stanwell

30 January 2014

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Lodged electronically via: http://www.aemc.gov.au
Reference: EPR0039

Dear Mr Pierce

Stanwell Corporation Limited (Stanwell) welcomes the opportunity to comment on the Optional Firm Access (OFA) Acknowledgement and Request for Comment Note (Note) as published by the AEMC on 5 December 2014.

While falling demand forecasts since the time of the Transmission Frameworks Review are material and will affect the potential costs and benefits of the OFA project, Stanwell consider this a second-order effect. That is, this decrease will simply make the immaterial and ambiguous potential benefits of OFA even more immaterial.

While forecasts of demand growth may vary over time, the ever-growing complexity of the OFA project appears to have no scope for reversal. Complexity inevitably creates cost, and given the limited potential benefits of OFA even under favourable conditions it is clear that there is likely to be a net detriment to the NEO and participants if OFA is introduced.

Attached is a detailed response to the Note.

We welcome the opportunity to discuss the matters raised in this response. Please contact me on (07) 3228 4529 should you wish to discuss this submission.

Yours sincerely

Luke Van Boeckel
Manager Regulatory Strategy

GPO Box 800 Brisbane Qld 4001
Stanwell Corporation Limited ABN 37 078 848 674 AFSL No. 238463 stanwell.com

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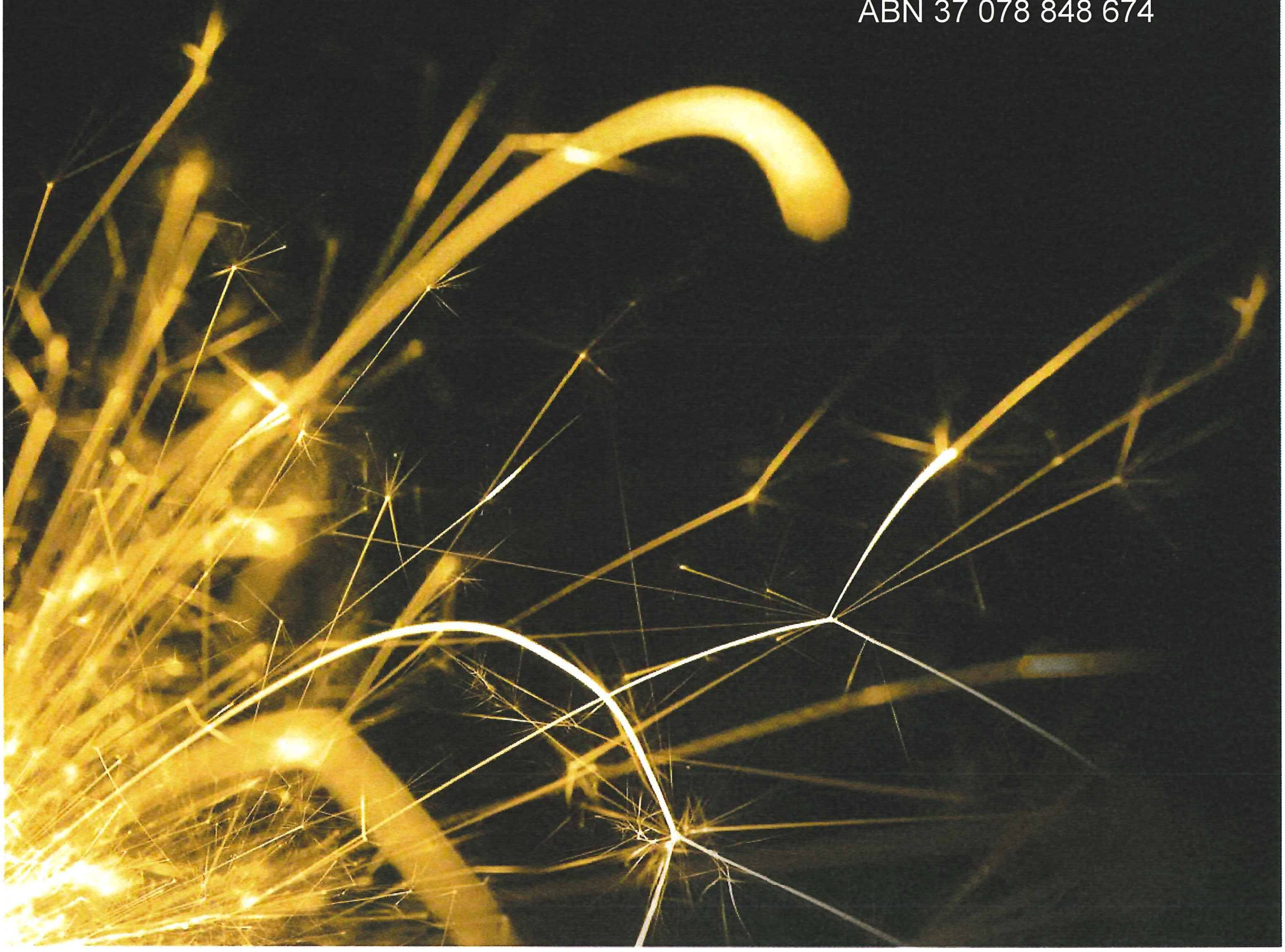
OPTIONAL FIRM ACCESS

RESPONSE TO AEMC NOTE

JANUARY 2015

Stanwell Corporation Limited
ABN 37 078 848 674



1. Executive Summary

Stanwell considers that the Optional Firm Access (OFA) Design and Testing process was initiated despite analysis that showed key concerns of the AEMC were immaterial. Most importantly, the ROAM Consulting report commissioned during the Transmission Frameworks Review (TFR) confirmed that

