Submissions - optional firm access model

This document sets out a summary of submissions of the issues raised relating to the optional firm access model in stakeholders' submissions to the First Interim Report, Supplementary Report on Pricing, and Request for Comment. It also sets out the AEMC's response to the issues raised. Note that where stakeholder views relate to the same issue, they have been grouped together in the table and responded to by the AEMC collectively. This summary of submissions has been prepared by the staff of the AEMC.

Table A.1 Summary of submissions

Issues raised	Stakeholder	AEMC response
Access settlement		
Consideration must be given for industrial facilities with co-generation in designing the access settlement regime.	Major Energy Users (MEU), First Interim Report submission, p. 16.	As described in section A.1.3 of Volume 2, access settlement arrangements, including metering, would only apply to scheduled and semi-scheduled generators and therefore would exclude most co-generation facilities. Any existing industrial facilities with scheduled or semi-scheduled co-generation would be covered by the grandfathering of existing metering arrangements.
Five minute access settlement could be operated with SCADA data used for dispatch targets	CS Energy, First Interim Report submission, p. 24.	Access settlement would operate on a thirty minute basis. However, as described in section A.1.2 of Volume 2 other options could be considered during any implementation phase, including potentially using a weighted average approach.
Oppose the market moving towards a five minute settlement due to high costs relative to low benefits.	Hydro Tasmania, First Interim Report submission, p. 3.	
It is unclear who make access settlement payments when interconnector participation in a flowgate is larger than the directed interconnector's entitlement.	Stanwell, First Interim Report submission, p. 9.	Firm interconnector right holders would receive payouts associated with their holdings. The remainder of the inter-regional settlement residue that is allocated to interconnectors would be paid back into access settlement.
If counter price flows are occurring, does the interconnector receive a zero or negative usage value for access settlements? Either approach will have ramifications.	Stanwell, First Interim Report submission, p. 9.	Payments to firm interconnector rights would not be based on flow, but rather on the level of firm interconnector right entitlements. Depending on the cause of the counter-price flow the outcomes would differ:

Issues raised	Stakeholder	AEMC response
		• Entitlements equal to the target entitlements (ie, purchased firm interconnctor rights): if the counterprice flow is caused only by non-firm generators being dispatched, in this case FIR holders get their full payments; • Entitlements below target: if the counterprice flow were to occur at a time when inter-regional flowgate capacity is below target, then firm interconnector right holders receive partial compensation; and • Entitlements negative (ie, inter-regional flow is providing network support): the TNSP would fund the negative inter-regional settlement residue, as they do now.
Access settlements should operate on the same basis as is currently used in the market – dispatch meters are used to define the “intent” of the market operator while revenue meters are used to determine all settlement values.	Stanwell, First Interim Report submission, p. 31.	Participation in constraint equations, and thus flowgates, would be specified on a dispatch unit basis. Therefore, as examined in section A.2 of Volume 2, access settlement would require a process of applying these participation factors onto revenue meters. Revenue meters would continue to be used for all billing.
“Net negatives” should be kept to a minimum in this logical mapping of auxiliary loads to access unit identifiers, even if this requires some element of dynamic (but predictable) allocation.	Stanwell, First Interim Report submission, p. 31.	As described in section A.2 of Volume 2 there would be no dynamic mapping of loads to access unit identifiers. This could lead to net negative flows occurring to some access unit identifiers. Dynamic mapping would require real time decisions to be made by the market operator, which may be difficult.
Support the proposal to require auxiliary load and generation to be electrically close.	Stanwell, First Interim Report submission, p. 32.	Noted. See section A.2 of Volume 2.

Issues raised	Stakeholder	AEMC response
In relation to network management, the operational and commercial association rules for auxiliary loads may not be meaningful if the load and generator are electrically close.	Stanwell, First Interim Report submission, p. 32.	The requirements for auxiliary load would not only for network management. It would not be appropriate for a generator to be able to undertake arrangements with a local load, so it could become an auxiliary load. See section A.2.2 of Volume 2.
There is likely to be a net auxiliary draw in the period prior to a unit being synchronised which does not sit well with the definition of temporal association.	Stanwell, First Interim Report submission, p. 32.	For most generators, auxiliary load associated with a generating unit would be operating in the same trading interval as the generator is exporting, even if this is not simultaneous.
Concerned for the cost to the “around five generating stations” who would not receive grandfathering arrangements for their metering - request more information on this point.	Stanwell, First Interim Report submission, p. 32.	This estimate was based on the number of generators that currently have auxiliary load that is not electrically close to generation. These generators would be informed during any implementation phase for optional firm access.
Concerned that proposals incentivise pursuing non-scheduled generation registration.	Stanwell, First Interim Report submission, p. 32.	Noted. See section A.1.3 of Volume 2.
Embedded generation is likely to have multiple connection points to the transmission network, it may be complex and subjective to evaluate access as a result.	Stanwell, First Interim Report submission, p. 32.	The market operator would determine the participation of embedded generators in constraints in the transmission network. This process would be unchanged by the implementation of optional firm access.
Concerned that the usage of capacity for entitlement means that generators receive firm access payments when offline. May create inefficient behavioural incentives.	AGL, First Interim Report submission, p. 3; Centre for Energy and Environmental Markets (CEEM), First Interim Report submission, pp.30-33.	See section A.1.7 of Volume 2.
Consider the usage of capacity as maximum entitlement is appropriate.	CS Energy, First Interim Report submission, p. 24.	

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It may be significantly simpler to use the rated nameplate capacity rather than historical output to cap entitlements. This would remove the market distortion caused by each generating unit having to run at maximum output at least once every two years.	Stanwell, First Interim Report submission, p. 32.	See section A.1.7 of Volume 2. Also, the Commission understands that many generators would need to operate at full capacity at least once over a two year period for testing purposes so the impact would be minimal.
Access settlement either exposes non-firm generators to large negative prices or dilutes firmness for all participants.	EnergyAustralia, First Interim Report submission, p. 2.	See section A.1.5 of Volume 2.
Flowgate support generators should be rewarded for the service they provide. This could be done by paying them a negative LRIC price.	CS Energy, First Interim Report submission, p. 11.	See section A.1.1 of Volume 2.
Loss factors are already taken into account in determining local prices so why do losses need to be especially considered in access settlement.	CS Energy, First Interim Report submission, p. 24	See section A.1.6 of Volume 2.
Firm Access Planning Standard		
Agree with the AEMC that the firm access planning standard and the firm access operating standard should be separate.	GDF Suez Australian Energy (GDFSAE), First Interim Report submission, p. 2; MEU, First Interim Report submission, p. 13; Lumo, First Interim Report submission, p. 2; Grid Australia, First Interim Report submission, p . 5; CS Energy, First Interim Report submission, pp. 10-11.	Noted. See chapter 5 of Volume 2.
Consumers may be exposed to the costs for TNSPs meeting the firm access planning standard.	MEU, First Interim Report submission, p. 13.	Firm generators would have paid the LRIC price for firm access. If the access price underestimated the cost, then consumers would pay for the difference. If the access price overestimated the cost, then consumers would

Issues raised	Stakeholder	AEMC response
		receive a benefit in lower network charges. Therefore, provided there is no systematic bias one way in the pricing model, consumers should not be exposed to the costs. While prices may be inefficient in one direction, in principle, the LRIC pricing method should not produce prices that are biased in one direction.
Unforeseen changes in load which diminish a generator's access may not be able to be responded to by the TNSP within the short term.	AEMO, First Interim Report submission, pp. 6-10.	While this may be the case in the short-term, the firm access planning standard and firm access operating standard would provide incentives on the TNSPs to respond in a timely manner to such unforeseen changes. The sell-back mechanism should also help with this (see below).
It is unclear whether investment required to meet firm access planning standard under these changed conditions has been sufficiently valued by the market to justify the cost.	AEMO, First Interim Report submission, pp. 6-10.	Generators would have the right to sell back firm access to TNSP at the long-run decremental cost. If this is more than the value the generator places on continuing to receive firm access, and potentially the augmentation, the generator could exercise this option. See section 7.5 of Volume 2.
Greater weight could be placed on incentives and not compulsion. Potentially a buyback mechanism could be used.	DSDBI Victoria, First Interim Report submission, pp. 3, 5.	
The firm access planning standard should cover investments which are favourable to generators without resorting to a regime which provides for, or requires, additional investments beyond the firm access planning standard to resolve congestion.	AEMO, First Interim Report submission, pp. 10-11.	Agreed. See section 5.2 of Volume 2.
Planning arrangements should not seek to maintain access levels during force majeure events.	AEMO, First Interim Report submission, p. 10.	The exact specification of the level of redundancy in the firm access planning standard would be considered in the implementation of optional firm access.

