Snowy Hydro

Transmission Frameworks Review Submission

10 October 2012

Executive Summary

The Optional Firm Access (OFA) proposal represents the most radical and fundamental change to the structure of the NEM since its inception in 1998. This highly complex model has the potential to change quite radically the incentives, behaviours and risk profiles faced by many market participants. If implemented, it will have far reaching impacts.

Given the significant nature of the proposal, it should only be considered for implementation if:

- There is a widely accepted serious and material failing of the current market design that needs to be addressed, and
- The OFA proposal clearly and unambiguously resolves this failing and does not have material unintended consequences.

Our analysis concludes that the OFA proposal meets neither of these two criteria. The theoretical problem that the proposal is intended to solve is in practice likely to be imposing minimal economic costs. In other words, the potential benefits from the implementation of the proposal—if it works as intended—are small.

At the same time, its direct implementation and operational costs will be significant. While the OFA concept has been outlined at a high level, there are many questions of detail and implementation that require resolution. More importantly, there are strong reasons to believe that the proposal—even when matters of detail are fully elaborated—would lead to unintended consequences, which would likely reduce the already low benefits and impose additional costs.

We conclude that it is difficult to find circumstances under which the benefits of the proposal would outweigh its costs.

What's the Problem?

The claimed benefits of the OFA proposal are that it will facilitate greater co-optimisation of generation and transmission investment, provide greater locational signals to new generators, reduce access encroachment of existing generators by new entrant generators, and reduce disorderly bidding.

This paper shows that:

- The benefits of greater co-optimisation of generation and transmission investment are likely to be small. We review the 10,000 MW of generation investments undertaken in the NEM during its existence. We find it is difficult to conclude that significant investment is in demonstrably inefficient locations—given other factors such as access to low cost and secure fuel supplies—or have led to inefficient transmission investment. To put it another way, there is no reason to believe that—had OFA been in place—a different set of locational choices would have been made, resulting in lower combined transmission and generation investment
- A study in New Zealand by the Electricity Authority (EA) that found the benefits of greater co-optimisation to be negligible—that is zero. The EA concluded that most transmission investment was driven by reliability needs and most generation locational decisions driven by access to secure and low cost fuel.
- Access encroachment of existing generators by new entrant generators may be efficient and indeed expected in a competitive market, even if it perceived as a material problem for the generators concerned. It is not widespread or pervasive and such events are usually transient—although the timescale for resolution may be longer than desired by the affected parties, and
- In regard to disorderly bidding, there is little consensus amongst participants and policy makers as to how to value the economic damage caused by disorderly bidding. Previous studies have concluded it is not a major problem, and in any event the OFA proposal may change incentives for generators to bid disorderly, but may not necessarily reduce those incentives in total.

Is OFA the Solution?

Rather than minimising the joint cost of transmission and generation, OFA may lead to additional, inefficient new investment in the transmission system. This is because if OFA is to make any difference, it must induce investment in transmission that would not currently pass Regulatory Investment Test—Transmission (RIT-T).

The RIT-T is a standard economic test that ensures that reliability investments are the least cost option and investments with market benefits only proceed if the net market benefits are positive—that is the benefits outweigh the costs. There is little evidence that the RIT-T is fatally flawed and is preventing projects with net economic benefits from proceeding. As profit maximising Transmission Network Service Providers (TNSP) should be actively researching possible projects that might pass the RIT-T in order to benefit from their construction, it is unlikely that the RIT-T is not achieving its objectives and that viable projects exist but aren't being implemented.

Thus, if OFA is implemented and the transmission system is augmented to provide firm access to generators, those augmentation projects, by definition, cannot be welfare enhancing for the market as a whole. If they were, the RIT-T would ensure that they would already be built and paid for by customers and not by individual generators. Such access projects may be privately beneficial or may be funded by generators as a defensive response to avoid the uncertain and unpredictable risk of being liable for compensation if they remain non-firm.

Further the OFA proposal materially increases the risks of the TNSPs. This is because they will become the compensator of last resort when firm generators are constrained and the compensation pool from non-firm generators is inadequate. Given this risk, the TNSPs approach to access augmentation projects will be highly risk averse—they will overbuild to the extent they can to minimise the risk of compensation. Again the result will be that the transmission network will become less efficient.

Our analysis shows that existing generators will have strong incentives to rush to secure firm access, once any transitional or grandfathering period elapses. They will likely do this for two reasons:

- First as a defensive measure to avoid liability for compensation if adjacent generators choose to become firm and they do not, and
- Second they should—under the long run incremental cost (LRIC) approach suggested—be able to secure the historical level of access that they currently enjoy for little or no cost.

The LRIC methodology to price access will lead to very complex negotiations between transmission companies, generators and the Australian Energy Regulator (AER), and will require an agreed long term baseline transmission development plan to calculate the incremental costs of access. The AER will be heavily involved in this process as customers paying the regulated transmission prices will bear the costs and risk of the inevitable mismatches between the LRIC prices recovered from generators and the actual cost of access augmentations.

Our analysis also shows that OFA is likely to have a negative impact on the level of contracts offered by generators and on disorderly bidding. In both cases, OFA may redistribute the incentives to offer contracts or bid at other than cost but it will not materially alter those incentives. This is because under the OFA, access is neither physically nor financially completely firm.

There are many unresolved issues and questions surrounding this proposal. In general we haven't commented on or analysed those ambiguities. While we acknowledge that the ambiguities may be fixed, the required solutions are likely to add to the cost and complexity of the proposal and are unlikely to reduce its serious economic failings—that is, that it will result in a materially less optimised and less efficient transmission system investments.

Finally we suggest that while the issue of access encroachment for existing generators is material and significant for the affected parties, it is does not appear to be an endemic and pervasive problem in the context of the entire NEM. The arguments for firm access to prevent encroachment have more to do with considerations of equity than market efficiency. If a solution is required, it should be more targeted—not a fundamental change to the entire market design.

In summary, the OFA proposal is a complex and wide ranging solution to a number of smaller scale problems—problems that may yield only small benefits to the overall market if solved—and it's not clear that OFA will do so. The cost of solving these problems will be high—both in terms of unwanted and unintended side effects and the significant implementation and operational costs.

1 Introduction

The AEMC's Transmission Frameworks Review was commissioned by the Ministerial Council on Energy (MCE), now the Standing Council on Energy and Resources (SCER) with the objective of undertaking a comprehensive review of the fundamental elements of transmission frameworks with a view to identify arrangements that will lead to cost efficient outcomes for consumers.

This submission considers the costs and benefits of the Optional Firm Access (OFA) regime. Under this proposal, generators will have the option of contracting for firm access—that is guaranteed ability to dispatch in the event of a transmission constraint—rather than the current open access arrangements.

The Commissions' view is that there are likely to be benefits from fundamental changes to generator access and that this review "represents a turning point in the evolution of the NEM".

Before contemplating such a fundamental change we need to ask:

- What problems will the implementation of the OFA proposal solve, how material are those problems and is there evidence that they may get worse in the future? In other words is the current transmission investment framework materially suboptimal?
- Is the implementation of the OFA proposal likely to solve the problems identified and thus lead to a more optimal outcome—that is, will the wide-ranging changes in the incentives and behaviours that the proposal will create for TNSPs and generators lead to or be likely to lead to the better achievement of the National Electricity Objective?
- Does the OFA proposal clearly and unambiguously solve the identified problems without unintended consequences—that is, do the benefits from solving the identified problems outweigh both the costs of implementation and the impact of new problems that may result?

In this submission we:

- Define the problem or problems that the OFA proposal is intended to solve and analyse the likely magnitude of those problems. The problems suggested include potential deficiencies in the co-optimisation of transmission and generation investment, access encroachment for existing generators and disorderly bidding—Section 2
- Assess whether the current transmission investment framework has led to sub-optimal outcomes, including whether the current Regulatory Investment Test-Transmission (RIT-T) is flawed. We also assess whether OFA is really optional for generators—Section 3; and
- Analyse the likely effectiveness of the OFA proposal. We look at whether it is possible to effectively manage both firm and not firm generators with different rights within a single, common meshed network. We analyse the issues that will inevitably arise from the mix of regulated and contractual revenue streams for TNSPs and from the proposed long run incremental cost pricing—Section 4.