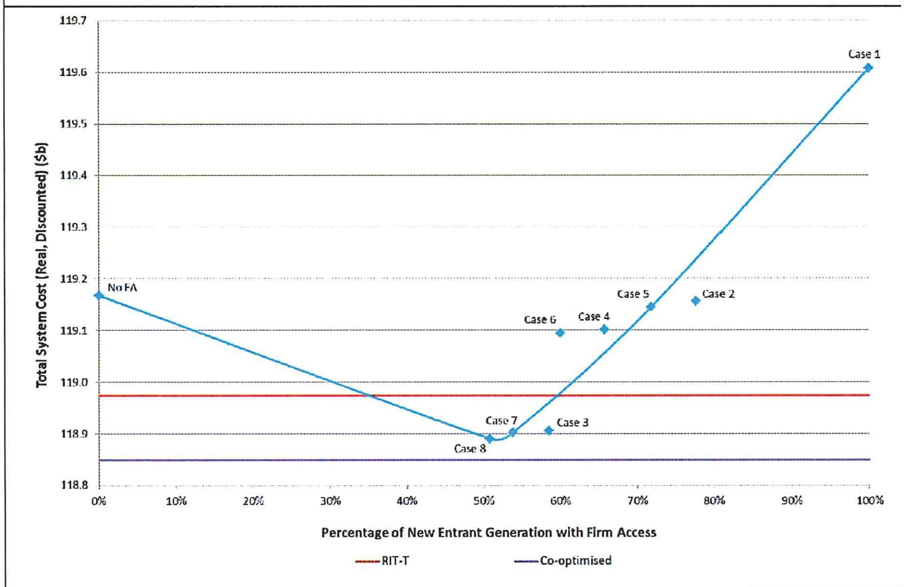
1. cost reflective locational signals under OFA are unlikely to significantly reduce total system cost (concern 1),
2. Transmission and generation coordination under current arrangements “are capable of delivering market outcomes that are closely aligned with theoretical best practice”, (concern 3) and
3. disorderly bidding represented a fraction of a percent of the resource cost of the NEM (concern 7).

In fact, the ROAM analysis showed that the performance of the OFA model was quite variable depending on the assumed amount of Firm Access (FA) that new entrant generators purchased. Figure 6.13 below is taken from the ROAM report and shows that the OFA model *can* be slightly cheaper than the RIT-T[1] under specific procurement scenarios, but it can also be more expensive.

This analysis also highlights the extremely marginal effect of a change to market design on overall investment costs. From a baseline approaching $119Bn, the modelled difference between RIT-T and OFA is between less than $100m saving (<0.1%) and $600m extra cost (<0.6%). This is despite ROAM deliberately using aggressive modelling inputs in order to maximise the observable differences between approaches. [2]

Given the complexity of OFA and the fundamental nature of the change to market design, Stanwell continues to be of the opinion that there is no case for change.

Figure 6.13 – Total System Costs: USE valued at MPC (Scenario 2)



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[1] RIT-T is used in this submission as a shorthand description of the current planning standards. Similarly, OFA is used as shorthand for the planning (and operational) standards that would apply to both FAS and reliability standard augmentations if the proposed changes are introduced. Stanwell acknowledge that the RIT-T process will remain integral to augmentations if OFA is introduced.

[2] ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013, page 5 “ROAM has selected Scenarios 1,2 and 3 from the AEMO planning studies, as these scenarios have a higher demand growth expectation, which is more likely to highlight potential changes in efficiency under the alternative packages”.

Since ROAM performed their analysis demand forecasts have fallen significantly across the NEM, further weakening the "case" for OFA improving co-optimisation.

Additionally, while OFA is proposed to apply to market scheduled and semi-scheduled generation and transmission networks, it does not incorporate distribution networks, non-scheduled generation, demand side response or storage. All indications are that these areas will constitute an increasing proportion of total system costs into the future.

The following table shows how none of the 7 concerns identified by the AEMC are resolved by OFA:

Problem identified by AEMC	**OFA will not solve this problem**
1. The lack of clear and cost-reflective locational signals	A simple mathematical analysis contained in this report proves that firm access does not provide any changed locational signal.
2. Inefficient TNSP planning	The TNSP is materially in charge of pricing firm access. Any firm access pricing errors will be borne by customers either through TUOS charges or passed on by the generator in wholesale prices.
3. Transmission and generation costs not co-optimised	OFA requires a TNSP to maintain two planning standards - the reliability standard and the firm access standard. Moving from the RIT-T to OFA has been modelled to cost between -$100m (saving) and +$600m (cost)[3].
4. TNSP and generator incentives are not aligned	The TNSP incentive scheme is described by the AEMC as "low powered" and "weak".
5. Difficulties managing 'price risk' between regions	*Dispatch* and *Access* are explicitly decoupled by OFA. OFA does not provide certainty of dispatch or access, particularly given that many unforeseen pricing events occur when the system is not in "normal" condition.
6. Lack of dispatch certainty during congestion	Firm access is subject to de-rating, uncertain quality of provision, minimal TNSP incentive arrangements and a non enforceable planning obligation.
7. Disorderly bidding	Incentives will remain. There will be a strong incentive for firm participants to bid in a disorderly way in the presence of congestion if their dispatch varies from their access level.

[3] ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013, figure 6.13

2. Introduction

The Optional Firm Access (OFA) project was initiated in March 2014 having arisen from the Transmission Frameworks Review (TFR) which ran from April 2010 to April 2013. The TFR in turn arose from the Review of Energy Market Frameworks in light of Climate Change Policies which ran from August 2008 to October 2009.

At the conclusion of the Transmissions Frameworks Review Stanwell determined that a substantive case for change had not been made, and that the proposed solution of OFA would be unlikely to address the concerns that had been raised during TFR. The subsequent OFA Design and Testing process has since reinforced Stanwell's concerns.

On 5 December 2014, and in response to a letter[4] to the COAG Energy Council, the AEMC called for submissions addressing:

1. The rationale for why stakeholders consider that the seven problems that OFA is attempting to address are no longer relevant.
2. If the problems are no longer relevant, whether there are circumstances in which stakeholders could envision any or all of these problems becoming relevant at some time in the future? If not, why not?
3. If the problems are still relevant, any alternatives to OFA to address them.

For each of the seven problems that OFA attempts to address, this submission demonstrates

- Why the problem is not relevant
- Why OFA does not solve the problem
- The alternatives to OFA to solve the problem

3. Concern 1: The lack of clear and cost-reflective locational signals

AEMC Concern 1: The lack of clear and cost-reflective locational signals for generators, such that their locational decisions do not take into account the resulting transmission costs

3.1 Why this problem is not relevant

The current RIT-T arrangements provide a clear locational signal because a TNSP must consider the full 'market benefits'[5] of an augmentation option and its alternatives. This consideration takes into account the total costs of transmission and generation (as well as other variables such as the degree of load shedding etc).