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The firm access planning standard should be a probabilistic standard and not deterministic.	AEMO, First Interim Report submission, p. 11; Stanwell, First Interim Report submission, pp. 4, 15.	As set out in section 5.2 of Volume 2, the purchase of firm access would represent a generator's economic assessment on the value of the provision of the firm access. Since generators would fund the development of the network they would take the risk of inefficient investment. On the whole, optional firm access would be expected to lead to a lower system cost for consumers than the current arrangements.
Forcing TNSPs to meet the firm access standard – in order to avoid any associated penalties – may necessitate ongoing investment by TNSPs in assets and infrastructure that are, increasingly, underutilised.	AGL, First Interim Report submission, p. 3; PIAC, First Interim Report submission, p. 5.	
Agree that a generator's decides the quantity of firm access purchased, so the firm access planning standard would be economic.	Grid Australia, First Interim Report submission, p.5.	
Worst case values for firm access planning standard parameters are likely to be chosen to limit TNSP liabilities under the firm access planning standard. Therefore less network capability will be available under the standard than were a probabilistic approach to defining the firm access planning standard taken. This passes risk to generators, reducing contract market liquidity.	Hydro Tasmania, First Interim Report submission, p. 2.	
A risk of uneconomic overbuild of network capacity as individual generators are not prepared to accept possibility of having capacity they know could get constrained off and hence unable to earn revenue.	AGL, First Interim Report submission, p. 3.	Each generator would make its own assessment of the amount of efficient investment. If the generator is risk averse and purchases firm access, than investing in fully firm access would be the efficient outcome.
Queries whether generators are able to set their own levels of reliability for firm access.	MEU, First Interim Report submission, p. 14.	There would be a single firm access standard to apply to all firm generators in each region. However, each generator would be able to choose its own firm access

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		level. See section 5.2 of Volume 2.
Difficult to see how benefits of optional firm access framework can be realised when reliability standards exceeds firm access standard.	Consumer Utilities Action Centre (CUAC), First Interim Report submission, p. 3.	The firm access planning standard and the reliability standard would be met concurrently. Generators would drive some of the transmission investment decisions. See section 5.2 of Volume 2.
Before considering options for enforcement of the firm access planning standard, consider that the AEMC should clarify the nature of the relationship between a generator and a TNSP.	Grid Australia, First Interim Report submission, p. 6.	The nature of the relationship between the TNSPs and generators is described in section 7.2 of Volume 2. The enforcement mechanism of the firm access planning standard is explained in section 5.5.2 of Volume 2.
The firm access planning standard is all but unenforceable due to information asymmetry between TNSP and AER.	Stanwell, First Interim Report submission, pp. 4,16.	
Support the firm access planning standard being classified as a conduct provision.	Snowy Hydro, First Interim Report submission, p. 9.	
Uunclear about mechanisms to allow for expenditure to meet congestion outside of the firm access planning standard condition but which are material.	Stanwell, First Interim Report submission, p. 16.	TNSPs would still be able to undertake a RIT-T. However, it would not include any benefits associated with non-firm generators.
AEMC should publish any empirical studies into the impact of possible definitions of firm access planning standards.	Stanwell, First Interim Report submission, p. 16.	While the AEMC has not undertaken any specific empirical modelling of the firm access planning standards, there are a number of other analysis that may be informative in this regard: • the transactional access runs undertaken by AEMO, and published on the AEMC's website, assumed a firm access planning standard based on peak demand;

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		• the prototype pricing model uses firm access planning standard conditions based on peak demand; and • the simulations of the optional firm access incentive scheme was done in order to inform the development of the firm access planning standard. This can be found in appendix C of Volume 1.
There need to be adequate investment and operational signals on TNSPs as part of the firm access standard.	DSDBI Victoria, First Interim Report submission, p. 2.	Agreed. See chapter 5 of Volume 2.
Firm Access Operating Standard		
Broadly supportive of incentive scheme.	Victorian DSDBI, First Interim Report submission, p. 5.	Noted. See section 5.3 of Volume 2.
Generally supportive of measures that aim to provide TNSPs with operational incentives to deliver the level of access agreed. Some operational uncertainty in the level of firm access provided is appropriate.	GDFSAE, First Interim Report submission, p. 2.	Agreed. See section 5.3 of Volume 2.
Applying incentives that take account of market conditions is broadly supported.	GDFSAE, First Interim Report submission, p. 3; Grid Australia First Interim Report submission, p. 6.	Agreed. See section 5.3 of Volume 2.
Supports incentives for TNSPs, but only where the benefits to consumers exceed the rewards to the TNSPs.	MEU, First Interim Report submission, p. 11.	TNSP rewards and penalties would be based directly on shortfall costs. See section 5.3.1 of Volume 2.

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Incentive scheme to incentivise TNSPs to operate its network efficiently would be necessary under the optional firm access model.	EnergyAustralia, First Interim Report submission, p. 3.	Agreed. See section 5.3 of Volume 2.
Supports financial incentives for TNSP as the best means to deliver efficient operational outcomes.	Grid Australia, First Interim Report submission, p. 3.	
Supports the symmetrical nature of the incentive scheme.	Grid Australia, First Interim Report submission, p. 6.	Agreed. See section 5.3 of Volume 2.
Incentive scheme should include rewards and penalties, but penalties should be steeper than rewards.	Snowy Hydro, First Interim Report submission, p. 9.	See section 5.3.3 of Volume 2.
If generators are required to pay a bonus to TNSPs, they may seek to recover this cost through higher pool prices. It is not clear why a generator should pay a reward when customers are the main beneficiaries of efficiency, through lower prices.	Origin, First Interim Report submission, pp. 10, 12.	See section 5.3 of Volume 2.
Generators must pay TNSPs even when TNSPs have not delivered the contracted level of service, providing the TNSPs are delivering over the theoretically efficient level of service. This is an unbalanced design.	Stanwell, First Interim Report submission, p. 4.	See section 5.3.3 of Volume 2. Further, TNSPs would only be required to provide access during a set of specified conditions.
The incentive scheme does not make the access product fully firm. Generators are still exposed to shortfall costs.	CS Energy, First Interim Report submission, pp. 13-14, 16.	See chapter 5 of Volume 2. Exposing firm generators to efficient shortfall costs would be appropriate.

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TNSP rewards under the scheme are not appropriate.	CS Energy, First Interim Report submission, p. 16.	See section 5.3.3 of Volume 2.
Incentive scheme does not provide financial certainty for generators.	CS Energy, First Interim Report submission, p. 17.	Noted. See chapter 5 and section B.1 of Volume 2.
It is appropriate for the incentive scheme to more directly reflect the value of access (revealed more accurately by generators) as opposed to the STPIS $10 materiality threshold currently in place.	Grid Australia, First Interim Report submission, p. 6.	Agreed. See section 5.3.1 of Volume 2.
AEMC should investigate whether incentive scheme should be based on costs the network monopoly is likely to incur, rather than shortfall costs.	CS Energy, First Interim Report submission, pp. 2, 13, 16.	See section 5.3.1 of Volume 2. By being based on shortfall costs, TNSPs would be incentivised to make a trade-off between the cost of improving the network, and the cost of shortfall (subjected to the nested caps). This incentivises TNSPs to deliver capacity at times generators value it most.
An incentive scheme linked to the potential benefits to generators may create incentives for TNSPs to "over-price" access.	EnergyAustralia, First Interim Report submission, p. 3.	AER would control the prototype pricing model. The TNSP would not be able to "over-price" access. By balancing the reward gained through improvements with the expenditure required to make improvements, over time the TNSP should reveal the most efficient shortfall cost. See appendix B of Volume 2.
Impact of network performance on notionally firm generators should be considered as part of the incentive scheme.	Stanwell, First Interim Report submission, p. 9.	Noted. See section 5.3.1 of Volume 2.
Supports an incentive scheme which aligns the interest of TNSPs and generators.	Stanwell, First Interim Report submission, p. 17.	Noted. See section 5.3.1 of Volume 2.

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Incentive scheme should incentivise delivery of firm access service to rights holders, not the delivery and operation of physical assets.	EnergyAustralia, First Interim Report submission, p. 3.	Agreed. See section 5.3.1 of Volume 2. Incentive scheme linked to the value of the shortfall to generators.
There should be no exclusions from the firm access operating standard.	MEU, First Interim Report submission, p. 14.	Agreed. See section 5.3.2 of Volume 2.
Incentive scheme should apply at all times.	Victorian DSDBI, First Interim Report submission, p. 5; EnergyAustralia, First Interim Report submission, p. 3; Snowy Hydro, First Interim Report submission, p. 9.	Agreed. See section 5.3.2 of Volume 2.
Nested caps should apply at all times, and be higher at system abnormal conditions.	Snowy Hydro, First Interim Report submission, p. 9.	See section 5.3.4 of Volume 2. Nested caps would apply at all times (as the incentive scheme as a whole would apply at all times). Differently structured penalties apply to the different conditions, because the shortfalls during these different conditions have different intrinsic characteristics which interact with the scheme in different ways – see section B.2 of Volume 2.
The firm access operating standard should have some carve outs where generator assumes the risk of the asset being unavailable.	CS Energy, First Interim Report submission, p. 12.	The firm access operating standard (and incentive scheme) would apply at all times. Risks to the TNSPs of extreme events would be managed through the nested caps. See sections 5.3 and B.2 of Volume 2.
For extreme rare catastrophic events, Stanwell supports a force majeure clause.	Stanwell, First Interim Report submission, p. 18.	A force majeure clause would be unnecessary due to the design of the nested caps. See section 5.3.4 and appendix B of Volume 2.

