NGF critique of Optional Firm Access (OFA) in TFR Second Interim Report, October 2012

Is Optional Firm Access really a user led model?

1. The following technical comments on the OFA model by no means suggest the NGF supports the adoption of the OFA model.

2. The NGF believes the AEMC is associating too much credence to the idea that market participants will lead transmission planning. We believe the central planning monopoly plays a pivotal role in OFA through the reliability baseline and calculation of LRIC access prices. This pivotal role could be exploited by the central planning monopoly if the incentives regime is poorly designed. Market participants cannot be said to lead transmission planning when all they are doing is responding to the central planning monopoly's asset building and pricing plan.

3. The previous paragraph discusses the roles of the central planning monopoly and participants in the competitive market. The OFA model presupposes that any investment made at the behest of the market participant is efficient. However the central planning monopoly will have a reliability baseline that is supposed to determine the most efficient expansion plan for the network. Association members believe the central planner's baseline may be inefficient if there is no market participant willing to trigger it with an application for access. Therefore there appears confusion at the heart of the OFA model as to who is acting as the agent of consumers in deciding if transmission is built. The central planning monopoly acts as an agent through the application of the reliability standards and economic tests, whereas the participant is the agent for consumers through purchasing access, costs of which will offset through a contract with a retailer. We believe the OFA model is flawed with two agents acting on behalf of consumers with different incentives, expressed as their capacity to pay.

4. The central planning monopoly is required under jurisdictional legislation to provide a reliable service to customers, wherever they are on the network and to consider through an economic test the different options, which may include transmission network augmentation, demand management or network support agreements with a generator(s). Importantly the concept of reliable supply includes provisions for credible contingencies which include the trip of a generator or transmission asset. The planning monopoly takes account of likelihood of above average demand from customers every year, usually expressed as a demand expected only one in ten years. The central planning monopoly is responsible for ensuring the system is secure with regards to voltage, frequency transient and oscillatory stability limits. Importantly the central planning monopoly is paid by consumers irrespective of whether the expected demand growth occurs.

5. The market participant receives pool revenue for actual generation volumes at a price adjusted for marginal losses to the node and difference payments on derivative contracts sold to retailers. In addition the market participant may receive ongoing "premiums" for risks of higher prices or demand through derivative contracts that pay difference payments when the RRP is greater than an agreed "cap" price. There are no payments for the provision of reserve capacity, therefore the participant expects to receive payment on actual levels of demand, with the peak demand expected once in ten years only occurring once in ten years. Importantly the participant is only paid by consumers if expected demand growth occurs.

6. The NGF is surprised the second interim report did not discuss the incentives on these two “agents” given the Review is all about the incentives on market participants and planning monopolies to coordinate efficient investment in generation and transmission. <u>We recommend the AEMC consider the different incentives on these two “agents” further.</u>

<u>The pivotal position of the network monopoly is a concern</u>

7. NGF members have expressed some concerns over the role of the network monopoly in the OFA proposal. It appears the OFA model has been premised on the network monopoly acting with integrity in dealing with the Regulator and access applicants without any incentive to exploit any rules to their advantage. In simple terms because the access charges are a regulated “prescribed” service by the REGULATOR as part of the Annual Allowed Revenue Requirement (AARR) the network monopoly is expected to be impartial in its dealings with access applicants and Regulator determinations. This assumption cannot be relied upon. For example, network monopolies have been found to push the Regulator in testing their interpretation of the Rules, (as is their right to), with these tensions often decided in judicial reviews. The Regulator has recently submitted Rules changes in response to strengthen its powers over the monopolies.

8. After suggesting there may opportunity in the OFA model for network monopolies to exploit their position, we must state that we do not believe this is the present intention of network monopolies, which have been lukewarm to the proposals to date. However just because a monopoly has no intention to support Rules at this stage does not mean they will not use them to their advantage after they have been made.

9. The NGF believes the incentives and control on the network monopolies may be poor because they are acting as an agent for consumers, as are generator applicants, as to how much transmission will be built. The key problem is the LRIC access charge signal which may encourage generators to make decisions that change the AARR without significant Regulator oversight or commercial negotiation from the generator. Given we believe the LRIC access signal may be more inefficient than the current arrangements of annual planning reports and RIT-T processes.

10. The OFA model requires the development of a baseline expansion plan for every *flowgate* (constraint) in the region and every region in the NEM. This will include consideration of *flowgate*s that are intra-regional *flowgate*s affected by inter-regional assets, such as voltage and transient stability limits across interconnectors. The expansion plan calculates a Long Run Incremental Cost (LRIC) which is the difference between the expansion costs with the generator included in the baseline and not included in the baseline (which would be solely reliability investments).

11. The NGF has concerns over the proposals for the “Reliability Generator” a*s* specified in the Technical Report for OFA. **<u>We believe that if a generator is requesting an access level that is commensurate to the level that is needed to be provided by reliability standard there should be no charge for that access</u>**. However the sections 6.2.3 and 9.3.1 Technical Report give grounds for us to doubt this to be the case.

    Reliability-driven expansion: Obligations on TNSPs to maintain jurisdictional reliability standards will continue in the OFA model. Possible future reliability expansion – expansion needed to maintain reliability standards –

would need to be modelled and included in the baseline expansion plan. That would be done by including suitable reliability generation (ie any non-firm generation for which peak-period access must be provided in order to maintain reliability) in the relevant pricing studies.56 If a reliability generator sought access, the calculated access price would then be zero, because the generator appears equally in the baseline studies and the adjusted studies. To avoid this anomaly, that particular generator would be removed from the baseline plan in that situation[1].

In any case, over time, as TA is sculpted back, existing generators will increasingly bear the cost of access charges and spare capacity on the existing transmission network is likely to become available[2].

12. Our consultants, Frontier Economics have highlighted these issues and have concerns that the network monopoly will derive access prices on the basis of forecast reliability generation which will be highly subjective. We are concerned that the Regulator could use these provisions to force existing generators to pay for the existing network, which would represent a significant wealth transfer from producers to consumers with no increase in efficiency

13. It appears the OFA model only allows an existing or new entrant generator to be a "Reliability generator" if the participant chooses to be un-firm and relies on reliability expansions to flowgates. This means that, as proposed, as soon as Transitional Access expires, generators should they request firm access will have to pay for the transmission network: for assets that have been built solely for reliability standards. The NGF believes this is inequitable and inefficient. We understand a counter argument that could be made in support of the OFA proposal is that generators have the option to benefit from the reliability investment by not purchasing firm access. This would be a difficult prospect for generators as the option is complex to exercise due to it being dependent on the network monopoly and the behaviour of other participants. The NGF expects the option will result in a high risk game where participants have to consider others' behaviour. This may result in situations of the prisoners' dilemma where all generators lose in purchasing firm access (suffering a wealth transfer to consumers), for no gain in efficiency.

