_{ik} \times FGP_k \qquad (12.15)$$

The derivation was based on the fact that if a generator participating in congested flowgates increased its output there would be need to be some redispatch to bring flowgate usage back to flowgate capacity. Thus, the second term on the RHS of equation (12.15) reflects the additional costs associated with congestion.

Now that the local price in the absence of congestion has been more accurately defined to reflect losses, this congestion cost should be subtracted from that revised price formulation, ie:

$$P_i = RRP \times MLF - \sum_k \alpha_{ik} \times FGP_k \qquad (12.16)$$

In section *12.2.9 Generator Access Settlement* it was demonstrated that, in the OFA model, a generator with zero access is paid its local price, as expressed in equation (12.15). In that case, losses were ignored and the RRP term on the RHS of equation (12.15) is the assumed payment from existing NEM settlements. If losses are included, then payment under existing settlement is RRP x MLF and so the aggregate payment to a generator without access is the RHS of equation (12.16).

Furthermore, because NEMDE takes account of both losses *and* congestion, as previously described, the local price defined by equation (12.16) is a clearing price: NEMDE will dispatch a generator if its offer price is below that local price.

Therefore, in summary, when losses are considered:

- the expression for local price is given by equation (12.16), whether or not there is congestion;
- the local price is a clearing price: a generator is dispatched by NEMDE if its offer price is below the local price;
- a generator with zero entitlements is paid the local price; a generator with some entitlements is paid higher than the local price;
- thus, the no regrets principle applies: any generator that is dispatched will be paid at least its offer price.

The access settlement process correctly applies the principles of the OFA model in the presence of intra-regional losses.

12.6 Transition Processes

12.6.1 Overview

As described in section *9.2.2 Transitional Access Allocation* there are two transition processes in which transmission capacity must be represented, to ensure that transitional access does not – in aggregate – cause TNSPs to breach FAS: the *TA scaling* process and the *TA auction* process.

As described in section *12.8 TNSP Planning and Operations under the Firm Access Standard* meeting FAS broadly means ensuring that a dispatch of firm generation is feasible under all likely network conditions.

Thus, issuance of TA is analogous to dispatching generation. So long as the "dispatch" implied by the TA issuance is feasible, the issued TA should not lead to any FAS breaches. The implications of this analogy for the design of the TA scaling and TA auction processes is discussed below.

12.6.2 Transitional Access Scaling

In the analogy, TA issuance is analogous to generation dispatch and so the TA allocated to an individual generator is analogous to its dispatch level. What is missing from the analogy is offer prices, which are needed to determine which generator gets dispatch priority. Let the analogy to these be referred to as *TA offer prices*. The lower the TA offer price for a generator, the more TA the generator will be issued. Of course, the generator cannot set its own offer price, as each generator would then bid -$1000 to maximise its TA.

That scenario is similar to the disorderly bidding seen in the current NEM design and its implications for TA issuance are worth exploring further. Under disorderly bidding, generators with the same participation factor in a binding constraint will be scaled back *pro rata:* each is dispatched in the same proportion to its availability. However, when generators have differing participation factors, other things being equal, generators with *lower* participation factors are dispatched first, even if the difference in participation is minimal: eg if there were two generators bidding at -$1000 having participation factors of 0.30 and 0.31, the first generator would be *fully* dispatched before the second generator had *any* dispatch. In the context of TA issuance, such an outcome might appear *efficient* (in that it maximises the aggregate amount of TA issued), but that efficiency is predicated on the accuracy of the constraint formulation and, specifically, the participation factors. If the participation factors were, instead, 0.31 and 0.30, the efficient outcome would be reversed.

To avoid such sensitivity of outcomes, it would be possible to *taper* the TA offer prices so that minor differences in participation factor only caused minor differences in TA issuance. An example of a tapered offer price: 10 TA offer bands are used, each applying to 10% of a generator's registered capacity; offer pricing in each band is the same for each generator: eg $10, $20,…,$100.

With a tapered offer, the impact of a minimal difference in participation factor would only be noticeable in one offer band: in the example above, the generator with 0.30 participation might be dispatched in 8 bands, say (and so receive TA for 80% of capacity), whilst the generator with 0.31 participation might then only be dispatched in 7 bands (corresponding to 70% of capacity). So, lower participation will lead to higher TA issuance, but in a proportionate rather than abrupt way.[163]

Using tapered TA offer prices would preserve the broad efficiency of the TA allocation but make it more *robust*: ie less sensitive to inaccuracies or uncertainties in constraint formulation. The appropriate trade-off between efficiency and robustness could be achieved by varying the gradient of the pricing taper: eg using $10, $11, $12… instead of $10, $20, $30….

It is proposed that interconnectors would be given lower priority in the TA allocation process. This would imply setting TA offer prices for interconnectors much higher than those for generators,[164] so that even with a low participation, an interconnector would not be allocated TA in preference to a generator.

12.6.3 Auction Process

The auction process is also constrained by the transmission network. The issued TA after the auction is completed must be accommodated by the transmission network with no breach of FAS. In the dispatch analogy, the auction represents a *change* to dispatch. The dispatch *after* the auction must be feasible, just as the dispatch *before* the auction is. So long as this feasibility is assured, it is not necessary to place additional constraints on the auction: eg that total purchases match total sales at a node or in a zone. It is still necessary to ensure that the auction clears *financially*, or at least there is no settlement deficit. So long as the same flowgate constraints are placed on the auction as were placed on the scaled TA, this is assured, for reasons explained later.

Unlike the TA scaling process, in the TA auction *generators* decide their TA offer prices. For convenience, the TA offer volume will relate to the TA *holding* after the auction, rather than the *change* in TA holding: ie the amount bought or sold at the auction.

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[163] Obviously, the impact could be made even smoother with, say, 100 offer bands.

[164] This is where the analogy with dispatch breaks down. Interconnectors do not have explicit offer prices in dispatch. However, a high interconnector offer price could be modelled in dispatch by assuming that the local RRP was very high ($10,000 say) and assuming that the remote RRP was only slightly lower ($9,000, say) so that local generation would always be dispatched in preference to the importing interconnector.