2 Problem definition

The AEMC characterise the question of generator access as being one of co-optimisation of generation and transmission investment—that is, creating investment and use incentives so that the lowest combined costs are achieved. The AEMC states that efficient outcomes are:

> *….likely to occur where the combined costs of generation and transmission are taken into account in investment and operational decisions for both generation and transmission, leading to lower costs overall.*

In the current framework, generators make new investments based on their own commercial considerations and TNSPs make transmission investments based on the regulatory test (RIT-T) on the basis of the least cost option to meet reliability standards plus any market benefits. The AEMC's concern appears to be that as these are separate processes, investors in new generation may make sub-optimal locational decisions that will require inefficient and unnecessary transmission investment.

However a number of stakeholders in submissions and presentations characterise the problem differently—they see the problem as new generators encroaching on the access of existing generators.

Both groups see the OFA proposal as playing a role in reducing "disorderly" bidding.

The AEMC, in the Technical Report Optional Firm Access also see the OFA proposal as addressing a plethora of generation side transmission issues including inter and intra-regional planning standards, TNSP investment and operating incentives, and congestion management.

In this section, we attempt to define and quantify the related but separate issues of co-optimisation, access encroachment and disorderly bidding as well as the wider scope of transmission issues claimed to be addressed by the OFA proposal.

2.1 Co-optimisation of generation and transmission

In ideal circumstances, there is no doubt that new investment in generation and transmission should be co-optimised to ensure that new generation capacity needed for the market is provided at the lowest combined cost of the generation and any associated transmission works.

Prior to the NEM, there was—at least theoretically—a high degree of co-optimisation through the central planning process. Investment decisions were made by the monopoly government owned businesses that had responsibility for both generation and transmission. These integrated monopolies could then make least cost decisions that encompassed both generation and transmission costs. However, even under central planning there were other influences on investment decisions in addition to least costs. Aside from overtly political influences, central planners were influenced by considerations such as the need to diversify fuel supplies or other system security considerations, such as the benefits of geographic diversity of the transmission system from power stations to loads.

In the NEM, power station investments decisions are devolved to individual investors, but transmission investment is still largely centralised—albeit on a firmer "least cost" basis in that there is greater transparency of transmission investment decisions and a high degree of oversight by the Australian Energy Regulator (AER).

The AEMC has suggested that there is therefore the potential for sub optimal investment decisions to be made as the old central planning process is now split between individual powers station investors and the TNSPs.

To analyse the extent of this potential problem, we look at:

- What factors influence generation locational decisions?
- What locational signals already exist?
- What evidence is there that enhanced locational signals are needed or would be beneficial?

What factors influence generation locational decisions?

The key locational driver for generation investment decisions is availability of a secure, long term and low cost fuel supply. For some types of generation such as wind and hydro it is almost the main driver as generators can only be built where there is an appropriate wind or water resource. Thermal generators such as coal or gas have a greater choice in that the fuel is transportable, but all else being equal, such generators would prefer to locate as close as possible to the fuel source. This is less so for gas generators as gas transmission costs are usually less than electricity transmission costs. Thermal generator locational decisions are also influenced by access to cooling water—particularly for coal fired generators. Obtaining planning consents for a power station site may also be a factor.

Since the start of the NEM in 1998, there has been over 10,000 MW of new generation—see Table 2.1.

Table 2.1: New Generation Capacity in the NEM—1998 to 2012

Region	Power Station	Owner	Date	Fuel Type	Capacity MW	Comments
QLD	Callide C	Callide JV	2001	Black Coal	900	Mine mouth power station
QLD	Millmerran	Intergen	2003	Black Coal	852	Mine mouth power station
QLD	Kogan Creek	CS Energy	2007	Black Coal	734	Mine mouth power station
NSW	Colongra	Delta	2009	OCGT	696	Adjacent to gas pipeline, old power station site
NSW	Uranquinity	Origin	2009	OCGT	652	Gas supply from NSW and Victoria
QLD	Darling Downs	Origin	2010	CCGT	618	Adjacent to transmission—supplied by 200 kilometre gas pipeline
VIC	Mortlake	Origin	2012	OCGT	536	Adjacent to transmission—supplied by 80 kilometre gas pipeline
QLD	Braemar 2	Arrow	2009	OCGT	507	Adjacent to transmission—supplied by 80 kilometre gas pipeline
QLD	Braemar 1	Braemar	2006	OCGT	470	Access to gas supply
SA	Pelican Point	International Power	2000	CCGT	461	Located close to load
QLD	Tarong North	Tarong	2002	Black Coal	443	Mine mouth power station
NSW	Tallawarra	Truenergy	2009	CCGT	441	Old power station site adjacent to gas pipeline
QLD	Swanbank E	CS Energy	2002	CCGT	360	Old power station site
VIC	Laverton North	Snowy Hydro	2006	OCGT	320	Located to minimise transmission constraints
QLD	Oakey	ERM	1999	OCGT	304	Access to gas supply

VIC	Valley Power	Snowy Hydro	2002	OCGT	303	Adjacent to existing power station
QLD	Yabula	AGL	2005	OCGT	240	Supports load in North Queensland
TAS	Tamar	Aurora Energy	2009	CCGT	208	Adjacent to major loads
SA	Quarantine	Origin	2002	OCGT	207	Access to gas supply
SA	Hallet	AGL	2002	OCGT	201	Access to gas supply
QLD	Colinsville	RATCH	1998	Black Coal	187	Supports load in North Queensland
SA	Lake Bonney	NP Power	2008	Wind	159	High quality wind resource
QLD	Yarwun	Rio Tinto	2010	Cogen	156	Waste heat utilisation
NSW	Redbank	Redbank Projects	2001	Black Coal	148	Located at source of fuel—mine tailings
VIC	Somerton	AGL	2002	OCGT	148	Received network support payments
VIC	Bogong	AGL	2010	Hydro	140	Located at existing dam site
QLD	Condamine	BG	2009	CCGT	135	Adjacent to fuel source
TAS	Bell Bay 3	Aurora Energy	2006	OCGT	120	Old power station site

From AER State of the Market and AEMO Statement of Opportunities reports

For all the coal fired power stations access to low cost coal and perhaps cooling water appear to have been key drivers as all are located adjacent to low cost coal resources. While this may have necessitated additional investment in transmission infrastructure, it is likely that overall the benefits of the low cost fuel would ensure a high degree of co-optimisation.

For the gas fired power stations, there is a trend to locate adjacent to major transmission lines with short gas pipelines to the gas source—logical as, all else being equal on an energy basis, transporting gas is usually lower cost than transporting electricity. In other words, as investors must bear the cost of extending the transmission system to their fuel source—given that there aren't transmission lines at the gas field—they are choosing the least cost solution by transporting the gas to a location with good transmission access.

Uranquinity Power Station may not be ideally located from the electricity transmission viewpoint, but its location may have more to do with its location on the gas pipeline linking NSW and Victoria—it can readily source gas from both markets. The location of Somerton and Laverton power stations appear to have been driven largely by electricity transmission considerations—that is there appears to have been a deliberate choice to locate in transmission rich areas, again suggesting a high degree of co-optimisation has been achieved from existing locational signals. We understand that Somerton received some revenue benefit from avoided transmission costs.

An important factor is the re-use of existing power station sites—logical as there is already transmission access and planning approvals may be less problematic. Colongra, Tallawarra and Swanbank E have all been constructed on existing sites where generation has been de-commissioned.

Examination of the new generation investments made in the NEM does not show any obvious examples where the increased locational signals proposed under OFA would have materially altered the locational decisions made by investors. While there may be debate about some individual power stations, there is no clear trend towards demonstrably inefficient locations—given other factors such as access to low cost and secure fuel supplies—or have led to inefficient transmission investment. To put it another way, there is no reason to believe that—had OFA been in place—a different set of locational choices would have been made, resulting in lower combined transmission and generation investment.

What locational signals already exist?

New generation investors already face a number transmission related locational signals. In considering the costs and benefits of the OFA, it is important to be clear about the degree of marginal strengthening of the current locational incentives.

Firstly as investors must pay the cost of any extensions needed to connect them to the transmission grid, they have strong incentives to locate close to existing infrastructure. The possibility of being constrained off and the higher loss factors that apply to highly loaded segments of the transmission system also should be regarded as powerful location signals.