14. The NGF considers the reliability baseline will struggle to include generation investments (given generators decide when and where to invest), as it does not include the non-network option process of the RIT-T which identifies if a generator (or demand side) option would be cheaper. This highlights a general problem with the interaction between the LRIC Access charge schedule and the "normal" planning processes of the RIT-T and Annual Planning Reports (APRs). It appears the LRIC Access Charges are not exposed to the same level of scrutiny as a RIT-T assessment and are therefore only lightly regulated. The NGF is concerned that generators could be charged the difference in expansion costs of an expansion schedule without this schedule being approved as efficient by the Regulator. We even doubt whether the expansion schedule from which LRIC Access Charges are calculated could ever be determined to be efficient given the Regulator presently only approves revenue for the next 5 year period and RIT-Ts are run on individual upgrade projects for the forthcoming revenue determination. There is a flawed circularity to the reliability baseline if generators have signals to invest through a dubious LRIC expansion plan and then those network assets to provide the Firm Access Standard are deemed to be efficient (because the generator or the "market" requested them).

15. By contrast the existing arrangements of the RIT-T, APR, NTNDP and revenue reset processes of the Regulator are far more transparent indicators that incentivise a generator where to connect to the transmission system. The present arrangements deliberately do not lock in the network

[1] AEMC Technical Report – Optional Firm Access p40

[2] AEMC Technical Report – Optional Firm Access P67

monopoly, Regulator and transmission users to the building of assets and payment of charges for periods into the future in the same manner as the OFA proposal. Our consultants, Frontier Economics have provided more information on the efficiency of the present arrangements and we recommend you consider their analysis of the efficiency of the two proposals.

16. The Technical Report discusses LRIC "pricing errors" in section 8.3.2.2 and it determines the following:

> "all of the drivers are *symmetrical*: they can operate in either direction and so associated impacts may be positive or negative, for each affected party. Ideally, the design of regulation (AARR forecasting and access pricing) should ensure these risks are *unbiased*, so that the positive and the negative average out over the longer term. Nevertheless, risk will remain and cannot be eliminated[3]."

17. There is also the following table, 8.1 which has been changed on the basis of the NGF's view which differs to the determination above.

Driver	**TNSP impact (first period)**	**TUOS impact (subsequent periods)**	**Firm generator impact**
TNSP expands inefficiently	negative	negative	none
TNSP expands super-efficiently1	positive	positive	~~none~~ negative
Access price understates efficient expansion cost	negative	~~negative~~ positive	positive
Access price overstates efficient expansion cost	positive	positive	negative

18. There are two key examples in the table 8.1:

19. Reports states if the *TNSP expands super efficiently* (i.e. deliver assets cheaper than the regulated efficient cost) the benefit is positive for the TNSP and there is no impact on the generator – this may not be entirely true – the generator may be entitled to some reward, given it is probably uncertain that the cost savings are actually genuine efficiency savings or price errors – these cannot be known for sure. Generators must trust the efficient LRIC price from the REGULATOR and cannot negotiate it themselves. Therefore we have changed the firm generator impact in row 1.

20. If the *TNSP access price overstates efficient cost* (i.e. deliver assets cheaper than the agreed regulated efficient cost due to pricing error) the benefit is positive for the network monopoly (as it can roll in the assets in the next price control) and the generator pays too much for access. Therefore we have changed the TUoS impact in row 2.

21. The only positive outcome for a generator is that *access price understates the efficient cost* – given the price is being issued by a directly regulated monopoly, with direct regulation being second to competition, this is the unlikely scenario and would only occur if the network monopoly was trading off revenue in the first period for more in the second, by misleading the generator that is fooled into triggering inefficient investment in assets.

[3] AEMC Technical Report – Optional Firm Access p.60

22. The most likely scenario is *Access price overstates efficient expansion* cost because generators are only making comparative decisions on investments in transmission – if all access prices are inflated by the network monopoly they will select the cheapest – which will still be inefficient even if "deemed" efficient because a market participant has requested it with an access application. If the network monopoly consistently over-prices which is where the investment turns out to be cheaper, and the Regulator is led to believe all investments are at an efficient price the network monopoly pockets the difference. Consumers and Generators lose. In this instance we believe the Regulator is undermined by the OFA model – what grounds will the Regulator have in disallowing the investment if a participant is willing to pay it in access charges?

23. Therefore one can only conclude that the likely scenarios are negative for generators and consumers – this differs from P60 comments where conclusions are asymmetrical risks – clearly with OFA the risks are not.

24. The NGF found it interesting that the Technical Report presented an example on P60-61 where a generator pays less than the efficient costs due to a pricing error by the monopoly (very unlikely) and the network monopoly does not recover costs due to differences between the payments and costs, (even if the pricing error did not occur). It is obvious this is wholly unacceptable to a network monopoly. The AEMC then concludes these problems could be fixed in section 8.3.3, through front ending access payments, (which is generator taking the cash flow implications); contingent projects reopener (ensures revenue adequacy in 1st price control) or shortfall roll up (granting all costs in next price control). All of these "solutions" protect the network monopoly at the expense of consumers or generators. The protection for the network monopoly creates incentive for them to exercise power over the OFA model. It is the NGF's contention that the obvious solution is not to lock generators and consumers into paying for assets through an LRIC Access Charge that will give an inefficient signal of transmission costs. This would mean not implementing the OFA proposal.

25. **Network Monopoly financial incentives**

26. The NGF doubts the efficiency of exposing the network monopoly to congestion compensation payments. It is suggested that this could be provided through "*TNSP support*" MWs that top-up the aggregate access entitlements above the *flowgate* capacity.

27. Firstly, we believe it is impossible for a network monopoly to provide the Firm Access Standard (FAS) through assets and then provide *TNSP Support* access. There is no funding from avoided costs (in assets) to pay for TNSP support MWs (they are locked into building the asset, so cannot fund compensation unless they explicitly price it in at the outset as a risk premium – which is not intended in the revenue regulation).