The value of agreed access is based on the difference between RRP and local price: the lower the local price, the higher value. To reflect this, the amount paid by a generator at the auction is:

Auction Payment\$ = TA purchased at node x (RRP – P)

Similarly, if the generator sells into the auction, the amount received by the generator would be:

Auction Receipt\$ = TA sold at node x (RRP – P)

where:

P is the local price for the generator

The RRP level is arbitrary – it is the difference that is important – so can be set at an arbitrary level: \$100, say. In dispatch, a generator is dispatched if its offer price is below the local price. In the analogy, a generator that is dispatched is allocated TA. So, how should a generator set its TA offer price in the auction?[165]

Consider first of all a generator who has been allocated 100MW of TA at the scaling stage and wishes to sell all of it if the auction clearing price (RRP minus local price) is higher than \$40. That is equivalent to wishing *not* to be dispatched if the local price is lower than \$60 (since \$100-\$60 = \$40). Therefore, the generator offers 100MW at \$60, leading to the following possible outcomes:

- if the local price is <\$60 (and so the clearing price > \$40) the generator is *not* dispatched, has 0MW after the auction, meaning it has sold 100MW;
- if the local price is >\$60 (meaning clearing price<\$40) the generator is dispatched to 100MW, meaning it has kept its initial holding.

Similarly, if a generator with no TA allocated in the scaling stage wishes to *buy* 50MW if the clearing price is lower than \$25, it will offer 50MW at \$75. The possible outcomes are:

- if the local price is <\$75 (and so the clearing price > \$25) the generator is *not* dispatched, has 0MW after the auction, meaning it has bought nothing;
- if the local price is >\$75 (meaning clearing price<\$25) the generator is dispatched to 50MW, meaning it has purchased 50MW at the auction.

In general, by submitting several price bands, a generator can indicate what quantity it wishes to buy or sell at different clearing prices.

Suppose that each generator, i, is allocated Q_i of TA (at its local node) in the TA scaling stage and, after the auction, its holding is R_i. Thus if $R_i>Q_i$ it has purchased TA at the auction and if $R_i<Q_i$ it has sold TA. R_i cannot be less than zero, meaning that a generator cannot sell more into the auction than it was issued at the TA scaling stage.

Q and *R* are both dispatch outcomes, which must be feasible on the transmission network. They are different, because the TA offer prices are different. *Q* is based on the tapered offer prices described in the previous section; *R* is based on offer prices submitted by generators, as described above. However, they must both obey the critical flowgate constraints and so:

$$\sum_i \alpha_{ik} \text{ X } Q_i \leq FGX_k$$

$$\sum_i \alpha_{ik} \text{ X } R_i \leq FGX_k$$

Now, the payment by each generator into the auction is the quantity purchased multiplied by the clearing price:

$$Pay\$_i = (R_i - Q_i) \times (RRP - P_i) \qquad (12.17)$$

[165] In practice, each generator would submit conventional bids or offers and these would be converted into TA offer prices in the auction process.

Recalling the formula for local price:

$$P_i = RRP - \sum_k \alpha_{ik} \times FGP_k \qquad (12.18)$$

Equation (12.17) becomes:

$$Pay\$_i = (Ri – Qi) \times \sum_k \alpha_{ik} \times FGP_k \qquad (12.19)$$

Where the FGPs are the flowgate prices determined in the *R* dispatch.

Aggregate payments into the auction are determined by summing equation (12.19) across all generators:

$$\begin{aligned} \text{Total Pay\$} &= \sum_i Pay\$_i \\ &= \sum_i \sum_k \{(R_i \times \alpha_{ik} \times FGP_k) - \sum_i \sum_k (Q_i \times \alpha_{ik} \times FGP_k)\} \\ &= \sum_k FGP_k \times \{\sum_i \{(R_i \times \alpha_{ik}) - \sum_i (Q_i \times \alpha_{ik})\} \end{aligned}$$

Now, flowgate prices are only greater than zero if the relevant constraint is binding: so

$$FGP_k > 0 \text{ implies } \sum_k (Ri \times \alpha_{ik}) = FGX_k$$

Therefore:

$$\text{Total Pay\$} = \sum_k \{FGP_k \times [FGX_k - \sum_i (Q_i \times \alpha_{ik})]\} \qquad (12.20)$$

Now, because the Q dispatch is feasible:

$$\sum_i (Qi \times \alpha_{ik}) \le FGX_k$$

Therefore, the difference term in equation (12.20) is never negative and, since flowgate prices are also never negative:

$$\text{Total Pay\$} \ge 0$$

That is to say, total payments made by purchasers in the auction will always equal or exceed total payments made to sellers. There will be a surplus only if one or more flowgates that are binding in the R dispatch are not binding in the Q dispatch. If the same set of constraints is binding in both dispatches, then the surplus will be zero and the auction will clear. To the extent that there is a surplus, this could be passed to demand-side users via a TNSP: similar to the SRA arrangements.

12.7 Entitlement Scaling

12.7.1 Overview

Section *4.2 Access Settlement Design* qualitatively describes the process for setting target and actual entitlements on flowgates. The sections below provide a mathematical description of this process, together with numerical examples. A further section describes the entitlement allocation process when generators are grouped.

12.7.2 Target Entitlements

Entitlement targets are based on the decomposition of agreed access into three components:

$$A_F = \min(AA, Avail)$$

$$A_{NF} = \max(Avail-AA, 0)$$

$$A_{SF} = \max(AA-Avail, 0)$$

where the subscript:

F refers to the firm access component

NF refers to the non-firm access component

SF refers to the super-firm access component

and:

A = access component

AA = agreed access amount

Avail = generator availability

Note that the algebra ensures that:

$A_F + A_{NF} + A_{SF} = \max(AA, Avail)$

$A_F + A_{NF} = avail$

$A_F + A_{SF} = AA$

Note also that access components are non-negative and that A_{NF} and A_{SF} cannot both be non-zero.

The *entitlement target* for each component is calculated by multiplying the access component by the generator's participation factor for the relevant flowgate:

$ET_F = \alpha \times A_F$

$ET_{NF} = \alpha \times A_{NF}$

$ET_{SF} = \alpha \times A_{SF}$

where:

α = flowgate participation factor

ET is the entitlement target

Note that:

$$ET_F + ET_{NF} = \alpha \times A_F + \alpha \times A_{NF} = \alpha \times (A_F + A_{NF}) = \alpha \times Avail \qquad (12.21)$$

A numerical example is provided in Table 12.2 below to illustrate the target setting process. Note that each generator belongs to a different access category.

Table 12.2 Calculation of Target Entitlements

Generator	Nodal Values					α_i	Flowgate Values		
	AA	Avail	A_F	A_{NF}	A_{SF}		ET_F	ET_{NF}	ET_{SF}
A (firm)	500	500	500	0	0	0.3	150	0	0
B (part-firm)	300	500	300	200	0	0.8	240	160	0
C (super-firm)	800	500	500	0	300	0.6	300	0	180
D (non-firm)	0	500	0	500	0	0.8	0	400	0
Total							*690*	*560*	*180*

The targets represent the *maximum* entitlements that generators will be allocated. In practice, one or more components will always be *scaled back*, through the entitlement scaling process described in the next section.