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When caps are reached, the incentives of the scheme will not be in place, potentially leading to inefficient outcomes. Risk through the scheme is disproportionately placed on the TNSPs. Incentive scheme too weak.	Origin, First Interim Report submission, pp. 7-9; Stanwell, First Interim Report submission, pp. 4, 18.	See section 5.3.4 of Volume 2.
Caps could provide incentives for TNSPs to game (eg, provide as much maintenance activity as possible on a single day, or bring forward scheduled work between years if the annual cap is met).	Stanwell, First Interim Report submission, p. 18.	Agreed. The design, and specific parameters, of the caps would need to avoid the possibility of such gaming. See section 5.3.5 and appendix B of Volume 2.
Nested caps not supported. Otherwise, there would be a situation where penalties are capped, but later, rewards are earned to reduce penalties payable.	Stanwell, First Interim Report submission, p. 20.	See section 5.3.3 of Volume 2.
MIC component of STPIS appears to be functioning well.	Origin, First Interim Report submission, p. 5.	Noted. See section 5.3 of Volume 2. The incentive scheme would replace (and would represent an evolution of) the market impact component of the STPIS as it applies to TNSPs.
The introduction of the incentive scheme would require the removal of the MIC component of the STIPIS scheme and changes to Network Capability Incentive Parameter Action Plan (NCIPAP) to ensure consumers are not paying rewards for acts that are also rewarded through the incentive scheme.	MEU, First Interim Report submission, pp. 12, 14.	With regard to the MIC, see section 5.3 of Volume 2. With regard to NCIPAP, were the optional firm access model to be implemented, the Commission agrees that care would need to be taken to ensure that there are not double payments to TNSPs.
Payments that have been made to TNSPs from the MIC component of the STPIS scheme are probably higher than the benefits to consumers.	CS Energy, First Interim Report submission, p. 14.	Noted. The optional firm access incentive scheme would be based on shortfall costs, and hence directly on the costs to firm generators of network constraints.

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MIC component of the STPIS scheme currently may create perverse incentives.	CS Energy, First Interim Report submission, p. 15.	Noted. See appendix B of Volume 2.
Replacing MIC component of STPIS scheme with new incentive scheme could be problematic if only small amounts of firm access are procured. This would mean that the TNSP only has an incentive to operate efficiently on a small part of its network. Also unclear whether reliability upgrades will be subject to the TNSP incentive scheme.	Stanwell, First Interim Report submission, p. 18.	It would be appropriate that TNSPs would not be incentivised to maintain network performance for non-firm generators, as these generators would have not signalled, through their firm access procurement decisions, that they sufficiently value access. The incentive scheme would only replace the MIC component of STPIS. Other components of STPIS would remain unaffected, and so TNSPs would still have incentives (and obligations) for consumer reliability.
Incentive scheme should be supported by a obligation for the TNSP to operate in an efficient manner.	Victorian DSDBI, First Interim Report submission, p. 5.	Agreed. See section 5.3 of Volume 2.
TNSPs should not be penalised for events outside of their control.	GDFSAE, First Interim Report submission, p. 3; Grid Australia, First Interim Report submission, p. 4.	Noted. See sections 5.3.4 and B.2 of Volume 2. Nested caps would limit risk exposure and provide incentives for TNSPs to rectify events quickly, even if initial cause of event was out of the TNSP's control.
Use of nested caps supported.	MEU, First Interim Report submission, p. 14; Grid Australia, First Interim Report submission, p. 7; Victorian DSDBI, First Interim Report submission, p. 5.	
Nested caps should be structured all the way down to trading intervals, in order to maintain the incentive properties of the scheme.	Grid Australia, First Interim Report submission, p. 8.	Noted. The AER would set the incentive scheme parameters. See sections 5.3.4 and B.2 of Volume 2.

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Incentive scheme option 1 (T-factor scheme) from the First Interim Report has a number of flaws. TNSP incentive scheme option 2 from First Interim Report supported over option 1.	MEU, First Interim Report submission, p. 14; Grid Australia First Interim Report submission, p. 7; Stanwell, First Interim Report submission, p. 19.	Agreed. See section 5.3 of Volume 2.
Total annual cap per TNSP could facilitate unnecessary wealth transfer between generators.	Stanwell, First Interim Report submission, p. 18.	Agreed. See section 5.3.6 of Volume 2.
Under incentive scheme, payments to/from TNSPs should only be to/from the affected generator and the relevant TNSP.	MEU, First Interim Report submission, pp. 13-14.	Agreed. See section 5.3.6 of Volume 2.
Incentive scheme must be designed to avoid unintended consequences (including risk exposure to consumers).	MEU, First Interim Report submission, p. 14.	Noted. See sections 5.3.5 and B.1 of Volume 2.
Incentive schemes are inherently complex. Multiple iterations are often required for schemes to work as planned. Rules should therefore include high level principles (allowing for flexibility rather than prescription), allowing the AER to design and refine the scheme over time.	AEMO, First Interim Report submission, p. 12.	Agreed. See section 5.3 of Volume 2.
Incentive scheme shares risks between TNSPs and generators. This may result in reduced contract market liquidity which would reduce competition in the market.	Hydro Tasmania, First Interim Report submission, p. 2.	Noted, see section 5.3.4 of Volume 2. The current design of STPIS also shares the risk of TNSP operations. The Commission considers that the optional firm access TNSP incentive scheme represents an improvement to the current STPIS.

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Incentive scheme should be low powered.	EnergyAustralia, First Interim Report submission, p. 3.	See section 5.3.4 of Volume 2.
Incentive scheme is too weak and low powered to sufficiently align TNSP and generator incentives.	Stanwell, Request for comment submission, First Interim Report submission, p. 3.	
There may be incentives for generators to create congestion to receive payments (either from TNSPs or non-firm generators). This may be easier if the generator has pre-warning of TNSP planned outages. The optional firm access model may *create* incentives for disorderly bidding.	Stanwell, First Interim Report submission, pp. 20-21.	Noted. In theory, there could be incentives for generators to try and create congestion in order to receive incentive scheme payments. However, in practice, the Commission considers that it may be difficult for generators to bid in a manner which creates high shortfall costs. Furthermore, TNSPs would be partially protected from this behaviour by the nested caps.
AEMC proposed benefit of option 2 of reduced disputes in the allocation of payments between generators is alarming, as there should be no disputes (the incentive scheme is mechanical, no judgement required).	Stanwell, First Interim Report submission, p. 20.	Agreed. The supposed benefits of reducing disputes was not taken into account when designing the incentive scheme in this Draft Report.
Shortfall costs should not be included in the RIT-T assessment.	Stanwell, First Interim Report submission, p. 21.	Noted. The Commission considers that shortfall costs associated with firm generators should be taken into account in the RIT-T assessment, as discussed in section 8.3 of Volume 2.
Frequently resetting the incentive scheme parameters could make evaluating the cost effectiveness of firm access for generators over the long-term difficult.	Stanwell, First Interim Report submission, p. 18.	Noted. However, resetting the incentive scheme parameters more frequently could result in a scheme that better reflects the efficient provision of access. Ultimately, this would be a matter for the AER in running the scheme. See section B.1 of Volume 2.

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Setting the initial level of service may be challenging for the AER.	MEU, First Interim Report submission, p. 14.	Noted. See section 5.3.5 and B.1 of Volume 2.
Unclear how the annual cap would be set. Unclear whether the network would need to be "fully sold".	Stanwell, First Interim Report submission, p. 20.	See section B.1 of Volume 2. The network would be "fully sold" (through the short-term auction) for the incentive scheme to operate effectively, so that, were historical performance to be the basis of setting the annual shortfall cost benchmark, historical performance was being compared on a consistent basis.
It is unclear whether the incentive scheme will apply for inter-regional access.	Stanwell, First Interim Report submission, p. 26.	See section 5.3.1 of Volume 2.
Incentive scheme should apply to both short-term and long-term access.	Stanwell, First Interim Report submission, p. 28.	Agreed. See section 5.3.2 of Volume 2.
Payment of the incentive scheme should occur through access settlement, rather than after the event.	CS Energy, First Interim Report submission, p. 16.	See section 5.3.3 and 5.3.6 of Volume 2.
Annual payments will not provide more certainty (in advance of purchasing access) to generators of incentive scheme outcomes.	Stanwell, First Interim Report submission, p. 19.	See section 5.3.3 and 5.3.6 of Volume 2. Any payments made by generators would be as a result of, and offset by, improvements in settlement outcomes for the firm generator as a result of reduced shortfall costs.
Pricing		
A imperfect pricing mechanism is likely to be more efficient than a regime which does not attempt to provide pricing signals. Perfectly costly reflective price signals are unrealistic.	AEMO, Supplementary Report on Pricing submission, pp. 1, 3.	Agreed. See section 6.1 of Volume 2.