28. The network monopoly can only provide TNSP support if it does not build the asset with the cost of the asset included in the AARR – it would act as a fixed insurance premium paid by the generators with the insurance payout made through the provision of *TNSP Support*. The network monopoly would have incentive to specify the NOC tiers and access entitlements at a very conservative level to ensure the insurance product of *TNSP Support* does not have to pay out. The NGF believes this will create all manner of poor incentives on the network monopoly. Another problem arises with this proposal in that the Regulator must negotiation TNSP Support on behalf of the generators with the network monopoly. A generator does not have choice as to whether the asset is built or the *TNSP support* is provided. This appears impractical – generators would not be

able to trust the Regulator who would represent them properly. The Regulator may make tradeoffs within the revenue reset process on behalf of consumers but at generator's cost – we question if the Regulator is conflicted.

Difficulties for users exercising the option is of concern

29. The NGF welcomes the OFA model being "no regrets" in that once a generator has committed to paying an administered incentive, it must remain doing so. This should prevent stranding of the network monopoly's assets triggered by the generator.

30. However we do believe there is opportunity for free-riding on either the monopoly or another user's triggered investments. This is because the access request may trigger a new "lump" of transmission to be built. This may provide excess system capability that will benefit unfirm generators that free ride on the G-TuoS payments of the firm generator. In the technical report, section 11.3.3 "Lumpiness" we have understood the following comments to be simply saying if one increases the capacity of a *flowgate* in excess of the utilisation, other constraints may get "tighter" than the first one.

31. *"The access request exhausts spare capacity on element A, prompting expansion and creating additional spare capacity. However, spare capacity is eroded on elements B and C but no expansion is prompted. The spare nodal capacity - the minimum of the spare capacities on the three elements - has actually decreased rather than increased, despite the lumpy expansion on element A. Therefore, apart from special cases where a generator node is close to the RRN, it may not be the case that additional spare access would be created as the result of a lumpy expansion. Thus, it appears plausible at least that lumpiness of transmission expansion will not create significant opportunities for free-riding[4]" AEMC Technical report- Optional Firm Access p.86*

32.

Table 11.1 Impact of lumpy expansion on spare access

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

33. This is not a major finding that eases the NGF's worries about free-riding incentives of the OFA model.

34. The example increases the NGF's concerns about free-riding as it shows a generator can contribute to assets that are utilised by others: this is between *flowgate* a-b. The next generator can free ride between *flowgate* a-b, but will have to contribute to *flowgate* b-c and possibly *flowgate* c-node. The table clearly shows free riding is possible and, if poorly designed the LRIC creates a first mover disadvantage ahead of element A.

[4] AEMC Technical report- Optional Firm Access p.86

35. **Pending access requests will prove difficult**

36. Section 6.3.5 of the Technical Report – Optional Firm Access discusses P.45 Pending Access Requests and suggests that the TNSP may consider the likelihood of other participants connecting in the calculation of the access charge offered to the applicant. This may present some difficulties. When generators connect to the grid, they consider multiple locations and projects (often the same company will do this) and these projects will compete against each other as the investor firms up access to site, network, fuel and plant costs. For the planning monopoly in considering the LRIC access charge there are three options.

37. The first is for the planning monopoly to consider all projects connecting, the amount of capacity could be well above the baseline and trigger major bring forward of capacity against the baseline (a very high LRIC charge). Under this option generators may be put off from progressing, just because there is demand from multiple projects for access, many of which will not go ahead, although generators would understand that the LRIC charge is maybe likely to reduce. In doing this, the signal is efficient, because it will encourage some applicants to rescind their application, but the rub is that the signal is susceptible to co-ordination problems upon acceptance. Firm offers can only be contingent of other generators connecting as well. The planning monopoly can only offer firm LRIC prices upon firm commitments by all connecting generators affecting the LRIC.

38. The second is for the planning monopoly to create an LRIC for each project, ignoring the other projects. This option would present a very low LRIC charge for both to connect: obviously if one signed first, then the other would have their offer from the planning monopoly rescinded. This would create a first come first served mentality for applicants to reserve access capacity ahead of other potential projects. This may create a queue with more viable projects behind less viable projects.

39. A third option, suggested in the report is the planning monopoly assumes some are real and some are not when offering LRIC terms to generators. The NGF considers the third option is just falsifying the LRIC through arbitrary decisions as the planning monopoly will have no information on the progress or likelihood of the projects in commencing to connection

40. We believe the best option is the second with all applications calculated separately and rescinded as soon as an applicant signed the connection and access agreement. The planning monopoly would then re-issue offers to all other applicants for connection.

41. **Firm interconnector rights may be affected by network monopoly bidding**

42. In section 10.3.5 of the Technical Report, it is suggested firm interconnector rights will be priced as bid (including bids from TNSPs on behalf of consumers) and if the bids exceed the cost then it will be built. The NGF believes the participation of the network monopoly is a distortion that should not be allowed. There are asymmetries in the information that the different participants will hold – how can the network monopoly be trusted to run the auction and bid? The only way to manage this is for the cost of the incremental assets to be known to the bidder beforehand otherwise the auction is skewed.

Efficient dispatch in the OFA proposal is far from guaranteed

43. One reason nominated that the OFA model requires the central planning monopoly to act as agent for consumers is because of the view that the current NEM model fails to adequately deal with sub-regional locational signals. The very premise of why the AEMC is proposing the OFA model is because there NEM's sub-regional signals are considered by some to be "imperfect[5]". Given this assessment members were surprised to see the AEMC recommend a model with imperfect locational signals.

44. The reason the OFA model is imperfect is because the design has retained the regional approximation for price. It has not used a local price for all generation and demand, therefore capping constrained on generators' prices at the RRP – this is the same as the NEM today. To its credit the OFA technical Report identifies efficient arrangements for constrained on generators (*flowgate support*), but explicitly discounts them. The association disagrees and recommends the payment of *counterflow incremental usage* through negative LRIC as being efficient, especially because the participation of these generators in the constraint equation or *flowgate* makes the trading arrangements firmer and should reduce overall system costs. We shall explain why later in the response. OFA deliberately ignores locational signals for constrained on generators by capping settlement for these generators at the RRP rather than local price and through no provision of negative LRIC access charges for what is called *counterflow incremental usage* in the OFA model. In addition there is no locational signal for load, which must pay the RRP irrespective of whether the local price is higher or lower. For loads that may participate in demand response, the exposure to the "wrong" price may lead to exacerbation of congestion through *flowgate*s because the load may curtail demand in response to a high RRP when the local price is low (behind a *flowgate*) or increase demand in response to low RRP when the local price is high (beyond the *flowgate*).