The current existence of a strong locational signal was confirmed by Frontier Economics[6]:

> *"The locational signals provided under the current transmission planning arrangements are more powerful than is commonly assumed. These signals arise through the operation of the RIT-T, including participants' expectations of how the RIT-T will be applied in future. The importance of the RIT-T lies in how it is used by TNSPs to determine where and when transmission investment ought to be undertaken to ensure reliability standards are maintained.*
>
> *Generators will tend to find it profitable to locate in areas where the TNSP considers that new generation will be built and hence has augmented or will augment the transmission network, thereby reducing actual and expected congestion. The AEMC acknowledges*

[4] The letter was to the COAG Energy Council from a group of concerned generators and retailers, including Stanwell.

[5] AER, *Regulatory investment test for transmission, Final*, June 2010, clause (1), p.3.

[6] Submission to Transmission Frameworks Review prepared by Frontier for the National Generators Forum http://www.aemc.gov.au/getattachment/7bb8fd27-07ec-4775-82b6-25f3ad8dd3df/National-Generators-Forum-Frontier-Economics-attac.aspx

that TNSPs' current planning processes send implicit locational signals to generation investors. Indeed, this is what lies behind the AEMC's concern that TNSPs' lack of information about generator costs can result in poor co-optimisation between generation and transmission investment.

The issue is therefore not the existence of signals created by the RIT-T, but the integrity and appropriateness of those signals as compared to the signals provided by alternative arrangements such as the OFA proposal."

3.2 Why OFA does not solve this problem

The ROAM report prepared for the AEMC as part of the TFR confirmed that cost reflective locational signals under OFA are unlikely to significantly reduce total system costs[7].

Access pricing under the OFA model is based on the Long Run Incremental Cost (LRIC) of the additional investment required to provide that access under the Firm Access Standard (FAS). For example if a reliability upgrade of a flow path would be required in say, 10 years, but the OFA request means that this augmentation would be required in only 5 years, the LRIC of the OFA request would be the NPV difference between the two investment timelines.

The locational signal presented to new entrant generators will be the *difference* between the LRIC of several possible connection locations, together with an estimate of the proportion of congestion risk at each location that would be avoided by having firm access. That is, when choosing between two locations the generator has four options instead of two (plus if the generator decides to buy firm access, a choice of how much firm access to buy).

OFA will not affect the locational decision of generators except in very specific circumstances:

- Assuming that new entrant generators estimate the cost of congestion when deciding on their location, and that the procurement of firm access is expected to mitigate the majority of that congestion risk, then the relative cost of firm access is likely to reflect the relative cost of congestion and OFA will not affect the generator's decision on where to locate.
- Assuming that new entrant generators estimate the cost of congestion but do not consider firm access to mitigate the majority of this risk, then it is unlikely that the introduction of OFA will result in these generators procuring firm access and hence OFA will not affect their decision on where to locate.
- Assuming that new entrant generators do not estimate the cost of congestion when deciding on their location it is unlikely that the introduction of OFA will result in them procuring Firm Access to mitigate this congestion and hence OFA will not affect their decision on where to locate

Expressed mathematically,

Let:

$C_{x,NF}$ be the $ value of a non firm generator's congestion at site x

$C_{x,F}$ be the $ value of a firm generator's congestion at site x

$LRIC_x$ be the $ value of Firm Access from site x to the relevant reference node

The four options available to a generator at two possible locations are:

1. Site at location A, don't purchase firm access and accept congestion risk ($0 \leq C_{A,NF}$).
   - Total cost is $C_{A,NF}$
2. Site at location A, purchase firm access (cost $LRIC_A$) and accept the residual congestion risk (_$C_{A,F} \leq C_{A,NF}$).
   - Total cost is $C_{A,F} + LRIC_{A.}$
3. Site at location B, don't purchase firm access and accept congestion risk ($0 \leq C_{B,NF}$).

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7 ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013, page 67

- Total cost is $C_{B,NF}$

4. Site at location B, purchase firm access (cost $LRIC_B$) and accept the residual congestion risk (_$C_{B,F} \leq C_{B,NF}$).
    - Total cost is $C_{B,F}$ + $LRIC_B$.

In the unlikely event that all other investment inputs are equal, the generator is likely to select the minimum of the four locational costs: $C_{A,NF}$, $C_{A,F}$+ $LRIC_A$, $C_{B,NF}$, $C_{B,F}$+$LRIC_B$.

There are some significant difficulties with this approach. It is extremely difficult for a generator to price congestion risk accurately. It is also extremely difficult to determine the proportion of congestion risk that procuring firm access will avoid.

Assuming that the generator assigns full congestion mitigation to the firm access ($C_{A,F}$=0, $C_{B,F}$=0)the generator's four options become $C_{A,NF}$, $LRIC_A$, $C_{B,NF}$, $LRIC_B$. The generator will likely select the minimum of these four options which is a choice between two estimated numbers ($C_{A,NF}$,$C_{B,NF}$) and two known numbers ($LRIC_A$,$LRIC_B$).

There are likely to be very few circumstances where site A has a higher congestion cost ($C_{A,NF}$) but lower LRIC ($LRIC_A$) than site B, or vice versa. This is because a higher LRIC implies that there is more congestion forecast at that site prior to augmentation[8].

If site A has a lot of forecast congestion compared to site B, then it follows that $C_{A,NF} > C_{B,NF}$ and $LRIC_A > LRIC_B$. This eliminates two of the four options ($C_{A,NF}$, $LRIC_A$) leaving the generator with only two options ($C_{B,NF}$, $LRIC_B$). These remaining two options represent a choice at location B between purchasing firm access or not. In the absence of OFA, the generator is also likely to site at location B since $C_{A,NF} > C_{B,NF}$.

Counterintuitive value flows and barriers to exit

Due to the definitions used in calculating flowgate entitlements, a number of counter-intuitive value flows may be produced, and the existence of a firm access agreement may provide a barrier to exit for existing plant. There appears to be no alternative definitions which would retain value for the purchaser of firm access but significantly reduce or remove these concerns.

A barrier to exit is created by the reliance on generator capacity as one input to a firm generator's flowgate entitlement. As a generator procuring firm access will be required to pay the firm access charge regardless of its capacity, it will be incentivised to retain its registered capacity at least equal to its firm access amount for the duration of the contract in order to receive an offsetting cash flow in the event of congestion. A similar concern has been raised by the University of NSW in relation to transitional access.