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LRIC supported as the best pricing method (with caveats).	Alinta, Supplementary Report on Pricing submission, p. 2; GDFSAE, Supplementary Report on Pricing submission, p. 1; AEMO, Supplementary Report on Pricing submission, p. 1; Grid Australia, Supplementary Report on Pricing submission, pp.1-2; Energy Networks Association, Supplementary Report on Pricing submission, p. 1.	See sections 6.6.1 and 6.5.2 of Volume 2. See section 6.11.2 of Volume 2 for a possible approach were access prices to deviate substantially from expected underlying costs.
Theoretically, the LRIC method will produce efficient prices. However, this is unachievable in practice. Prices do not reflect costs, and could therefore result in inefficient investment decisions by generators.	CS Energy, Supplementary Report on Pricing submission, pp. 2-4.	
The model could not be materially improved by changes to the model inputs or assumptions – it is the stylised nature of the model which is the issue.	Origin, Supplementary Report on Pricing submission, p. 1.	
LRIC method reliant on forecasts which may be inaccurate.	AGL, Supplementary Report on Pricing submission, p. 2; SADSD, Supplementary Report on Pricing submission, p. 2.	
The DCC approach may be more appropriate in some circumstances.	SADSD, Supplementary Report on Pricing submission, p. 2; AEMO, Supplementary Report on Pricing submission, p. 2.	
Many deficiencies and limitations in the prototype pricing model can be overcome.	DIgSILENT, Supplementary Report on Pricing submission, pp. 1, 26.	Noted. See section 6.10.3 of Volume 2.

Issues raised	Stakeholder	AEMC response
Prototype pricing model appears to be able to demonstrate relativities in pricing due to spare capacity and locations.	DIgSILENT, Supplementary Report on Pricing submission, p. 6.	Noted. See section 6.10.4 of Volume 2.
The prototype pricing model provides quite weak locational signals.	Stanwell, Supplementary Report on Pricing submission, pp. 3, 5.	
More confidence is required in the pricing model before a decision can be made to proceed with the optional firm access model.	AGL, Supplementary Report on Pricing submission, p. 4.	The Commission acknowledges limitations with the prototype pricing model (see section 6.10.3 of Volume 2), and considers that many of these could be improved with more time, resources and data availability. See section 6.11.2 of Volume 2 for a possible approach were access prices to deviate substantially from expected underlying costs.
Stylised approach will systematically overstate prices.	EnergyAustralia, Supplementary Report on Pricing submission, p. 1; AGL, Supplementary Report on Pricing submission, p. 1; Snowy Hydro, Supplementary Report on Pricing submission, p. 1; Origin, p. 6; CS Energy, Supplementary Report on Pricing submission, pp. 2-3; Stanwell, Supplementary Report on Pricing submission, p. 7..	See sections 6.6.1 and 6.11 of Volume 2.
Argument that prices will be broadly reflective over time, with under- and over-predictions of costs averaging out, requires high volume of argumentation expenditure, which is currently not the case.	TasNetworks, Supplementary Report on Pricing submission, p. 3.	
Systematic overpricing will result in windfall gains for TNSPs.	Stanwell, Supplementary Report on Pricing submission, p. 4.	

Issues raised	Stakeholder	AEMC response
Inaccuracies in pricing may result in costs being passed to consumers or generators.	SADSD, Supplementary Report on Pricing submission, p. 2; Grid Australia, Supplementary Report on Pricing submission, 2.	See section 6.11.2 of Volume 2 for a possible approach were access prices to deviate substantially from expected underlying costs.
By locking in net present cost of future transmission investment, without considering alternative expansion plans, the LRIC is likely to result in less efficient pricing outcomes.	Origin, Supplementary Report on Pricing submission, p. 1; Origin, Request for comment submission, p. 3.	Generators will pay a fixed price, set when the firm access is registered. This promotes financial certainty for generators. See section 6.4 of Volume 2.
Certainty in prices, stability in prices and avoiding one-on-one negotiations are not sufficient to justify the proposed approach.	EnergyAustralia, Supplementary Report on Pricing submission, p. 1.	
Supports access prices fixed at time of access procurement.	GDFSAE, Supplementary Report on Pricing submission, p. 1.	
Stylised pricing model results in financial uncertainty for generators.	Origin, p. 6.	
Before committing to purchasing access, generator would want to be able to reconcile access cost (through the pricing model) with access value (through settlement).	CS Energy, Supplementary Report on Pricing submission, pp. 4-5.	Upon purchasing firm access, the TNSP would be required to meet the firm access standard (a combined planning standard and operating standard). The Commission acknowledges that the access provided would not be fully firm. See chapter 4 of Volume 2. Given the requirements on the TNSP, a generator may be able to estimate the likely value derived through access settlement and compare this to the fixed cost, provided through the pricing methodology.
Various input and methodological limitations in the current pricing prototype model, which could result in inefficiencies and/or systematic over-pricing, including:	SADSD, Supplementary Report on Pricing submission, p. 1; EnergyAustralia, Supplementary Report on Pricing submission, p. 2; AGL, Supplementary Report on Pricing	The Commission acknowledges limitations with the prototype pricing model (see section 6.10.3 of Volume 2), and considers that many of these could be improved with more time, resources and data availability. See

Issues raised	Stakeholder	AEMC response
• no replacement capital expenditure, or simplistic possible replacement capital expenditure profiles; • no operational expenditure; • inappropriate security adjustments; • simplistic large-scale network replication expansion plans; • inter-regional access prices and inter-regional flow not included; • inappropriate access growth / generator entry assumptions and transitional access sculpting, which indicate that central planning remains a feature of the optional firm access model; • lumpiness and costing assumption; • inappropriate forecasts of peak demand at nodes; • exclusion of stability constraints from the model; • errors in network characteristics; • treatment of losses; • inappropriate exclusion of committed TNSP work; • the use of direct current load flow calculations (rather than alternating current); • discrepancies versus real NEM operations.	submission, pp. 2-3; Grid Australia, Supplementary Report on Pricing submission, pp. 2-4; Snowy Hydro, Supplementary Report on Pricing submission, pp. 1-2; Alina, Supplementary Report on Pricing submission, pp. 2-3; Origin, Supplementary Report on Pricing submission, pp. 2-3; AEMO, Supplementary Report on Pricing submission, pp. 1-2; TasNetworks, Supplementary Report on Pricing submission, p. 2; Stanwell, Supplementary Report on Pricing submission, pp. 3-4, 6-8, 10-11; Stanwell, First Interim Report submission, p. 24; CS Energy, Supplementary Report on Pricing submission, pp. 2-4, 14; DIgSILENT, Supplementary Report on Pricing submission, pp. 5-6, 12-24, 26; Dr Col Parker, Supplementary Report on Pricing submission, pp. 3, 6, 8, 12, 26-30.	section 6.11.2 of Volume 2 for a possible approach were access prices to deviate substantially from expected underlying costs.

Issues raised	Stakeholder	AEMC response
The pricing model will not be correlated to the NTNDP or TNSP annual planning processes.	EnergyAustralia, Supplementary Report on Pricing submission, p. 2.	The pricing model would use assumptions that are consistent with the assumptions and outputs of the NTNDP and TNSP annual planning processes.
In an environment of mature and stable technologies, to the extent that inaccuracies in the pricing model are present in both the base line and adjusted expansion plans, the incremental costs between them (upon which the LRIC is based) should be relatively accurate. But, if technologies change over time, this assessment might not hold true.	Grid Australia, Supplementary Report on Pricing submission, p. 2.	Transmission costs in the pricing model could be based on projections of future costs, allowing the LRIC to more accurately take account of the possible changes in cost (over time) to alleviate the same constraint.
Forecasts of generator entry have changed considerably in recent years. This could create pricing volatility if these forecasts are updated into the pricing model.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	To the extent that any input assumption changes, this would need to be updated in the pricing model, with the potential for changes in prices. During any implementation process for optional firm access, a process (with public consultation) for updating the pricing model would need to be developed. The Commission agrees that update to the pricing model could create volatility in prices, which would need to be balanced against not updating the model, which would result in allowing known inaccuracy to prices to remain in place.
Effort to manually determine inter-connector costs (for the purpose of pricing) would be high.	Stanwell, First Interim Report submission, pp. 24-25.	Noted. LRIC model would price cost associated with thermal constraints. Manual modelling would only be used for those costs which would be incurred immediately to address stability constraints (due to the use of the DCC method to address inter-regional stability constraints). The Commission understands that currently TNSPs do similar modelling, so this approach does not impose substantially more costs than at the moment. See section 6.7 of Volume 2.