45. The NGF, in response to the First Interim Report, recommended the AEMC consider whether the NEM's treatment of weaker sections of the grid is resulting in efficient outcomes. The NEM, relying on a regional price has to administer these incentives through non-network options evaluation in the RIT-T, directions by AEMO and network support agreements. We are bemused the AEMC has ignored these comments and recommended a model that also relies on these existing features of the current NEM design. This is because we contend the weaker sections of the grid are where the chance of inefficient coordination of generation and transmission is greatest. This is because, unlike the main sections of the grid, generator or transmission expansion is infrequent and subject to significant discrepancies in terms of the incremental increase required. There is far greater chance of stranding or duplication of assets irrespective of whether they are generator or transmission assets, in addition, per unit costs are exaggerated because of poor economies of scale. The corollary is true of investments in the sections of the grid that are highly utilised and where demand growth is almost certain to require incremental capacity expansion of some kind. It appears the OFA model has concentrated on the stronger sections of the grid, where we suspect there is no inefficiency in the present arrangements.

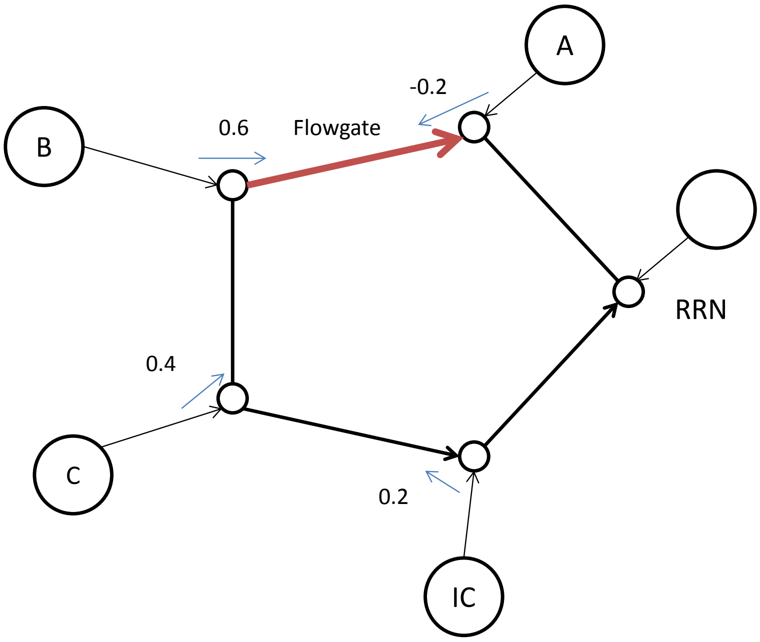
46. The OFA model may be flawed by ignoring these subregional signals. The NEM is characterised by a number of looped constraints where generators' output passes via the constrained *flowgate* and via other transmission *flowgate*s that are unconstrained. Depending on the flow of the

[5] AEMC - Transmission Frameworks Review Second Interim Report p.14-15

generators' output through the *flowgate* they either have a positive or negative *participation factor* (or constraint coefficient in NEM speak) in the *flowgate*. The present design of the OFA model would only calculate a LRIC access charge for generators with a positive participation factor in the *flowgate* and therefore encourages generators to locate away from the *flowgate* where their participation factor will be lower. Admittedly this incentive would reduce the congestion across the *flowgate* than if the generator located closer to the *flowgate*, but it would still increase congestion on the *flowgate*. There is no incentive for the generator to locate where the participation factor is higher, but negative, which would serve to defer reliability investments across the *flowgate*. It is likely that generators with negative factors may not be adequately rewarded and would in this circumstance not support flow across the gate, which means all those with positive participation factors receive less access when compared to the dispatch outcome with adequate *flowgate* support. This wouldn't be such a problem if the OFA model was financially firm, but it isn't. The NGF believes the OFA model has to include locational signals for generators with negative participation factors in order to improve the "firmness" of the access provided to those with positive participation factors.

47. We recognise there is an obvious problem with providing local pricing for generators with negative coefficients: because the local price is above the RRP (which it probably will be if the constraint is binding) paying the constrained on generators would result in NEM settlement being in deficit (because demand is not exposed to the local price, instead the lower RRP). In addition, if there were few generators in the looped constraint with a negative coefficient then they may have local pricing power. This may encourage the generator to cause the constraint to bind, even if its costs to generate are lower than the RRP, by pricing away from cost, because it knows it can receive a higher local price. These behaviours are likely to be inefficient. The NGF therefore concludes that although the locational signal is imperfect, the practicalities of implementing constrained on payments are insurmountable if demand does not pay the local price.

48. The reason the constrained on generators in a looped constraint do not wish to generate is not just because they receive a price lower than their offer price. If the difference in marginal cost of those with a positive coefficient and the generation at the RRN is great and the offer price of the generator with a negative coefficient to the generator at the RRN is not as great is it favourable to dispatch the generators within the constraint rather than the generator at the RRN. This is because paying more for the generator with the negative coefficient is offset by dispatching more cheap generation with a positive participation factor through the *flowgate*. A problem with OFA model is that the benefit from doing this resides with the generator with the positive participation factor, therefore the generator with the negative participation factor will stop providing the *flowgate* support and the RRP (which is now higher) will be set by generation at the RRN. This is shown in the following figure and tables, using the settlement example provided by the AEMC. The scenario is a looped flow with generator A having a negative participation factor. Generators B, C and the Interconnector have positive participation factors.



49. In the first scenario I have set the offer price of the generator to $55, at cost. Given the different coefficients between C at 0.4 and A at -0.2, $55 makes increasing dispatch at A and C more competitive than at the RRN at $50. For example the cost of increasing dispatch at A and C is to supply 1MW yet ensure LHS<=RHS is $47 better than the $50 offered at the RRN. These numbers are shown in the top right hand corner. This scenario is unlikely to occur because the support generator is losing money and won't want to depress the price.

50. In the second example the offer price of the support generator is increased to $61 which is just past the point of inflection where dispatching the support generator is more expensive than the generator at the RRN. This is the expected outcome under the OFA model and is the benchmark price pool debtors would be expected to pay.

51. In the third example the offer price of the support generator is reduced to $60 which is at the point of inflection where dispatching the support generator is the same as the generator at the RRN. In this example the support generator is dispatched. Although the price is the same as the previous example, the dispatch is more productively efficient, which can be seen by the higher overall margin for generators, especially those with positive participation factors, as the negative coefficient generator makes a loss. The positive participation factor generators are dispatched to a greater extent and because they are the cheapest this lowers overall cost. The productive efficiencies are greater than the losses accruing for the generator with the negative participation factor. It may be sensible to consider how the OFA dispatch could encourage this efficient behaviour.