One instance of counter-intuitive value flows would occur if an intermittent (or peaking) generator were to be available with non firm access under lightly constrained network conditions and pricing (local and node) below it's economic dispatch level. Despite not wanting to be dispatched, such a generator would have an entitlement and other non firm generators dispatching above their entitlement would need to pay access settlements to the available intermittent generator. This can be observed in the AEMO modelling presented in Appendix E of their Draft Report[9].

3.3 Alternatives to OFA to solve this problem

Minor alterations to the RIT-T framework may improve the locational signal. Changes may include improving the integrity of the assumptions used by the TNSP.

4. Concern 2: Inefficient TNSP planning

AEMC Concern 2: TNSPs estimating the benefits of transmission development, where those benefits are better known to generators, and the risk of inefficient decisions being borne by consumers rather than the decision-maker;

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[8] The lumpiness of network investment may dilute this assumption.

[9] AEMO Optional Firm Access Draft Report, December 2014, http://www.aemo.com.au/Electricity/Market-Operations/Optional-Firm-Access

4.1 Why this problem is not relevant

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

The AEMC has even acknowledged that

> *"There is limited firm evidence that the current arrangements have caused significant coordination issues to date."*[10]

4.2 Why OFA does not solve this problem

This concern assumes that customers will not bear the risk of inefficient decisions under OFA.

Assuming that a new entrant generator estimates the cost of congestion and finds that it is more expensive than the cost of firm access, then the generator will logically purchase firm access. This does not mean the generator solely bears the risk of inefficient decisions as the primary source of this inefficiency will likely relate to the modelling used to price firm access. Stanwell have addressed this issue in some detail in response to the AEMC's Supplementary Report on Pricing. Regardless of the accuracy of the LRIC pricing (including the event that the modelling was correct) consumers would still bear the cost up to the ability of the generator to pass on the cost of firm access through the wholesale market, while the generator would bear the residual cost.

If the model under-prices firm access, consumers bear the risk of inefficient decisions based on central planning information. The firm access could be under-priced because:

- the actual augmentation cost is higher than modelled. The TNSP will bear this risk until the asset is rolled into the Regulatory Asset Base (RAB) at the subsequent revenue reset[11], from which point consumers will bear the cost[12]. This is supported by FTI Consulting in their report: *"At most the TNSP would be exposed to 100% of the difference between its actual costs and the LRIC estimate, but only until the end of the current regulatory period. Thus consumers would bear most of the risk of over-runs."* [13]
- the commitment to providing firm access causes an augmentation to progress that would ultimately not have been required at the time assumed in the baseline assumption (or at all). Customers will pay for this error through unnecessary TUOS charges between the end of the notional LRIC period and the time that the augmentation should have occurred (if at all)[14].

If the model over-prices firm access, consumers still bear the risk of inefficient central planning information. The firm access could be over-priced because:

- the augmentation costs less than modelled. Any savings to consumers would not accrue until after a regulatory reset, as indicated above for cost overruns. Once the asset is rolled into the RAB, consumers would only receive lower TUOS than under the reliability standard if such savings would not be likely to have occurred in the baseline scenario as well.
- the modelled augmentation does not need to be constructed or is not constructed before a reliability augmentation would have occurred. There would be no (additional) TUOS charge as there is no (additional) asset however there would likely be wholesale market impact as the generator attempts to recover cost with no reduction in congestion.

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[10] AEMC, *Transmission Frameworks Review Final Report*, 11 April 2013, Exec summary page iii

[11] The revenue reset may occur before or after the LRIC period with slightly different effect.

[12] If the cost over run would also have occurred in the base case/reliability upgrade then the effect on TUOS will be minimal.

[13] FTI *Critical assessment of transmission investment decision-making frameworks in the National Electricity Market*, 4 April 2013, page 27 item 5.4

[14] The concept of parties paying for defined time periods is used here for convenience. It is likely that both firm access charges and TUOS would be smoothed over the life of the transmission asset.

- a reliability augmentation would have occurred earlier than forecast under the original baseline assumption (due to new demand forecasts etc.). The generator will bear a higher LRIC cost than it should have rather than consumers paying TUOS for this period. While the generator is the entity "making the decision" it is based largely on information controlled and produced by the TNSP or modeller.
- the actual augmentation is constructed later than expected when determining the LRIC. If the delay in construction would have similarly occurred under the baseline assumption (as revised for new demand forecasts etc.) then consumers bear the cost of that delay *not* occurring.

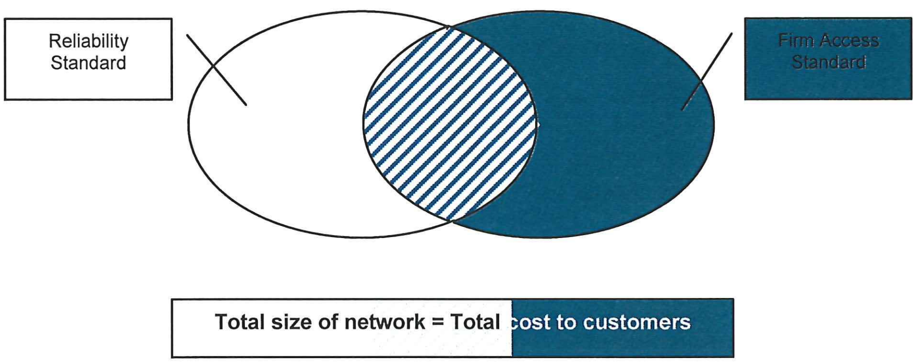
Stanwell is also concerned by the proposal to include a "contingent auction" in the RIT-T process for reliability augmentations. The examples provided by the AEMC confirm that while (in these examples) net TUOS may decrease by the inclusion of this feature, total cost would increase due to the rational recovery of costs by generators through the wholesale market. Even where generators are only able to recover a small component of these costs, the total cost to consumers in the AEMC's examples will be higher than necessary as a more expensive augmentation is progressed.

Firm access pricing is likely to require market or regulatory oversight – or both – in order to ensure that the assumptions and methodologies used for pricing are reasonable. This adds to the costs of OFA. The FTI report notes that in Great Britain such processes are subject to regular stakeholder scrutiny. In addition to adding costs, this arrangement is unlikely to be effective in the NEM given the information asymmetry between stakeholders and the TNSP. Recent network spending differentials between regions shows how similar engagement processes have had limited effect.

