Oakley Greenwood

Impact of OFA on Generators

prepared for:
Australian Energy Market Commission

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Introduction

The Australian Energy Market Commission (AEMC) has requested Oakley Greenwood to provide an assessment of the impact on financial certainty for generation and the efficiency of dispatch under Optional Firm Access (OFA) for the National Electricity Market (NEM).

The assessment is to assist AEMC in its design and testing of the OFA model at the request of the Council of Australian Government's Energy Council (Energy Council - previously the Standing Council on Energy and Resources) following the AEMC's Transmission Frameworks Review.

Our review does not involve quantitative forecasting or modelling and is based primarily on our own experience and judgement. The review has also been informed by review of relevant documents published by AEMC and the Australian Energy Market Operator (AEMO) including the AEMC's Transmission Framework Review and Technical Report, AEMO's First Interim Report and Draft Report as well as one-on-one discussions with a number of generation businesses operating in the NEM. Our review therefore does not comprehensively assess the materiality of either the problem or the solution. We understand AEMC has separately sought quantitative modelling for this purpose. However, we have developed an OFA settlement model to independently validate and demonstrate aspects of our analysis and conclusions.

How does OFA change the NEM?

Introduction of OFA would represent a major change to arrangements for network investment and incentives for how scheduled generators participate in dispatch within the overall investment, operation and settlement cycle of the NEM.

The aims of the OFA regime include to:

- Improve coordination between siting of transmission and generation assets;
- Improve coordination between operation of transmission and generation; and
- Create incentives for generators to submit bids with efficient prices for dispatch.

In order to achieve these aims generators will need to change their decisions about one or more of investment, contracting and bidding for dispatch. OFA will be implemented by changes to rules relating to network augmentation and access and by creating new incentives within energy settlement.

OFA will not change other rules, for example relating to dispatch and the primary pricing arrangements for energy or ancillary services. External policies or commercial environment in which businesses operate will not be changed by the rules for OFA.

Assessment of the impact of OFA requires consideration of how the changes to be made for OFA will change the overall decision making environment for generators.

We found the direction of change was more readily assessed than materiality, which may change over time.

The NEM model before OFA (status quo)

Status quo transmission network development and operation.

The capability of the shared network away from the immediate point of a generating unit's connection is decided by Transmission Network Services Providers (TNSPs). The shared network capability therefore determines the capability to carry the output of each generating unit to market.

TNSPs work within a regulated planning process that is designed to deliver the most cost effective network that allows sufficient generation overall to reach customers.

Although there are some incentives to site generation away from congested parts of the network, the current process does not allow individual generators to optimise their individual situations or to acquire protection against the commercial impact of network congestion.

Hub and spoke market approximation

The NEM market concept is a series of regional hubs and spokes connecting customers and generators via transmission networks (or more precisely, connecting to the incoming side of distribution networks that carry supply to individual customers). The regional hubs (the Regional Reference Nodes) are interconnected.

This representation is an approximation.

Over the life of the NEM there have been circumstances where the hub and spoke approximations have created incentives and opportunities for generators to bid prices for dispatch that are well away from their economic value. In classifying bid prices as inappropriate, considerable care needs to be taken as the energy-only design expects generators' bids to reflect both the economic value of risk of shortfall as well as complex inter-temporal costs within a relatively simple standard bid structure.

As a result although economic value will often be close to the commonly referenced short run variable cost benchmark it may also range from very low to very high depending on the circumstances.

What does OFA do?

OFA is designed to provide a mechanism for generators to acquire commercial assurance against the effect of congestion. Generators will be able to pay TNSPs to build additional network over and above the level the TNSP would have built and maintained in any event (base plan). Purchase of OFA will require TNSPs to construct a minimum level of network capability sold to generators and provide the generators with commercial protection against the effect of congestion up to the level of OFA they have acquired, subject to certain limitations. OFA will therefore allow generators to optimise their individual operation better than the status quo.

Introduction of OFA will trigger transactions within the NEM's energy settlement process.

If there is no network congestion, payment will be at the regional node price.

When network congestion does occur, and a generator is dispatched above the level of OFA it holds, and this is at the expense of another being dispatched below its holding, revenue will be deducted from the generator dispatched above its entitlement in order to compensate the generator dispatched below its entitlement.

As a result OFA represents a significant shift in the principles under which the network is provided and paid for and the associated changes to energy settlement will reduce and often remove the rationale for offering prices that may distort dispatch and market price.

Summary of findings

OFA likely to become the norm

- On balance, once it is introduced, we expect the majority of generators will be competitively incentivised to hold relatively high levels of OFA.
- Transitional allocations will play a significant role in creating the environment for high levels of OFA. Subsequent competitive pressures and the design features of the OFA regime will mean it is unlikely generators will materially reduce the level of OFA as transitional arrangements expire.
- The theoretical option of all generators in a part of the network opting to not hold OFA does not seem likely in these circumstances.

Energy contracting to increase – depending on circumstances and initially marginally

- On balance, we expect OFA will lead to higher levels of energy contracting.
- However, the materiality of increase in contracting will be dependent on the circumstances of each generator, future network configuration and capability and on the geographic distribution of future generation plant.
- Initially the change in overall level of energy contracting may be marginal – consistent with adequate capacity at present and surplus generation suppressing energy price and therefore the impact of congestion.
- In the longer term, our expectation is that the incidence of congestion will grow. OFA then will be more valuable and allow contracting levels to be retained or increased.
- Network congestion, at least at current levels, is more likely to be a factor in decisions about siting of new generators. As a result OFA could influence the coordination between transmission and generation from the start, although little market driven new investment in generation is anticipated for a number of years.
- External policy factors and industry structure will continue to interact with the operation of the rules of the NEM including the operation of OFA. There is a risk these will interfere with the operation of the OFA mechanisms.
- The risk of scaling back of entitlement concerns some generators. We expect the effect will be incorporated by experience, but remain a significant one-off risk factor.

OFA will remove the rationale for strongly negative bids, discipline non-cost reflective bids but have less impact on portfolios

- OFA will strengthen incentives for generator bids for dispatch to reflect economic value.
- In particular, OFA will substantially remove the impact of the approximation inherent in the NEM design for bidding to the price floor and discipline many instances of non-cost reflective bids.
- In the course of the work we confirmed the broad conclusions relating to cost reflective dispatch bids described in publications by AEMC and AEMO. But we concur with the caveats each organisation has put on the conclusions and that other factors can have material impact on the outcome.

- The most significant caveat relates to the impact of generators within portfolios. We conclude that it is not safe to assume the impact of OFA on bidding behaviour will be as comprehensive as it is implied from analysis of AEMC publications to date. The materiality of the portfolio impact will be variable and hard to predict.

Price – Network cost to fall, spot and contract hard to predict due to competing influences

- Energy price comprises the net of spot and contract. Customer price comprises energy price plus regulated network charges and other fees.
- OFA will transfer some costs from network tariffs to energy charges and create factors that reduce some components of price and other factors that may result in an increase. The balance of factors will change over time.
- In the longer term we are unable to predict whether the net effect will be an increase or decrease with any surety from qualitative analysis.
- In the short term there will be more factors tending to reduce the price to customers than to increase it.
- Volatility is more likely to increase than decrease as generators seek to recover higher fixed cost.

Other issues

Smaller generators may 'set and forget' but be at a resource disadvantage to optimise

- OFA will offer smaller generators the opportunity to 'set and forget' issues around network congestion. The ability to do this would be an advantage. However, 'set and forget' implies these generators will operate very conservatively or simply accept OFA as a cost without optimising their positions. Additional effort to optimise OFA will fall disproportionately on small low resource generators.

Baseline waiting game

- Depending on the details of the final implementation, there is likely to be tension between generators' demand for access and the TNSP planning baseline. The AEMC Technical Paper acknowledges this risk by the suggested treatment of reliability investment in calculation of cost of OFA (LRIC) but also notes the interface with the policy for reliability standards to co-exist with OFA.[1]

Risk of reduced negotiation and opportunities for innovation

- There is a risk of reduced flexibility in the relationship between TNSPs and generators that may inhibit bespoke access solutions as TNSPs will be obliged to focus on OFA which will require resources, but voluntarily consider other arrangements. Flexibility in detailed drafting of rules around OFA may mitigate this risk – the Technical Paper discusses some of the issues.[2]

1 Refer Technical Paper sections 6.2.4 and 6.3.8

2 Refer Technical Paper section 7.3

2. Background

The Australian Energy Market Commission (AEMC) has requested Oakley Greenwood to assess the impact on financial certainty for generation and the efficiency of dispatch under Optional Firm Access (OFA) for the National Electricity Market (NEM).

The assessment is to assist AEMC in its design and testing of the OFA model at the request of the Council of Australian Government's Energy Council (Energy Council - previously the Standing Council on Energy and Resources) following the AEMC's Transmission Frameworks Review.

Introduction of OFA would represent a major change to arrangements for network investment and incentives for how scheduled generators participate in dispatch within the overall investment, operation and settlement cycle of the NEM. Forecasts of market outcomes that will occur after introduction of OFA involve assessment of how generators will respond to the changed environment. The direction of change is more readily assessed than the materiality which may change over time. Our review is based primarily on our own experience and judgement and has also been informed by review of material published by AEMC and the Australian Energy Market Operator (AEMO) and one-on-one discussions with a number of generation businesses operating in the NEM. We have also developed an OFA settlement model to independently validate and demonstrate aspects of our analysis and conclusions. Our brief is focussed on the direction and broad materiality of the impact of OFA. Other work is considering quantitative market and system wide impacts and accordingly we do not comprehensively assess the materiality of either the problem or the solution.

3. Incentive analysis

Efficient markets for electricity typically comprise a combination of incentives within competitive energy and ancillary service markets together with regulatory mechanisms for monopoly shared network parts of the industry.[3] Prices for energy and ancillary services are relied on to create incentives for individual market participants to make efficient decisions about the timing, size and location of supply and to a lesser degree, customer demand.

In markets such as the NEM, the equivalent decisions for regulated networks currently rely on system-wide optimisation and central forecasts of demand and new generator costs by TNSPs and market authorities. Commercial incentives are also built into the regulatory arrangements to encourage prudent use of capital and operating expenditure and to account for energy market implications in TNSPs day to day operations.

OFA is designed to change that balance in the NEM so that more of the decision making about network investment will be made by individual generator participants responding to commercial incentives. Generators would have the option of purchasing financial access to market at a regulated cost. Financial access to market means that generators holding OFA would receive the market price up to the level of access they have acquired rather than simply the level of dispatch – subject to a number of conditions.

3 and sometimes separate capacity markets

Accordingly OFA will significantly shift the underlying philosophy of the design of the NEM. The OFA mechanism will affect decisions about networks in the investment phase in much the same way as settlement is designed to influence forward contracting for energy and therefore of generation investment. The commercial impact will also create a range of incentives that affect the way in which generators bid into the energy and ancillary service markets.