52. The answer may be in assigning *flowgate* support access to the constrained on generator or paying the LRIC access charge to them.

Table 1	Support given at cost
Scenario No.	6
Scenario Name	Loop Flow
Offset	50

Table 2: Demand and Transmission Assumptions

Flowgate Capacity	500
Region Demand	2000
Flowgate Support	-33
Effective FG Capaci	533

Table 3: Dispatch Costs

base dispatch cost	54,167
inc1 dispatch cost	54,125
inc2 dispatch cost	54,213
total dispatch cost	162,505
Regional Price	47
Flowgate Price	42

Table 4: Entitlement Scaling Factors

Firm Scaling	0.44
NF scaling	0.00
Goal Seek	0.44
Error	0.000000000

Table 5: Generator Input Assumptions and Dispatch

Generator	availability	agreed access	participation	SRMC	offer price	base dispatch	inc1 dispatch	inc2 dispatch	base usage	inc 1 usage	inc2 usage	LMP	RRP MW Change	RRP $/MWh
RRN Gen	1000	0	0	50	50	0	0	0	0	0	0	47	0.00	0
A: Support	1000	1000	-0.2	55	55	167	165	167	-33	-33	-33	55	0.67	37
B: Firm Con-off	1000	1000	0.6	40	40	0	0	0	0	0	0	22	0.00	0
C: Firm	1000	1000	0.4	30	30	833	835	834	333	334	333	30	0.33	10
Firm IC	1000	1000	0.2	20	20	1000	1000	1000	200	200	200	38	0.00	0
total	5000					2000	2000	2001	500	501	500		1.00	47
limit						2000	2000	2001	500	501	500			

Table 6: Entitlement Scaling

Gen	Avail	Access	participati	SF targ	F Targ	NF Targ	SF act	F act	NF act	Support	Total act
RRN Gen	1000	0	0	0	0	0	0	0	0	0	0
A: Support	1000	1000	0	0	0	0	0	0	0	-33	-33
B: Firm Con-off	1000	1000	0.6	0	600	0	0	267	0	0	267
C: Firm	1000	1000	0.4	0	400	0	0	178	0	0	178
Firm IC	1000	1000	0.2	0	200	0	0	89	0	0	89
total				0	1200	0	0	533	0		500

Table 7: Generator Settlements and Margins

Generator	Avail	Cost	Offer Price	Dispatch	Usage	Entitlement	RRP Pay	Access Pay	Total Pay	G costs	Margin	Margin/ MW	RRP margin
RRN Gen	1000	50	50	0	0	0	0	0	0	0	0	0.00	-3
A: Support	1000	55	55	167	-33	-33	7,778	0	7,778	9,167	-1,389	-1.39	-8
B: Firm Con-off	1000	40	40	0	0	267	0	11,111	11,111	0	11,111	11.11	7
C: Firm	1000	30	30	833	333	178	38,889	-6,481	32,407	25,000	7,407	7.41	17
Firm IC	1000	20	20	1000	200	89	46,667	-4,630	42,037	20,000	22,037	22.04	27
total					500	500	93333	0	93333	54167	39167		

Table 1	NO SUPPORT (what is expected to happen)
Scenario No.	6
Scenario Name	Loop Flow
Offset	50

Table 2: Demand and Transmission Assumptions

Flowgate Capacity	500
Region Demand	2000
Flowgate Support	0
Effective FG Capaci	500

Table 3: Dispatch Costs

base dispatch cost	55,000
inc1 dispatch cost	54,950
inc2 dispatch cost	55,050
total dispatch cost	165,000
Regional Price	50
Flowgate Price	50

Table 4: Entitlement Scaling Factors

Firm Scaling	0.42
NF scaling	0.00
Goal Seek	0.42
Error	0.0000000000000

Table 5: Generator Input Assumptions and Dispatch

Generator	availability	agreed access	participation	SRMC	offer price	base dispatch	inc1 dispatch	inc2 dispatch	base usage	inc 1 usage	inc2 usage	LMP	RRP MW Change	RRP $/MWh
RRN Gen	1000	0	0	50	50	250	248	251	0	0	0	50	1.00	50
A: Support	1000	1000	-0.2	55	61	0	0	0	0	0	0	60	0.00	0
B: Firm Con-off	1000	1000	0.6	40	40	0	0	0	0	0	0	20	0.00	0
C: Firm-off	1000	1000	0.4	30	30	750	753	750	300	301	300	30	0.00	0
Firm IC	1000	1000	0.2	20	20	1000	1000	1000	200	200	200	40	0.00	0
total	5000					2000	2000	2001	500	501	500		1.00	50
limit						2000	2000	2001	500	501	500			

Table 6: Entitlement Scaling

Gen	Avail	Access	participati	SF targ	F Targ	NF Targ	SF act	F act	NF act	Support	Total act
RRN Gen	1000	0	0	0	0	0	0	0	0	0	0
A: Support	1000	1000	0	0	0	0	0	0	0	0	0
B: Firm Con-off	1000	1000	0.6	0	600	0	0	250	0	0	250
C: Firm	1000	1000	0.4	0	400	0	0	167	0	0	167
Firm IC	1000	1000	0.2	0	200	0	0	83	0	0	83
total				0	1200	0	0	500	0		500

Table 7: Generator Settlements and Margins

Generator	Avail	Cost	Offer Price	Dispatch	Usage	Entitlement	RRP Pay	Access Pay	Total Pay	G costs	Margin	Margin/ MW	RRP margin
RRN Gen	1000	50	50	250	0	0	12,500	0	12,500	12,500	0	0.00	0
A: Support	1000	55	61	0	0	0	0	0	0	0	0	0.00	-5
B: Firm Con-off	1000	40	40	0	0	250	0	12,500	12,500	0	12,500	12.50	10
C: Firm	1000	30	30	750	300	167	37,500	-6,667	30,833	22,500	8,333	8.33	20
Firm IC	1000	20	20	1000	200	83	50,000	-5,833	44,167	20,000	24,167	24.17	30
total					500	500	100000	0	100000	55000	45000		

Table 1	Support given
Scenario No.	6
Scenario Name	Loop Flow
Offset	50

Table 2: Demand and Transmission Assumptions

Flowgate Capacity	500
Region Demand	2000
Flowgate Support	-33
Effective FG Capaci	533