Issues raised	Stakeholder	AEMC response
High cost to upkeep pricing model.	EnergyAustralia, Supplementary Report on Pricing submission, p. 4.	See section 6.6 of Volume 2.
Frequent review of the inputs and model assumptions are necessary.	Stanwell, Supplementary Report on Pricing submission, p. 14; DIgSILENT, Supplementary Report on Pricing submission, p. 27.	
Unclear how commercially sensitive information on industrial demand can be incorporated in a publicly available model. The pricing model must be transparent.	TasNetworks, Supplementary Report on Pricing submission, p. 3; Stanwell, Supplementary Report on Pricing submission, pp. 13-14; DIgSILENT, Supplementary Report on Pricing submission, p. 27.	Noted. The pricing model would be publicly available to the extent that commercial-in-confidence issues were resolved. Alternatively, only some elements could be publicly available.
The pricing model must be easy to use.	Stanwell, Supplementary Report on Pricing submission, p. 13.	Agreed. The AER would be responsible for developing the pricing model, were optional firm access to be implemented.
In general, the model is easy to operate.	DIgSILENT, Supplementary Report on Pricing submission, p. 26.	Noted. Further changes have been made to improve the usability of the model. See section 6.10.2 of Volume 2.
Better references of sources inputs should be given.	DIgSILENT, Supplementary Report on Pricing submission, p. 27.	Noted. See section 6.10.3 of Volume 2. While efforts have been made to detail inputs, some inputs have required judgements to be made by AEMC staff, owing to data limitations. Were optional firm access to be implemented, all inputs, sources and judgements would be documented by the AER.
There could be inefficiencies if network investment is negotiated between a TNSP and generator, but prices for firm access are set by the AER.	Origin, First Interim Report submission, p. 2.	Network investment would not be negotiated. Generators would agree to pay a price based on a regulated model (determined through the methods described in chapter 6 of Volume 2). Investment would then made by the TNSP, subject to the RIT-T process as appropriate (see section 8.3 of Volume 2).

Issues raised	Stakeholder	AEMC response
Pricing model is inconsistent with the Optional Firm Access, Design and Testing Review Terms of Reference, in that it does not include inter-regional access.	Stanwell, Supplementary Report on Pricing submission, pp. 4, 8.	The pricing prototype has been updated to allow for estimates of inter-regional access prices.
How can generators be more involved in the process of determining upgrade requirements? What changes need to be made to the RIT-T process?	DIgSILENT, Supplementary Report on Pricing submission, pp. 7, 24.	See section 6.6.1 of Volume 2. The stylised expansion plans on which access prices are predicated would not be the actual plans that the TNSP would follow in augmenting the network (which would continue to require RIT-Ts were materiality thresholds met, as is currently the case). Also see section 8.3 of Volume 2.
Stylised method may result in network augmentations different to that actually undertaken by the TNSP.	Dr Col Parker, Supplementary Report on Pricing submission, p 1.	
The stylised assumptions and methodology of the pricing model could 'leak' into RIT-Ts and revenue proposals.	EnergyAustralia, Supplementary Report on Pricing submission, pp. 1-2.	
LRIC approach to network planning could constrain the ability of the market to respond to changing market conditions, compared to the current RIT-T arrangements.	Origin, Supplementary Report on Pricing submission, p. 2.	
Commission should consider mechanisms to align prices with actually incurred costs if material discrepancies arise.	Grid Australia, Supplementary Report on Pricing submission, p. 2; AGL, Supplementary Report on Pricing submission, p. 3.	See section 6.11.2 of Volume 2.
LRIC prices should be allowed to be negative.	CS Energy, Supplementary Report on Pricing submission, p. 12; EnergyAustralia, Supplementary Report on Pricing submission, p. 4; AGL, Supplementary Report on Pricing submission, p. 4.	See section A.1.1 of Volume 2.

Issues raised	Stakeholder	AEMC response
Modelled forecasts of generator access should not be included in stylised model.	GDFSAE, Supplementary Report on Pricing submission, pp. 1-2.	See section C.2 of Volume 2.
Assumptions regarding renewal of access may cause inaccuracy in pricing and may also cause a divergence from the forecasting information sourced from the NTNDP.	AGL, Supplementary Report on Pricing submission, p. 3.	
Requests that the Commission considers the extent to which forecast generator retirements would be included in the pricing model baseline.	Grid Australia, Supplementary Report on Pricing submission, pp. 3-4.	
Assumption that all generation is balanced at the regional reference node could distort pricing accuracy.	Origin, Supplementary Report on Pricing submission, pp. 1-2; Dr Col Parker, Supplementary Report on Pricing submission, p 6.	See table D.2 of Volume 2. Also note that the assumption that all major industrial demand is added to the regional reference node is made in the *prototype* pricing model (for reasons of data confidentiality) and would not be made were the optional firm access model to be implemented.
Pricing model is inflexible to customisation of access.	EnergyAustralia, Supplementary Report on Pricing submission, p. 4.	See section 7.2.3 of Volume 2.
Scope for strategic procurement (with regard to access term), to avoid costs associated with lumpy investment.	AGL, Supplementary Report on Pricing submission, p. 3.	See section C.6.4 of Volume 2.
Unclear from prototype pricing model what the LRIC pricing outcomes should be in the situation where: • existing network capacity is sufficient to accommodate firm access request; and	AGL, Supplementary Report on Pricing submission, pp. 3-4.	See section C.1 of Volume 2. The LRIC pricing method takes into account the value of spare capacity. In the special case that there is zero projected growth on an element, then the long run incremental costing access price would be the same as the deep connection

Issues raised	Stakeholder	AEMC response
• no additional network maintenance expenditure is required beyond that required to meet reliability obligations.		charge curve. Therefore, if the access request does not prompt an immediate expansion then the access request would be zero, subject to any additional network maintenance expenditure required beyond that required to meet reliability obligations. If there was no additional maintenance expenditure, the total price would be zero.
Anomalies between theoretical access prices produced by LRIC, LRMC and DCC approaches (as detailed in figure C.1 of Volume 2) and the indicative prices produced by prototype pricing model.	AGL, Supplementary Report on Pricing submission, p. 4.	Figure C.1 shows the theoretical prices relating to *one network element.* For an individual network element: • DCC < LRIC < LRMC (to the far left of figure C.1); • DCC < LRMC < LRIC (to the immediate left of the discontinuity in the DCC line in figure C.1); or • LRMC < LRIC < DCC (to the right of figure C.1). Prices produced by the prototype pricing model for each of the three methodologies are the summation of LRIC, LRMC and DCC costs respectively, *across all network elements.* For example: • The DCC method would only produce prices of $0 if no network elements are immediately expanded as a result of the access request. DCC prices are typically above zero because some network elements are immediately expanded, but others are not. • The DCC price could be above the LRIC price (despite the LRIC price being less than the LRMC price) due to the effect of summing the cost of multiple elements.

Issues raised	Stakeholder	AEMC response
Pricing model currently not applicable to the specific features of Tasmania.	Grid Australia, Supplementary Report on Pricing submission, p. 3; Alinta, Supplementary Report on Pricing submission, p. 3.	Agreed. See section C.4 of Volume 2 and chapter 11 of Volume 1. These issue would have to be resolved as part of the implementation of the optional firm access model, were it to be implemented in Tasmania.
Stylised LRIC model represents central planning.	Snowy Hydro, Supplementary Report on Pricing submission, p. 4.	It is acknowledged that projections are part of the pricing model proposed. However, this does not make it central planning – generators are still responsible for making decisions that influence where the transmission network will be built.
For the pricing of inter-regional access using the LRIC model, what conditions will be being modelled for the network? For instance, under firm access planning standard conditions, the 'from' region will typically be unconstrained (as concurrent intra-regional access is counter to the inter-regional flow). However, firm access planning standard conditions may not be the typical conditions when price separation between regions occur.	Stanwell, First Interim Report submission, p. 26.	Noted. The design of the firm access planning standard conditions, and hence the pricing model, may need to take this issue into account.
The only reason that the LRIC model would need to be included in the optional firm access model is to provide a pricing signal for *new entrant* investors. Otherwise, access should be traded between generators on a secondary market.	CS Energy, Supplementary Report on Pricing submission, p. 2.	Noted. While generators may trade their access (see chapter 7 of Volume 2), regulated prices would be needed for the procurement of firm access for new generator entry, increases to the level of firm access for existing generators, and once transitional access is sculpted for existing generators.
Reliability access distorts pricing for existing generators.	CS Energy, Supplementary Report on Pricing submission, pp. 5-11.	See section 5.2.6 of the Transmission Frameworks Review.