TNSPs must build against two network standards

Under OFA, transmission companies must plan to build their network against two standards - the Firm Access Standard and the Reliability Standard. Generators will pay for network built through the firm access standard and the transmission company will pay for network built through the reliability standard. In both cases the customer ultimately pays for the entire network as both the generator (through the wholesale market) and the transmission company (through network charges) will attempt to pass these costs on to customers.

With two planning standards, the transmission network will likely be larger than it would have been and customers will ultimately pay more. This is illustrated in the Venn diagram below.



The proposed firm access planning standard will be a deterministic standard rather than a probabilistic standard. Deterministic standards currently apply in NSW and QLD[15] whereas probabilistic standards currently apply in Vic and SA. Compared to probabilistic standards, deterministic standards have resulted in excessive network spending and high network charges for customers. Expansion of deterministic standards to the southern States may inflict southern

[15] Powerlink has recently moved away from deterministic planning towards probabilistic planning

customers with the same excessive network charges that apply in NSW and QLD and entrench such inefficiencies in the Northern states.

Statements regarding the benefits to customers of OFA rely on generators either purchasing firm access where the cost of firm access is less than the cost of congestion, or on generators being unable to pass through to consumers the extra cost where firm access is more expensive than the cost of congestion.

In the former case, the RIT-T already allows for network augmentations on "market benefits" grounds, and so it is difficult to see how consumers would gain a significant benefit from the addition of a second standard. Under the existing RIT-T the market benefit is measured with respect to the whole market whereas under OFA the market benefit would only be that which accrues to a single participant (the firm access applicant). Where the market benefit under OFA is greater than the market benefit under the RIT-T, increased network spending will occur compared to the RIT-T. Ultimately consumers will pay for this increased network spending.

The assumption of generators being unable to pass on the cost of firm access is also flawed. To the point that additional access is created, consumers will be faced with the cost that can be passed through by the generator, possibly offset by a reduction in congestion costs faced by the generator.

To the extent that firm access generators are unable to pass on the cost of firm access, investors and financiers will increase the required return on subsequent generation investments or refinancing to offset this risk. The generator would then attempt to recover this cost from the market, and ultimately consumers.

4.3 Alternatives to OFA to solve this problem

Minor alterations to the RIT-T framework may improve the locational signal. Changes may include improving the integrity of the assumptions used by the TNSP.

5. Concern 3: Transmission and generation costs not co-optimised

AEMC Concern 3: the resulting planning of transmission networks not being co-optimised to minimise the combined costs of generation and transmission;

5.1 Why this problem is not relevant

The ROAM Consulting analysis commissioned for TFR found the proposals offered no material advantages to the existing arrangements.

> *"The existing and both proposed packages are capable of delivering market outcomes that are closely aligned with theoretical best practice."* [16] and
>
> *"The modelling has shown that overall system costs are very similar under all frameworks"*[17]

5.2 Why OFA does not solve this problem

Stanwell is concerned that the ROAM Consulting report prepared for the AEMC as part of the TFR was used by the AEMC to indicate benefits from the development of OFA. The differences in modelled outcomes relating to co-optimisation of transmission and generation investment were acknowledged by ROAM to be immaterial compared to the size of the market and ambiguous as to whether they are cost increasing or decreasing.

According to ROAM "*it is clear that the difference in total system cost over the 17 year outlook period between the [fully optimal] co-optimised method and the RIT-T approach is small in relation to total fixed, variable and fuel costs… This analysis therefore suggests that in the context of the Australian NEM the potential gains in allocative and dynamic efficiency from*

[16] ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013, exec summary page i

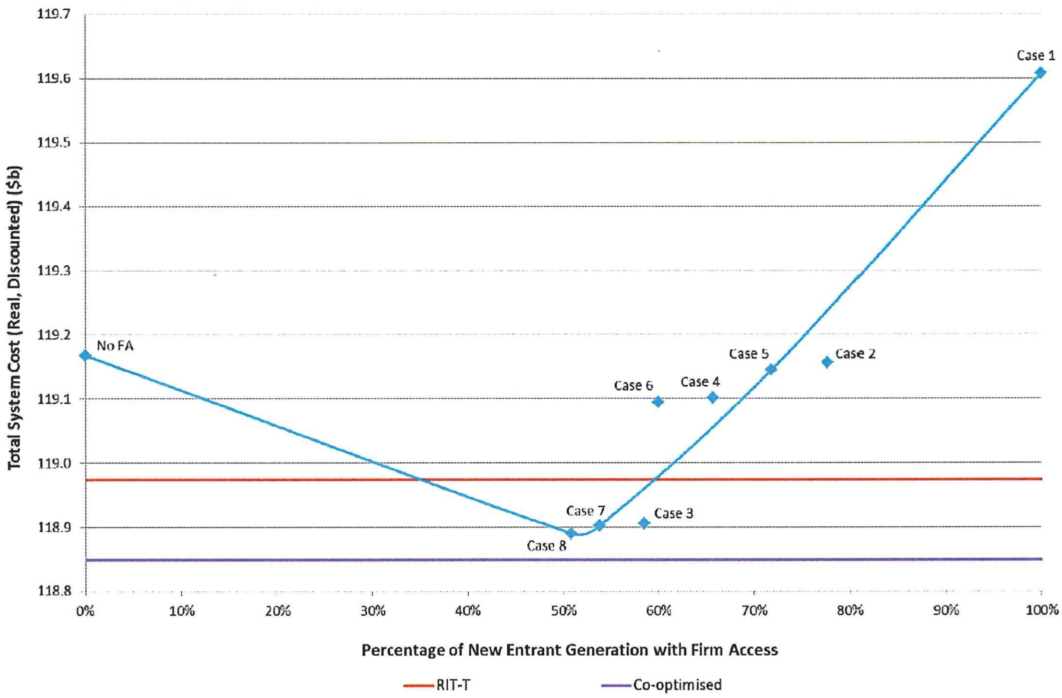
[17] ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013, page 81

incorporating transmission considerations into generation development decision making are relatively small.[18]"

The ROAM analysis showed that the performance of the OFA model was quite variable depending on the assumed amount of Firm Access (FA) that new entrant generators purchased. Figure 6.13 below is taken from the ROAM report and shows that the OFA model *can* be slightly cheaper than the RIT-T[19] under specific procurement scenarios, but it can also be more expensive.