12.7.3 Actual Entitlements

For a flowgate to be congested, there must be the *potential* for total flowgate usage to be greater than flowgate capacity. Recall that flowgate usage is:

$$U_i = \alpha_i \times G_i \qquad (12.22)$$

where:

U_i = flowgate usage of generator i

G_i = dispatch output of generator i

For congestion, there must be some possible set of generator outputs, G_i, such that:

$$\sum_i (\alpha_i \times G_i) = \sum_i U_i > FGX \qquad (12.23)$$

Now since dispatched output can be no higher than availability:

$$\begin{aligned} \sum_i ET_{Fi} + \sum_i ET_{NFi} &= \sum (\alpha_i \times Avail_i) && \text{(from equation (12.21))} \\ &\geq \sum (\alpha_i \times G_i) && \text{(since } Avail_i \geq G_i\text{)} \\ &> FGX && \text{(from equation (12.23))} \end{aligned}$$

Therefore, if a flowgate is congested, it is not possible to allocate all generators their firm and non-firm target entitlements and some scaling back is always required.

Entitlement scaling is based on the principles:

- total actual entitlements must equal flowgate capacity;
- a single *firm scaling factor* is applied to all firm and super-firm entitlements, and a single *non-firm scaling factor* is applied to all non-firm entitlements;
- firm entitlements are only scaled back when non-firm actual entitlements have been scaled back to zero; and
- super-firm actual entitlements are only provided to the extent necessary to offset the scaling back of firm entitlements: ie the sum of firm and super-firm actual entitlements is no higher than the firm target entitlement.

The formulae for determining actual entitlements, based on target entitlements, are presented in Table 12.3, below.

Table 12.3 Formulae for actual entitlements

Symbol	Meaning	Calculation
k_F	firm scaling factor	using a goal seek algorithm
k_{NF}	non-firm scaling factor	$k_{NF} = (FGX - \sum EA_F) / \sum ET_{NF}$
EA_F	actual firm entitlement	$k_F \times ET_F$
EA_{NF}	actual non-firm entitlement	$k_{NF} \times ET_{NF}$
EA_{SF}	actual super-firm entitlement	$\min\{ET_F - EA_F, k_F \times ET_{SF}\}$
EA	actual (total) entitlement	$EA_F + EA_{PF} + EA_{SF}$

To illustrate these formulae numerically, actual entitlements are calculated, from the targets presented in Table 12.2, under two different scenarios:

- *scenario one*: low flowgate capacity; FGX=522
- *scenario two*: high flowgate capacity; FGX=802

These outcomes are presented in Table 12.4, below.

Table 12.4 Actual entitlements under two capacity scenarios

	Target Entitlements			Actual E: scenario 1 k_F=0.6; k_{NF}=0				Actual E: scenario 2 k_F=1; k_{NF}=0.2			
Generator	*Firm*	*NF*	*SF*	*Firm*	*NF*	*SF*	*All*	*Firm*	*NF*	*SF*	*All*
A	150	0	0	90	0	0	90	150	0	0	150
B	240	160	0	144	0	0	144	240	32	0	272
C	300	0	180	180	0	108	288	300	0	0	300
D	0	400	0	0	0	0	0	0	80	0	80
Total	*690*	*560*	*180*	*414*	*0*	*108*	*522*	*690*	*112*	*0*	*802*

In scenario 1, flowgate capacity (=522MW) is less than the aggregate firm target entitlements (=690MW). Therefore, since firm entitlements must be scaled back, no non-firm entitlements are provided. Note that generator C does not have its entitlements scaled back by as much as generator A does, because of the contribution from super-firm components

In scenario 2, no scaling back of firm entitlements is necessary and so some non-firm entitlements are provided.

Note that total firm and non-firm target entitlements equal 1250MW, meaning that if flowgate capacity exceeded 1250MW there would be no congestion.

12.7.4 Grouping

Where generators are grouped, the entitlement scaling process proceeds as follows:

1. *Calculate generator targets*: target generator entitlements are calculated as described in section *12.7.2 Target Entitlements* above.
2. *Calculate group targets*: group entitlements are calculated, based on the aggregate target entitlements of the group members.
3. *Calculate group actuals*: actual group entitlements are allocated, using the process described in section *12.7.3 Actual Entitlements* based on group, rather than generator, target entitlements.
4. *Calculate generator actuals*: group entitlements are allocated between members, using a similar algorithm to that used for allocating flowgate capacity between groups.

Steps 2 and 4 are described further below.

To avoid confusion between groups, generators and group members, it will be assumed in the discussion below that *every* generator belongs to a group.[166] A group can have just a *single* member, so generators in such groups will have entitlements determined exactly as described previously.

Entitlement targets for a group are defined as follows. First, the *summed entitlement targets*, *SET*, are calculated: these are simply the sum of the generator target entitlements across all of the generators in a group:

$$SET_{Fg} \equiv \sum_{i \epsilon g} ET_{Fi}$$

$$SET_{NFg} \equiv \sum_{i \epsilon g} ET_{NFi}$$

[166] Note that no generator is permitted to belong to more than one group.

$SET_{SFg} \equiv \sum_{i \in g} ET_{SFi}$

$SET_g \equiv \sum_{i \in g} ET_i = SET_{Fg} + SET_{NFg} + SET_{SFg}$

where:

$\sum_{i \in g}$ means the summation is across all generators, i, belonging to the group, g

Next, the group entitlement targets, GET, are defined in terms of the SETs according to the four equations below:

$$GET_{Fg} \equiv SET_{Fg} + \min(SET_{NFg}, SET_{SFg}) \quad (12.24)$$

$$GET_{NFg} \equiv SET_{NFg} - (GET_{Fg} - SET_{Fg}) \quad (12.25)$$

$$GET_{SFg} \equiv SET_{SFg} - (GET_{Fg} - SET_{Fg}) \quad (12.26)$$

$$GET_g \equiv GET_{Fg} + GET_{NFg} + GET_{SFg}$$

Table 12.5, below, illustrates the calculation of group targets using the generators from the example in the previous sections. It is assumed that generators B and C have joined together to form a group. Generators A and D each remains ungrouped: ie each is the sole member of a group.