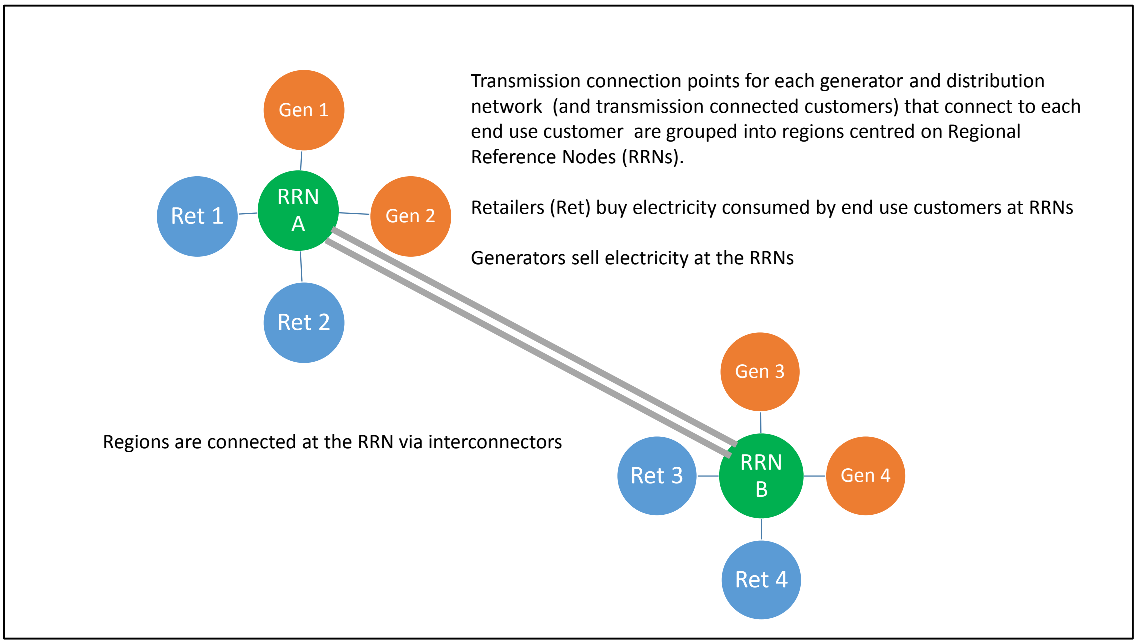
The potential impact of OFA is complex as it may affect a number of the inter-linked mechanisms within the market. It will also interact with external policy (for example renewable investment) and commercial settings (for example capital market conditions and regulations) in the same way as other energy market decisions. Analysis of impact is different to a description of the mechanism and for our task we have developed a comparison of the way in which generation and network investment and operation interact now, and how this might be changed by OFA. In doing this we recognise that generation and network components of the NEM interact in many ways across a broad time scale and our comparison focusses on only those aspects relevant to assessment of the impact OFA on generators.

4. Status quo (no OFA) generation-network interactions

4.1. Hub and spoke approximation

The NEM market concept is a series of regional hubs and spokes connecting customers and generators via transmission networks (or more precisely, connecting to the upstream side of distribution networks that carry supply to individual customers). The regional hubs (the Regional Reference Nodes) are interconnected. In this representation all demand and all generation is located on the spokes connected to the regional hubs - Figure 1.

Figure 1 Hub and spoke market model



If there is a limitation on the output of any generator due to the capacity of the network within a region, the model assumes another generator on another spoke will pick up the difference or power will flow from a generator connected to an adjoining hub along an interconnector. A calculation of which combination of generators delivers the most efficient outcome is repeated each five minutes within a mathematical representation of the limits, or constraints, on network capability in constraint equations.

However, this representation is an approximation. In practice the transmission networks within each region are meshed rather simple spokes and demand is located across the meshed network. A consequence of the meshing is that the network capability affecting one generator can be dependent on the output of other generators and also on the level of customer demand in that area of the network at the time. The constraint equations used to manage dispatch are the interface between the reality of the meshed network and the simple hub and spoke concept. Over time AEMO (and previously NEMMCO) has refined the representation with the result that the outcome is close to that of a more direct representation of the meshed network, however, as a result the constraint equations are complex.

Generators are paid for their production at the price calculated at the regional node adjusted by a factor that accounts for losses on their spoke in the model. Generators may be limited from supplying all that they are capable of producing at the prevailing price due to constraints and will be paid for the reduced amount at the regional price.

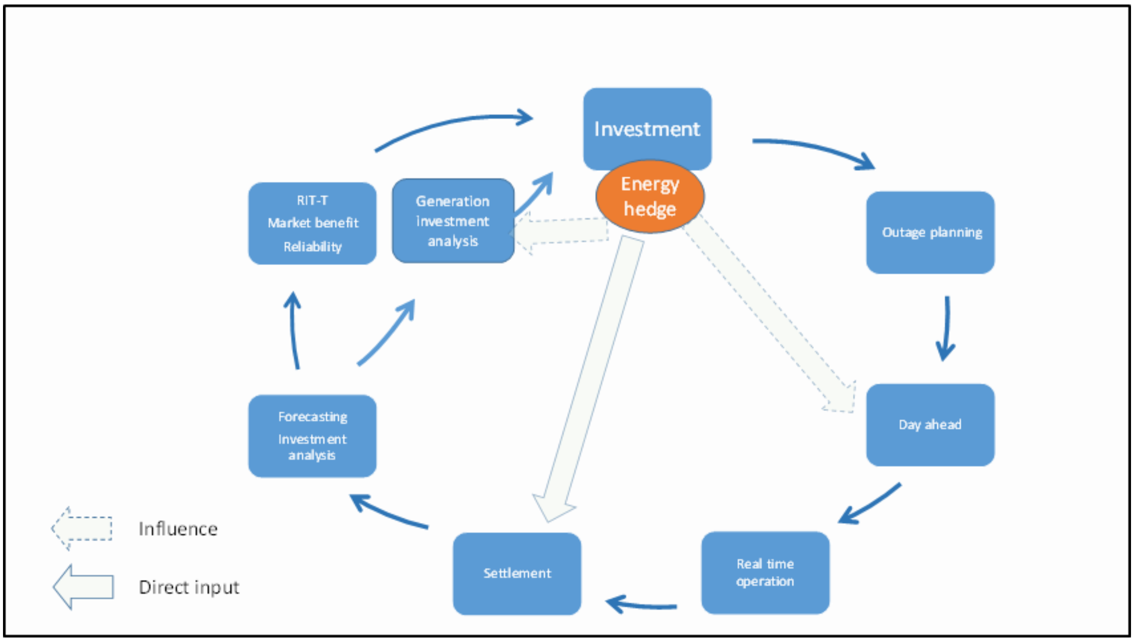
Over the life of the NEM there have been circumstances where the hub and spoke approximations and the regional price concept have created incentives for generators to offer prices for dispatch that are well away from their economic value.

Figure 2 illustrates the flow of decision making under current arrangements that we consider should be accounted for in assessment of the changes that introduction of OFA will bring. Starting at the top of the figure, when generation and network investment to meet customer demand in the near term are in place, the next stage of operation of the industry is for generators and network businesses to plan maintenance and manage other outages. This stage is followed by preparations for 'real time' when electricity is produced and delivered to customers. Operational preparations include TNSPs ensuring the equipment is in place to safely monitor and control network operation, for example around voltage control and that the configuration of circuits is optimal. Generators perform similar tasks with their plant and equipment but also prepare and submit bids for dispatch in the market. The system operator prepares by ensuring it forecasts demand, checks reserve levels and has adequate levels of ancillary services at its disposal.

Once electricity has been delivered to consumers, metering and settlement functions analyse operations and settlement statements are prepared and ultimately generators are paid and customers incur expenses.

The settlement outcomes then feed into future decisions that are based on commercial incentives and the cycle repeats.

Figure 2 NEM lifecycle - status quo



4.2. Key features of the status quo

In the context of analysis of the impact of OFA on generators, the key points about the status quo arrangements to note are:

- The current regime for network investment beyond connection assets is a largely regulated process. AEMO as the National Transmission Planner and TNSPs undertake planning for expected levels and location of demand, anticipated size and location of generators. Results of this planning are subject to consultation and account is taken of planned new generation and demand, but there is nevertheless considerable judgement exercised by the planners.
- TNSPs make final decisions about investment in the shared network and recover costs through regulated charges on customers. Significant investments are subject to more extensive consultation through the Regulatory Investment Test for Transmission (RIT-T). There is scope for generators to fund network augmentation and also provision for market network service providers (MNSPs) to develop network.
- Generators have no assurance that access to market will be maintained for their units. New entrant generators can establish nearby and congest the network being used by an incumbent.

- Generators and TNSPs are able to negotiate funded augmentations. These are additions to the network paid for by generators but generally without any guarantee of access. There is scope within the rules for TNSPs to offer a guarantee or compensation but to our knowledge none have ever done so – the closest we have heard of is for payment of some of the costs in the event another generator makes use of the funded assets, presumably as the TNSP would then expect to recover a share of the costs from the other party. In interviews generators reported favourably on a small number of funded augmentations that have been agreed with TNSPs, although most were small scale, for example dynamic line capacity monitoring, ramp down schemes and minor switchyard additions. These all assisted the applicant and were negotiated one-on-one with the relevant TNSP. In each case the generator was satisfied with the outcome and accepted the risk that another generator might free ride on the capability at some point in the future.
- The regulatory regime under which TNSPs may recover costs of building and operating the network include incentives designed to encourage efficient capital spending and efficient operation and timing of outages for maintenance including alignment of network capability with times where it is of more value in the energy market.
- In the NEM's regionally priced energy-only settlement, generators face a potentially volatile energy price. Generators can face price risk if they contract between regions, but not within regions. Energy contracts allow generators to manage the effect of volatile price but leaves them exposed to volume risk. Volume risk occurs whenever a generator cannot deliver the volume it has contracted to hedge. Volume can be limited by the availability of generation plant or limitations within the network resulting in network congestion.
- When network congestion occurs and there are multiple generators seeking to use the limited capacity there are strong commercial incentives for the generators to rebid in the energy market to protect energy financial hedging positions. Generators at risk of being constrained to low levels of output have an incentive to offer prices for dispatch at the minimum allowable level of -$1,000/MWh. This practice effectively signals a generator's willingness to 'share the pain' of congestion as dispatch is then pro-rated across the offered volume not by price. This sharing can of course lead to inefficient dispatch if the lowest cost (as opposed to price) generator is not given highest priority. However, as noted in the following points it is difficult to assess true cost at a time when generators are asked to reduce and inter-temporal cost considerations are accounted for. That said, it is implausible that the economic cost of all generators is always -$1,000/MWh whenever congestion occurs and hence some loss of dispatch efficiency is likely to occur.
- In certain circumstances there are also incentives for generators to bid in a way that creates congestion. These incentives generally only exist as a result of particular and ad hoc combinations of network configuration, distribution of demand and in some instances the ownership structure of portfolios where a single entity controls generation on either side of a potentially congested part of the network. Observed examples are discussed in the AER's State of the Energy Market Reports.[4]
- The energy-only market design relies on generators reflecting the risk of supply scarcity in the prices they offer for dispatch and this price can be very high. As a result offered prices may legitimately rise above simple short run costs for short periods when reserve capacity is low, such as at times of peak demand. However, for much of the time economic value will tend to be reflective of their short run cost;