Table 3: Dispatch Costs

base dispatch cost	55,000
inc1 dispatch cost	54,950
inc2 dispatch cost	55,050
total dispatch cost	165,000
Regional Price	50
Flowgate Price	50

Table 4: Entitlement Scaling Factors

Firm Scaling	0.44
NF scaling	0.00
Goal Seek	0.44
Error	0.000000000

Table 5: Generator Input Assumptions and Dispatch

Generator	availability	agreed access	participation	SRMC	offer price	base dispatch	inc1 dispatch	inc2 dispatch	base usage	inc 1 usage	inc2 usage	LMP	RRP MW Change	RRP $/MWh
RRN Gen	1000	0	0	50	50	0	0	0	0	0	0	50	0.00	0
A: Support	1000	1000	-0.2	55	60	167	165	167	-33	-33	-33	60	0.67	40
B: Firm Con-off	1000	1000	0.6	40	40	0	0	0	0	0	0	20	0.00	0
C: Firm	1000	1000	0.4	30	30	833	835	834	333	334	333	30	0.33	10
Firm IC	1000	1000	0.2	20	20	1000	1000	1000	200	200	200	40	0.00	0
total	5000					2000	2000	2001	500	501	500		1.00	50
limit						2000	2000	2001	500	501	500			

Table 6: Entitlement Scaling

Gen	Avail	Access	participati	SF targ	F Targ	NF Targ	SF act	F act	NF act	Support	Total act
RRN Gen	1000	0	0	0	0	0	0	0	0	0	0
A: Support	1000	1000	0	0	0	0	0	0	0	-33	-33
B: Firm Con-off	1000	1000	0.6	0	600	0	0	267	0	0	267
C: Firm	1000	1000	0.4	0	400	0	0	178	0	0	178
Firm IC	1000	1000	0.2	0	200	0	0	89	0	0	89
total				0	1200	0	0	533	0		500

Table 7: Generator Settlements and Margins

Generator	Avail	Cost	Offer Price	Dispatch	Usage	Entitlement	RRP Pay	Access Pay	Total Pay	G costs	Margin	Margin/ MW	RRP margin
RRN Gen	1000	50	50	0	0	0	0	0	0	0	0	0.00	0
A: Support	1000	55	60	167	-33	-33	8,333	0	8,333	9,167	-833	-0.83	-5
B: Firm Con-off	1000	40	40	0	0	267	0	13,333	13,333	0	13,333	13.33	10
C: Firm	1000	30	30	833	333	178	41,667	-7,778	33,889	25,000	8,889	8.89	20
Firm IC	1000	20	20	1000	200	89	50,000	-5,556	44,444	20,000	24,444	24.44	30
total					500	500	100000	0	100000	54167	45833		

Additional Gross Margin for constrained off	1667
Additional gross margin overall (less losses of support gen)	833

Somehow the arrangements need to pay the addiitonal gross margin to support Gen

53. There is no obvious problem with paying the generator for incremental counterflow usage with a negative LRIC access charge. This would reward the generator for deferring transmission investment in providing a reliable supply of electricity to consumers. Consumers would be better off for avoiding the transmission investment which would duplicate reliable supply provided by the existing generation facility. Other generators with positive participation factors would be better off as they do not need to procure access across the *flowgate*. In other words, an efficient outcome would occur. An alternate paying a negative LRIC access charge for *counterflow incremental usage* may be to allow negative coefficient generators to "own" the additional *flowgate* access their generating provides. They would then have the right to sell this to generators with positive participation factors.

54. The OFA is no firmer than NFA

55. NGF members cannot see any difference between the firmness of the OFA models and Non Firm Access models. They are both non-firm. Under the current arrangements you receive access to the RRN for the quantity of generation in the *flowgate*, with the total quantity being the capability of the *flowgate*. This remains true for the optional firm access model where $\sum E = \sum U = FGx$. All the OFA model does is ration *flowgate* capacity between participants in a different manner than existing arrangements.

56. If generators were asked tomorrow what access they want we would not expect significant bring forward of capacity to expand the capacity of *flowgates* across the NEM. It is our presupposition that an efficient level of transmission capability is present in the NEM today with congestion risk already accounted for in the generator station's forced outage risk which in expected reduced capacity terms is greater than any reasonable assessment of congestion risk (ie. it is this forced outage risk which caps the level of Contracts the generator owner is willing to sell).

57. A particular criticism of members of the OFA model is the reference to access scaling under tiers of *normal operating conditions* ("NOCs"). It is expected that access level entitlements will have to be written into access agreements for each and every existing and possible *flowgate* (constraint) that the generator participates. These access agreements specify the levels contingent on different operating conditions. The NGF has assumed this would represent outage conditions, then multiple outage conditions and at the worst N-2 conditions. If we take for example the Central-Southern constraint in Queensland, such NOC1 could be all circuits in service, NOC2 a particular circuit on outage and NOC3 could be when the loss of two circuits is considered a credible contingency (such as for a lightning storm). Under such conditions the *flowgate* capacity diminishes, which is exactly what happens in the NEM today. However in the NEM today these values are not written into access agreements and generators experience these different tiers from time to time, occasionally being constrained off more than they may wish. Upon these tiers being written into the access agreements it clear that there is a level of basis risk (since the generator behind the constraint may have to pay compensation to a firmer generator) under these different operating conditions, of which there is no certainty as to the frequency of these instances occurring. The NGF expects these lower tiers would be used to set maximum hedge limits (the maximum level of swaps or caps that may be sold forward).. Hence by definition the OFA would decrease the

overall level of Contracts offered by generators in the market. The Association believes this would contrary to the NEM objective and increase overall costs for end consumers.

58. A key change to the OFA model from the first interim report to the second is that firm generators can pay into access settlement if they are "access short" which means their utilisation of *flowgate* capacity is greater than their entitlement. This is described in P28 of the Technical report as an improvement on the model from the first interim report, as the link between access and dispatch is removed thus reducing the incentive for disorderly rebidding. The rub is that this is the <u>key flaw at the heart of the OFA model – the firm generator is NOT firm</u>. For a firm generator to pay into access settlement if they are generating above their entitlement, which means the scaling has been so severe the access is not firm. In this case another firm generator would not be dispatched, but have entitlement (again scaled down) and would be paid compensation by the other firm generator. We discuss in later sections of this response the incentives for generators to offer prices away from cost to manipulate access settlement payments between generators. We doubt that an easy competitive equilibrium can be achieved in this "zero-sum game" in the few instances where the scaling is so significant that firm generators are exposed to the local price for a significant portion of their output.