Table 12.5 Calculation of group entitlement targets

Group	SET_F	SET_{NF}	SET_{SF}	SET	GET_F	GET_{NF}	GET_{SF}	GET
Gen A	150	0	0	150	150	0	0	150
Gens B and C	540	160	180	880	700	0	20	720
Gen D	0	400	0	400	0	400	0	400
total	690	560	180	1430	850	400	20	1270

The algebra ensures that the group targets for the single-member groups are the same as for the corresponding individual generators. Recall that a generator cannot have both its non-firm or super-firm targets greater than zero and so $\min(SET_{NF}, SET_{SF})=0$ for a single-member group. Therefore, from equation (12.24), $GET_F=SET_F$. Correspondingly, from equations (12.25) and (12.26), respectively, $GET_{NF}=SET_{NF}$ and $GET_{SF}=SET_{SF}$.

It will be seen that the group firm target for the two-member group (700MW) exceeds the summed target (540MW): 160MW of the super-firm entitlement of generator C has been pooled and “converts” the non-firm target of generator B into a firm target. In a sense, generator C is lending its surplus access to generator B, who has an access shortfall. In general, for grouping to be beneficial, at least one generator in the group must have a non-firm target and at least one must have a super-firm target: meaning that $\min(SET_{NFg}, SET_{SFg})>0$.

The group targets feed into the algorithm described in the previous section to determine group actual entitlements, with the following changes:

- group entitlement targets, GET are used instead of generator targets, ET;
- group actual entitlements are calculated instead of generator actual entitlements.

The group entitlements are calculated for the same two scenarios as in the previous section and are presented in Table 12.6, below.

Table 12.6 Group actual entitlements under two scenarios

	Target Group Entitlements			Actual E: scenario 1 k_F=0.6; k_{NF}=0				Actual E: scenario 2 k_F=0.93*; k_{NF}=0.0			
Group	*Firm*	*NF*	*SF*	*Firm*	*NF*	*SF*	*All*	*Firm*	*NF*	*SF*	*All*
A	150	0	0	90	0	0	90	138	0	0	138
B & C	700	0	20	420	0	12	**432**	645	0	18	**664**
D	0	400	0	0	0	0	0	0	0	0	0
Total	*850*	*400*	*20*	*510*	*0*	*12*	*522*	*784*	*0*	*18*	*802*

(*) Figures in this scenario are rounded; scaling factor to 2 decimal places and MW to 0 decimal places.

Compare the results in Table 12.6 with those for the ungrouped case in Table 12.4. It is seen that the scenario 1 results are similar: the grouping has had no apparent effect; the group entitlement for the B&C group (432MW) is just the sum of the previously calculated ungrouped entitlements (144MW+288MW). This is because, in the ungrouped case, the super-firm target is fully utilised and so converting it into a firm target (through the grouping process) has no effect: the scaling of the firm and the super-firm targets is the same.

However, there is a large impact from grouping in scenario 2. The grouped entitlement (664MW) now exceeds the sum of the ungrouped entitlements in Table 12.4 (272MW + 300MW = 572MW). Because, in the ungrouped case, the firm targets were not scaled back, the super-firm target had no value. In the grouped case, the super-firm target allows generator C's non-firm target to be "converted" into firm. The increase in the aggregate firm target means that firm must now be scaled back slightly (k_F=0.93) and non-firm is scaled back to zero. The firm scaling means that generator A is allocated a slightly lower entitlement than in the ungrouped case. The non-firm scaling means that the non-firm generator D now gets zero entitlement, compared to 80MW in the ungrouped case. (Of course, flowgate capacity is the same as before, so if B and C are to have an increased allocation, A and/or D must have a reduced allocation.)

The group actual entitlements in the single-member groups are simply allocated directly to the member generator. In multi-member groups, the allocation works exactly as in the flowgate allocation described in section *12.7.3 Actual Entitlements* except that:

- the allocation is only between the group members rather than between all generators; and
- only the group actual entitlement is allocated, rather than the full flowgate capacity.

Table 12.7, below, shows how the entitlement for the B & C group (the numbers in bold in Table 12.6) is allocated between generators B and C in the two scenarios.

Table 12.7 Allocating group entitlements between members

	Target Entitlements			Actual E: scenario 1 k_F=0.6; k_{NF}=0				Actual E: scenario 2 k_F=1; k_{NF}=0.77			
Generator	*Firm*	*NF*	*SF*	*Firm*	*NF*	*SF*	*All*	*Firm*	*NF*	*SF*	*All*
B	240	160	0	144	0	0	144	240	124	0	364
C	300	0	180	180	0	108	288	300	0	0	300
Total				*324*		*108*	*432*	*540*	*124*		*664*

The entitlements for B and C in scenario 1 are identical to the ungrouped situation (refer Table 12.4). In scenario 2, in the ungrouped situation, B and C were allocated 272MW and 300MW, respectively (again, refer Table 12.4). When grouped, Generator B's situation is unchanged, because the super-firm target it lent to Generator C does not affect Generator B's allocation: it would have received no super-firm allocation anyway. However, the lending has substantially improved Generator C's position.

12.7.5 Group Agreements and Free Riding

C gains the most benefit from pooling in the above example because it has a low level of agreed access relative to its availability. Within a group, an internal group agreement would typically require that each member of the group procured an agreed access amount proportionate to its needs, to prevent any generator free riding. For example, it might be that B and C had each agreed to procure access equal to 50% of their *registered capacity*. B only appears to have procured a relatively low amount because it has a relatively high availability in the *snapshot* that has been analysed, as illustrated in Table 12.8, below.

Table 12.8 Ratios of access to capacity and availability

Generator	Capacity	Agreed Access	Availability in Snapshot	Access/ Capacity	Access/ Availability
B	600	300	500	50%	60%
C	1600	800	500	50%	160%

In another settlement period, C might have a high availability compared to B, meaning that B would be the main beneficiary of pooling in that period.

12.8 TNSP Planning and Operations under the Firm Access Standard

12.8.1 NOC1 FAS Obligation

As described in section *5.2.4 FAS Implications for Flowgate Capacity*, a TNSP is required to ensure that, at each NOC1-tagged congested flowgate:

$$\text{Effective Flowgate Capacity} \geq \sum \text{target firm entitlements}$$

Effective flowgate capacity is the RHS of a flowgate constraint, adjusted to include flowgate support. It is therefore determined by three factors:

- transmission capacity;
- local demand;[167] and
- the dispatch of flowgate support generation.

The target firm entitlement for a generator is defined by the formula:

$$\text{target firm entitlement} = \min(\text{agreed access, availability}) \times \text{participation factor}$$

This is the level of flowgate usage for the generator when it is dispatched at the lower of its agreed access and availability.