4 State of the Market, See sections 1.9.4 & 1.9.5.

- Further, generators must use the standardised market template and format to submit dispatch prices and quantities to convey complex commercial and technical trade-offs within their plant that are not explicitly considered in the market dispatch process run by AEMO. For example, in making decisions relating to the start-up, minimum loading, and shut down of plant, especially for slower starting plant, offer prices can at times be well below nominal short run costs based on fuel cost, including negative. As a result it is not a simple matter to distinguish between competitive and efficient offers and ones that are inefficient and uncompetitive.
- As a result, generators have only limited means to communicate both operating and commercial limitations and operating preferences affecting their plant. Generators are required to commit their generating units to service ready to receive dispatch instructions (self-committed units) or to offer them as units capable of rapidly starting in response to instructions (fast start). Most thermal units have a practical minimum level at which they can operate and most also incur significant costs for starting or stopping. As a result the most economic operating pattern can be to continue operating through short periods of low demand and associated low price or to include limits on the rate at which the market dispatch can vary their output (ramp rate).[5] A number of these limits relate to operation over time – inter-temporal limits. The bidding provisions in the rules allow generators to submit, and with some limitations adjust, parameters such as the price for different levels of output, the ramp rate and minimum run time (inflexibility). These provisions allow generators to communicate these factors to the NEM's dispatch process which considers only a single five minute time period each time it runs and therefore does not consider inter-temporal factors.
- When the prices offered for dispatch are uncompetitive or inefficient they can change the mix of generators called for dispatch and the cost of production in the market can rise, meaning the efficiency of dispatch suffers. However, considerable care needs to be taken to identify which prices are uncompetitive and lead to inefficient outcomes for the prevailing circumstances and which do not.
- Historically, the circumstances which are open to bidding that is designed to create congestion have been transient, but there have been a number of them. It is not the role of this assessment to comment on the nature or materiality of such events. However, as OFA is expected to alter the incentive for congestion to be created in this way, discussion of them is relevant to consider how OFA may alter the associated incentives.

For most generators, while network congestion can create volume risk, the majority of generators interviewed for this assessment reported that breakdown of their own generating units is a more significant source of volume risk. This risk prompts many generators to limit contracting to around the level they can support after breakdown of their largest unit – although different generators assess this risk in different ways and set contracting limits accordingly. This situation is supported by anecdotal reports over many years and our assessments of bidding behaviours, but confirmation requires commercially confidential information that was not available. The situation also highlights the role of portfolios as a means to manage plant related volume risk as a portfolio allows businesses to self-insure for breakdown of multiple generating units more flexibly than they can by trading specific contracts.

5 The AEMC is currently considering amendments to the National Electricity Rules in this area

Risk of network congestion, which therefore limits network capability, can be a more significant limit on contracting for generators connected to parts of the transmission network that are more susceptible to network congestion. The Snowy generators are a case in point. Snowy has effectively no local demand and therefore must export either north towards Sydney and Canberra or south into Victoria and is therefore at risk of being constrained and suffering volume risk due to the condition of the networks and also to the operating regimes of other generators that also use the same networks. Their focus is on capability to deliver energy which can be limited by either generating or network capability.

There is a distinction between Snowy and many other generators that are dependent on a limited transmission network such as in the case of remote wind generators. These other generators are generally connected by shorter lines to strong parts of the network than is the case for Snowy and therefore share with fewer other generators. There are, however, significant exceptions.

The capability of parallel lines is generally limited by the weaker line as failure of the stronger line will mean most of the flow on the stronger line will be forced down the weaker line.[6] In addition congestion can occur or be created as a result of the combination of generator bidding behaviour and network configuration favouring some generators and disadvantaging others.

For example the network in the south east of South Australia is comprised of parallel lines with quite different capacities and is also part of an interconnector. Intermittent generators have also connected to the weaker line creating a complex set of constraints. The network in this area is being upgraded. Basslink, a Market Network Service Provider (MNSP) based interconnector between the Tasmania and Victorian regions connects into major network connection points in the Latrobe Valley. Under the NEM dispatch arrangements MNSPs can bid in a manner which delivers dispatch priority to an MNSP over generators when both are bidding to the price floor. This can be advantageous to Tasmanian generators and detrimental to Latrobe Valley based generators under outage conditions within Victoria. High profile instances of congestion and at times perverse prices have prevailed in the Queensland region and between NSW and Queensland over a number of years for different reasons.

In each of these types of conditions OFA would offer a mechanism for affected generators to obtain insurance against the commercial implications – subject of course to the cost.

4.3. Implication for market outcomes (pre-OFA)

Many factors influence generator siting including access to fuel and other services as well as current and planned transmission access and low loss factors – a point reiterated by generators in interviews and consistent with our industry experience working with potential new entrants. However, once generators have made a decision about where to locate, TNSPs future network plans are affected by these decisions and subsequently future generation investments. As a result there is a constructive tension between the two activities.

6 This is an approximation – for example failure of the stronger of two lines will increase losses and may also see a redistribution of flow across the power system and less total flow on the remaining line than was previously flowing on the pair.

Rational new investors in generation can be assumed to assess if the proposed point of connection will create congestion and inhibit operation of their plant. Generators interviewed noted that it would be normal practice to make such an assessment. This observation also aligns with our experience in the market including working with potential new entrants. However, incumbent thermal plant can readily be exposed to greater levels of congestion by new entrant plant with low variable operating cost, such as wind. Generation located on major flow paths, in particular interconnectors, may be affected by distant plant located along the interconnector. This type of situation is understood to have been a significant driver for affected generators to argue for some form of access right such as OFA.

The opportunity and requirement for generators to bid prices relating to factors such as for fuel and variable operating and maintenance cost and other technical and commercial considerations in particular inter-temporal factors, can also be used for purely for commercial benefit. For example, the opportunity to bid negative prices reflects the genuine possibility that a generator's cost will increase if its output is lower than the technical stable minimum operating level – where maintenance costs can rise due to mechanical stress or high cost auxiliary fuels must be used to maintain flame stability. If the alternative is to shut the affected unit down it may not be able to return to service for many hours due to technical limitations and its replacement will of necessity be at a higher cost. Accordingly, bidding to the price floor might be a purely rational commercial tactic under some circumstances and some individual 5-minute dispatch cycles. But bidding low prices might also be a signal that the costs for dispatch to low output (or to shutdown) will be high and thus inconsistent with efficient dispatch over a day compared to just the single 5-minute dispatch period in isolation. Put another way, negative prices may at times be in merit.

Approximations in the network model, especially the presence of loops, are well understood to make counter-price flows inevitable and may occur even with in-merit bidding. The AEMC Technical Report (chapter 11) documents the reasons. The fixed location of region boundaries can also exacerbate the effect.

Bidding in merit order based on short run economic value may not be commercially optimal when congestion occurs under the status quo and hence bidding away from that cost is entirely rational. However, it may result in inefficient dispatch if the relative order of dispatch changes.

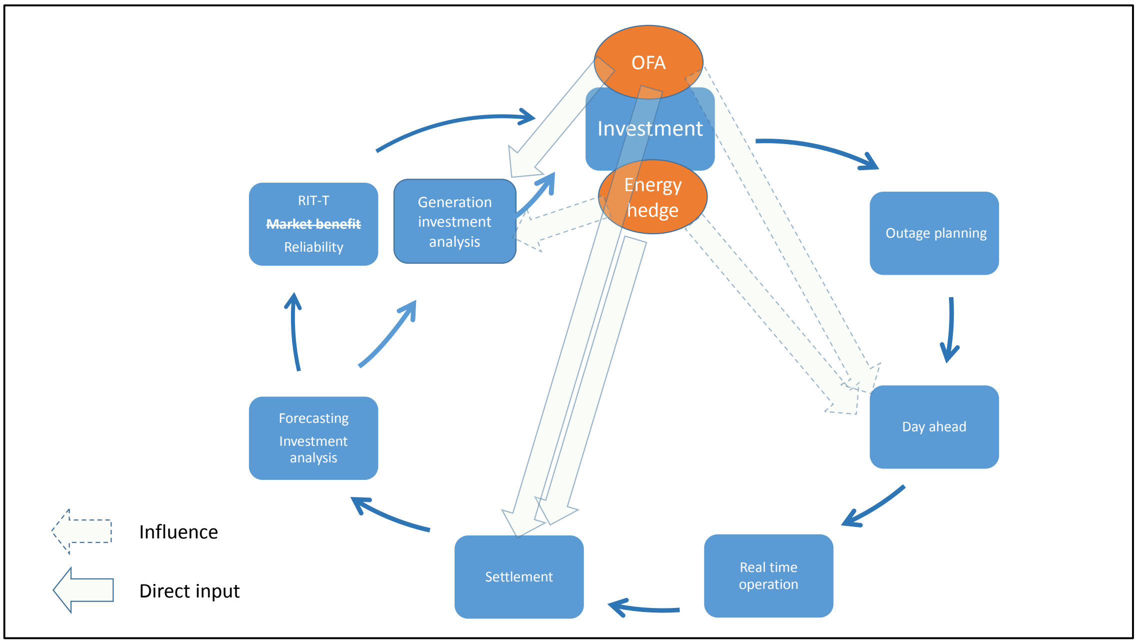
Network congestion readily creates conditions where one or more generators has pricing power and in the past these generators have used this power to exacerbate price excursions.

The contract markets in the NEM are now well established with both Over the Counter (OTC) and exchange based instruments. The role of contracts in the NEM is often under-reported and its role understated, but anecdotally the vast majority of energy consumed is supplied under an explicit contract or implicit contract within a vertically integrated gentailer. Gentailers do not need to trade contracts with external parties. Individual generators can either sell contracts to hedge a customer's purchases or be accounted by a gentailer for the level of generation that can be relied on to generate at times when price rises above the agreed contract price.

5. Generation-network interactions with OFA

Now considering how the operating cycle and associated incentives will appear after introduction of OFA – see Figure 3. The key change is that market benefits are no longer considered within the TNSP investment assessment but reliability assessment remains. Instead, OFA replaces market benefits. OFA is shown with direct linkages to generation investment which is also linked to energy hedging as it is in the status quo. OFA is also a direct input to settlement and indirectly to maintenance and operational planning of both networks and generation, bids and offers from generators. While the change appears limited, the effect is significant.