This analysis also highlights the extremely marginal effect of a change to market design on overall investment costs. From a baseline approaching $119Bn, the modelled difference between RIT-T and OFA is between less than $100m saving (<0.1%) and $600m extra cost (<0.6%). Given the complexity of OFA and the fundamental nature of the change to market design, Stanwell continues to be of the opinion that there is no case for change.

Figure 6.13 – Total System Costs: USE valued at MPC (Scenario 2)



As can been seen on the chart above, compared to the RIT-T, OFA is expected to have minimal impact on the effectiveness of network investment, and with a modelled range biased towards increasing rather than decreasing total costs. This situation occurs because under OFA, the transmission company must meet two planning standards - the Reliability Standard and the Firm Access Standard.

Note that this inefficiency is distinct (and additional) to the recently observed inefficiencies in transmission and distribution network spending which have occurred due to inaccurate forecasts, information asymmetry and conservative reliability standards.

Since ROAM performed their analysis, demand forecasts have fallen significantly across the NEM, further weakening the "case" for OFA improving co-optimisation.

Additionally, while OFA is proposed to apply to market scheduled and semi-scheduled generation and transmission networks, it does not incorporate distribution networks, non-

[18] ROAM Consulting, *Modelling Transmission Frameworks Review*, 28 February 2013, pages 66-67

[19] RIT-T is used in this submission as a shorthand description of the current planning standards. Similarly, OFA is used as shorthand for the planning (and operational) standards that would apply to both FAS and reliability standard augmentations if the proposed changes are introduced. Stanwell acknowledge that the RIT-T process will remain integral to augmentations if OFA is introduced.

scheduled generation, demand side response or storage. All indications are that these areas will constitute an increasing proportion of total system costs into the future. In fact, OFA risks incentivising new non-scheduled generator investment ahead of new scheduled generator investment, thereby reducing market transparency.

This is because the OFA model applies only to scheduled and semi scheduled generators (and interconnectors) as these are the only participant types that have variables in constraint equations that can be changed. Accordingly non-scheduled generators obtain costless access which is more firm than that which is able to be purchased by scheduled and semi-scheduled generators.

5.3 Alternatives to OFA to solve this problem

As the existing arrangements have been stated by ROAM to be aligned to theoretical best practice, there appears to be no rationale for change.

6. Concern 4: TNSP and generator incentives are not aligned

AEMC Concern 4: the importance of TNSPs' operating their networks to maximise availability when it is most valuable, and the challenge they face in doing so given their lack of exposure to the financial costs of reductions in capacity;

6.1 Why this problem is not relevant

Prior to the existing TNSP incentive scheme, generators were concerned that TNSPs had no regard for the impact their outage decisions had on the wholesale price. These concerns have been generally allayed by the current incentive scheme despite the incentive scheme not having any wholesale price components. Stanwell understand that the current incentive scheme design is based on the TNSP being a monopoly which is regulated based on minimal to no exposure to wholesale price outcomes. Changing this exposure would likely have consequences for TNSP revenue regulation.

6.2 Why OFA does not solve this problem

The extent to which TNSPs will be exposed to the financial costs of reductions in capacity will be highly dependent on the design of the TNSP incentive/penalty scheme.

The TFR indicated that TNSPs would only pay *some portion* of the shortfall cost arising from capacity reductions below the Firm Access Standard and are likely to have significant discretion on whether to provide firm access in the operational timeframe.

FTI address this issue in their report to the AEMC during the TFR process

> *"Given the asymmetry of information between TNSP and regulator, there is an inevitable risk that the supposedly firm access rights become only "optionally firm", i.e., effectively interruptible at the discretion of the TNSP. This would undermine the whole basis of the OFA proposal."* [20]

Stanwell believe that the OFA Design and Testing process has confirmed that TNSPs are expected to retain limited exposure to the financial costs of reductions in capacity.

6.3 Alternatives to OFA to solve this problem

A review of the existing transmission incentive scheme may reveal areas for further improvement.

7. Concern 5: Difficulties managing 'price risk' between regions

AEMC Concern 5: the difficulty that market participants have in managing the risk of price differences between different regions of the NEM, with a resulting negative impact on the level of contracting between generators and retailers in different regions.

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[20] FTI *Critical assessment of transmission investment decision-making frameworks in the National Electricity Market,* 4 April 2013, page 28 item 5.6

7.1 Why this problem is not relevant

Stanwell believes that this concern is greatly overstated. Stanwell conducts both wholesale and retail activities in regions where it does not own or operate generation, and we consider the options for the management of basis risk in the current market design are sufficient.

Settlement Residue Auction (SRA) units are defined as being non firm and are priced accordingly. SRAs are non firm in part because of the fully co-optimised nature of constraints which, by definition, include interconnector terms. This means that interconnectors are able to be de-rated and negative settlements are allowed to accumulate if there is net benefit to the market and therefore, customers. This was a conscious market design decision in order to benefit consumers overall.

Liquid financial markets exist in most states that allow participants to firmly hedge their exposures in a given region if they choose to do so. Financial markets also provide participants with a greater range of product specifications compared to SRAs.

Interregional trades (where traders sell one state and buy another in a single trade) are increasingly common. Such arrangements provide the most frequently used alternative to non firm SRA units for interregional hedging.

7.2 Why OFA does not solve this problem

This is similar to concern 6 regarding dispatch and access which is discussed below. OFA does not provide certainty of dispatch or access, particularly given that many unforeseen pricing events occur when the system is not in "normal" condition.

We note the NERA report which states that, despite FTRs being fully firm (or "fixed" in the lexicon of OFA), in relation to augmentations between pricing regions:

> *"FTRs have not been found to incentivize new merchant transmission investment..."*[21]

and

> *"The return function on FTRs and ARRs remain uncertain for merchant investors, and further these potential investors are concerned about "free-riding" issues, including the fact that new investment in transmission could eliminate existing congestion and largely nullify the value of FTRs and ARRs in the near term."*[22]

OFA will create intra-regional basis risk for generators since all consumption is priced at the regional reference node whereas generators will earn the local price. Contract buyers will require derivatives referenced to the regional reference node but generators will face intra regional basis risk unless they sell at their local node. While the procurement of Firm Access may mitigate some of this risk it will be at a cost and some scaling risk will remain.