Consider a dispatch study set up as shown in Table 12.9 below.

[167] As discussed in section *12.2.3 Transmission Capacity versus Flowgate Capacity*.

Table 12.9 Dispatch Study for analysing NOC1 Obligation

Generation Side	Demand Side
Dispatch of firm generation at lower of agreed access and availability	Supply forecast nodal demands
Dispatch of an assumed level of flowgate support generation	Balance of demand located at RRN

The balance of demand is included at the RRN to ensure that total generation equals total demand. That balance could be positive or negative.[168]

If that dispatch is feasible, that implies that no transmission constraints that would be placed on the dispatch are violated: since otherwise a change to the dispatch would be required. The form of those constraints would be:

$\sum$target firm entitlement – flowgate support ≤ flowgate capacity

Meaning that:

$\sum$target firm entitlement < effective flowgate capacity

Therefore, a *sufficient* condition for a TNSP meeting its FAS obligation under Tier 1 NOC (when the FAS scaling factor is 100%) is that the dispatch of generation described in Table 12.9 is feasible and secure on its transmission network.

This load flow condition is *sufficient* but not *necessary*. The FAS only requires that sufficient flowgate capacity is provided at *congested* flowgates, whereas the load flow condition ensures sufficient capacity at *all* flowgates. If a TNSP could be confident that a particular flowgate would *never* be congested, it would not explicitly need to maintain capacity on that flowgate.

In particular, the adding of balancing demand at the RRN is liable to cause congestion – in the load flow study - *locally* to the RRN which could never arise in practice. Such congestion can safely be ignored by the TNSP.

12.8.2 Scenario Analysis

The load flow described above depends upon assumptions on:

- nodal demands;
- availability of firm generation; and
- dispatch of flowgate support generation.

Therefore, this load flow condition would need to be checked under a range of conditions, such as:

- high and low demand levels;
- high level of firm generator availability; and
- low level of flowgate support.

Where low levels of flowgate support created problems in meeting the load flow condition, a TNSP may have to enter into network support agreements with the relevant generators.

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168 Adding a negative demand is equivalent to adding generation at the node.

12.8.3 Tier 2 and higher Normal Operating Conditions

Under a NOC tier 2 or above, the FAS scaling factor reduces the level of effective flowgate capacity required. This can be modelled in the load flow by scaling back the assumed dispatch of firm generation correspondingly, based on the formula:

Firm generator dispatch level = min(assumed availability, FAS scaling factor x agreed access)

That will cause reduced flows on all flowgates, not just those affected by the assumed conditions (eg outages) causing the higher tier NOC. However, on the flowgates unaffected by the outage, the tier 1 FAS requirement applies and this has already been verified by the load flow described previously and does not need to be checked again. Therefore, the scaled-back dispatch study is used simply to check flowgate capacity on those flowgates that are *affected* by the outage.[169]

Checking the FAS requirement under every possible combination of events that could create the particular NOC tier would obviously be impractical. However, typically in transmission networks there are worst-case events that drive planning and operation: eg outage of a particular heavily loaded line in a weak part of the network. So long as there is sufficient transmission capacity to accommodate the subset of worst-case events, it can generally be assumed that FAS will be met under the remaining event combinations that have not been explicitly checked.

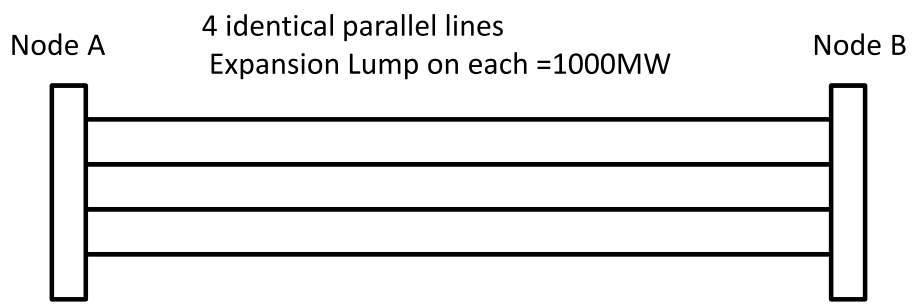
12.8.4 Summary

Monitoring and managing FAS obligations under a wide-range of operating conditions is likely to be challenging for a TNSP. It is important, therefore, that TNSPs are provided with a learning period before significant financial penalties are imposed for FAS breaches. This is what has been proposed in section *9.2 Transition Design*.

12.9 Meshedness in Access Pricing

As discussed in section *6.2 Access Pricing Design* a meshedness factor is applied to transmission lumpiness in the access pricing model. This is to reflect the fact that, in a heavily meshed part of the network, lumpiness of transmission expansion is less relevant and so effective lumpiness is lower. This effect is illustrated in Figure 12.8 below.

Figure 12.8 Lumpiness and meshedness



Because the four lines are identical and the access pricing model considers each element separately, the model will schedule expansion of all four lines at the same time, meaning that the total transmission capacity between the two nodes is increased in lumps of 4000MW. Clearly, it is more realistic to model expansion of this capacity at 1000MW at a time, which is achieved by setting the effective lumpiness of each individual line at 250MW. In general, the pricing model defines lumpiness as:

[169] Ie those flowgates who constraint equations have changed as a result of the outage: eg to reflect the change in network topology.

lumpiness = expansion lump / meshedness

In the figure, the expansion lump is 1000MW and the meshedness is 4, meaning that each line is assumed to have lumpiness of 250MW.

That *meshedness=4* in the example is apparent, but how should meshedness be determined in a general situation? It will be seen, for the simple example network, that if 100MW is injected in at node A and withdrawn at node B, then a 25MW flow is generated on each line. The ratio of the injection to the line flow gives the line's *meshedness* (100/25 = 4). This formulation can be applied to meshedness for all network topologies, ie:

meshedness = (MW of injection and withdrawal at each end of the line)/(lineflow)

The higher the meshedness, the more alternative paths there are, or the higher the admittance of these alternative paths relative to the line admittance.[170] It is straightforward to calculate meshedness on general network topologies using this definition.

12.10 Annual Payment Profiling

12.10.1 Overview

As discussed in section *6.2.4 Payment Profiling Algorithm* there will be a need to specify an algorithm for converting the lump-sum access charge calculated by the access pricing methodology into a stream of annual access payments which, at a specified discount rate, have an NPV equal to the calculated lump sum.[171]

The algorithm would specify the *default* payment profile; customisation of this payment would be permitted in accordance with the TNSP's customisation policy.