Figure 3 NEM life-cycle with OFA



5.1. Key features

In the context of OFA:

- To a TNSP, OFA is a direct input to the planning standard against which it is measured and will replace the market benefits component of the TNSP's investment decision making process. The TNSP will still be required to undertake a RIT-T to identify the most cost-effectively means to provide the agreed level of OFA and meet the reliability standard;
- To Generators, in principle OFA is an additional form of insurance – insurance against loss of revenue due to network congestion. It is therefore shown in Figure 3 in a similar way to energy contracting which can more readily be seen as insurance against high short term energy prices. Within the industry overall, however, OFA is more than insurance, it is a mechanism to require and allow generators to influence network investment decisions.
- The operation of OFA in settlement has been described in detail in AEMC material and also by AEMO and will not be extensively repeated here.[7] In its simplest form:
  - Spot market pricing will be changed and where congestion occurs both the existing regional price and a new local price will be used;
  - In the absence of network congestion, the local price and the regional price will be the same and thus the flow gate price (the difference between regional and local prices) will be zero (ignoring losses) and settlement outcomes will be unchanged from current arrangements.
  - If congestion does occur, the local and regional prices will differ and the flow gate price will be greater than zero.

7 Technical Report, AEMO OFA First Interim Report

- Each generator will be assigned an entitlement for the half hour settlement period and a deemed use of the flow gate.
- Each generator will pay or receive an amount in addition to payment at the regional price based on the product of the flow gate price and the difference between their entitlement and usage of the flow gate.

- The process for settlement of energy contracts will be unaffected. The net result is that generators that use more than their entitlement will effectively fund payment to other generators that have used less than their entitlement. The level of each generator's entitlement will be determined by the lower of the amount of access it has purchased and a scaled back level such that the sum of the entitlements of all generators affected by congestion at the time matches the available network capacity. Equivalent provisions are made for inter-regional settlement.
- To generators, OFA impacts energy market settlement in a similar way to energy hedges. The local price is not new in itself as a local price has always been available within NEMDE, however, it will now be used directly in settlement.
- To date there has been considerable attention paid to the likely changes to generator bidding in industry debate about OFA. While bidding behaviour is important, a key role of OFA is to replace TNSP decision making about network investment (or retirement) over and above the network needed to meet reliability standards. In the short term some form of transitional OFA is to be allocated. This allocated access will be related to the existing network and generation portfolio and hence have little immediate impact on investment activities, but is likely to have an impact on bidding behaviour. In the long term, and assuming any transitional allocation is not granted in perpetuity, generators will need to assess how much OFA access to purchase and will therefore need to value access compared to the (regulated) price it is available for. Valuation is discussed in more detail later.

5.2. OFA impact on generators

OFA will have a significant effect on generators. In the same way that energy hedging and dispatch bidding are inter-related under current arrangements, the level and type of OFA, energy hedging and dispatch bidding will be inter-related under the OFA regime. The following discusses each of these areas and highlights the inter-relationship.

5.2.1. How much OFA to hold?

The first question is whether generators are likely to hold OFA and if so how much?

Our view is that any optionality implied in the name is illusory and there will be little commercial option except possibly for selected parts of a portfolio participant. The reasons for this are as follows.

Looking firstly at transitional allocation. We anticipate these allocations will be critical not only to commercial risk during the transition but also to establishing the market norm. Transitional allocation is to be mandatory and will therefore impact settlement immediately. On the other hand it is likely that under present market conditions the cost of purchasing OFA (which is to be at the Long Run Incremental Cost – LRIC) for many locations should be low and therefore it would not be a difficult choice to buy – not withstanding that there are a number of locations distant to major load centres and typically subject to congestion where price might be high unless these sites are to be addressed through the equivalent of network support.

Allocation at no cost, or purchase at low cost, will mean a high level of firm access across the market from the start. This will set a commercial and market participation precedent and be very difficult to unwind. The reason for this view is as follows.

- We expect that the likely options will be for all generators in a section of the network to hold substantial OFA or to not hold OFA at all (i.e. to be non-firm). Transitional allocation will remove this choice at the start. Only if all generators in an area choose not to replace transitional OFA would it be likely that OFA will not continue and become the norm. Our assessment is that commercial risks of becoming non-firm while neighbouring generators remain firm will mean it would be unusual for this to occur and hence a high level of transitional allocation will determine the long term outcome. That is, a generator that takes the initiative and substantially reduces the level of OFA will be exposed – the opposite to a situation where a generator decides to purchase OFA when others are non-firm given that the tactic of bidding to low prices is available to 'share the pain' at present. Put another way, we expect considerable asymmetry in the competitive choice between moving from a high to low level of entitlement compared to moving from low to high.
- The existence of the OFA arrangement may change the nature of commercial risk assessments. This will occur if congestion risk moves from being a component of a bundle of risks to a separable credit risk factor that can be assessed explicitly by risk managers, internal investment committees and by external parties such as financial institutions. The separable nature of OFA is illustrated in Figure 3 showing OFA as an equivalent mechanism to energy contracting. To the extent standard industry practice changes to routinely assess the level of OFA this will be another factor that will tend to establish OFA as a normal part of the NEM.
- Similarly, new entrants, when they arrive, will carry too much risk to not hold OFA when other generators competing for any congested network are holding OFA as the access settlement will penalise any party in this position. If there were to be a mix of firm and non-firm generators, especially for generators wishing to sell contracts, OFA results in either a better outcome (firm) or a worse outcome (non-firm) than now if congestion arises – note the status quo would no longer be available. Non-firm generators are only approximately indifferent if all generators affected by a congested flow gate are also non-firm. The AEMC Technical Paper also concludes that firm access will be widespread for similar reasons. [8]

If the question of how much OFA to hold is considered from a bottom up value perspective it can be compared to insurance. Under a design closer to a more traditional bilateral insurance mechanism it is likely generators would assess the merits of holding OFA in a similar fashion to their current assessments of energy hedging and business continuance insurance. This assessment can be made independently by each generator and would see generators compare the cost of buying the insurance to the probability weighted risk and resultant cost of an insurable event occurring in the absence of insurance. Uninsured generators would continue to face volume risk but not price risk. Insured generators would receive compensation for lost volume. In principle generators will do this with OFA as well and we would expect that if the LRIC was less than the cost they would face, then generators would purchase.

8 Technical Report section 11.2.4

However, OFA is more complicated as the payout is generator to generator, not insurer to generator. In the event of congestion where there is a mix of firm and non-firm, non-firm capacity will face volume and price risk whereas the firm generator will *only* face volume risk and be compensated for lost volume (within the limits of the design). In a situation where generators are relatively highly contracted this results in a far more severe cost of not carrying insurance to the point where generators will be unlikely not to hold OFA.

In summary we expect generators to hold significant levels of OFA.

5.2.2. Valuation – levels of OFA

Working from the proposition that OFA will be held generally across the market, generators will need to consider what level of OFA to hold, especially as transitional access falls away.

Ideally this would involve a valuation of potential financial losses and gains with different levels and types of OFA. This assessment will involve forecasts of congestion, assessment of the level of OFA to be held by neighbouring generators and forecasts of settlement. Settlement calculations will be the least complex part of this process although still an involved process that may require use of a 'goal seek' algorithm or similar.[9] Assessing likely levels and incidences of congestion will be more difficult and is one of the more complex analytical tasks in any power system given the number of interacting physical and commercial behavioural issues that can influence outcomes. A robust analysis will be very resource intensive and require high level skills. Alternatively rules of thumb may emerge – e.g. hold OFA to cover energy contract exposure or possibly related to minimum load.

Our impression from interviews is that generators overall are yet to assess the likely level or strategy for deciding how much OFA to hold after transitional allocations begin to fall away. Given final decisions about whether OFA is to be introduced or not and if it is what the level, timing and process of transitional allocations is to be, this is understandable.

Our expectation is that different generators will take different positions depending on their organisational structure, relative costs (e.g. base, intermediate, peaking, intermittent) and the nature of other generators they may share network access with (i.e. are part of the same flow gate(s)):

- Groups of large independent (non-portfolio) multi-unit generating stations (now quite rare within the NEM): The principal commercial driver for these generators will be to protect revenues to back energy hedges - typically around the 'n-1' level. A sensible strategy would be to purchase firm access to this level at a minimum and treat it as a cost of doing business. As discussed earlier, a balance between the level of energy hedges and base level of OFA would on average tend to result in a higher level of energy contracting than now - probably only marginally initially. Additional access would be assessed commercially and depend on the prevailing LRIC based on quantitative analysis of expected levels of congestion and LRIC prices for different scenarios. The assessment would involve detailed network forecasting and an understanding of the LRIC price curve for different levels and types of OFA.

9 Technical Paper, see Table 12.3

- An independent multi-unit generating station (or stations) that shares access with a significant station(s) that is part of a portfolio. This type of generator would also be seeking to protect contracted capacity but may be at risk of manufactured congestion due to bidding by the portfolio. It would also seek firm access to cover energy hedges but its trade-off between the value of increased contracting and OFA would be impacted by its assessment of the increased risk of scaling, including as a result of assessment of portfolio bidding and would tend to support somewhat higher level of OFA. This assessment would be more complex and the band of uncertainty and risk of inefficient decision greater.
- Portfolio generator with geographic diversity. The level of OFA that this type of generation business would hold is the most difficult to predict. It would be less likely to seek excess OFA as any scaling back affecting one of its generators would be unlikely to materially affect all of its units at the same time. For a similar reason it could also afford to carry a lower level of any OFA as congestion would be unlikely to affect all parts of its portfolio and accordingly geographic diversity would be an advantage. Portfolio generators would typically have staff capability to monitor instances of congestion and rebid with the aim of shifting dispatch to generation units not currently affected by congestion and thereby reduce exposure to access settlement charges.
- Individual remote generators that are relatively unaffected by other generators (e.g. remotely connected wind farms):
  - This group of generators is most likely to be exposed to material congestion in a world where TNSPs only construct (or maintain) network to meet their reliability obligations. In particular generators constructed on the basis of other than energy market price – for example renewable or fuel mandates – are more likely to be constructed at times and to a degree that does not align with customer reliability requirements and therefore not align with TNSP base plans;
  - Network connections to this group are also less likely to be part of a mashed network and hence network outages will have a proportionally higher impact than outages of the meshed network have on other generators;
  - OFA would therefore offer these generators a mechanism to firm up the physical connection and therefore access to market. In interviews remotely connected generators reported the historical annual impact of congestion of up to 5 per cent. Given our expectation of increased congestion and especially if renewable and or fuel mandates continue, this impact would rise. The LRIC for this group may also be vary significantly by location. LRIC may be low if it can be provided through what we can be described as 'low hanging fruit' that has been the basis for some funded augmentations reported by some generators, on the other hand it may be high because of its remoteness;
  - A strategy to purchase sufficient OFA to cover average output has been suggested for wind generators. It is not apparent why OFA equivalent to average output would necessarily be optimal as the value would be very much dependent on the alignment of the profile of wind strength with the profile of market price and network capability. For example if wind strength was on average stronger overnight and weakest at times of peak when the FAPS obligation for access is calculated, OFA to support average production could be an inefficiently high level. However, if a wind generator were to consider a lower level of OFA it would need to be very cognisant of the risk of becoming part of a shared flow gate as other generators construct and the network changes. This example highlights the complexity of the analysis needed to deliver more coordinated level of network investment as opposed to simply shifting the decision and risk to generators; and

  - Another consideration is the form of contracting. Wind farms are often built under some form of offtake agreement and the business case for purchasing OFA may be affected by which party carries the risk of network congestion under the agreement.