59. Entitlements based on availability could encourage inefficient behaviour

60. The NGF recognises the design of OFA only aims to compensate generators for congestion risk and not dispatch risk. This is enacted by capping access entitlement at generator availability. There are some clear drawbacks in this approach in that reporting availability to the system operator is an obligation in most power markets in order to ensure system reliability. Placing such a significant financial incentive to over-declare availability in the OFA model when constrained could create some inefficiency in system operation. The system operator is likely to believe there is more capacity available behind a constraint. This wouldn't be a particular problem with radial constraints as this capacity is of little use to the system operator in ensuring a reliable system, however for looped constraints it could encourage generators with very low participation factors in a looped *flowgate* to over declare capacity, thus giving the system operator a false basis upon which to make decisions such as to lack of reserve issue notices or to procure reserves.

61. Should the AEMC continue to link entitlement to availability for each firm generator, the NGF considers it may be sensible to review the design of OFA where access entitlements of generators that are unavailable are allocated to unfirm generators. The NGF contends that a superior option is to allocate the capacity from a firm generator that is unavailable to other firm generators, possibly making them "super-firm". The AEMC should consider which option is most efficient. We note at the outset of the OFA model it probably doesn't matter as there will not be an entrant who's exercised the option of going unfirm and therefore it is just a reallocation of existing capability to existing generators.

62. Local pricing under constrained circumstances may encourage inefficient behaviour

63. In the NGF's response to the First Interim Report we questioned the merits of generators within a constraint equation competing in a discretionary price auction. We recommended the AEMC reconsider the efficiency of using discriminatory auctions behind constraints and uniform price auctions otherwise. This was because the previous incarnation of OFA has compensation payable between generators based directly on their offer prices. We believed, rather than help overcome

uncompetitive behaviour[6], discriminatory price auction behind a constraint appeared to give rise to the opportunity to exercise inefficient behaviour by unfirm generators.

64. We conclude the changes made to the OFA model, whereby a local price is calculated under a uniform auction, do reduce the chances of inefficient behaviour occurring, but this is only the case where there are numerous generators within the *flowgate*. The second interim report concludes that there will be a "*tug of war*[7]" between firm and non-firm generators within a *flowgate* where offered prices will drive dispatch towards access levels. We believe this analysis is premised on the concept that a competitive equilibrium will develop through repeated, low value instances where generators can respond to each competitor's behaviour. This will not be the case for *flowgate*s that infrequently become constrained, there will be few occasions and these occasions, if they are associated with a lower NOC tier may be short and severe. It is difficult for members to believe a competitive equilibrium will be achieved under these arrangements. The NGF recommends the AEMC continue to consider whether there is sufficient protection for firm generators from strategic offer prices of non-firm generators. If generator investors believe their firm capacity may be affected by behaviour of competitors they will discount the value of such access – this will undermine the very premise of the model.

Generator bidding could still lead to productive inefficiencies

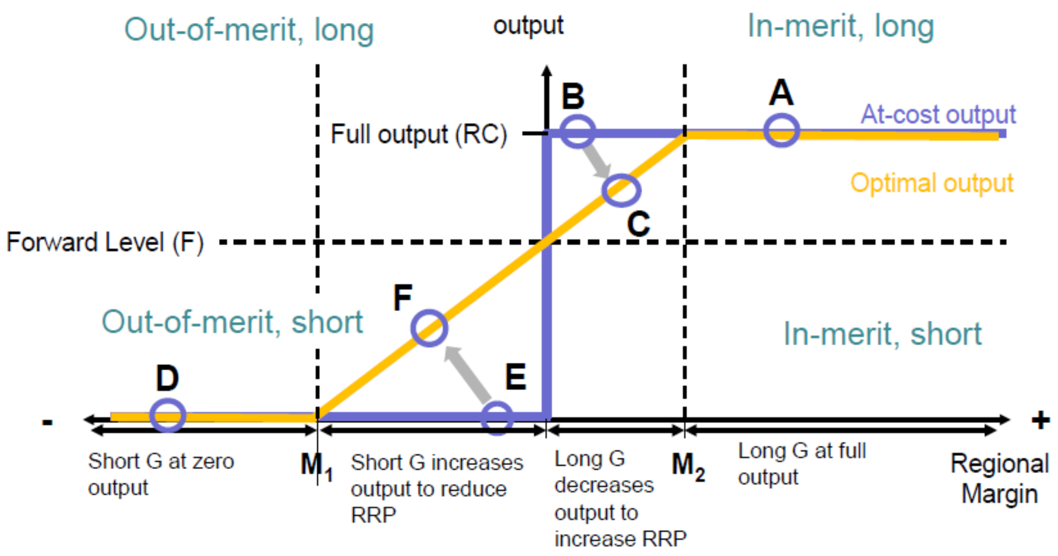
65. In this section we discuss the behaviour of participants in offering prices and volumes when "access long" or "access short". The Technical Report concludes that optimum local bidding will be equivalent to optimum regional bidding. The NGF believe this may not be true as generators tend to "support" the RRP for the value of contracts (value into the future) and will not do so for the local price. In addition the allocation of access levels is not made through the trade of financial derivatives and would be expected to be less efficient. This means there is more opportunity for sub-optimal local bidding to occur when instances for inefficient regional bidding are low.

66. The figure from the Technical Report (Figure 11.2) page 89 suggests that generators that are short generation to derivative contracts will increase output to reduce RRP, and vice versa in order maximise margin. This is logical, but is a purely temporal assessment because the generator has to consider the forward curve in both cases.

[6] Discriminatory auctions are sometimes considered more efficient when market power, especially collusive behaviour, is an issue because discriminatory auctions remove the guarantee that all will get the same, and increases the cost of signalling behaviour.

[7] AEMC Second Interim Report p.53

Figure 11.2 Illustration of regional bidding



67. In this example it correctly assesses that the profitability is reduced by the volume of contracts sold (because the increase in RRP only increases the payments above the contract level (the small proportion unhedged, not for full generation). However in reality the generator may be incentivised to increase price further because it may deliberately sacrifice profitability within that trading interval for a higher price on contracts (the proportion that will be hedged in the future). For example should it have a large volume of contracts it wishes to sell. This will often be a profit maximising exercise because the volume of contracts to be sold (hedged) is greater than the volume exposed to the spot price in this single trading interval because the duration of contracts extends for a significant period (calendar or quarter). It may be that increasing the forward curve may be more profitable than maximising gross margin in that dispatch interval.