7.3 Alternatives to OFA to solve this problem

This does not appear to be a problem so does not warrant any intervention to solve.

If SRA non-firmness is considered a problem, then the source of the problem - co-optimised constraints - could be studied. It is assumed that co-optimised constraints lead to better market efficiency and lower costs for customers than constraints without interconnector terms. The magnitude of this benefit could be studied compared to the cost of the non firmness of SRAs.

8. Concern 6: Lack of dispatch certainty during congestion

AEMC Concern 6: The lack of certainty of dispatch faced by generators when there is congestion, compounded by the inability of generators to obtain firm access, even where they fund augmentations of the transmission network;

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[21] NERA, *Review of Financial Transmission Rights and Comparison with the Proposed OFA Model*, 12 March 2013, page 9

[22] NERA, *Review of Financial Transmission Rights and Comparison with the Proposed OFA Model*, 12 March 2013, page 8

8.1 Why this problem is not relevant

While dispatch risk during periods of congestion tends to be high profile due to the existence of disorderly bidding, there are well established rules providing limitations on this risk. These include Market Price Floor bidding and tiebreaker rules. Given these arrangements, Stanwell manages this risk as part of 'business as usual'.

Stanwell does not consider dispatch risk to in any way limit our ability to hedge. The risk of physical plant availability is far greater than dispatch risk. Stanwell employees who have worked for other NEM employers also confirm that dispatch risk is not a limiting factor in the hedging strategies of these generators.

8.2 Why OFA does not solve this problem

The costs of dispatch uncertainty to a generator are likely to be far less than the cost of firm access.

Dispatch is the act of generating electricity in response to AEMO dispatch instructions. Access is the ability of a generator to physically transport electricity on the transmission network[23].

OFA has no effect on the certainty of dispatch for generators whether there is congestion or not. In fact, OFA explicitly decouples dispatch and access. *Dispatch* processes remain subject to both congestion and market behaviour; however market behaviour may be influenced by the proposed access arrangements. *Access* remains subject to congestion through the pro-rata decreases in access for generators holding the same type of access (Firm or Non-Firm) when the transmission system is operating below the desired level of transfer.

Regarding the current (in)ability of generators to obtain preferred access even after funding network augmentation there are many caveats:

1. Under the current arrangements, generators could arguably have dedicated assets commissioned in order to obtain firm access, however the cost is likely to be prohibitive as would be the case under OFA
2. The firm access gained by a generator under OFA is not linked to a specific network augmentation, but is generic access to the Transmission system as a whole – albeit referenced to a specific source and destination. If a generator funds a network augmentation then all owners of firm access that utilises that augmentation will benefit equally (on a pro-rata basis), and all generators with non firm access that utilises that augmentation will also benefit equally (on a pro-rata basis, albeit less than firm generators).
3. Unlike most schemes investigated, Firm Access is "firm not fixed". It is still subject to de-rating, can be diluted by subsequent Firm Access requests and appears likely to receive minimal compensation through Transmission Network Service Provider (TNSP) incentive arrangements where financial loss occurs due to access falling short of contracted levels.
4. The payment of the agreed charge for the provision of Firm Access does not require the construction or commissioning of the notional augmentation, only a requirement for the TNSP to 'plan' to provide the contracted level of access.

OFA is not optional

Under OFA, participation in access settlement would be mandatory for all scheduled and semi-scheduled generators. In other words, OFA is not optional. It will only be the partial hedge for the newly introduced intra-regional basis risk provided by a firm access agreement which will be optional.

The OFA model assumes that a generator can reasonably estimate the congestion risk associated with a specific location, further estimate the reduction in that risk that would occur

[23] This is again distinct from an Access *right*, which is the right to physically transport electricity or be compensated for not doing so.

through the procurement of Firm Access, and use this information to determine whether or not to pay for preferred access to the network.

Such analysis is hugely problematic for a number of reasons, but most notably that the generator does not know what other projects may occur or have requested access, and so can not evaluate the impact of those projects on its own congestion risk. Future generation and transmission developments which the potential purchaser was not – and likely could not be - aware of at the time of deciding whether to procure Firm Access could have material effects on the viability of the generator. This risk was one of the primary issues identified during the Review of Energy Market Frameworks in light of Climate Change Policies[24].

For example a generator who (correctly) choses not to purchase firm access as it is locating in an uncongested area may subsequently find itself subject to Firm access penalties if another generator locates such that it creates congestion, but purchases Firm Access. The later generator would face a higher congestion estimate given the knowledge of the presence of the first generator, and hence be more incentivised to purchase Firm Access. Such access may be primarily derived from existing reliability assets which was previously available to the existing participant as non firm access[25] on an uncongested flow path.

The first generator would likely not be aware of the proposed entry of the second generator until after the second generator has the ability to start the OFA procurement process. As such, even if the first generator recognised the increased congestion risk inherent in the entry of the second generator, evaluated the constraint impact and requested Firm Access it would likely be "second in queue" for firm access and hence not receive the benefit of existing reliability access.

Accordingly it is likely that generators may feel compelled to purchase firm access regardless of the constraint evaluation. Such an outcome – where most or all participants buy firm access whether they expect congestion or not – would likely lead to the sub-optimal outcomes examined by ROAM consulting and discussed earlier (figure 6.13) where users (both consumers and generators) pay more for transmission than necessary.

OFA may reduce market transparency

Under OFA it seems likely that generators will not be able to reliably calculate their access amount ex-ante. This would increase the uncertainty faced by generators in excess of the current dispatch risk.

One of the key requirements that does not appear to have been addressed is the requirement that generators be able to determine what their access entitlement is in real time and is likely to be in the short term.

Determining of access entitlements requires knowledge of the

- flowgate actual enablement,
- flowgate target enablement,
- generator capacity for all units affected by the flowgate[26],
- generator availability for all units affected by the flowgate, and
- flowgate participation factors.

Of all these factors, generators only have reliable access to generator capacity information[27]. In order for OFA to maintain the current level of market transparency, all the other factors need to be available to the generator in real time and the pre-dispatch window.