Issues raised	Stakeholder	AEMC response
Sell-back mechanism may be more appropriate than including replacement expenditure in the LRIC model.	CS Energy, Supplementary Report on Pricing submission, p. 12.	Both the sell-back mechanism and inclusion of replacement expenditure in the pricing model would be appropriate. However, these elements are not reflected in the prototype model. It is expected they would be included in the pricing model if optional firm access were to be implemented.
Prototype pricing model cannot handle multiple access requests at different locations.	DIgSILENT, Supplementary Report on Pricing submission, pp. 6, 23; AGL, Supplementary Report on Pricing submission, p. 3; Grid Australia, Supplementary Report on Pricing submission, p. 3.	See section 7.2 of Volume 2. TNSPs would be able to give informal information to generators regarding access prices at any time. To the extent that a generator wishes to make multiple access purchases, the TNSP would be able to indicate the impact of a particular access request on the price of other access requests (were they to be made subsequently).
Impact of generator dispatch influences load flows.	Dr Col Parker, Supplementary Report on Pricing submission, pp 6-12.	Notwithstanding a number of improvements that could be made to the model as suggested, the model does not include *generator dispatch* as part of the load flow calculations. Instead, it includes *firm access*, which is analogous to dispatch for the purpose of load flow calculations. The inputs to the model should take account of the total and projected level of firm access, because under the firm access planning standard, the TNSP would have to plan to provide this level of access to the regional reference node (under the specified conditions).
How long-term line flows are calculated is misreported in the Supplementary Report on Pricing.	DIgSILENT, Supplementary Report on Pricing submission, p. 15.	Noted. Long-term line flows calculations now accurately reported in the Draft Report.
Dupe parameter has no bearing on direct current loadflow calculations.	DIgSILENT, Supplementary Report on Pricing submission, pp. 16-18.	The dupe parameter is not used directly in the direct current loadflow calculation. Parallel lines must have the

Issues raised	Stakeholder	AEMC response
		admittance parameter updated to reflect the new parallel admittance, which is representative of total admittance rather than per individual line.
Contingency analysis in prototype pricing model may be departing from theoretically derived results.	DIgSILENT, Supplementary Report on Pricing submission, pp. 19-20.	The Commission, using the input numbers published by DIgSILENT, was unable to replicate the results that diverged from the theoretically correct results. The Commission notes that the short-term rating (st rating) is used in the evaluation of post contingent capacity rather than the continuous rating (ct rating) values that DIgSILENT have published.
DCC calculations in prototype pricing model may be departing from theoretically derived results.	DIgSILENT, Supplementary Report on Pricing submission, pp. 20-21.	The DCC calculation takes into account the weighted average cost of capital ('wacc' parameter). Setting this parameter to zero appears to gives the results expected by DIgSILENT.
Generators may pay substantially more or less than one another at the same node, due to first- or second-move advantages.	AGL, Supplementary Report on Pricing submission, p. 3; CS Energy, Supplementary Report on Pricing submission, pp. 12-13.	See section 7.2.2 of Volume 2.
Queuing mechanism may be an effective way to price the renewal of transitional access that expires concurrently.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	
Randomisation of queuing order not appropriate.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	
Prices being distorted as a result of access requests being withdrawn from the queue.	AGL, Supplementary Report on Pricing submission, p. 3.	

Issues raised	Stakeholder	AEMC response
Over course of access request negotiation, prices could change as a result of other access requests.	Grid Australia, Supplementary Report on Pricing submission, p. 3.	
Credit support arrangements will be required to avoid a generator prompting an expansion through the procurement of firm access and subsequently pulling out of the agreement, with the risk that customers bear the cost of shortfalls in revenue.	Victorian DSDBI, First Interim Report submission, pp. 4-5.	Noted. See section 7.5.2 of Volume 2 for a discussion of how the LRDC may guide the level of credit support required.
Inter-regional access		
Auction (including secondary trading) is likely to be the most efficient manner of offering inter-regional firm access.	GDFSA, First Interim Report submission, p. 3; Lumo, First Interim Report submission, pp. 2-3.	Agreed. See section 7.3 of Volume 2.
Support the aggregation of bids through an auction in order to expose the maximum market value of such rights.	Stanwell, First Interim Report submission, p. 26.	Agreed. See section 7.3.1 of Volume 2.
An auction alone may not reveal the value of a long lived investment.	Grid Australia, First Interim Report submission, p. 8.	Noted. The Commission considers that the inter-regional auction alone is the appropriate mechanism for long-term, inter-regional procurement. See section 7.3 of Volume 2.
Auction method of procuring inter-regional access may be unnecessary.	CS Energy, First Interim Report submission, pp. 2, 20.	See section 7.3 of Volume 2.
A generator that wants inter-regional access should be able to buy it outside of the auction process.	CS Energy, First Interim Report submission, p. 20	An auction is preferred to other procurement methods for the reasons discussed in section 7.3.1 of Volume 2.

Issues raised	Stakeholder	AEMC response
Parties should be able to acquire access on inter-connectors for longer than one year.	MEU, First Interim Report submission, pp. 10, 15.	Agreed. See chapter 7 of the technical report.
Concerns regarding the governance of the inter-regional auction, particularly TNSP involvement.	CS Energy, First Interim Report submission, p. 20.	See section 6.9 of Volume 2.
Complexity of procurement for inter-regional access compared to intra-regional access will discourage purchasing of inter-regional access.	Stanwell, First Interim Report submission, pp. 5, 24.	Noted. The Commission considers that the auction procurement method for inter-regional access is preferable to other procurement methods for the reasons discussed in section 7.3.1 of Volume 2.
Parties other than market participants should be able to acquire firm inter-regional access.	MEU, First Interim Report submission, p. 10.	Agreed. See section 7.3.1 of Volume 2.
Unclear why the access planning standard definition is annual, but that firm interconnector rights could be auctioned in quarterly blocks.	Stanwell, First Interim Report submission, p. 24.	Noted. See section 7.3.2 of Volume 2. The Commission has not determined all the specifics of the auction design.
Unclear as to the restrictions that would need to be placed on inter-regional access procurement.	Stanwell, First Interim Report submission, p. 24.	
It would be consistent with the concept of the optional firm access model that augmentation would be pursued if generators were willing to pay, even if the augmentation is bigger than a more "optimal" solution.	Stanwell, First Interim Report submission, p. 25.	
Consumers should not be underwriting costs if the beneficiaries are generators and retailers who have bid into the auction.	MEU, First Interim Report submission, p. 15.	See section 7.3.1 of Volume 2. The revenue from the sale of firm interconnector rights should cover the estimated cost associated with providing new firm interconnector rights.

Issues raised	Stakeholder	AEMC response
Increase in inter-regional access in one direction is likely to lead to an increase in capacity in the other direction. The auction should take this into account.	Stanwell, First Interim Report submission, p. 26.	Noted. See section 7.3.2 of Volume 2. The Commission has not determined all the specifics of the auction design. However, the auction design should take this into account.
Inter-regional access based on the incorrect premise that there are discrete limitations of the interconnector assets themselves, rather than deeper on the meshed network.	CS Energy, First Interim Report submission, p. 19; MEU, First Interim Report submission, p. 10.	Under the firm access planning standard, TNSPs would be obliged to provide access. This could be achieved either through upgrading the particular interconnector asset, or other assets in the meshed network, depending on which was the cost effective way of alleviating a constraint.
How would the revised the RIT-T process ensure that costs exceed benefits for inter-regional access?	MEU, First Interim Report submission, p. 15.	See section 8.3 of Volume 2. Through its procurement decisions, a generator would indicate that firm access purchased has a positive net benefit.
Concern that a TNSP factoring in intra-regional considerations into decision to expand interconnectors may (unnecessarily) favour inter-connectors.	Stanwell, First Interim Report submission, p. 25.	
What will happen to SRAs under the optional firm access model?	Lumo, First Interim Report submission, p. 3; AGL, First Interim Report submission, p. 3.	Under the optional firm access model, firm access rights will replace SRAs. A proposed phase-out of the current SRA arrangements is discussed in AEMO's Optional Firm Access Draft Report (December 2014).
A dominant market player may purchase all access on an interconnector to prevent other parties having access.	MEU, First Interim Report submission, p. 7.	The Commission acknowledges that the inter-regional auction would need to be well designed, to avoid this potential issue. Note that inter-regional capacity is not limited in the long-term, as additional capacity can be constructed (if signalled through the auction).