- Remote generation (e.g. wind farms) that share access with thermal peaking generation. The business case for a peaking generator typically relies on it having access at times of peak price, presumably near times of peak demand. A peaking generator may therefore seek a relatively high level of firm access related to the level of contracts it proposes to offer or higher if it is cost effective. Wind generation will have a lower cost of production and presumably a lower bid price and hence if congestion occurs it may be dispatched in preference to the thermal generation. Currently this situation would lead to bidding to the price floor. But under OFA, the peaking generator would be compensated and to the extent an intermittent generator is operating above the level of access it has decided is optimal would make payments under access settlement. This situation again highlights the importance of careful analysis that a wind generator would need to undertake unless it were simply to choose to purchase a high level of OFA.

In summary, we expect that although there will be a generally high level of OFA across the generation sector for the reasons discussed in the previous section, different generators will take different positions depending on their organisational structure, relative costs (e.g. base, intermediate, peaking, intermittent) and the nature of other generators they may share network access with (i.e. are part of the same flow gate(s))

5.2.3. Impact on energy contracting behaviour

Energy contracts stabilise revenue to generators and the expenses of wholesale customers by hedging the risk of volatility and uncertainty in Spot Price. Contracting also creates a financial exposure for generators that do not, for any reason, dispatch at least the contracted volume. As noted in section 5.2.1, for the majority of generators, plant performance is *currently* the dominant limitation on levels of contract they are willing to sell. This is consistent with our expectations given that for most generators the probability of plant failure is higher than network failure and that the potential impact of most network failures within the existing meshed networks has less effect than plant failure. Accordingly, for the majority of generators, mitigating the impact of loss of revenue due to network congestion will have only minor impact, at least in the short term.

In the case of portfolios, congestion risk is an even lesser concern as portfolios by definition have multiple generating stations which are generally connected to different parts of the transmission networks and are therefore unlikely to be affected by congestion across the entire portfolio at any particular time. In principle, generator-generator contracting can provide a similar level of insurance for independent generators, but in practice is understood to be impractical as a full substitute. As a result portfolios have a higher inherent contracting capacity than independent generator stations but are less affected by congestion.

Notably, some generators interviewed considered there would be a marginal increase in risk under OFA due to scaling and others considered that there would be a reduction allowing higher contracting volume, all else being equal. The majority highlighted the complexity of analysis that would needed to make an informed and efficient judgement. Risk and uncertainty of scaling back of OFA levels was highlighted.

Our view is that, on balance, OFA will increase the assurance generators should have about the level of contracting and this will allow higher levels of energy contracting than without the OFA regime. However, the materiality of increase in contracting will be dependent on the circumstances of each generator, future network configuration and on the geographic distribution of future generation plant and may be small initially.

We expect experience will provide the best demonstration of the impact of scaling and will be factored into decisions about the level of energy contracting, which will on average increase. Risk of scaling will also affect decisions about the level of firm OFA to hold. However, scaling risk will also be dependent on design of the conditions which will set the TNSP Firm Access Planning Standard (FAPS) which will be determined by the final drafting of the NER provisions.

We also anticipate the incidence and impact of congestion will grow rather than fall in the future relative to the current situation of falling demand and suppressed energy prices due to over-supply of generation and generation technology shifts towards more distributed generation resources and the existing transmission network ages and requires replacement or retirement. To the extent an increase in congestion will lead generators to reduce the level of energy contracting, OFA will allow it to be maintained or increased.

It is also pertinent to note that there are emerging situations where transmission built on the basis of earlier planning decisions and connects existing generation to load centres but is approaching the end of its economic life. Major capital expenditure will be required to maintain the existing capability. This expenditure may not be justified on reliability grounds given development of other generation projects not reliant on the aging lines.[10] In this circumstance there would be a case for the affected generators to purchase OFA to fund the refurbishment or accept increased risk of congestion. Clearly the affected generator(s) will need to assess the costs and benefits and may well opt to accept higher congestion. Elsewhere we have noted that there are a number of relatively small funded augmentations that have been agreed by generators and TNSPs that did not involve any commitment to firmness. While the existing funded augmentation provisions could be used in the case of ageing assets, the size of the commitment would probably make it untenable without some guarantee of access.

In summary, we anticipate OFA will allow some increase in energy contracting. Initially the effect will be small. In the longer term there will be a tendency for congestion levels to increase and OFA will allow contract levels to be at least maintained.

5.2.4. Impact on bidding behaviour

Confirmation of expected responses to OFA incentives

OFA will strengthen incentives for generator market bids for dispatch to be cost reflective, in particular it will dis-incentivise bidding to the price floor when congestion does occur, which at times can lead to inefficient dispatch. In the course of the work we confirmed the broad conclusions relating to cost reflective dispatch bids described in publications by AEMC and AEMO that formed part of the starting point for this review. These incentives generally counteract the effect of fundamental approximations inherent in the NEM market model when congestion occurs.

Appendix A illustrates the effects showing basic intra-regional constraints and showing cost reflective bidding with and without OFA and how OFA allows generators to achieve the same results as bidding to the price floor – albeit under the stylised conditions of the example.

However, we note the caveats AEMC and AEMO placed on their conclusions and that other factors can have material impact on the outcome.

Portfolios

The most significant caveat relates to the impact on generators within portfolios.

10 Interview with Powerlink, November 2014

Collectively, existing portfolios, including of gen-tailers, dominate the current generation sector. Portfolios are a logical and rational development given the market and broader financial environment. However, the role of portfolios has noted in analysis of existing inefficient bidding practices. The Technical Paper notes that the implications of portfolios were not accounted for in the analysis. AEMO has noted that some of the incentives for changed behaviours should not be expected to change behaviours around loops (i.e. within meshed networks) where the same business operates generating units at different points on the loop.[11]

Strategic bidding (subject to limitations within the rules) of different assets within a portfolio is entirely rational. A significant benefit of a portfolio is create internal flexibility to, for example, dispatch another generator within the portfolio in the event of breakdown of another without the need to rely on external parties and market mechanisms. Appendix B illustrates how portfolio behaviour is not disciplined by OFA incentives which is consistent with experiences in other markets.

Accordingly it is not safe to conclude that OFA will have the general disciplining effect on dispatch efficiency or price that has been discussed to date. Intuitively, some behaviours will be disciplined, but others not. The geographic and technology structure of the portfolios will impact how influential a portfolio may be. As the network configuration evolves, so too will the effect of a given portfolio.

The critical characteristic will be the degree to which a portfolio player can and does wilfully create congestion in the prevailing circumstances.

OFA will undoubtedly change the nature of bidding and especially during the initial period of transition allocations discipline some aspects of bidding but it will also open up the possibility of other forms of strategic bidding.

OFA reduces scope for commercial negotiation, innovation and transparency

In interviews with generators who had opposed OFA in earlier written submissions to AEMC the question was put as to whether by arguing against OFA that the status quo and all that entailed with access risk and interactions with TNSPs, was therefore better. As might be expected, all confirmed this was the case. This response was consistent with the advice that congestion was not a prime concern. They also noted that although there have been improvements and there is scope for further improvement in the process for network augmentation and interactions with TNSPs, the status quo is better overall than their understanding of OFA.

A point put by a number of parties in a number of cases is that the status quo provides more scope for innovative, bespoke solutions to access and therefore the associated cost. Generators provided a number of examples of relatively modest investments funded by various generators in this regard. We have not attempted to assess how many of these undertakings have been agreed but our general impression is that there is only a limited number. None of the examples involved firm access although there were examples of undertakings to revisit costs in the event other generators also connected in the same area. These undertakings provided a more graded level of access and cost.

11 Technical Paper Section 11.5.3 & AEMO First Interim Report, Section 3.6.3.

There was a general concern about asymmetry of exposure to costs in that TNSPs will only be able to provide OFA at the regulated (LRIC) price based on the approved methodology. Notwithstanding that generators would receive holdings of OFA, they would be unable to test or confirm that the price they would need to pay would be the most cost-effective price or best suit their needs. More generally there was concern that while their price is set for the term of the arrangement, TNSPs would be at a commercial risk only until the next regulatory period after which any difference in cost (either higher or lower) from the price being paid by generators would be transferred to customers through TUOS. Generators would therefore have far more at stake than TNSPs.

There was also repeated concern about the risk of entitlements being scaled, notwithstanding TNSPs would be subject to risk of commercial penalty if contracted OFA (the FAPS) is not met and generators may receive some of the penalty, but it would not be commensurate with the lost access payment.

Our view of these concerns is that while they each have merit in respect of risk of reduced innovation and a philosophical objection to regulation, they are being made in an environment of suppressed energy prices where it will be difficult to recover any additional costs. Further, OFA will reduce (but not eliminate) an advantage of portfolios. This point again highlights the importance of the transition period and process assuming transitional access is granted or is at very low cost and is not in perpetuity.

5.3. OFA impact on market outcomes

On the basis that reliability of supply is not impacted by OFA, the key general market issue is price.

Wholesale energy price comprises the net of spot and contract (used as a general term for a number of types of financial instruments that hedge spot price). Customer price comprises energy price plus regulated network charges and other fees.

Forecasting the impact on price is complex as OFA may create factors that reduce some components of price and other factors that may result in an increase and can be explained as follows:

Referring to the market model described in section 4.1, under OFA, generators are to pay for some of the shared transmission network where they do not pay now. All else being equal, when OFA is fully functional (after transition arrangements have been phased out), the proportion of industry costs borne by generators will rise and a percentage of TNSP costs will no longer be charged directly to customers. These changes should see an increase in energy cost and reduction in network cost. If this change was the only change there would be no reason to think a transfer of allocation of cost would change the net price to customers.

However, if the objectives of greater coordination between generation and transmission and improved dispatch efficiency are realised, the overall increase in generator costs should be less than the fall in transmission tariffs and the net cost to customers will fall.