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[24] AEMC Industry Forum, 17 August 2009. Accessed from AEMC website January 2015. http://www.aemc.gov.au/getattachment/a50a3acf-b34c-478a-b47f-95fb0b6af00e/Summary-of-Discussions-Industry-Forum-Sydney-17-Au.aspx

[25] Noting that under the 2014 OFA process this access is now assumed to be sold at short term auctions.

[26] As expressed in the TFR, *"…entitlement would be based on the lesser of its agreed access level and its rated generating capacity, and would also depend on the prevailing network conditions"*.
AEMC, Transmission Frameworks Review Final Report, 11 April 2013, page 30

Currently generators do not have sufficient information to reliably determine the flowgate actual enablement, although for some constraints this is expressed explicitly. Most constraints include terms which are opaque to market participants such as line ratings, even when binding.

Flowgate target enablement will require publication of an additional dataset in order for participants to determine their access level. Where flowgate actual enablement is above target enablement, the difference is required to inform participants on the availability of non firm access. Where flowgate actual enablement falls below target enablement, the difference is required to inform participants of the extent of firm access scaling which is occurring.

Generator availability is currently published by generating unit in arrears and by region in advance. Under OFA generators would require access to this information at the unit level in real time as well as in advance through pre-dispatch in order to calculate how non-firm access is allocated, if it is available.

Flowgate participation factors are assumed to be derived directly from the published constraint equations, however, these equations can change without notice, including at the time of dispatch[28]. In addition, flowgate participation factors can change in response to TNSP or DNSP network changes, and current procedures do not provide market participants with an adequate understanding of either the real time or forecast effect of these changes on participation factors. Such changes could have a significant effect on how much firm access a generator has to the regional reference price, creating hedging risk for firm generators.

8.3 Alternatives to OFA to solve this problem

While generators may suffer some costs as a result of dispatch uncertainty during congestion, these costs are small compared to other generators costs. The cost of alleviating this problem is likely to far outweigh the benefit.

9. Concern 7: Disorderly bidding

AEMC Concern 7: The resulting incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion;

9.1 Why this problem is not relevant

Stanwell has consistently expressed its concern on excessive regulator focus on "disorderly bidding" as being an ineffective use of regulator and participant resources. The analysis contained in the TFR consultant reports supports this position.

The consultant reports state that over the three historical years analysed: *"the cost of disorderly bidding in terms of productive efficiency has not been material"*[29]. ROAM estimate the cost as between $3m and $15m which is a small fraction of the resource cost of the NEM, however removing the effect of an observed n-3 event[30] reduces this range to $3m to $7.5m.

9.2 Why OFA does not solve this problem

The TFR final report claims that the introduction of OFA would *"reduce the incentives for disorderly bidding"*[31] and refers to the FTR and ROAM reports for the extent of the resulting "efficiency benefit". The forecast improvement in the cost of disorderly bidding under OFA of

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[27] It is relatively unusual for a generating unit to change its rated generating capacity and this information is published by AEMO. Stanwell understand that for OFA, AEMO intend to define capacity as the maximum output of a generator over the preceding two year period.

[28] On 22 May 2014 the factors in the constraint N>>N-MPWW_ONE_9 were altered by AEMO in real time in the response to an internal performance appraisal.

[29] AEMC, *Transmission Frameworks Review Final Report*, 11 April 2013, page 111

[30] An n-3 event represents a significant departure from system normal conditions. Such events are not captured under the majority of OFA modelling and so its inclusion in this one aspect creates inconsistency. Under such a derating it is likely that firm access holders would have had their rights significantly scaled back, possibly increasing incentives for disorderly bidding, however there appears to have been no modelling of this aspect of the event.

[31] AEMC, *Transmission Frameworks Review Final Report*, 11 April 2013, page 110

$8.8m is heavily weighted to the end of the 17 year modelling timeframe which are the most likely to be affected by divergence between reality and assumptions.

ROAM also conclude that "*The historical assessment of disorderly bidding supports the observations of market participants that such events are primarily triggered by non-system normal transmission events. Accordingly, the behaviour of generation and the operation of settlements under the OFA package will be critically important during these periods.*"[32] Despite this, neither ROAM nor (to Stanwell's knowledge) subsequent modelling has focussed on, or even incorporated, consideration of constraints other than system-normal.

The incentives for generators to offer electricity in a non-cost reflective manner (also known as "disorderly bidding") would remain in place under OFA. ROAM acknowledge that their base analysis does not account for the changed incentives for disorderly bidding[33] but conclude that the cost of disorderly bidding is generally small compared to the cost of an outage[34].

Stanwell considers that many of the root causes of "disorderly bidding" remain unaffected by OFA. For example under OFA, a generator that is dispatched below its access level during congestion remains incentivised to bid in a manner that will set the local price as low as possible because the firm access revenue will exceed the dispatch cost.

Similarly, there is an implicit assumption that the procurement of firm access will reflect economically efficient dispatch however this is unlikely. During congestion under OFA, low cost generators with no access, partial access or scaled firm access may be incentivised to bid in a way to reduce output in favour of high cost generators who have firm access. This has a detrimental affect on economic efficiency.

Even accepting the results of the ROAM modelling at face value highlights the ineffectiveness of the OFA proposal. The modelling shows that removing the majority of disorderly bidding across the NEM will result in a cost reduction of less than $10m per year, but shows no analysis of the cost of firm access which has "created" this "efficiency". Stanwell considers it highly likely that the cost would be orders of magnitude greater than the benefit.

The introduction of OFA may also introduce new forms of perverse bidding behaviour such as bidding to reduce output in order to create headroom on a constraint and bidding to bind a constraint. These behaviours will have efficiency costs and the magnitude of these costs may exceed the cost of disorderly bidding.

9.3 Alternatives to OFA to solve this problem

As "the cost of disorderly bidding in terms of productive efficiency has not been material", it appears that there is no need to solve this "problem".

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32 AEMC, *Transmission Frameworks Review Final Report*, 11 April 2013, executive summary page ii

33 ROAM page 29 "There may be new types of disorderly bidding that may replace the inefficiencies which may occur under the existing Package 1 framework. These potential events have not been reported on in this assessment."

34 ROAM page 53 Table 6.2 shows the cost of 4 notional outages and the cost of disorderly bidding under those outages. In 3 of the 4 scenarios the cost of disorderly bidding is a small fraction of the outage cost. It is unclear how in the fourth case the cost of disorderly bidding under the outage actually exceeds the cost of the outage.