68. A similar case can be made for the negative margin case where it is not in the interests of the generator to maximise profitability in a single period should it wish to sell hedge contracts in the future derived off the RRP. As long as the generator is hedging a greater proportion of its capacity than it is leaving exposed to the pool price this is an important consideration.

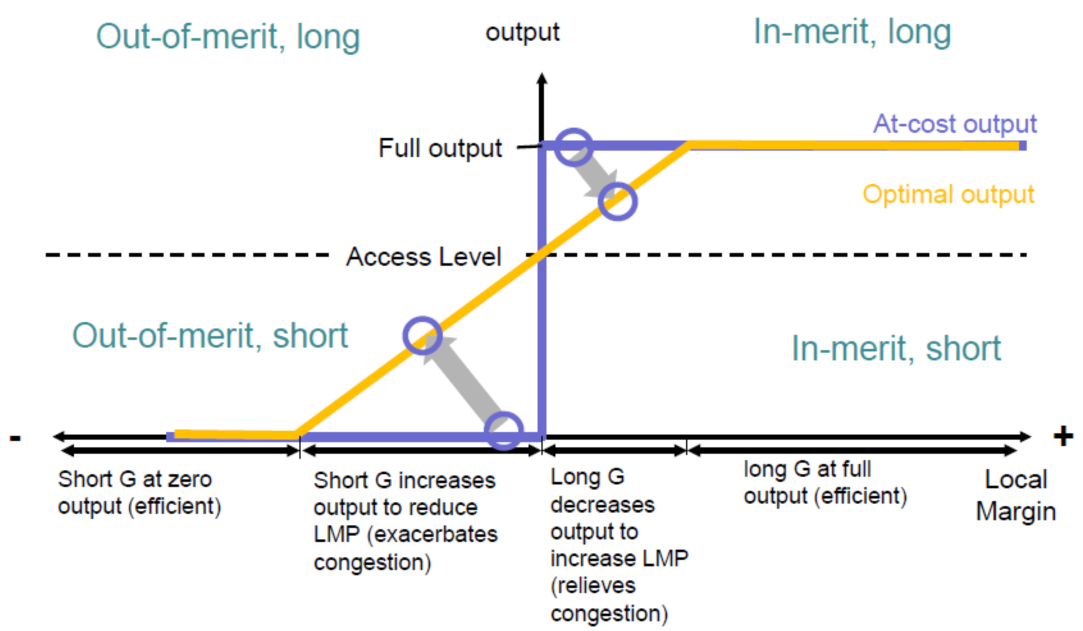
69. It can be observed that such productive inefficiencies ensue in the NEM when peaking generators owned by one participant are running when another participant withdraws baseload capacity. This is seen when a retailer-generator exposed to the spot price (due to demand greater than generation) runs a peaking generator with a high cost, but at lower than cost bid prices. The reason this phenomenon occurs in the NEM is that the mix of generating capacity owned by each participant is imperfect so productive inefficiencies follow. This is a normal feature of any market which does not have a perfect mix of capital stock and competitors.

70. The "local bidding" case is explained in the Technical Report on p.91 in Figure 11.3 below. It shows how a generator that is short volume and out of merit will increase generation to reduce LMP and exacerbate congestion (to maximise their access compensation payments). In this instance it will be in the interest of the generator that is out-of-merit to congest the *flowgate* to receive access payments in excess of losses in generation. This means that generators may have to <u>deliberately increase generation to constrain the *flowgate*</u> if they have access holdings in order to

get a pay-out. If the out-of-merit short generator is paying access charges it will behave in this manner to offset the fixed charges.

71. The comparison with optimal regional bidding (as asserted by the AEMC) does not hold true in this instance. As opposed to regional derivative contracts, the access right becomes more valuable the more they "sell down" the local price and constrain the *flowgate*. This is because they can increase the compensation payable which offsets the access charges.

Figure 11.3 Illustration of local bidding



72. If we consider the in-merit long position, which means the generator can reduce their volume, but increase the local price which will have the effect of increasing margin of the volume generated above the access level. This serves to reduce compensation payable to other generators, but has no effect on the revenues associated with the access volume, which "receives" the RRP. The generator that is in-merit, long may have no access at all and therefore their interest is in <u>maintaining headroom</u> in the constraint so that it receives the RRP rather than the local price.

73. It is therefore true that both will aim to generate up to their access levels, although there is no certainty that their access levels equate to an efficient level of dispatch. This is where a comparison with hedge contracts settled against the RRP needs to be made. The level of hedge contracts held by a participant against a generating plant fundamentally reflects, (rather than tactical contracting decisions by the participant), the supply and demand for hedge contracts, now and in to the future. The futures and forwards market allows for the efficient transfer of dispatch between units as generators become in or out of the money against the forward curve. The same is not true for access allocations which may be made by the Regulator or through a one off allocation and auction process, with a regulated charge. In summary, the NGF believes the <u>opportunity for sub-optimal bidding arises in the OFA model</u> because generators will attempt to offer prices away from cost depending on whether they are access long or short. Significant productive inefficiencies could ensue if generators access allocations are different to their expected dispatch.

<u>Other points the AEMC should consider:</u>

74. Frequency control ancillary services constraints (FCAS)

75. We consider the OFA model does not appropriately deal with Frequency control ancillary services constraints (FCAS). From reading the technical report we consider the market ancillary services for frequency control will continue to be dispatched as today. To do this will affect the interconnector rights and allocation as in some instances FCAS constraints are locational and set the interconnector limits. As designed any interconnector allocation of access will not pay out in instances where an interconnector is constrained due to FCAS constraints.

76. How should, market, non-scheduled generators be treated?

77. If generator is market, non-scheduled, then they only receive local price (i.e. non-firm). The reason for saying this is that if a generator affects a *flowgate* it should not get a free ride by being included in the RHS of the constraint equation.

78. Changing flow patterns, such exports from distribution networks.

79. In the future one would expect flows from distribution network bulk supply points onto the transmission network. This would be when the embedded generation is in excess of the local demand. In such an instance the Distribution Network Service provided is accessing the shared transmission network and should be placed under the OFA model. It has the choice of either facing the local price or purchasing access via a LRIC charge. We would expect the DNSP to pass these charges on DUoS embedded generator charges. The association expects this could have consequential impacts to the Small Generator Aggregator Rule change should the aggregator's customers be exporting onto the transmission network.