Further, if the objective of reducing inefficient bidding by generators that artificially raises energy price is realised, there will be a reduced transfer from customers to generators and this will also reduce price to customers.

On the other hand, after expiry of transitional allocations, purchase of OFA will increase generator fixed costs with the expectation of also maintaining or increasing (variable) revenue by reducing congestion that would otherwise emerge. To illustrate the effect of this logic in more detail:

- Consider a highly idealised situation and assume that the market benefit test under the status quo would have resulted in augmentation and that the OFA regime delivers the same augmentation. As a result congestion and dispatch are the same and therefore energy market revenue and contract revenue are also unchanged from the current situation. If the generator has purchased exactly the correct amount of access for its dispatch it will have zero access settlement. Under the status quo, the generator may have needed to engage in bidding to the price floor but would not under OFA, but in this idealised world there would be no change in dispatch.
- The net result is higher cost to the generator and no change in revenue, consistent with transfer of some costs of transmission to the generation sector. This situation will not be sustainable unless energy price rises or generators accept a lower profit. In the case of a peaking generator the increase in costs will only be able to be recovered at peak times meaning higher peak prices and potentially more volatility (or through an equivalent increase in cap contract price). Competition will determine whether price rises or the affected generators realise lower profit, which in part will be determined by how the market price cap is set. In the longer term this effect will be equivalent to changing the capital cost of new entrant generators so that those generators locating in sections of the network with lower network charges are preferred – a desirable outcome.

As noted, to the extent OFA disciplines behaviours that produce uncompetitive or inefficient prices there will clearly be a reduced wealth transfer due to reduced spot price. However, it is very difficult to definitively identify which high prices are the result of behaviours that OFA will address and which are periods approaching genuine scarcity.

In summary, OFA will lead to increases in some components of customer price and decreases in others. In the short term downward pressures will be dominant but in the longer term the balance of impacts on price is hard to predict.

Inter-regional impacts

Inter-regional implications including counter-price flows and negative settlement residues described in the AEMC and AEMO papers show a similar set of incentives for cost reflective bidding consistent with access.

The OFA regime will include a mechanism that will firm up hedging across interconnectors and should therefore facilitate easier inter-regional contracting compared to the status quo.

The market and therefore customers will be the major beneficiary of improved trading, in particular the characteristic that will prevent negative settlement residues that in the end are funded by customers through transmission tariffs.

In the longer term generators considering siting near interconnectors, or more precisely in locations where interconnectors may play a material role in their dispatch and willingness to contract, should assign lower risk to these sites and this will support the objective of improved coordination of generation and transmission.

As with intra-regional issues, portfolios are less likely to be impacted by OFA, but overall will have reduced flexibility to exploit leverage over inter-regional congestion. However, this leverage is very dependent on the circumstances under the status quo and should be expected to continue to be so under OFA. It is therefore impractical to predict the materiality of change that will accrue due to OFA.

5.4. Other issues

5.4.1. Baseline waiting game

Assuming transitional allocation rolls away (as it is expected to), we expect there will be tension between generators demand for access and the TNSP planning baseline. This will occur if for no other reason than what is not paid for in the baseline and charged to customers in politically sensitive TUOS charges, will be paid for by generators. The potential for this situation to arise will grow with increased participation of geographically distributed generation resources, controlled demand side and price responsive customer demand. These changes will require more rather than fewer judgements by TNSPs in the preparation of baseline plans. The more augmentation included in the baseline the lower the cost of access will be.

This situation may be a non-issue if there is sufficiently strong oversight of the baseline by the AER, but this means reliance on a regulatory measure as a protection for a competitive initiative – a necessary trade-off?

5.4.2. Resource and skill implications

OFA aims to ensure more efficient coordination between generation and transmission by shifting some of the decisions about network investment to generators. Without access to sufficient resources and skills there is a risk of simply shifting costs to the generation sector without improving efficiency. Generator to generator incentives within the OFA settlement will rapidly discipline generator bidding. However, any inefficiency in decisions about network investment made by generators will be sunk costs and potentially passed through to customers - not withstanding that holdings can be traded or sold back to the TNSP, possibly crystallising the cost of an inefficient decision by a particular participant, but not changing the economic cost.

Efficient functioning of the OFA regime therefore presumes that the skills and resources will shift to the generation sector. A similar (and successful) shift in resources was an integral part of creation of the energy market as it shifted decisions relating to generation investment from utilities to the generation sector. Adequate information, skill sets and resources will need to be available to the generation sector if the result is to be a net improvement.

5.4.3. Smaller generators at a resource disadvantage

Smaller generation businesses face a particular resource issue. OFA will offer smaller and remote generators the opportunity to 'set and forget' issues around network congestion. The ability to do this will be an advantage and may allow them to reduce resource costs compared to the status quo. However, 'set and forget' is a strategy that would be most applicable for:

- Remote generators that do not share access with other generators to any significant degree and thus are the dominant generator in flow gates that might affect their settlement;
- Generators that choose not to monitor opportunities for short term access, trading or sell-back in any depth in order to optimise their positions. This would mean OFA is a sunk cost – a viable commercial position to take but not necessarily economically optimal; or
- Generators that choose to hold a high level of OFA. This would be a strategy better suited to peaking generators than intermittent generators who will generally not hold OFA approaching capacity but more likely something less (possibly related to average capability) and therefore be partially non-firm when their capacity is high (when wind is blowing).

5.4.4. Reduced negotiation and opportunities for innovation

In the short term the practical alternative to the OFA regime is the status quo, possibly with some minor modifications. A number of generators interviewed expressed blunt opposition to additional regulatory processes as a matter of principle. By default they were accepting the status quo as ‘not perfect but satisfactory’. This argument has merit in respect of the requirement under the status quo for negotiation with TNSPs if congestion is expected to be an issue.

In interviews a number of generators noted that under the status quo arrangements innovative bespoke arrangements have emerged, including a number of funded augmentations – albeit for minor works and only a small number of examples were noted. The conventional wisdom is that funded augmentations simply don’t happen but their existence demonstrates that there is scope for innovation and agreements under the current regime – even though they offer no guarantee of access. The existence of funded augmentations also supports the fundamental objective of OFA: to provide a tool to enhance access.

We do not expect funded augmentations to be an alternative for OFA, especially for works of any significance. The emergence of funded augmentations should be seen as guidance about detailed implementation rather than affecting the core go no-go decision about whether to proceed with OFA. However, the examples also indicate there may be cost effective but unused ’low hanging fruit’ available.

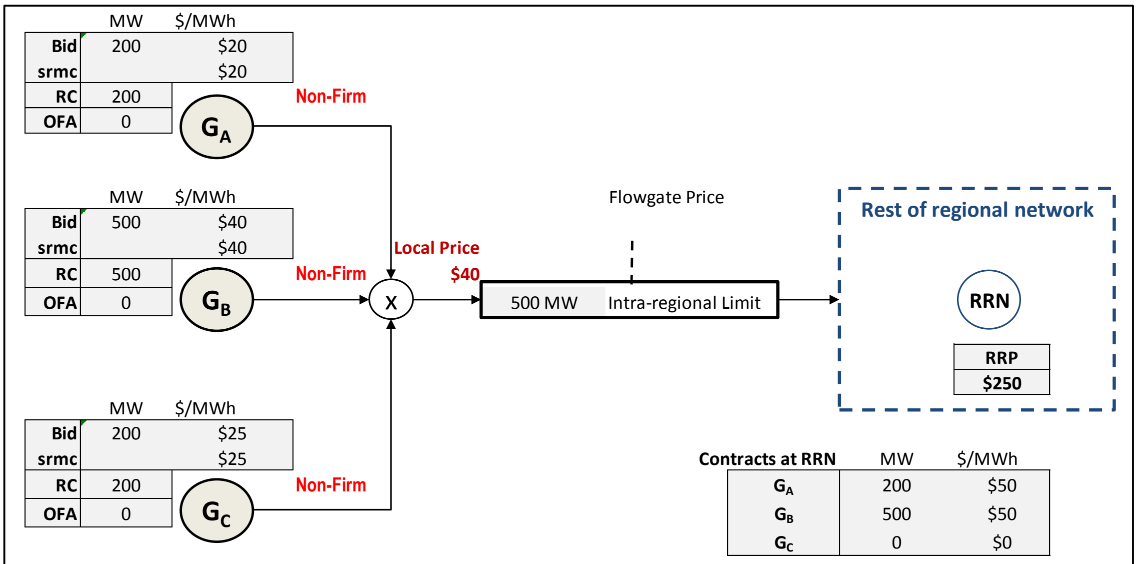
Accordingly it would be desirable to avoid institutionalising negotiations around applications for OFA noting that consideration of OFA will be an obligation of TNSP resources but consideration of funded and bespoke arrangements is currently voluntary. The risk of inadvertently suppressing such innovation can be mitigated by flexibility around detailed rules. The Technical report discusses a number of the related issues.[12]

12 Refer Technical Paper section 7.3

Appendix A OFA v status quo examples

Status Quo with intra-regional constraint and cost reflective bidding (ignoring transmission losses). Flow gate capacity equals 500MW (well less than sum of availability (900MW) and less than contracted capacity (700MW))

Figure 4 Status Quo - Cost reflective constrained network



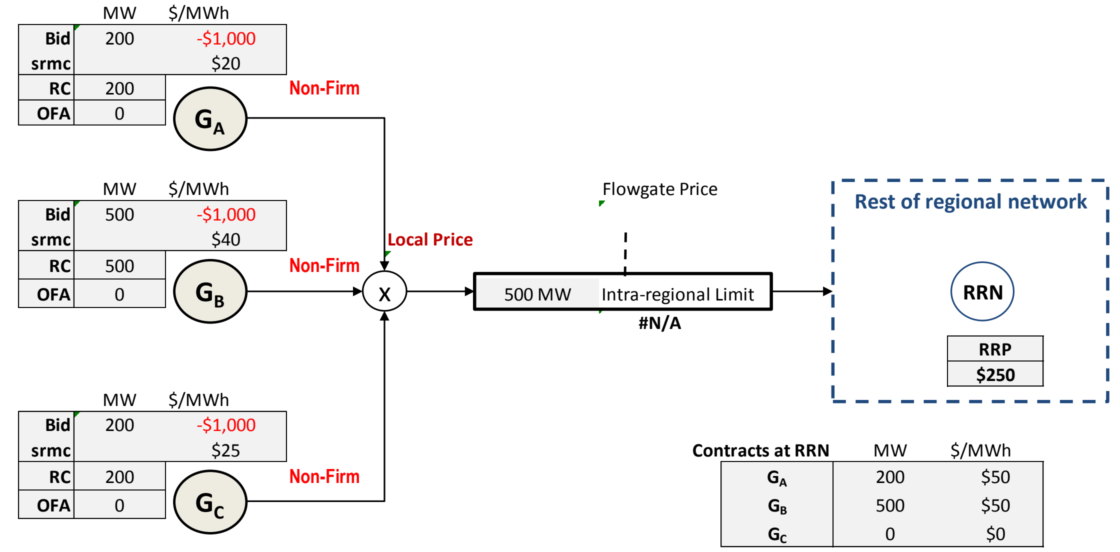
Without OFA

	Energy		Contracts			Combined (no OFA)		
	Dispatch	**Settlem't**	**Vol**	**Price**	**Settlem't**	**Revenue**	**Cost**	**Net Revenue**
G_A	200 MW	$50,000	200 MW	$50	-$40,000	$10,000	-$4,000	$6,000
G_B	100 MW	$25,000	500 MW	$50	-$100,000	-$75,000	-$4,000	-$79,000
G_C	200 MW	$50,000	0 MW	-	-	$50,000	-$5,000	$45,000
Tot	**500 MW**	**$125,000**	**700 MW**		**-$140,000**	**-$15,000**	**-$13,000**	**-$28,000**