The possibility of being constrained off is real and significant for new investors. Unlike many other markets, there is a high cost to enter the generation market—the investment of hundreds of millions if not billions of dollars on the power plant. No rational investor would build in an area where they are likely to be subject to constraints on their access to the transmission network and thus the regional reference price (RRP). The high fixed costs of investment ensure that few if any generators are built with the aim of displacing existing generators from the market. Even if the new generator has a lower SRMC than all existing generators and thus will always be dispatched first, then the excess of capacity created by their market entry will result in low prices and the new generator will not recover their LRMC—unless competing generators exit the market.

This suggests that the existing locational signals—particularly the probability of having access constrained—is a powerful incentive to locate in "access rich" parts of the network.

It also suggests that once located, it would be unusual for that access to be constrained by further new generators deliberately locating in the area to compete over the limited access.

Would enhanced locational signals be beneficial?

Given that other factors such as access to a reliable supply of low cost fuel and cooling water for thermal generators or high quality wind or water resources for renewable generators are significant drivers of power station location, the benefits of further co-optimisation incentives for transmission and generation may not be great.

The New Zealand Electricity Authority (EA) conducted a study of the benefits of co-optimisation of generation and transmission in July 2010[1]. The EA modelled two cases:

- A base case where locational price signals played no role in the choice of generation location and the consequent investment in grid upgrades or their timing. That is, the least cost generation options were built regardless of the interconnection costs necessitated by those private generation investment decisions; and
- A co-optimised case where cost reflective locational price signals influenced generation location decisions and grid upgrade decisions. This second stage

[1] *Transmission Pricing Review: Stage 2 Options*, Electricity Commission, July 2010

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was intended to simulate the outcome of having a pricing regime that results in co-optimised transmission and generation investment.

The difference in the total combined generation and transmission costs between the two cases was taken to be the estimate of the benefit of co-optimisation.

The difference in NPV terms was NZ$14 million compared to the NPV of total costs over the 31 year study period of NZ$19 billion. In regard to these results, the EA stated:

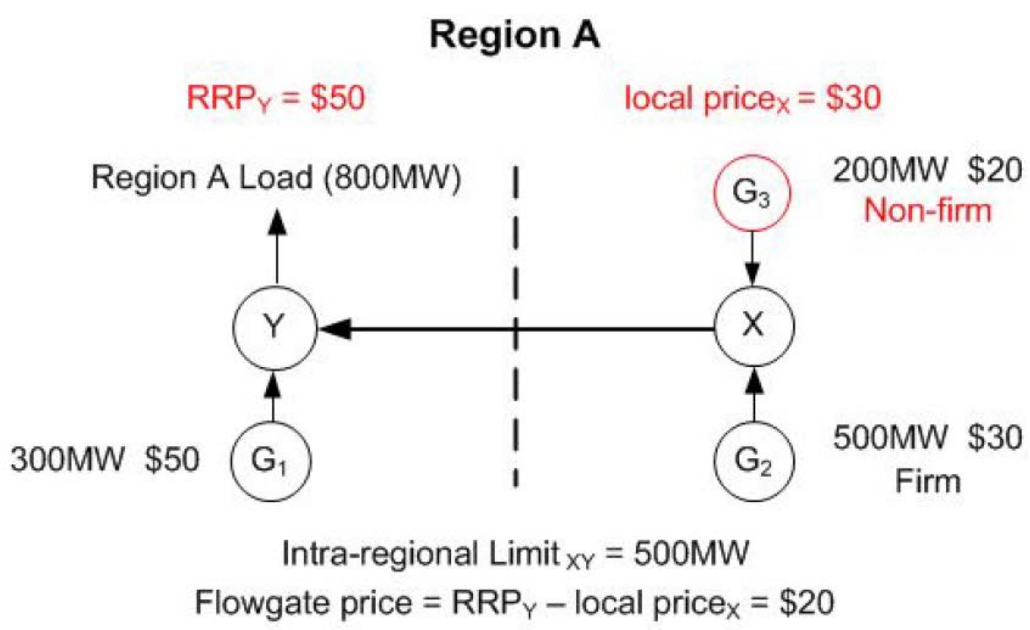
> *These results suggest the benefit from full locational signalling is very low. In fact, given the margin of error associated with estimating the input parameters for the modelling, it is reasonable to interpret the $14m benefit as being zero.*

Overall, the EA concluded:

> *The Commission's analysis to date suggests that there may be little benefit to locational signals for generators when considering options for transmission investment for solely economic reasons, given the current grid and generation patterns and likely generation and transmission expansion scenarios.*
>
> *The Commission considers that these results reflect the fact that remote generation investments are likely in the short to medium term to be driven more strongly by other factors than transmission costs; factors such as fuel costs, fuel availability, and resource consents.*

The EA analysis found that the overwhelming driver for transmission investment over the 31 year period was to meet reliability standards. This is entirely logical. Moreover, such reliability driven investment almost always relieves any transmission constraints. A simple example is seen by considering the Commission's simple example of a flowgate constraint shown in Figure 2.1.

Figure 2.1: Flowgate Constraint



Source: from Box 3.3, *Transmission Frameworks Review Second Interim Report*, AEMC, August 2012

If the load in Region A increases above 800 MW, then in the absence of additional generation locating on the load side of the flowgate, a transmission upgrade to add capacity to the flowgate is the next lowest cost option. And, of course, if we take the bid prices of the generators shown as indicative of their marginal costs, a new generator of significant size would only locate on the downstream side of the flowgate if their short run marginal cost was lower than at least G_1.

Obviously, care must be taken in extrapolating the results of a New Zealand study to the NEM. The New Zealand transmission system is stringier than Australia's and the generation mix is quite different. Nevertheless, the study does illustrate that the benefits of further co-optimisation in Australia may well be small as:

- Fuel cost and availability as well as other location specific factors are the key drivers of generation locational decisions; and
- The need to meet reliability standards in the face of growing demand is the major driver of transmission investment.

Concern has been raised that as the nature of generation in the future is changing—that is greater investment in renewable and low carbon generation—that co-optimisation problems may be more likely. We suggest the reverse might well be the case as the location of those future generators will be more strongly tied to fuel resources, particularly for wind, hydro, biomass and geothermal generation. This means that the drive to find low cost fuel resources, such as highly prospective wind farm sites, will likely outweigh transmissions costs. We also note that future generation is likely to be smaller in scale and more distributed than the current generation mix built largely under a central planning model. We do not see another power station of the scale of Bayswater or Eraring being contemplated. This too will lessen transmission system impacts.

2.2 Access encroachment

Generators, however, say that the problem with access is new entrant generation causing constraints and reducing the access of existing generators. For example International Power states:

> *In the NEM, generator access levels are become increasingly uncertain as transmission network utilisation increases and the frequency and intensity of congestion grows.*[2]

This is a quite different problem to co-optimisation and one that may require a different solution. At least on a theoretical level, if a new entrant generator locates in an area with existing generators and, through having a lower short run marginal cost, displaces those generators by encroaching on the access they previously had then this may well be efficient, co-optimised and welfare enhancing. It does of course reduce competition in the generation market and by treating generation as a sunk cost may reduce investor confidence.

In other circumstances discriminatory charges levied on new entrants to preserve the market share of incumbents might be seen as anti-competitive. In the current open access regime, it is competition—that is the level of generator bids—that broadly determines access in most circumstances. This is entirely appropriate in a competitive market. Access to markets is not sacrosanct—for example owners of existing assets in

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[2] International Power Australia, *Submission to the AEMC Transmission Frameworks Review*, 29th September 2010

other markets such as shopping centres, can do little to prevent a competitor locating nearby.[3]

In many ways it is a decision for policy makers—is market efficiency enhanced by protecting existing generators from competition "for the market" and thus allowing them to focus on "competition in the market"? Generators seeking regulatory change to allow firm access are doing so largely on the grounds of equity rather than market efficiency.

As Table 2.1 shows, the lack of any firm access for generators and the potential for encroachment of their current level of access by new entrants has not prevented some 10,000 MW of new generation—representing an investment in the order of some $15 billion—being constructed.

However, there have been existing generators that have had access reduced through the arrival of new entrants. Some examples include:

- International Power's gas turbines at Snuggery (78MW) facing increasing constraints from several wind farms constructed in the area
- At times of high Victorian demand when Loy Yang B, Loy Yang A and Valley Power are generating and Basslink is flowing into Victoria, transmission congestion arises and access is rationed to manage congestion; and
- The 855 and 871 lines in Central Queensland where transmission constraints result in generators such as Callide and other Southern Generation being constrained.