Issues raised	Stakeholder	AEMC response
		See the technical report for possible approaches to the auction design.
Is there an interaction between the inter-regional access product and the inter-regional TUOS product that is due to commence in 2015?	MEU, First Interim Report submission, p. 15.	Any interactions between the two processes would be considered during any implementation phase for optional firm access.
How are TNSPs obliged to provide inter-regional firm access, despite the auction being run by AEMO?	MEU, First Interim Report submission, p. 15.	Inter-regional firm access that is procured through the auction would create FAS obligations on the TNSP, in an identical manner to intra-regional firm access. See chapter 7 of Volume 2.
Potentially there could be no interconnector product. Instead, generators in the exporting region could purchase firm access in the importing region.	CS Energy, First Interim Report submission, p. 19.	The design of option firm access is that generators are either able to purchase access between a node in a region and the local regional reference node (intra-regional access), or between regional reference nodes (inter-regional access). Therefore, under the current design, generators could not purchase firm access in the importing region as contemplated by CS Energy.
Supports the concept of short- and long-term inter-regional access.	Stanwell, First Interim Report submission, pp. 25-26.	Agreed.
Supports the market operator running the auctions with pricing input from the TNSPs.	Stanwell, First Interim Report submission, p. 26.	Agreed. See sections 7.3.3 and 6.9 of Volume 2.
Short-term firm access		
Supports incentives to maximise utilisation of the existing network.	Hydro Tasmania, First Interim Report submission, p. 2.	Noted. See sections 7.4.4 and 7.4.5 of Volume 2.

Issues raised	Stakeholder	AEMC response
Short-term access issuance highly complex, although an auction is probably appropriate.	Stanwell, First Interim Report submission, p. 27.	Noted. See section 7.4 of Volume 2 for the rationale for the short-term access procurement process.
Short-term access should be bought or sold between existing holders bilaterally. The auction process is unnecessarily complex.	CS Energy, First Interim Report submission, p. 22.	Auction is preferred for the reasons discussed in section 7.4 of Volume 2. Given that an auction would be preferred, it is appropriate that generators could participate in this auction to sell their existing access.
Not supportive of TNSPs being able to sell excess capacity.	CS Energy, First Interim Report submission, pp. 21-22.	Revenue from sale of excess capacity would be allocated to TUOS customers. See section 7.4.5 of Volume 2.
Revenue from the short-term auction should go to the party that funded the original augmentation that resulted in the spare capacity.	MEU, First Interim Report submission, pp. 15-16.	See section 7.4.5 of Volume 2.
Revenue recovered by TNSPs from short-term auction sale should be kept to a minimum.	Lumo, First Interim Report submission, pp, 3-4.	
Allocation of sales revenue from the auction depends on the provenance of the access.	Stanwell, First Interim Report submission, p. 29.	
Allocation of revenue from short-term auction needs to be defined.	Stanwell, First Interim Report submission, p. 5.	
Defining the access to be sold in the short-term auction, or using financial incentives for TNSP to reveal how much access should be sold in the short-term auction, could be problematic.	Stanwell, First Interim Report submission, p. 30.	Noted. See section 7.4.4 of Volume 2.

Issues raised	Stakeholder	AEMC response
Short-term firm access product may create incentives for the TNSP to down-play transmission capability to allow revenue to be earned on short-term issuance.	Snowy Hydro, First Interim Report submission, p. 10.	See sections 7.4.4 and 7.4.5 of Volume 2.
Financial incentives are a better means to ensure TNSPs look for opportunities to increase network capacity, rather than strict obligations to sell all capacity.	Grid Australia, First Interim Report submission, p. 9.	See sections 7.4.4 and 7.4.5 of Volume 2.
Source of access (ie, how much access is released in the short-term access) needs to be defined.	Stanwell, First Interim Report submission, p. 5.	See section 7.4.4 of Volume 2.
Why is the short-term product limited to quarterly auctions?	MEU, First Interim Report submission, p. 15.	See section 7.4 of Volume 2 for why auctions would be an appropriate method for procuring short-term access. The auctions would be run quarterly, although this frequency may be changed after more consideration during implementation.
Supports quarterly blocks for short-term access.	Lumo, First Interim Report submission, p. 2; Stanwell, First Interim Report submission, p. 27.	
Supportive of secondary trading functionality of short-term auction.	Lumo, First Interim Report submission, p. 2.	Agreed. See section 7.4.6 of Volume 2.
Short-term horizon should be clearly defined.	MEU, First Interim Report submission, p. 15.	Agreed. See section 7.4.2 of Volume 2.
The distinction between long- and short-term access is artificial and undesirable for generators.	EnergyAustralia, First Interim Report submission, p. 4.	Noted. The short-term and long-term products differ in their procurement method, but the settlement outcomes for generators would be identical between short-term and long-term access. In part the distinction is driven by the lead time of development for new transmission capacity.

Issues raised	Stakeholder	AEMC response
TNSPs should be able to hold unsold long-term access created from customer funded augmentation as an asset thus reducing their cost of capital (and hence cost to consumers).	EnergyAustralia, First Interim Report submission, p. 4.	If the creation of spare capacity due to investment to meet reliability standards is considered a problem, one possible solution is discussed with regard to reliability access in the Technical Report.
Reserve price of zero prohibits the TNSP from efficiently releasing additional capacity into the auction at a price to cover any associated cost.	Grid Australia, First Interim Report submission, p. 9.	Noted. See section 7.4.3 of Volume 2.
Auction reserve price should apply for TNSPs offering additional firm access above that required, and for generators selling their existing access. This may create additional complexity to the auction design.	Stanwell, First Interim Report submission, p. 28.	
Reserve price of zero for access arising from existing network.	Stanwell, First Interim Report submission, p. 28.	
Short-term access dilutes long-term access. Short-term access should not have the same level of firmness as long-term access. Some short-term sales revenue should go to long-term access holders as compensation. Excess capacity would be created by long-term access purchase.	Stanwell, First Interim Report submission, p. 5; CS Energy, First Interim Report submission, pp. 2, 21.	See section 7.3.1 of the First Interim Report. Furthermore, TNSPs will be required to meet the firm access planning standard obligations regardless of the amount of short-term access sold. Excess capacity has not been paid for, in full, by generators procuring long-term access – access is discounted to represent the spare capacity created.
Appropriate that short-term intra- and inter-regional access are issued through the same process.	Stanwell, First Interim Report submission, p. 27.	Agreed. See section 7.4.1 of Volume 2.

Issues raised	Stakeholder	AEMC response
Firm interconnector rights should not be aggregated before clearing in the short-term auction.	Stanwell, First Interim Report submission, p. 27.	Noted. See section 7.4.3 of Volume 2 and the technical report for a description of the short-term auction design.
Concept of short-term horizon is necessary. It may be simpler to define it with reference to the current SRA forward sale period.	Stanwell, First Interim Report submission, p. 27.	See section 7.4.2 of Volume 2.
What happens if circumstances change such that a TNSP's network no longer provides access during the firm access planning standard specified conditions, but there is not enough time to augment the network?	Stanwell, First Interim Report submission, p. 27.	See section 5.2 of Volume 2. The obligation on TNSPs would be a planning obligation only.
Transitional access		
Generator investments were made on the basis of current implicit access design and transitional access should reflect this implicit access.	GDF Suez, First Interim Report submission, p. 4; Stanwell, First Interim Report submission, p. 36; EnergyAustralia, First Interim Report submission, p. 4.	Agreed. As described in section 9.2.1 of Volume 2 the provision of transitional access would include recognition of some of the implicit access regime currently existing for existing generators.
Appropriate for sunk investments to be protected from significant regulatory shock.	Stanwell, First Interim Report submission, p. 36; CUAC, First Interim Report submission, p. 1; EnergyAustralia, First Interim Report submission, p. 4.	
Original sale price of formerly state owned generators likely included some consideration of costs of access.	GDF Suez, First Interim Report submission, p. 4;	Any consideration of access during the sale of a generator is a confidential, contractual matter between the current and former owners.
TNSPs could be required to undertake consumer funded augmentations to meet generator's allocated transitional access.	Hydro Tasmania, First Interim Report submission, p. 3; CEEM, First Interim Report submission, pp. 2-3; Grid Australia, First Interim	See section 9.4.3 of Volume 2.