- By default all generators have only non-firm access.
- The highest priced generator (G_B) is dispatched for 100MW and makes significant contract payments resulting in a loss of $79,000
- Total dispatch cost is $13,000

Status Quo with intra-regional constraint and disorderly bidding to the price floor. Flow gate capacity equals 500MW (well less than sum of availability (900MW) and less than contracted capacity (700MW))

Figure 5 Status Quo - Constrained network and uncompetitive bidding



Without OFA

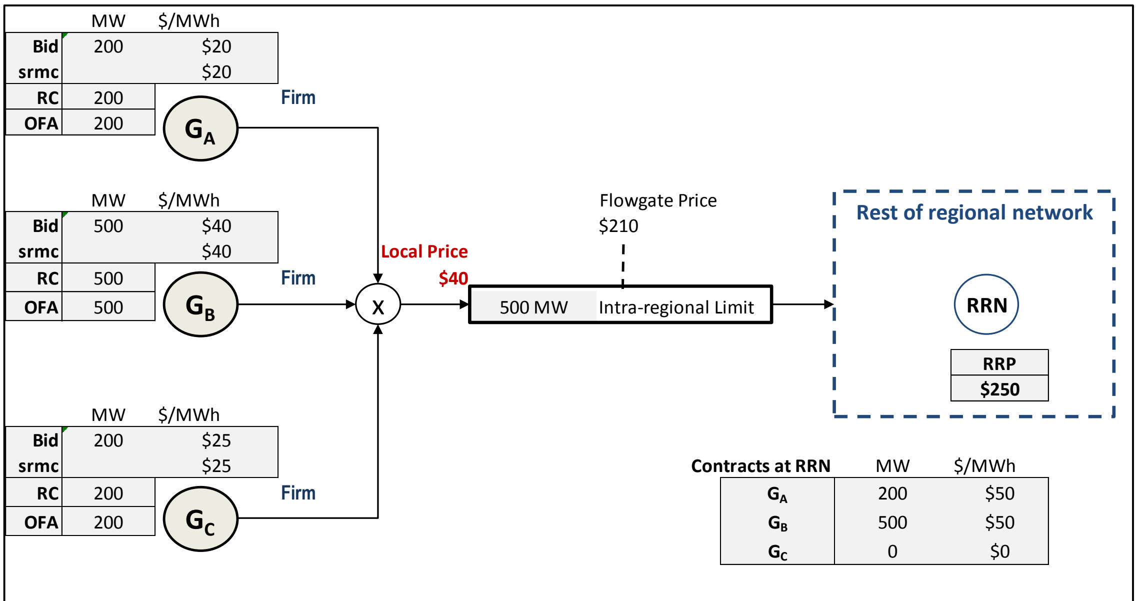
	Energy		Contracts			Combined (no OFA)		
	Dispatch	Settlem't	Vol	Price	Settlem't	Revenue	Cost	Net Revenue
G_A	111 MW	$27,778	200 MW	$50	-$40,000	-$12,222	-$2,222	-$14,444
G_B	278 MW	$69,444	500 MW	$50	-$100,000	-$30,556	-$11,111	-$41,667
G_C	111 MW	$27,778	0 MW	-	-	$27,778	-$2,778	$25,000
Tot	**500 MW**	**$125,000**	**700 MW**		**-$140,000**	**-$15,000**	**-$16,111**	**-$31,111**

- By default all generators have only non-firm access.
- All generators bid to the price floor and dispatch is pro-rated (by the size of the -$1,000/MWh bands which are assumed to equal total capacity). G_B loss is reduced to $41.667 at the expense of G_A. GB cannot achieve a better position as this could only occur if GA or GC bid a higher price and sacrificed their own net revenue position
- Total dispatch cost increase to $16,111 showing dispatch is less efficient

With OFA, intra-regional constraint and cost reflective bidding. Flow gate capacity equals 500MW (well less than sum of availability (900MW) and less than contracted capacity (700MW)).

This case represents a situation where the FAPS has not been met in the particular half hour and scaling has been required.

Figure 6 OFA - cost reflective bidding, OFA scaling required



Without OFA

	Energy		Contracts			Combined (no OFA)		
	Dispatch	Settlem't	Vol	Price	Settlem't	Revenue	Cost	Net Revenue
G_A	200 MW	$50,000	200 MW	$50	-$40,000	$10,000	-$4,000	$6,000
G_B	100 MW	$25,000	500 MW	$50	-$100,000	-$75,000	-$4,000	-$79,000
G_C	200 MW	$50,000	0 MW	-	-	$50,000	-$5,000	$45,000
Tot	**500 MW**	**$125,000**	**700 MW**		**-$140,000**	**-$15,000**	**-$13,000**	**-$28,000**

Plus OFA

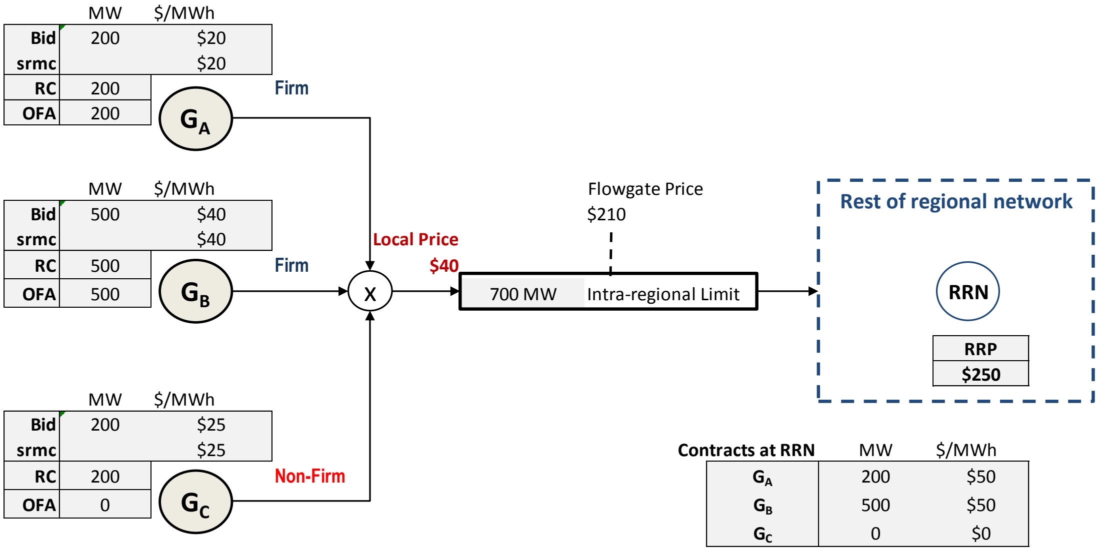
	Access Settlements				Total
	Entitlement [E]	Usage (U)	E-U	Settlem't	Net Rev inc OFA
G_A	111 MW	200 MW	-89 MW	-$18,667	-$12,667
G_B	278 MW	100 MW	178 MW	$37,333	-$41,667
G_C	111 MW	200 MW	-89 MW	-$18,667	$26,333
Tot	**500 MW**	**500 MW**	**0 MW**	**$0**	**-$28,000**

- With OFA, as expected, and all generators bidding at cost dispatch outcomes are the same as under the status quo with cost reflective bidding (but differ from the disorderly bidding outcome).
- OFA settlement leaves GB in the same position as bidding to the price floor (making a loss after spot, energy contract and access settlement) of $41,667.
- Access settlement amounts for GA and GC are similar but their contract exposures are different and hence their net positions do not match their bidding outcomes.
- Although it is a loss in case GA is better off under OFA illustrating the potential for higher contracting under OFA (all else being equal).

OFA Cost reflective bidding. Flow gate capacity equals 700MW (matching sum of contracted capacity but less than sum of available capacity (900MW).

This is the situation where purchase of OFA has seen the TNSP increase capacity to match the contracted level of OFA (the FAPS). The FAPS is met but there is no spare capacity available for non-firm generators.

Figure 7 OFA - Cost reflective bidding - flow gate capacity matches FAPS



Without OFA

	Energy		Contracts			Combined (no OFA)		
	Dispatch	Settlem't	Vol	Price	Settlem't	Revenue	Cost	Net Revenue
G_A	200 MW	$50,000	200 MW	$50	-$40,000	$10,000	-$4,000	$6,000
G_B	300 MW	$75,000	500 MW	$50	-$100,000	-$25,000	-$12,000	-$37,000
G_C	200 MW	$50,000	0 MW	-	-	$50,000	-$5,000	$45,000
Tot	**700 MW**	**$175,000**	**700 MW**		**-$140,000**	**$35,000**	**-$21,000**	**$14,000**