These constraints are acknowledged to have a material impact on the access of the generators involved. However, for many of the existing constraints, there are reliability-driven transmission investments in train that have the potential to mitigate their impact:

- For the constraint impacting Snuggery Power Station, ElectraNet have released a Project Assessment Draft Report for consultation in accordance with the requirements of the Regulatory Investment Test – Transmission (RIT-T).[4] The PADR recommends a preferred option for investment to increase the transfer capability of the South Australia to Victorian (Heywood) Interconnector to deliver a net market benefit through significant reductions in generation dispatch costs over the longer term. The preferred option to install a third transformer and 500 kV bus tie at Heywood in Victoria, plus other works including reconfiguration of the 132 kV. The estimated commissioning date for this option is July 2016; and
- For the 855/871 lines constraint, PowerLink has commenced the construction of the Calvale to Stanwell 275 kV line augmentation, which will increase the supply capability between Central West Queensland and North Queensland. The proposed commissioning date of this additional 275 kV line is summer 2013/14, as stated in Powerlink's Annual Planning Report 2011.

This demonstrates that many of the constraints impacting generation access are transient in nature. There have been previous examples of such constraints, for example at Tarong and Armidale that have caused material generation constraints in the past but now no longer exist.

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[3] Except, perhaps, to influence planning processes to ensure competing developments do not proceed.

[4] *South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T: Project Assessment Draft Report*, ElectraNet and AEMO, September 2012.

It is axiomatic that reliability driven transmission investments will tend to reduce generation constraints and cannot increase them. Examination of the simple flowgate model at Figure 2.1 shows that in the absence of any generator locating on the downstream side of the flowgate, an augmentation of the flowgate transfer limit is the only option that can meet increased demand on the downstream side of the flowgate. It is also clear that while a generator locating on the downstream side of the flowgate will not reduce the constraints faced by the upstream generators, it clearly cannot increase them.

Of course, the fact that these constraints are transient and will tend to be built out by reliability driven transmission augmentation projects does not lessen the impact on the generators involved. However, it is not clear that under the OFA proposal the situation would be any better for two reasons:

- The approval processes—both for regulatory approval and planning consents for transmission lines as well as the time required for construction means that major augmentations are a lengthy process; and
- The complex OFA negotiations between the impacted generators, the TNSP and the AER will not shorten this process. We discuss this later in Section 4.3.1.

Even under the current rules, there are options for generators affected by emerging constraints caused by new entrants. The affected generators could lobby their TNSP to undertake a RIT-T analysis of solutions and we understand that this has in fact occurred. There is also the possibility of using Clause 5.4A—under which a generator can pay for enhanced access under the current Rules. This is the concept of a "funded augmentation"—that is an augmentation for which the TNSP receives revenue other than through the Chapter 6A regulatory process. The AEMC regards the Clause 5.4A process as unworkable as "the TNSP could not prevent other generators from connecting to the network and using capacity".

As an aside, many generator constraints are highly transient as they are caused by transmission outages—usually planned outages. It is likely that some of the impact of outages on generators could be mitigated if TNSP's had greater regulatory incentives to consider the market impact of outages.

Finally we suggest that while the issue of access encroachment for existing generators is material and significant for those generators, it does not appear to be an endemic and pervasive problem in the context of the entire NEM. The arguments for firm access to prevent encroachment have more to do with considerations of equity than market efficiency. Even if it were economically efficient to address this problem, it may well be more effectively done by a more targeted solution—not a fundamental change to the entire market design.

2.3 Disorderly bidding

Both the AEMC and the generators concerned about access encroachment consider that the OFA proposal has the potential to reduce disorderly bidding—that is generators behind a constraint bidding below their short run marginal costs to ensure dispatch and payment at the RRN price.

Valuing disorderly bidding or mispricing has been a contentious issue in the NEM for many years. The AEMC estimated that production costs across the NEM were $8 million higher for a mispricing scenario than in the base case in which all generators were assumed to bid their capacity at short-run marginal cost.[5] This represented less than 0.5 per cent of the total annual production costs of more than $1.7 billion. This, the AEMC stated showed that "the impact of constraints binding and causing inefficiency through mis-pricing was relatively low".

The have however been other estimates of a higher impact by other parties. They key issues in any such analysis from past bid behaviour is how to establish a credible counterfactual, coupled with the difficulty in determining the SRMC of a generator—what, for example, is the SRMC of a hydro generator or a thermal generator with a take or pay fuel contract?

Given the lack of an agreed methodology to value the problem of disorderly bidding—it is difficult to see the value of solving this problem through the OFA proposal as being anything but a peripheral benefit.

We also note that the OFA proposal may not in fact reduce incentives for generators to engage in disorderly bidding but merely shift them between firm and not firm generators. The AEMC claims that the OFA proposal will eliminate disorderly bidding.[6] They do so on the basis that OFA de-links access from dispatch. However, neither the physical access nor the financial compensation is actually firm under the OFA. Generators who have firm access are incentivised to bid below cost to increase compensation. We discuss this further in Section 4.3.2.

2.4 Other Transmission issues

The AEMC, in the Technical Report: Optional Firm Access, also see the OFA proposal as addressing a plethora of generation side transmission issues. The issues are:

- Generator transmission pricing
- Intra-regional planning standards
- Inter-regional planning standards
- TNSP investment and operating incentives; and
- Congestion management

This is shown in Figure 3.1 of that report.

There isn't much doubt that the OFA proposal will affect all of the above and force changes to the existing processes. There is far less certainty that these existing processes have problems or failings that can meaningfully be addressed by the OFA proposal, or if these are problems for which the OFA is the optimum solutions.

In regard to planning standards and TNSP incentives, we show in Section 4.3.1 of this report that TNSPs will be incentivised to set higher—and likely economically inefficient—standards as their incentives will be skewed by the likelihood that they will become liable for access compensation payments to generators if firm generators are constrained.

In regard to congestion management, the OFA proposal will either:

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[5] AEMC, *Final Report, Congestion Management Review*, June 2008

[6] Technical Report: Option Firm Access, Section 2.3.1

- Manage congestion in a different, but arguably no better way. In the current open access system, congestion is broadly managed by available capacity to generators on the basis of competitive bids in most circumstances. Under the OFA capacity is allocated by the amount generators are willing to pay for access—payments that are not necessarily economically efficient or pro competition, or
- Build out congestion without regard to the economic efficiency of doing so and with additional risk—that of compensation payments—being born by TNSPs and thus by customers.

2.5 Conclusions

The AEMC definition of the problem that OFA is intended to solve is not clear—is it co-optimisation of generation and transmission investment or is it protecting the access of existing generators? This lack of clarity is further highlighted by the AEMC's Figure 3.1 in the Technical Report: Optional Firm Access, which suggests that OFA is a solution to all generation side transmission issues. While, if implemented, it will certainly impact many of the areas claimed, it is not clear that there are wider problems to solve—or that OFA is the solution.

In regard to co-optimisation, the benefits from greater co-optimisation don't seem clear and compelling as factors such as the availability of low cost fuel is a key factor for generation locational decisions—not transmission—and there are already locational signals. Further, most transmission investment is motivated by the need to meet the reliability standards for loads and this tend to build out generation constraints as a natural consequence.

There is a problem that in some circumstances existing generators can have their access degraded by new entrants. In many respects this is a transitory problem as reliability motivated transmission investments tends to build out these constraints in time. In any event, it is not clear that adding the OFA negotiation processes to the existing quite lengthy regulatory and planning approvals process and construction time for transmission projects will result in speedier resolution. It is also not clear that access encroachment is inefficient in an economic sense although it may be viewed by impacted participants as an issue of equity.

Disorderly bidding does not appear to be sufficiently material to warrant a solution of the magnitude of the OFA proposal.

All of this may possibly change in the future as the impact of climate change policies change the nature of generation investment. However, renewable generation, such as wind, hydro and geothermal is highly locational specific and it is not clear that transmission locational signals will be a significant influence in locational decisions. Further, the nature of generation investment generally in the NEM is changing from the central planning approach that developed the bulk of existing pre 1998 generation to a more market driven and commercial focus. It is unlikely, for example, that in the future commercially financed projects will result in new generation investments of the size of Bayswater or Eraring Power Stations or the Snowy Scheme. This trend to smaller, more diverse projects will likely ease the requirements for associated transmission investments.