Regulatory issues associated with the payment profiling are discussed in section *8.3.2 TNSP Risk from Lumpy Access-Driven Expansion Costs*. In that section it is noted that risks arise from differences between the payment profile and the profile of carrying costs of regulated assets that is applied under revenue regulation. The risk is borne by the TNSP in the first regulatory period of the access agreement and borne by demand-side users in subsequent regulatory periods. Risks can be mitigated by minimising these differences. This objective is considered and applied in this section.

12.10.2 Revenue Regulation and Carrying Costs

Under the building block approach to determining regulated revenue, the allowed annual revenue associated with an asset in the Regulatory Asset Base (RAB) is:

$$\text{Real Revenue} = \text{WACC} * \text{DRC} + \text{D} \qquad (12.27)$$

where:

WACC is the *real* regulated rate of return for the TNSP

DRC is the depreciated replacement cost for the asset

D is the annual depreciation

The depreciation schedule is typically *straight-line* over the asset life and the DRC is generally approximated by the historical asset cost (in real terms). These assumptions are used in the discussion below, although it would be possible to adopt different assumptions.

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[170] Admittance is a measure of how easily power flows through a line.

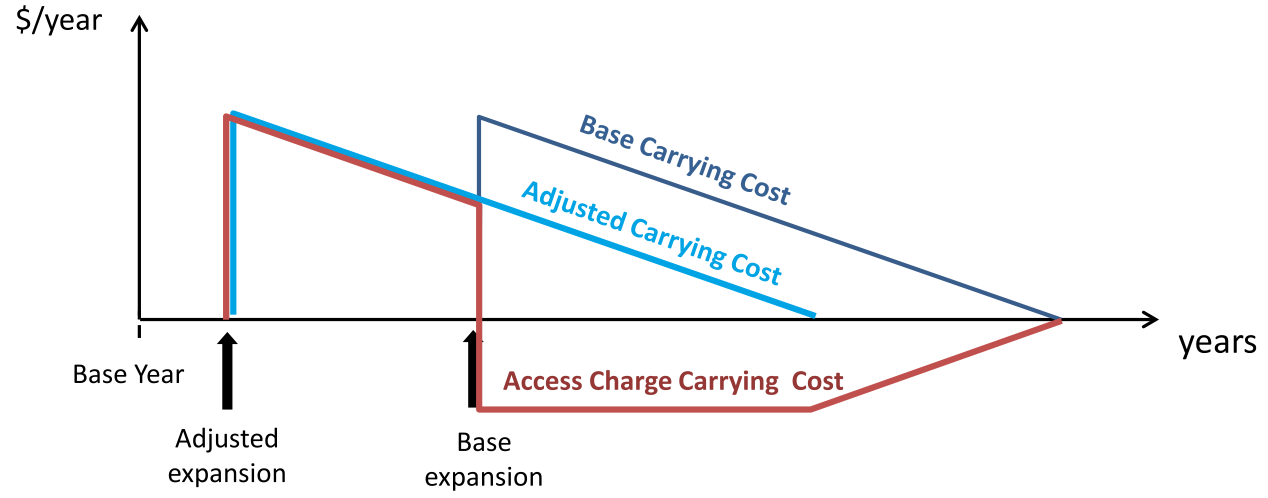
[171] The discount rate would probably be based on a forecast of regulated WACC.

An expansion plan in the access pricing methodology is a set of expansions on the shared network, with each expansion taking place at a defined time and for a defined capital cost. The annual carrying cost of each expanded asset can then be determined by applying equation (12.27) and these costs can be summed across all assets in the expansion plan to give an annual carrying cost for the plan.

The LRIC methodology calculates the access charge as the difference in NPV between two expansion plans: the adjusted expansion plan and the base expansion plan. Thus, an annual carrying cost for the access charge can be determined by taking the difference between the annual carrying cost for the adjusted plan and that for the baseline plan.

An example of this is illustrated in Figure 12.9, below, in relation to a very simple access charge that is based on the advancement of a single planned expansion.[172]

Figure 12.9 Example of access charge carrying costs



Since the NPV of the carrying cost of each asset in each plan equals the NPV of the capital cost, by aggregation the NPV of the access charge carrying cost equals the access charge lump-sum. That equivalence makes the carrying cost a possible annual payment profile. However, it is clear from Figure 12.9 above that such a profile would be unacceptable. It would imply high positive charges in the early years followed by negative charges (ie rebates) in later years. Given the long asset life, the rebates could continue for years – decades in fact – after the end of the access agreement.[173]

Nevertheless, this analysis does illustrate how the costs for a TNSP in providing access might be substantially *front-ended*: ie occurring primarily at or near the start of the access agreement.[174] Ideally, the payment profile should endeavour to reflect this front-ending, whilst avoiding the problem of annual rebates being required after the end of the agreement.

Since it is discrepancies in the *first* regulatory period which are most problematic (since these affect the risk-averse TNSP) a possible approach would be to set annual payments equal, in NPV terms, to annual carrying costs in in the first regulatory period, and then base them on a conventional straight-line repayment plan for the remaining years of the agreement, in order to provide the correct NPV in aggregate. Such a profile is illustrated in Figure 12.10, below, for the simple access