Plus OFA

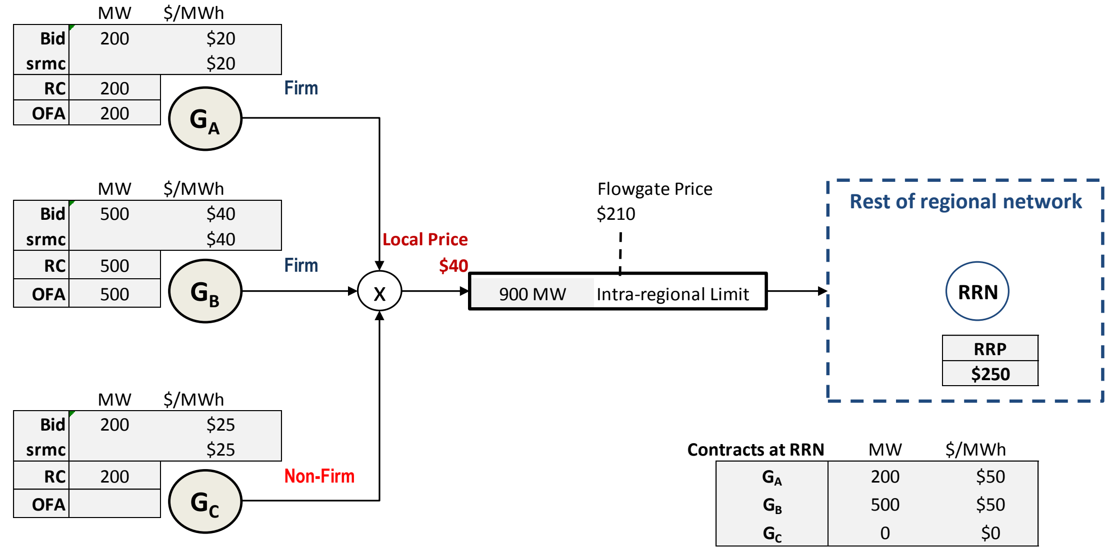
	Access Settlements				Total Net Rev inc OFA
	Entitlement [E]	Usage (U)	E-U	Settlem't	
G_A	200 MW	200 MW	0 MW	-	$6,000
G_B	500 MW	300 MW	200 MW	$42,000	$5,000
G_C	0 MW	200 MW	-200 MW	-$42,000	$3,000
Tot	**700 MW**	**700 MW**	**0 MW**	**-**	**$14,000**

- With OFA, as expected, and all generators bidding at cost dispatch outcomes for the lower cost generators (GA and GC) are the same as under the status quo and GB is dispatched higher.
- GA's dispatch matches its contract volume and its access entitlement and it has zero access settlement. GA receives net revenue in line with its contracted arrangement.
- GC effectively uses 200MW of GBs access which is reflected in the equal and opposite access settlement to leave GB also receiving net amount in line with its contracted amount.
- GC makes a small positive net margin.

OFA Cost reflective bidding. Flow gate capacity equals 900MW (matching sum of contracted capacity and sum of available capacity (900MW)

This case may occur if the network reliability standard resulted in the TNSP augmenting (or retaining) the network capacity in excess of the FAPS (in which case the OFA holdings of GA and GB may have been low)

Figure 8 OFA - Cost reflective bidding - flow gate capacity exceeds FAPS



Without OFA

	Energy		Contracts			Combined (no OFA)		
	Dispatch	Settlem't	Vol	Price	Settlem't	Revenue	Cost	Net Revenue
G_A	200 MW	$50,000	200 MW	$50	-$40,000	$10,000	-$4,000	$6,000
G_B	500 MW	$125,000	500 MW	$50	-$100,000	$25,000	-$20,000	$5,000
G_C	200 MW	$50,000	0 MW	-	-	$50,000	-$5,000	$45,000
Tot	**900 MW**	**$225,000**	**700 MW**		**-$140,000**	**$85,000**	**-$29,000**	**$56,000**

Plus OFA

	Access Settlements				Total
	Entitlement [E]	Usage (U)	E-U	Settlem't	Net Rev inc OFA
G_A	200 MW	200 MW	0 MW	-	$6,000
G_B	500 MW	500 MW	0 MW	-	$5,000
G_C	200 MW	200 MW	0 MW	-$0	$45,000
Tot	**900 MW**	**900 MW**	**0 MW**	**-$0**	**$56,000**

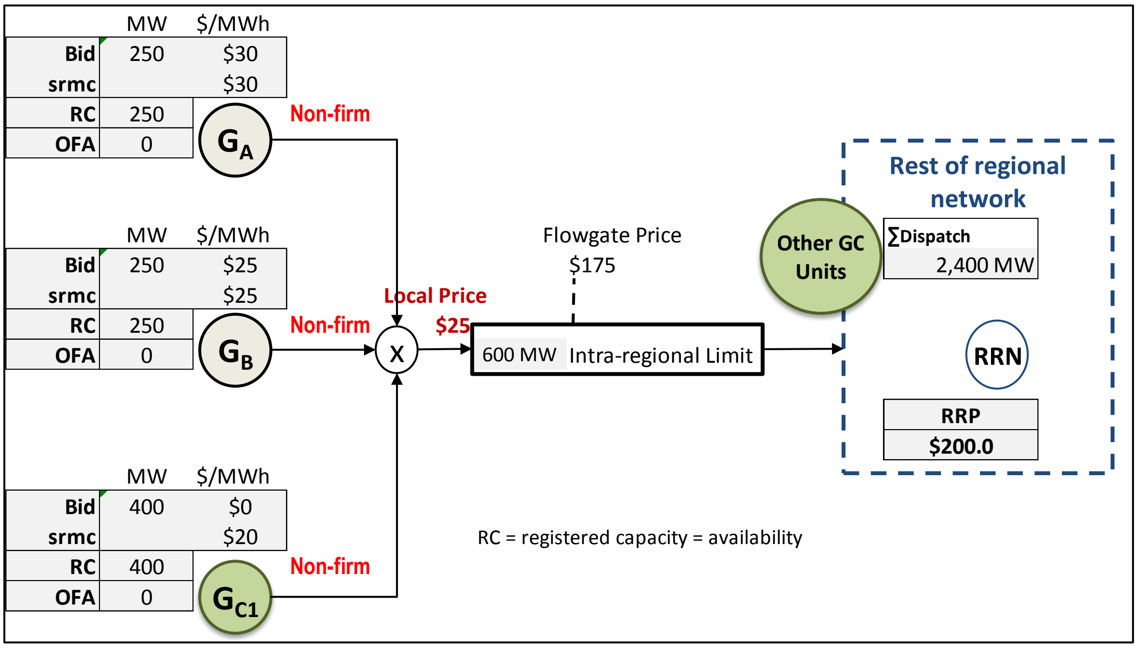
- Dispatch results reflect higher dispatch of GB up to the higher constraint. Hence dispatch cost increases but remains efficient (assuming it dispatch of GB at $40/MWh is the most efficient across the system).
- Both firm (GA and GB) and non-firm (GC) generators use no more than their entitlement in access settlement which is zero in all cases leaving GA and GB in the same (unconstrained) situation as the case with flow gate limit of 700MW but GC now makes considerably higher return.

Appendix B Portfolio scenarios

Assume a scenario with three generators upstream of a transmission constraint, one of which belongs to a portfolio generator with significant capacity on the other side of the constraint. G_A, G_B and G_{C1} are within the constrained region and G_{C1} is part of GC, a portfolio generator with significant capacity on the other side of the constraint. Suppose that GC has some ability to influence the extent to which the constraint binds.

Assume initially that neither G_A nor G_B has procured firm access and that they each bid at srmc as illustrated below.

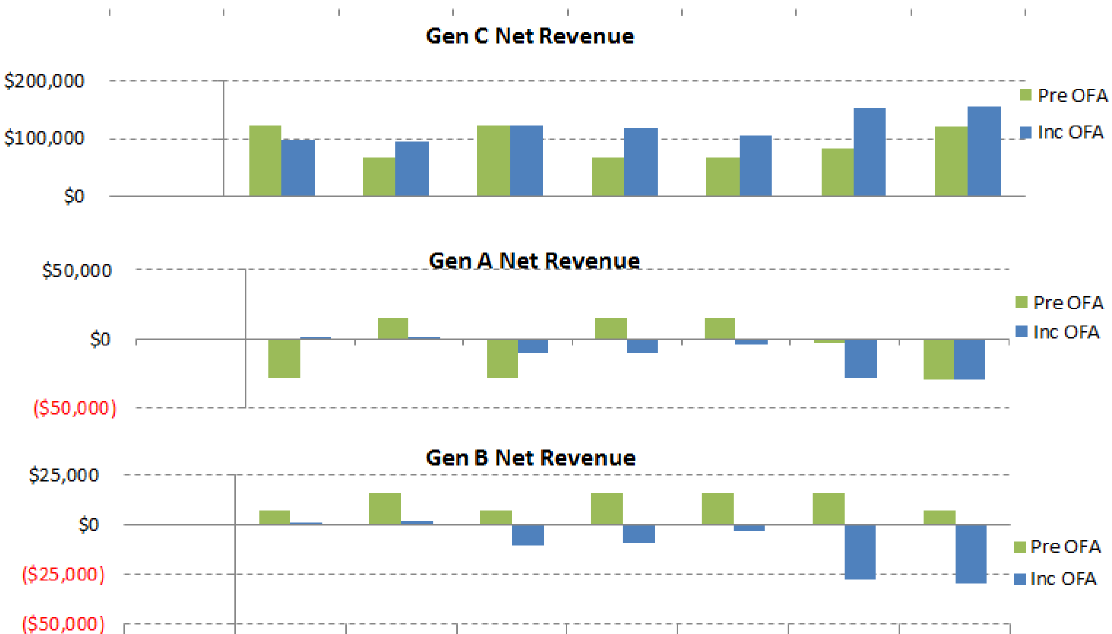
Figure 9 Non-firm portfolio case



The following charts illustrate net revenues under different bidding and firm access strategies adopted by GC. The nominal flow gate limit is 600 MW except in the three right hand scenarios where GC has been able to limit the constraint further – with flow on effects to the RRP – and replace lost generation from within the rest of its portfolio. The nominal RRP is $200. The x axis labels indicate the approach adopted by GC in each scenario. Net revenues are shown pre and post OFA, excluding any contract positions, and indicate that the portfolio is able to benefit from manipulating the constraint. Obtaining firm access increases GC benefits in all instances except where it bids at srmc, does not manipulate the constraint, and has firm access.

The following shows the same scenarios but with GA and GB fully firm. The results are similar but with firm access providing some compensation for GA and GB and reducing the benefits to GC of firm access.

Similar but smaller impacts are evident when contract positions are included (200 MW each for GA and GB and 2,000 MW for GC, all at $60), the impacts of GC having firm access being more pronounced.



xtra GC P/F dispatch	0 MW	0 MW	0 MW	0 MW	100 MW	200 MW	400 MW
GC Firm Access	0 MW	0 MW	400 MW	400 MW	0 MW	400 MW	400 MW
FG	600 MW	600 MW	600 MW	600 MW	500 MW	400 MW	200 MW
GC1 Bid	$20	$35	$20	$35	$35	$35	$35
RRP Impact	0%	0%	0%	0%	1.0%	2.0%	5%

Appendix C References

Transmission Framework Review	AEMC 2013, Transmission Frameworks Review, Final Report, 11 April 2013, Sydney
Technical Report	AEMC 2012, Transmission Frameworks Review, Technical Report: Optional Firm Access, 16 August 2012, Sydney
AEMO First Interim Report	AEMO 2014, Optional Firm Access AEMO First Interim Report, July 2014, Melbourne
AEMO Draft Report	AEMO 2014, Optional Firm Access AEMO Draft Report, 23 December 2014, Melbourne
NER	National Electricity Rules
State of the Market Report	Australian Energy Regulator, State of the Market 2014, Available at https://www.aer.gov.au/node/29358