3 Is the current transmission network sub-optimal?

Investment in the transmission network is currently a regulated function with all major projects required to pass the Regulatory Investment Test—Transmission (RIT-T). The RIT-T is a conventional cost benefits analysis that ensures that:

- Transmission investments that are necessary to ensure that the TNSP maintains reliability and service standards for load are the least cost option taken on a whole of life basis; and
- Transmission investment that have market benefits such as increasing competition between generators or reducing deadweight losses proceed if those benefits outweigh the costs.

Transmission investment projects can also proceed on the basis of a combination of the least cost reliability option and market benefits.

The result is that the current transmission represents a constrained optimisation—that is the network meets current reliability standards at the least cost and constraints that cause generation to be dispatched at other than the least cost are built out—but only if there are net benefits to the market as a whole.

An unconstrained network—that is where all combinations of load and generation are simultaneously feasible is unlikely to be economic. The benefits of building out all constraints impacting on generators may not exceed the costs.

So we have constrained optimisation—if there are market benefits of relieving generator constraints then those projects should proceed under the current RIT-T.

Thus, fundamentally, if a generator choses the OFA option and contracts with a TNSP for firm access and the TNSP augments the network—then such augmentation cannot be efficient or welfare maximising. In fact, if a generator pays for access and causes some augmentation to the transmission system, this can only be because:

- There is a fatal and systemic flaw in the RIT-T such that projects with positive market benefits does not pass the test; or
- The generator receives private benefits that make the project attractive but overall there is a disbenefit to the market; or
- The generator decides to contract for firm access to avoid the cost and risk of making compensation payments to other firm generators—that is OFA isn't optional.

In this section we explore these three propositions that are necessary to understand why some generators wish to change the current constrained optimisation of the transmission system.

We conclude that the resulting transmission system under an OFA model will likely be higher cost and less efficient than the status quo.

3.1 Is the RIT-T flawed?

It is difficult to see that the RIT-T is so fatally flawed that it would prevent transmission projects with positive market benefits being constructed to relieve generator constraints.

The RIT-T itself is a standard economic cost benefit analysis. It has been amended and modified over time in response to shortcomings and issues that have arisen with earlier incantations. In regard to market benefits, it captures all possible economic benefits. It does not capture the wealth transfers that may occur as a result of transmission constraints. While this is correct from an economics viewpoint, from a policy maker's perspective, wealth transfers can be problematic if they are large and sustained. However, as shown in Section 2.1 many transmission constraints impacting generators are, at least in the medium term, transient as they are usually relieved by reliability driven investments.

The RIT-T process already includes a degree of generation and transmission co-optimisation. This is because the process obliges TNSPs to look at both network and non-network solutions as the least cost options to meet reliability standards. Non-network solutions can include network support agreements with generators, demand side participation and generation options. In regard to generation options, TNSPs are required to follow an open and transparent process to procure generation alternatives before moving to network augmentation. Since any generator responding to the process would be eligible for a revenue stream up to the avoided cost of the transmission augmentation over and above market revenues from the generation of energy, this provides a strong incentive for investors to locate in areas that will minimise future transmission costs. The fact that this has not occurred suggests that other factors such as access to secure and low cost fuel resources are more powerful commercial incentives to generation locational decisions by investors.

One criticism levelled at the RIT-T is that it is carried out by transmission planners who may not be responsive to market needs and thus projects with benefits aren't evaluated. This seems unlikely as profit maximising TNSPs will always be motivated to build any project that meets the RIT-T and thus allow them to achieve stable regulated returns on the investment. There shouldn't be any hesitation on the part of a profit maximising TNSP. In this regard it is ironic that in rule changes proposals before the AEMC the incentives offered for investment by TNSPs (and DNSPs) are being questioned on the basis that they are excessive and have led to over building and gold plating.

The RIT-T process is a transparent and public process involving several stages of consultation. This enables interested stakeholders such as generators subject to constraints related to the subject of any RIT-T analysis to makes submissions on the options proposed and the assumptions underlying such analysis and thus have some influence on the final specification of the chosen option. It also requires evaluation of non-network alternatives—that is generation.

Further, generators affected by transmission constraints are free to lobby TNSPs to conduct RIT-T analysis on options to relieve those constraints. While this isn't a formal right, we are advised that such discussions have taken place and upgrades have occurred as a result.

If the TNSP was unwilling to undertake the analysis, the generators could lobby the AEMC to exercise its Last Resort Planning Power (LRPP)[7]. Under this power the AEMC can direct a TNSP to undertake a RIT-T analysis of a transmission upgrade. In their guidelines to the exercise of this power, the AEMC noted:

> *The AEMC is mindful that interested stakeholders may wish to make the AEMC aware of matters that may be relevant to the exercise of the LRPP.*

And

[7] Clause 5.6.4 of the NER

> *While the AEMC is not bound to take action upon receipt of general information or adopt a suggested course of action, the AEMC considers that a free flow of information is in the public interest and wishes to encourage such input into its exercise of the LRPP.*

The LRPP applies to projects or problems that impact inter regional transmission only and this may limit its usefulness to impacted generators. However, some of the constraints commonly cited as impacting on generator access have some inter regional impacts and thus would be captured by the LRPP. We are not aware that any generator or other party has approached the AEMC suggesting that they exercise this power.

The current NER also has the concept of a "funded augmentation"—that is an augmentation of the transmission system not funded through the regulatory process. In theory, generators could use this option to pay for transmission works that would improve their access. The AEMC states that this option is unworkable—presumably on the basis that the generator would have no rights to the enhanced capacity as the TNSP could not prevent other new generators locating to take advantage of the additional capacity.

3.2 Private versus Public Benefits

If we accept that the RIT-T isn't fatally flawed and thus isn't precluding projects that have net market benefits, then a possible reason for generators to contract for firm access is that it enables them to capture private benefits.

This is because the RIT-T captures the ***net*** market benefits so any augmentation that relieves constraints and provides market benefits greater than its cost should be built. However, the distribution of the market benefits may vary—that is there may be a combination of some market dis-benefits and some benefits that fall unequally on various generators.

Hypothetically at least it may be that a transmission augmentation project might not provide net market benefits that are greater than the construction cost but might provide private benefits to an individual generator or subset of generators impacted that are greater than the cost and thus that generator (or generators) will be incentivised to fund the construction and capture those private benefits.

However, this means that projects funded by generators under the OFA proposal under these circumstances will result in the construction of upgrades where there are gross (private) benefits accruing to some generators but there may not be net market benefits.

In other words, the OFA proposal may result in projects being constructed that would not pass the RIT-T and thus not deliver net benefits to the market.

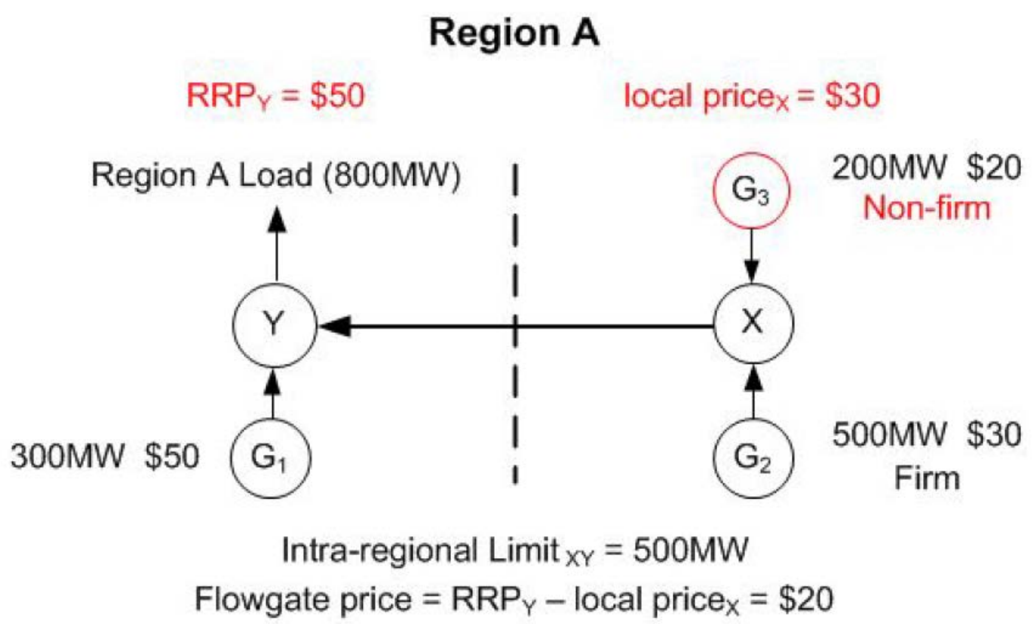
3.3 Is OFA Optional?