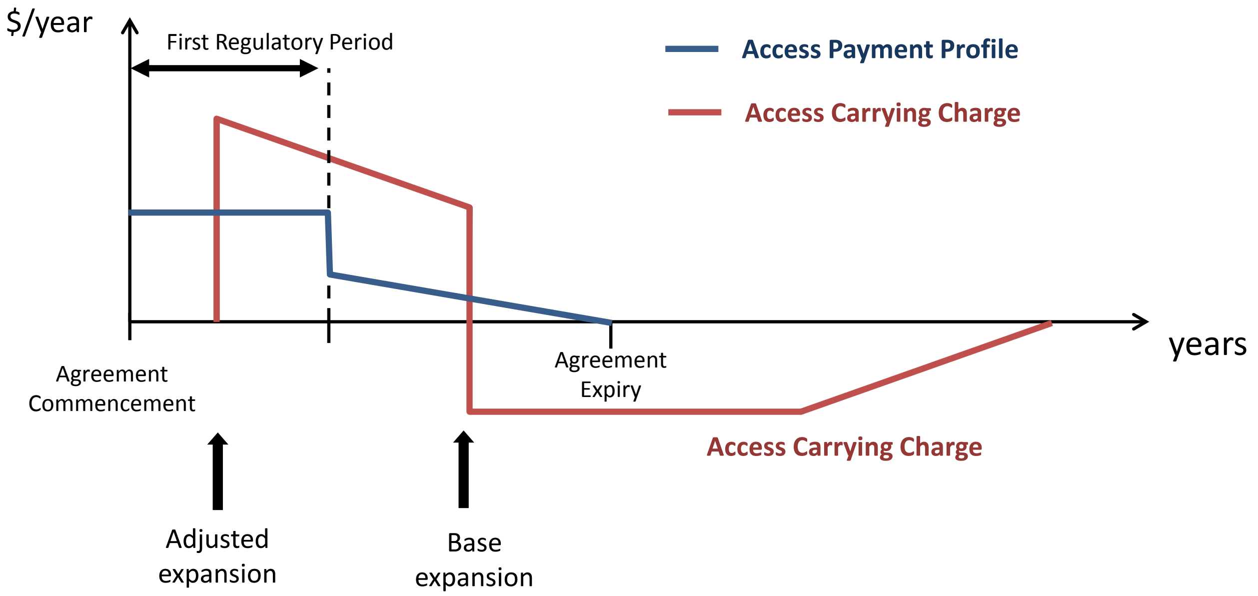
[172] There could be many other expansions in the plans, but if the timing of expansions is the same in the two plans, their carrying costs will cancel out.

[173] In practice the rebates would continue until the year in which the two plans *converged* following the expiry of the access agreement.

[174] This will not always be the case: if there is substantial spare capacity, for example, any advanced expansion may not occur until many years after agreement commencement.

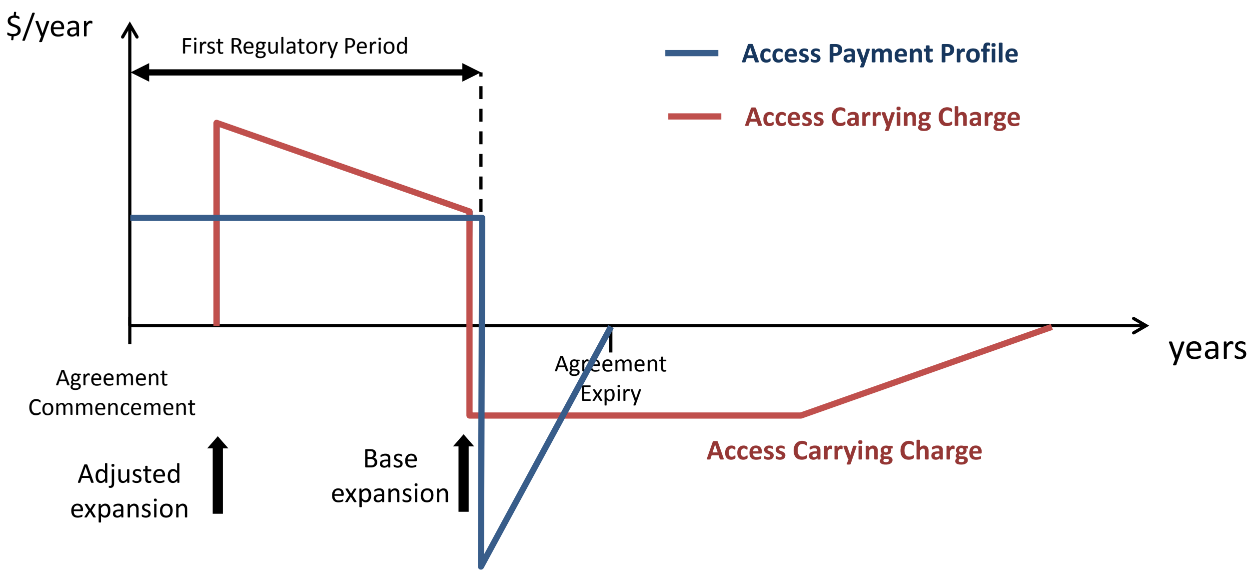
charge described in the previous figure: in the figure, the NPV associated with the payment profile during the first period is equal to the NPV associated with the carrying charge.

Figure 12.10 Possible access payment profile



However, this payment profile may not be reasonable if the NPV of carrying costs after the first regulatory period is negative, since this would mean *overcharging* for access in the first regulatory period and then *rebating* this overcharge subsequently. This situation would arise in the example shown in Figure 12.11, below, which is the same as the previous example, except that the first regulatory period is twice as long.

Figure 12.11 An impractical access payment profile



12.10.3 Indexing of Annual Payments

The revenue formula provided in equation (12.27) is in *real terms* and so the revenue allowance is indexed by CPI. Any annual payment profile based on carrying costs would similarly be defined in real terms and indexed by CPI.

In the revenue formula, WACC is adjusted on each regulatory reset. Correspondingly, any payment profile would be indexed by WACC. The payment profile would be defined by a *repayment profile*, R, from which the annual payment is determined using the formula:[175]

$$PAY_t = (AC - CR_t) \times WACC_t + R_t$$

where:

AC is the lump sum access charge

WACC is the regulatory WACC applying in year t

R_t is the repayment amount in year t

CR_t is the cumulative repayment for year t

$CR_0 = 0$

$CR_t = CR_{t-1} + R_t$

$R_1 + R_2 + \ldots + R_T = AC$

Year T is the final year of the access agreement

The repayment profile, R, could be set in order to keep the TNSP whole in the first regulatory period, as discussed in the previous section. However, leaving that objective aside, any repayment schedule could potentially be applied, using the formula above.

[175] The formula may change slightly, depending upon whether payments are made at the start or end of each year.