Issues raised	Stakeholder	AEMC response
	Report submission, p. 10; AEMO, First Interim Report submission, pp. 6-7.	
The Commission should consider transitional access arrangements in the context of a scenario of low or declining demand.	Grid Australia, First Interim Report submission, p. 10.	The future is uncertain, and the transitional access arrangements are designed to operate in multiple future scenarios. The length of the initial X period would be considered in more detail at the implementation stage of optional firm access.
Market conditions indicate that not many new entrants are expected during the transitional period.	CS Energy, First Interim Report submission, p. 26.	
Significant time would elapse before the introduction of optional firm access, so existing generators would be able to prepare. This should be taken into account when determining transitional access allocations.	Victorian DSDBI, First Interim Report submission, p. 5.	
Increasing costs for new entrants could increase the costs relating to reductions in carbon emissions.	CEEM, First Interim Report submission, pp. 13-15.	
Any transitional access must be designed with consideration of balance sheet impacts.	EnergyAustralia, First Interim Report submission, p. 4.	Agreed. See section 9.2.1 of Volume 2.
Allocating access to existing generators will help new investments as investors will have confidence in market design.	EnergyAustralia, First Interim Report submission, p. 4.	
Gifting of transitional access would create wealth transfer from consumers to existing generators.	PIAC, First Interim Report submission, p. 6.	Provision of transitional access through the Option iii hybrid model, along with sculpting of this transitional access, should minimise wealth transfers compared to a direct allocation.

Issues raised	Stakeholder	AEMC response
Transitional access allocation would be a barrier to entry for new entrants.	PIAC, First Interim Report submission, p. 6; CEEM, First Interim Report submission, pp 6-7.	As described in section 9.3.6 of Volume 2, there would be a secondary market for transitional access. Therefore, a new entrant would be able to purchase transitional access from another generator, or firm access directly from the TNSP.
Transitional access could operate a market distortion if existing generators could raise prices due to increase costs for new entrants.	PIAC, First Interim Report submission, p. 6; CEEM, First Interim Report submission, pp. 7-9.	
Transitional access could be allocated through an auction.	CS Energy, First Interim Report submission, p. 25; PIAC, First Interim Report submission, p. 6; Snowy Hydro, First Interim Report submission, p. 12; CEEM,First Interim Report submission, p. 15-16.	See section 9.3.3 of Volume 2.
Transitional access could be allocated to new entrants when they enter during the transitional period. When a generator enters there should be enough time for any impacted existing generator to procure access up to the level they need.	CEEM, First Interim Report submission, pp. 16-17.	As discussed in section 9.3.6 of Volume 2, it is difficult to reserve such transitional access for new generators. In addition, this would lower the location signal for new entrants and reduce the benefits of the optional firm access model.
The impact of all transitional allocation methods on wholesale prices and investment should be modelled before a choice is made on transitional access policy.	CEEM, First Interim Report submission, p. 20.	The Commission has not undertaken such modelling on the provision of transitional access since it considers that such modelling is complex, and would not be informative, since the outcomes from transitional access may be different when optional firm access is implemented.
Some transitional access would be necessary to minimise perceptions of regulatory risks to investors in generation. This should be the minimum required to maintain capital costs at low level, while minimising wealth transfers from consumers.	CEEM, First Interim Report submission, p. 3.	See section 9.2.1 of Volume 2.

Issues raised	Stakeholder	AEMC response
Transitional access limits allocation to firm interconnector rights, which could restrict inter-regional trade.	Victorian DSDBI, First Interim Report submission,, p. 5; Alinta, First Interim Report submission, p. 5; Origin, First Interim Report submission, p.8.	Under Option iii participants would be able to purchase an efficient level of transitional firm interconnector rights in the initial auction, or through secondary trading. See section 9.3.6 of Volume 2.
As new entrant plant would have the ability to decide whether to enter the market in the knowledge of firm access, the price paid for access by its competitors is immaterial.	Stanwell, First Interim Report submission, p. 34.	See section 9.3.6 of Volume 2.
Increasing costs for new entrants while allocating free access to existing generators could delay efficient market exit by existing generators.	CEEM, First Interim Report submission, pp 11-12.	The usage of Option iii as described in section 9.3.4 of Volume 2 would minimise this concern as existing generators considering becoming fully firm would be required to purchase transitional access. Furthermore, the X period would be for a short period such as five years.
Initial allocation of transitional access should allow TNSPs to be firm access standard compliant.	Stanwell, First Interim Report submission, p. 36.	Agreed, see section 9.3 of Volume 2.
Any determination of initial allocation will require the cooperation of generators. There could be rent seeking behaviour, thus resulting in an excess of transitional access allocations.	CEEM, First Interim Report submission, p. 4.	The initial allocation of transitional access would be determined through a network model prepared by the TNSPs. The potential for generator gaming would be minimal.
Sculpting is not the way to ensure consumers do not pay for an augmentation to retain transitional access for a generator. Rather, TNSPs should ask generators their willingness to pay for the retention of this access.	GDF Suez, First Interim Report submission, p. 4.	If generators are willing to pay to retain firm access, this could be done through exercising the renewal right as transitional access is sculpted back.

Issues raised	Stakeholder	AEMC response
Peaking plants should not be sculpted as they rely on rare critical price events for all their revenue. However, if alone among generators peaking plant were not sculpted this would overstate their required capacity at most times.	ERM Power, First Interim Report submission, p. 5.	All generation types are to be treated identically in the provision and sculpting of transitional access.
The majority of new entrants will be peaking plants and renewable generators and so only the investors in these technologies need be protected. Indeed, protecting existing generators may increase the cost of capital for new entrants if it signals a government view to protect existing generators from competition.	CEEM, First Interim Report submission, p. 4.	
Intermittent generator bids in transitional allocation should be based on analysis of their historical generation patterns relative to the peak periods, rather than their capacity.	Stanwell, First Interim Report submission, p. 48.	
As baseload generators operate closer to their capacity than peaking plant, they are more likely to be access short. May create incentives on peaking plants to cause constraints to receive access payments. Consequently baseload generation should receive a higher allocation than peaking plant.	CS Energy, First Interim Report submission, p. 29.	
Transitional access should not be allocated to existing generators as it will discourage investment in renewables.	ACF, First Interim Report submission, p. 4.	
Do not support sculpting of transitional access.	Stanwell, First Interim Report submission, p. 5; GDF Suez, First Interim Report submission, p. 4	See section 9.4 of Volume 2.

Issues raised	Stakeholder	AEMC response
There should be a rapid and complete scaling back of transitional access.	Victorian DSDBI, First Interim Report submission, p. 5.	
There should be a liquid secondary market for transitional access which would allow new entrants to easily purchase the firm access they require, rather than sculpting of transitional access.	GDF Suez, First Interim Report submission, p. 4; Stanwell, First Interim Report submission, p. 37; EnergyAustralia, First Interim Report submission, p. 5.	
Sculpting of transitional access is likely to create an abrupt change in aggregate levels of access.	Stanwell, First Interim Report submission, p. 37.	
The potential for degradation of the transmission network is the only reason to sculpt transitional access.	EnergyAustralia, First Interim Report submission, p. 5.	
Many of the potential benefits of the optional firm access model only occur if generators are holding firm access. Sculpting of transitional access would not work towards meeting these benefits	Stanwell, First Interim Report submission, pp. 36-37.	
Transitional access should not be sculpted before generators have had a learning period, have gone through a procurement timeframe, have had time to adjust their forward contracting, and all the regulatory arrangements are fully adjusted.	Stanwell, First Interim Report submission, p. 38.	All of the identified elements are important in determining sculpting length, see section 9.4.3 of Volume 2.
Setting residual life for transitional access with generators nominating lengths opens the way for rent seeking behaviour.	CEEM., First Interim Report submission, p.4.	The Commission considers that the process of determining generator's economic life would be difficult. See section 9.4.5 of Volume 2.

Issues raised	Stakeholder	AEMC response
NTNDP and similar documents are conservative about generator closures and not likely to provide rigorous foundation for determining economic life of generators.	CEEM, First Interim Report submission, p.4.	
Residual amount of firm access should not be allocated to existing generators on the basis of projected plant life as projected plant life is largely arbitrary, and it will allow generators who no longer need it to monetise their access.	Victorian DSDBI, First Interim Report submission, p. 6.	
Transitional access should be allocated for an individually determined life of generator.	Stanwell, First Interim Report submission, p. 38.	
In the model used for Option i increasing demand only at the regional reference node is not reflective of constraint conditions under the firm access planning standard or reality.	Hydro Tasmania, First Interim Report submission, p. 3; Stanwell, First Interim Report submission, p. 48.	The additional load is not to represent network topography, but to allow the model to balance. The simulated load is best located at the regional reference node. See section B.5.2 of the First Interim Report.
Support allocating transitional access to generators then interconnectors.	Stanwell, First Interim Report submission, p 46; CS Energy, First Interim Report submission, p. 18.	See section 9.3.2 of Volume 2.
Urges that caution be used when attempting to aim to maximise the allocation of access as it may result in less equitable allocations.	Stanwell, First Interim Report submission, p. 48.	Under Option iii described in section 9.3.4 of Volume 2 all generators within a region would receive the same allocation in terms of percentage of their existing capacity.
Method proposed could potentially create a dead weight cost on generators located near interconnectors - because of the erroneous assumption that sent out energy must be consumed at the regional reference node under conditions of a non-existent constraint.	Origin, First Interim Report submission, pp. 11-12.	