The AEMC, in the proposal in the discussion paper and at the seminar in Sydney, stress that contracting for firm access is optional—that is that generators are not required to contract for firm access. However, while this is true in a formal sense, the OFA proposal materially changes the risks of generators that do not contract for firm access. Thus those generators have no option—they must respond and manage the increased risks—either through changes to bidding behaviour or by themselves contracting for firm access.

This is because non-firm generators will become liable for compensation if other generators located on the same side of a constraint contract for firm access. This will completely change the risks and thus the bidding strategy of non-firm generators and expose them to unpredictable and unquantifiable compensation payments. The compensation payments could result in non-firm generators being unable to recover their LRMC—at the extreme, they may only be able to recover their SRMC.

A second reason for all generators to seek to become firm is the proposed generator access standards component of the OFA proposal. These standards apply only to firm generators and the TNSP has no obligation to provide access to non-firm generators. Thus in a flowgate with constraints, the first firm generator will simply be allocated firm access at the expense of non-firm generators.

Figure 3.1: Flowgate Constraint



Source: from Box 3.3, *Transmission Frameworks Review Second Interim Report*, AEMC, August 2012

In regard to liability for compensation, as shown in Figure 3.1, and assuming that the offer prices are representative of their SRMC, for the non-firm G3 if it continues to offer its output at $20, compensation of $20 will be payable to G2 leaving a contribution of only $10 towards fixed costs rather than the previous $30—the difference between G3's SRMC and the flowgate price of $20. At the extreme, if G2 decreases its offers to say $21, then G2's compensation liability will increase and it will then only be receive $21 leaving a contribution of $1 towards fixed costs. This reduction by G2 is possible as G2 is actually incentivised by becoming firm to make bids that do not reflect its costs—disorderly bidding—to increase its compensation. G2 does, if it adopts this strategy of reducing its bids, increase its risk of being dispatched at $21—below cost—if it is the marginal generator.

However, as long as there is a non-firm generator on their side of the flowgate, firm generators such as G2 can bid less than cost secure in the knowledge that the adjacent non-firm generators are now incentivised to bid at their SRMC—or higher—to minimise possible compensation payments.

The logical response thus for G3 is to also contract for firm access—not because it requires firm access but as a defensive response to G2 becoming firm and through that process being allocated all of the flowgate capacity—capacity that previously was shared between G2 and G3 in accordance with their bids and, at the extreme, in proportion to their capacity.

This creates an immediate issue for the OFA proposal—what happens if both G2 and G3 at the start of OFA request firm access from the TNSP? The key question is which generator is an increment to the other generator. Looking at Figure 3.1 it is clear that the first generator contracting for firm access can be given that access for zero incremental cost—assuming no projected growth. Either G2 or G3 can be given firm access as their individual capacities are less than or equal to the flowgate capacity. That capacity, of course, will come entirely from the other generator—that is, instead of being shared on the basis of the lowest cost bids, capacity will now be allocated to the first party contracting for firm access.

Thus, as soon as the OFA regime starts it would be entirely rational for both G2 and G3 to contract for access. This would have three effects:

- On the basis that requests for firm capacity on a common flowgate are dealt with simultaneously by the TNSP, the effect of both parties applying would have the effect of raising the cost of firm access ***to the other party***. In other words, the benefit of being allocated the available capacity for little or no cost that accrues to the first request for firm access would be negated. Essentially this would maintain the same competitive balance between the two generators and not allow one generator to gain a first mover advantage
- For both generators, contracting for access would eliminate the possibility of being required to pay compensation—in fact both would now be eligible to receive compensation; and
- The TNSP would upgrade the flow gate to now provide for at least 700 MW of capacity. In fact, the incentives on the TNSP would be to raise the capacity of the link above 700MW to ensure that in all circumstances neither G2 nor G3 would ever be constrained off from their respective contracted levels of access. This is because if G2 and G3 are both firm and either is constrained off, then the TNSP would be required to pay compensation.

The end result is that the TNSP would upgrade the link and recover the cost from the incremental payments for firm access that will be made by G2 and G3 in terms of their access contracts.

The customers—the region load of 800MW—would receive no benefit from this augmentation. They would receive an immediate disbenefit in that they would be required to pay the not insubstantial implementation and operations costs of the new OFA dispatch and compensation mechanism. Arguably as the competitive position of G2 and G3 has not changed it is possible that the costs of access—or some portion of it may be passed on to customers.

Even if this doesn't occur and the regional price remains set by G1 at $50, the impact of OFA would be:

- Customers lose as they meet the implementation and operations costs
- G1 loses as their dispatch is now reduced by 200MW. This may incentivise them to increase their bid price and recover some of this loss from customers
- G2 may win or lose in that they are now dispatched for an additional 300MW, less the price they paid for access; and

- G3 loses as they have paid for access that they otherwise would have obtained by having the lowest SRMC.

The overall result is that the market has become less efficient and investors in G1 and G3 will have reduced profitability—or they may maintain profitability if G1 is successful in passing on the losses associated with its reduced dispatch to customers.

A secondary impact is that the incentives for disorderly bidding have changed—but not necessarily been reduced. In the current scenario, in circumstances where both generators can be confident that G1 is the marginal generator and will set the regional price at $50, both G2 and G3 have the incentive to bid at the price floor of -$1,000 to ensure maximum dispatch. The flowgate capacity of 500MW would then be shared in proportion to the capacity that each offers.

Under the OFA proposal, with both G2 and G3 now firm, their incentive is to bid below cost in most circumstances as it will not impact the price they receive when dispatched, but if constrained will increase the compensation payable by the TNSP..

3.4 Conclusions

The current transmission investment test, the RIT-T has resulted in a broadly efficient balance for the overall market between investment and constraints.

It is difficult to conclude that the RIT-T has failed to identify possible projects that would result in net market benefits given the incentives on TNSPs to seek out projects that meet the RIT-T and the ability of generators impacted by constraints to lobby for such projects.

If implemented, therefore, the OFA proposal will likely result in access being contracted by generators either where there are private benefits (and an overall market disbenefit) or as a defensive response to increase competitors costs and avoid the cost and risk of compensation.

Both circumstances are likely to result in OFA projects that would not have met the requirements of the RIT-T and thus by definition will not be welfare enhancing and will lead to a less constrained but less optimised and higher cost system. OFA will also likely result in TNSPs over building augmentation projects that offer firm access as they may become liable for compensation in circumstances where all generators request firm access.

The OFA proposal will change, but not necessarily reduce the incentives for generators on the upstream side of constraints to engage in disorderly bidding.

4 Will it work and is it an effective solution?

4.1 Mix of firm and non-firm in a meshed system?

A key issue for the OFA proposal is whether it is possible to have a mix of firm and non-firm generation sharing a single meshed transmission network co-existing without interference.

The OFA proposal implicitly acknowledges that this isn't possible as non-firm generators are compelled to pay compensation to firm generators—essentially for no other reason than to create a revenue source for that compensation.

In the current open access model, scarce access is allocated between generators on the generally on basis of their costs as reflected in their bids. This isn't always the case and we recognise that there are exceptions and anomalies that may have quite serious financial impacts for individual participants. However, overall the current approach-despite its limitations has been relatively successful with the level of constraints being quite low. Under the OFA proposal, access will now be allocated differently both initially for existing generators and then for future new generators.

For existing generators, if as we suggest will be the case, most generators will initially apply to firm up their existing access rights through contracting for at least a similar level of firm access to that which they currently have been receiving on an open access basis, then the task of allocating and pricing the access sought will be complex and challenging. It will necessarily involve a great deal of subjectivity and may not be acceptable to all stakeholders. In effect the TNSPs will be forced to allocate the existing access equitably between the existing generators on the basis of sunk costs and not incremental costs. Generators will approach the issue with the not unreasonable viewpoint that under the existing arrangement they have enjoyed a certain level of access and thus there should not be a problem providing that level of access for minimal cost as the transmission system will not require augmentation.