OFA Model Glossary

Defined Term	Meaning
access	*network access*
access charge	a charge payable by a generator to its local TNSP in return for receiving firm access
access settlement	a new AEMO settlement process in the OFA model through which *access-long* generators receive payments and *access-short* generators make payments
access-long generator	(for a *generator*) being dispatched at a level below its *access* level, thus entitling it to payments from *access settlement*
access-short generator	(for a *generator*) being dispatched at a level above its *access* level, thus obliging it to payments into *access settlement*
agreed access (amount)	the nominal amount of access specified in an *firm access agreement*, which may vary between peak and off-peak periods
abnormal operating condition	a transmission operating condition specified as an abnormal operating condition in the firm access standard
availability	for a conventional generator, the offered availability; for an intermittent generator, the Unconstrained Intermittent Generation Forecast
capacity shortfall	the difference in a settlement period between *target flowgate capacity* and actual *flowgate capacity* when the latter is less than the former
congested flowgate	a *flowgate* whose capacity is fully utilised in dispatch and which is causing dispatch to be constrained
constrained off	(for a *generator)* dispatched below its *preferred output*; a firm, constrained-off generator will typically be access-long and so entitled to payment from access settlements
constrained on	(for a *generator)* dispatched above its *preferred output*
deep connection cost	the immediate (but not future) incremental costs to a TNSP associated with providing additional firm access: ie only including those costs that must be incurred *prior* to access commencement.
directed interconnector	an *interconnector* in a specified direction: ie northerly or southerly
dispatch access	the right to be dispatched in NEM dispatch at a specified MW level in accordance with a dispatch offer and paid the local price on dispatched output
effective flowgate capacity	the amount of capacity that is allocated between *generators* in the entitlement scaling algorithm; equals the *flowgate capacity* plus the *flowgate support* plus the *TNSP support*
embedded generator	a distribution-connected *generator*
exporting region	the region from which a *directed interconnector* withdraws power
firm access (service)	a transmission service provided to generators that have a *firm access agreement* with their local TNSP, up to the level of the *agreed access* amount

Defined Term	Meaning
firm access agreement	an agreement between a TNSP and a generator which specifies the service parameters for the provision of *firm access* service
firm access level	(for a *generator*) the lower of the generator's *agreed access* and *availability*
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 a *firm access agreement* and an *agreed access amount* equal to its availability
firm interconnector	an *interconnector* for which AEMO holds some *agreed access* in trust
firm interconnector right	a right to receive a specified proportion of the IRSR proceeds of a *firm 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 RHS of the corresponding NEMDE transmission constraint
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 LHS of the corresponding NEMDE transmission constraint
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
flowgate support	the aggregate, absolute *flowgate usage* of *flowgate support* generators
flowgate support generator	(with respect to a *flowgate*) a *generator* with a *participation factor* less than zero
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	a power station, or the generating company responsible for the power station, depending upon the context
generator node	the transmission node at which a *generator*, or the distribution network used by an *embedded generator*, connects to the shared transmission network
hybrid flowgate	a *flowgate* in which *generators* and *interconnectors* both participate
importing region	the region into which a *directed interconnector* injects power
interconnector	a notional entity that is dispatched by NEMDE to transfer power from one RRN to a neighbouring RRN across a regulated interconnector
inter-regional access	network access provided to a directed interconnector, from the RRN in the exporting region to the RRN 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 RRP between two neighbouring regions
inter-regional settlement residue	the fund, held in trust by AEMO, into which, or from which, settlement payments relating to *directed interconnectors* are paid
intra-regional access	*network access* provided to a *generator*, from its *generator node* to the *RRN* in its *local region*
local region	(of a generator or access agreement) the region in which the relevant generator node is located
local price	the marginal value that a generator at a node provides to economic dispatch; the locational marginal price
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
network access	the right to be paid in AEMO settlement the difference between RRP and LMP for a specified MW level
non-firm access	the access received by generators that do not have an *firm access agreement* and so do not receive a *firm access service*
non-firm access level	(for a *generator*) the difference between *availability* and *agreed access amount,* when the former takes a higher value
non-firm generator	a generator without a *firm access agreement.*
normal operating condition	a transmission operating condition specified as a normal operating condition in the firm access standard
part-firm generator	a generator with a *firm access agreement* and an *agreed access amount* less than its availability
preferred output	the quantity of a *generator's* availability that is offered at or below the RRP
regional price	the price paid to a dispatched generator in regional settlement; the Regional Reference Price
reliability access	the peak-time access provided to a *reliability generator*
reliability generator	a *non-firm generator* who nevertheless receives peak-time access as a result of a TNSP expanding transmission to meet a *demand-side reliability standard*
remote region	a region other than the *local region*
service parameters	values contained in an *access agreement* specifying *access amount*, term, location and so on.
settlement residue auction	the auction through which AEMO sells SRA rights

Defined Term	Meaning
SRA right	the right to receive a specified proportion of the *inter-regional settlement residue* for a specified *directed interconnector*
super-firm access level	(for a *generator*) the difference between *agreed access amount* and *availability,* when the former takes a higher value
super-firm generator	a generator with a *firm access agreement* and an *agreed access amount* greater than its availability
target firm entitlement	(for a *generator* on a *congested flowgate*) the product of the *firm access level* and the *participation factor*
target flowgate capacity	the minimum amount of *flowgate capacity* that a TNSP must provide on a congested flowgate to comply with FAS
target non-firm entitlement	(for a *generator* on a *congested flowgate*) the product of the *non-firm access level* and the *participation factor*
target super-firm entitlement	(for a *generator* on a *congested flowgate*) the product of the *super-firm access level* and the *participation factor*
TNSP support	(at a flowgate) the absolute value of the negative *flowgate entitlement* allocated to TNSPs pursuant to a financial quality incentive regime
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

Abbreviations

Abbreviation	Meaning
AARR	Aggregate Annual Revenue Requirement
AEMO	Australian Energy Market Operator
AFMA	Australian Financial Markets Association
AOC	Abnormal Operating Condition
CPI	Consumer Price Index
DNSP	Distribution Network Service Provider
DSRS	Demand-side Reliability Standards
FAS	Firm Access Standard
FG	Flowgate
FGP	Flowgate Price
FGX	Flowgate Capacity
FIR	Firm Interconnector Right
FTR	Fixed Transmission Right
IRH	Inter-regional Hedge

Abbreviation	Meaning
IRSR	Inter-regional Settlement Residue
LHS	Left-hand Side
LMP	Local Marginal Price
LRIC	Long Run Incremental Cost
LRMC	Long Run Marginal Cost
MP	Market Participant
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NOC	Normal Operating Condition
NPV	Net Present Value
NTP	National Transmission Planner
OFA	Optional Firm Access
RHS	Right-hand Side
RRN	Regional Reference Node
RRP	Regional Reference Price
SRA	Settlement Residue Auction
TA	Transitional Access
TFR	Transmission Frameworks Review
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
UIGF	Unconstrained Intermittent Generation Forecast
WACC	Weighted-average Cost of Capital

Algebraic Variables used in Equations

Variable	Meaning
A	access level
C	marginal generating cost
E	flowgate entitlement
F	forward quantity
FGP	Flowgate Price
FGX	flowgate capacity
FP	forward price
G	dispatched output
IC	dispatched interconnector flow

Variable	Meaning
LMP	local marginal price
Pay$	Settlement Payment. Positive value means payment *from* AEMO settlement
RRP	regional reference price
U	flowgate usage
α	flowgate participation factor