Whatever process is used to decide how the existing access will be allocated amongst generators seeking firm access and how much they will pay, the process will inevitably impact on any remaining generators that have not sought firm access. They will now face the risk and cost of compensation or having to reduce their capacity offered to the market to manage the constraint.

Again, turning to the flowgate example in Figure 2.1, if G2 requests firm access for 500MW, then ignoring load growth this could be provided at zero cost by allocating all of the flowgate capacity. This, of course means that G3 as the lowest cost generator will see their access reduced and become liable to compensation. This makes it clear that the OFA proposal cannot be implemented without fundamentally changing the current access rights of non-firm generators.

In reality, managing access is infinitely more complex. Consider the realistic scenario where G3 and G2 have different ramp rates. It may then not be possible for the non-firm generator to respond to the changing generation pattern of the firm generator to avoid liability for compensation. Similarly if the non-firm generator is a wind generator—that is semi scheduled or must run. Since there is no bid price—effectively it is less than -$1000—then if the wind generator causes a constraint, what is the bid price that is used to calculate the compensation that they should pay?

Another level of complexity is that given the many thousands of constraint equations, flowgates are virtual and will come and go as flows from generators to loads vary. Generators will be required to continually monitor this complexity to establish bid behaviour, contracting levels and for non-firm generators their potential liability for compensation.

4.2 Issues with the long run pricing mechanism

The OFA proposal suggests that the payments generators make for firm access be derived via a long run incremental cost (LRIC) methodology that calculates the cost as the difference between the NPV of the total costs of a baseline expansion plan and an adjusted expansion plan. The baseline expansion plan is the plan in place before access is requested. The adjusted plan is the baseline plan plus the additional works needed to provide the access that is being sought.

The LRIC methodology is described as being a "stylised" methodology that assumes away some of the complexity inherent in transmission planning.

The baseline plan will need to be developed by TNSPs through open and transparent consultation processes. It will also need to cover the maximum planning horizon for which access might be sought. Logically proponents of new generation seeking access will want a fixed price for a defined level of access for a period that equates to the economic life of a power station—at a minimum of around 15 years for project financed developments and potentially up to 30 to 50 years.

Creating this baseline plan will be contentious for a number of reasons:

- The AER will be required to approve the baseline plan as since the generators seeking access will only be required to pay for increments over the baseline plan, customers through regulators will of necessity pay for the plan
- Existing and potential generators will have a vested interest in ensuring that the baseline plan's assumptions are as favourable to their access needs as possible—that is they will lobby to maximise the cost of the baseline plan and thus minimise the cost of increments to support their firm access
- The baseline plan, of necessity, will need to make assumptions about future generation locations—even on a nominal basis—for additional generation needed to meet load growth—that is reliability generators as described in the proposal; and
- How are the LRIC impacts of existing generators evaluated?

In this section we discuss these issues.

4.2.1 AER approval of the Baseline Plan

The baseline plan will require regulatory approval by the AER as customers—through regulated revenue—will pay for the baseline plan. This is because access seekers will only be required to pay for the increment. The OFA proposal suggests that in many instances the firm access sought can be provided by bringing forward projects already scheduled in the future. In this case, the access seeker will pay the incremental cost—that is meet the financing gap—and customers will pay for the full cost of the project from the time it was planned to be required in the baseline plan.

This LRIC approach creates a number of issues:

- The scope, scale, cost, risks and timing of these future projects will be highly uncertain but the AER will be required to make a firm determination that the incremental costs charged to the access seeker are reasonable and equitable and do not represent a subsidy from regulated customers

- The AER will be approving regulatory expenditure on projects that may not be required in the baseline plan for perhaps ten or fifteen years, perhaps two to three regulatory reset periods ahead—an essentially firm pre-commitment on behalf of customers; and
- If circumstances change between the establishment of the appropriate LRIC costs and the period when the project was estimated to be required for reliability purposes then either customers or the TNSP will bear the risks.

On this last issue, consider the simple flowgate example shown in Figure 2.1 and assume that G3 now requires firm access and under the LRIC methodology is required to pay for an augmentation of the flowgate. The TNSP determines that the flowgate capacity would need to be increased in say five years to ensure that the increasing load can be supplied in terms of the reliability standards. G3 pays for the cost of bringing forward the augmentation by five years. However, after five years circumstances have changed and the augmentation is now no longer required. This might occur if a new generator unexpectedly constructs on the downstream side of the flowgate, perhaps as a result of finding a new fuel source. Alternatively a major industrial load may have closed down.

Customers paying regulated charges now find themselves paying for an augmentation that isn't needed and provides them with no benefits as the generator requiring access has only paid for the cost of bringing the project forward, not the project itself.

Similar issues arise with the length of time that a generator may wish to contract for. To ensure cost recovery did not pass on to customers, a generator requiring a new augmentation for access—that is not bringing forward a planned reliability project—could only contract for the economic life of the assets needed to supply that access—a life that may be far longer than the power station life.

Even if the planned future reliability driven project does proceed as scheduled, there is still the issue of managing the construction cost. It would be inappropriate to require the TNSP to take this risk as in essence they would be required to construct the project to an indicative budget set perhaps ten or fifteen years earlier. It would be extremely difficult for the AER to ascertain how much of any cost variation was due to inefficiency of the TNSP and how much resulted from inaccuracy in the initial indicative estimate. The result will be that regulated customers will carry all the risks of asset stranding and cost over runs.

4.2.2 The complexity of establishing the baseline plan

Establishing the baseline plan will involve a complex consultative process between the TNSP, the AER and existing and future generators.

TNSPs will likely be motivated to reduce any risks arising from the OFA proposal—that is all else being equal they will seek a "high growth high cost" baseline. This is because it will reduce any risks they may face from either having to pay compensation if the system cannot provide firm access to contracted generators and reduce any construction cost risk they face.

The AER will be motivated to ensure that the baseline is fair and equitable to regulated customers in that is does not represent a subsidy between customers and access seekers and that the baseline expenditure is efficient, prudent and the least cost option.

Existing generators that have firm access will be lobbying for a minimalist baseline plan to ensure that future access seekers have the highest costs possible. Non-firm generators and potential future access seekers will be motivated to lobby for the highest cost baseline plan to protect their existing non-firm access costs or reduce the costs of future access requests.

Further, such a long run and indicative plan will be highly sensitive to the assumptions and all of the various stakeholders will have views on the range of assumptions that are reasonable but tend to support their own interests.

4.2.3 Future generation location

One of the key assumptions will be the location of the hypothetical new generators needed to ensure future load growth can be supplied. The OFA proposal suggests that if an actual new generator seeks access at the site of one of these hypothetical generators then the baseline will need to be recast without the hypothetical generator as to do otherwise would result in the actual generator facing a zero incremental cost for access. This suggests endless possibilities for new generators to game the OFA access process by seeking to locate as close as possible to the hypothetical generators without triggering their removal but taking some advantage of the baseline transmission network that supports the hypothetical generator.

4.2.4 Access of existing generators

We suggest it is highly likely that all existing generators are likely to seek firm access approximately equal to their historical level of non-firm access. This is likely for two reasons:

- Firstly as a defensive response to avoid the cost and risk of becoming liable to compensation to firm generators; and
- Second, because logically under the baseline plan the incremental cost of obtaining that access will be low—essentially zero.

The OFA proposal suggests a transition period with some degree of declining grandfathered access. However, there doesn't appear to be any suggestion that existing generators cannot immediately contract for firm access for the period beyond a transitional period.

This would appear to create substantial equity issues as the transmission network providing the firm access has previously been paid for by customers, but existing generators that contract for firm capacity will enjoy the benefits of that access—and be advantaged over new entrants. The AER will be required to somehow oversee an equitable allocation of sunk costs on a reverse incremental costs basis—that is what the transmission network would look like if a particular existing generator wasn't there.

This solution would be to establish a series of baseline plans without each individual generator for the purposes of determining the LRIC payable. It is difficult to see that this would not be a complex, difficult and highly arbitrary process that would not necessarily result in existing generators paying an appropriate cost for the benefits of access. Any type of grandfathering of access will potentially advantage existing generators and disadvantage new entrants.

4.3 What incentives and behaviours will it create?

The OFA proposal has the potential to radically change the incentives and behaviours of a range of industry participants. In this section we summarise those changes for TNSPs and for generators.

4.3.1 TNSPs' behaviours and incentives

We see the following behaviours and incentives for TNSPs:

Risk aversion will lead to overbuilding

TNSPs will become risk adverse in all aspects of contracting with generators for firm access as they may become liable for compensation in that they are the compensator of last resort if all generators on the upstream side of a flowgate chose to become firm—as we suggest is a likely outcome—to avoid generator liability for compensation.

The level of compensation paid by TNSPs pose some interesting questions for policy makers. If the TNSPs are required to fully compensate firm generators that are constrained off then TNSPs will—unless they can pass the costs to regulated customers—become highly risk adverse and will be incentivised to overbuild all such firm access augmentations. Conversely if they are not required to fully compensate constrained off firm generators, then the value of access to those generators will be severely downgraded.

This requirement for TNSPs to become the "compensator" of last resort is theoretically sound in that it incentivises TNSPs to act efficiently within the framework of the OFA. However, given that the TNSP is a regulated monopoly, there are clear limits to the incentive impacts of such an arrangement—limits that revolve around the source of funds for compensation and the resultant effect on the risk profile of the TNSP:

- If the source of funds is purely from access payments from generators, the incentives will be to over build and over price access augmentations to limit downside risk
- If the source of funds is purely from customers, then the TNSPs will have no great incentives to ensure that access augmentations and prices are technically and financially appropriate—other than the normal pressures placed by the AER
- If the source of funds is the TNSP, then they will require compensation through the regulated return for the additional risks that they face—costs that will be paid by customers; and
- Finally, if the compensation is scaled to reduce these impacts, the value of firm access to generators will be degraded—and uncertain.

TNSP risks will also increase to the extent that their revenue will come partly from regulated services to customers and partly from commercial negotiations with generators. In Section 4.2 we discuss pricing issues and point out the potential for gaps and overlaps to arise between the provision of regulated and access services on a single meshed network. This may arise if the costs of an augmentation are shared between generators and customers and the regulated customer portion does not meet the requirements of the RIT-T or otherwise is not deemed to be prudent and efficient by the AER.

If TNSPs are required to take more risk, then under the regulatory framework they should be appropriately compensated—that is the equity beta in the regulated WACC should rise accordingly. Given the scale of the TNSP regulated asset base at about $16 billion, a 0.5 per cent increase in WACC might result in additional charges to customers of some $80 million. In theory this will be offset—at least to some extent—by the additional revenue they gain from access charges paid by generators. A question to be resolved is that, given access services will be a TNSP monopoly service, what will be the appropriate level of WACC allowed by the AER as the basis for generator access charges?

Complex access negotiations

Negotiations between TNSPs and generators seeking access will be complex—much more complex than the current negotiations that take place for generator connection. Those negotiations have proven so unsatisfactory that the AEMC has proposed a suite of processes and regulation to ensure that new connections happen efficiently in a draft rule change determination.

The negotiations over access will be an order of magnitude more complex than those for connection. This will especially be so as the AER will be heavily involved—both in terms of approval of the baseline transmission development plan and its assumptions and in the calculation of the LRIC costs. The negotiations will, essentially, be required to be carried out on a tripartite basis. The costs involved in access payments are also likely to be materially more significant than connection costs.

There is also the question of whether these negotiations are public and involve consultation. We suggest that they should be public given that customers, through regulated revenue requirements, will be responsible for any shortfall between the cost of any augmentation to provide firm access and the revenue received from those generators.

4.3.2 Generators Behaviours and Incentives

The OFA proposal provides strong incentives for the following behaviours by generators:

A rush to firm access

Since the OFA proposal isn't optional as non-firm generators will be liable to pay compensation, we suggest that the majority of generators will seek firm access—if only as a defensive measure to avoid liability for payment.

This will be further exacerbated if there is any free rider benefit for existing generators—and this is likely given the difficulty in establishing LRIC costs for access to the existing network—a network that has already been paid for by customers. On a strictly incremental basis existing generators should be able to contract for the historical level of access they have received under the current open access regime for little or no cost.

Little change to incentives to contract

Generators must already manage outage risk which for most plants is much higher than the risk of being constrained off. Thus while they may pay for access to avoid compensation, it is difficult to see that the new non-firm generators will offer more capacity into the wholesale (or retail) contract market. Managing outage risk will still remain the major determinate of the level of contracts offered by generators.

This is especially so as to the extent there remain non-firm generators, as their risk of being constrained will increase. In effect the current level of constraint that is spread—somewhat arbitrarily—among all generators will be concentrated on the non-firm generators. Thus even if there is a small increase in contracts offered by firm generators, there will be a corresponding decrease in the contracts offered by non-firm generators. The same total contract capacity will just be redistributed in a difference manner. This will reduce productive efficiency as non-firm generators will withhold capacity to avoid constraining off firm generators and becoming liable for compensation.

The design of the OFA proposal also makes it unlikely that contract levels will increase. This is because it is proposed that the level of "firmness" will vary for several reasons:

- Access will only be firm under system normal conditions and will be scaled in other conditions. Those conditions will not be transparent to the generator as they will involve the interplay of the thousands of constraint equations and the current operational state of the transmission network. While to some extent these can be monitored by generators—at a cost—scaling events will essentially be random and unpredictable; and

- The level of compensation will not be firm. This is because if there aren't enough non-firm generators to pay the appropriate compensation, then in theory TNSPs will become liable. In Section 4.3.1 we discuss that this compensation is unlikely to be complete as to do so would create unmanageable financial risks for TNSPs.

Since this "not quite firm" physical access coupled with "not quite firm" financial compensation is underwriting firm financial contracts that are firm to the MCP, then generators will be reluctant to contract as their risk of unfunded contract for difference payments will be increased—that is the basis risk between the price they receive and the RRN price will increase. The response from generators will either be to reduce the level of contracts offered or to require a higher premium to cover this uncertainty—or both.

Disorderly bidding will not necessarily reduce

The incentives for disorderly bidding by generators behind a constraint will change, but not necessarily decrease. In the simple flowgate example shown in Figure 2.1, G2 and G3 currently have incentives to bid at -$1000 in circumstances where they are confident that G1 will be the marginal price generator. If they do this, the flowgate capacity will be allocated in proportion to their capacity.

If G2 is firm and G3 remains non-firm then:

- G2 will have an incentive to bid below their SRMC if for no other reason than if they are constrained off then they will be entitled to higher compensation; and

- G3 will have an incentive to bid above their SRMC, again to reduce any compensation payable if G2 is constrained.

Thus incentives for disorderly bidding will change but not necessarily reduce.

5 Summary

In this report we look at the costs and benefits of the Optional Firm Access (OFA) regime.

In Section 2 we analysed the various problems that the OFA proposal was designed to address. We concluded that there is little evidence that the greater co-optimisation of generation and transmission investment will lead to material economic benefits. In regard to access encroachment, we concluded that while this was an issue for individual generators, it was not a pervasive problem for the market and, in any event, it wasn't necessarily inefficient. The economic cost of the final problem—disorderly bidding—has not been found to be material in studies carried out by the AEMC.

In Section 3 we concluded that as the current transmission network wasn't sub optimal, then the RIT-T which controls transmission investment wasn't fatally flawed. We then analysed why, under an OFA model, generators would seek to pay for access and fund network augmentation projects that would not be efficient under the RIT-T. We concluded that generators would pay for access if they believed they could capture private benefits from projects that weren't welfare enhancing for the overall market. We also saw strong incentives for generators to pay for access to avoid the cost and risk of becoming liable to compensate adjacent firm generators.

In Section 4 we analysed the incentives that the OFA model creates for generators and TNSPs and the likely behaviours that would result from those incentives. We found that TNSPs, to avoid liability for compensation if firm generators are constrained, would be risk averse and tend to over build any access augmentation to the extent they could under regulatory scrutiny. We also found that existing generators:

- Would all be likely to seek firm access as they could do so at low cost and it would protect them against the cost and risk of compensation payments; and
- Would be likely to reduce the level of contracts offered to the market—or at best not increase the level—as the OFA proposal is neither physically or financially firm

We also found that the incentives for disorderly bidding might change between generators but it is difficult to see that they would be substantially lower in total.

Conclusion

On this basis, we conclude that:

- the benefits of the OFA model—largely greater co-optimisation—are at best small
- the unintended consequences of the OFA model—an over built and less efficient transmission system—are potentially large; and
- the cost and complexity of the OFA model are substantial.

For these reasons, we conclude that the OFA proposal is unlikely to contribute to the achievement of the National Electricity Objective.