International Power Australia

Submission to the AEMC Transmission Frameworks Review – Directions Paper

EPR0019

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Introduction

International Power GDF Suez (IPRA) appreciates the opportunity to comment on the directions paper in relation to the Transmission Frameworks Review.

In this submission we will not seek to reiterate all the views that we set out in response to the issues paper, but rather we will clarify and expand on these views where the directions paper suggests to us that this will be helpful.

1. The Role of Transmission

The objective of reliable and economic supply of electricity as expressed in the National Electricity Objective appears to be common ground, but there are a variety of views on how the role of transmission should contribute to this.

While a “central-planning” model appears necessary for the myriad of customers, we believe that a different role is necessary to the achievement of the NEO in relation to the interaction between generators and transmission.

We note that virtually every decision in relation to the installation of new generation is not centrally managed and is made by the proponent (subject to certain technical minima). For example –

- The choice of fuel and the arrangements for its supply,
- Technology used and the level of efficiency in the use of fuel and the trade-off with capital cost,
- The level of redundancy in plant design, and hence reliability of operation
- Physical location, environmental considerations and availability of cooling water
- Contractual off-take and financial arrangements

The common feature is that the proponent is driven by competition between generators to seek the best balance for their intended role in the market. The current Rules imply, and this assumption appears to be unchallenged, that commercially driven decisions by plant proponents in a competitive environment will give results consistent with the NEO.

We contend that the primary role of decision making by the proponent who will bear the market consequences of their choice should apply equally to transmission arrangements, and for the same reason.

In order to achieve this –

- The proponent should have a choice of different locations and different levels of network access,
- The charges paid by the proponent for transmission service should accurately reflect the costs of that level of service at that time and at that precise location,
- The operational consequences, over the operational life of the proposed generator, of that choice should, as far as reasonably possible, be predictable (level of access and cost) by the proponent before the choice is made.

Central planning approach is appropriate when generation and transmission have common ownership. However the NEO objectives are best delivered by market mechanisms and competitive forces acting in a decentralised decision making environment.

We note that main opposing voice in support of the current transmission arrangements is strongly correlated with common, government ownership of generation and network service provision.

We suggest arrangements which are regarded as satisfactory only when there is common ownership on both sides of the relationship cannot be regarded as satisfactory in the wider context.

We also propose that in considering the transmission arrangements, the Commission should have primary regard to meeting the NEO in the future development of electricity supply. We suggest that government-owned generation is a legacy issue that, while requiring due attention while it persists, is most unlikely to play any material part in further development of electricity supply. Thus the arrangements should be designed to promote the NEO in the context of private investment in generation, and hence in the absence of common ownership covering both transmission and generation.

There are other legacy issues that might be seen to argue against a rational, future-based decision on the role of transmission. There is a mixed history in the payment for transmission services. Some generators have implicitly paid for transmission services through the purchase of generation assets with established network access. Other generators, installed during the operation of the NEM, have gained access in circumstances where the indirect cost of that access was imposed in large part on other participants, in the form of unexpected levels of congestion.

We propose that the Commission should consider the role of transmission predominantly in the light of future compliance with the

NEO, and where necessary allow the mixed legacy that the market has inherited to work its way out of the system over time.

2. Nature of access

We support the concept of open access for generators to the transmission network under the NER. By this we mean that an intending generator that

(a) Satisfies reasonable technical requirements, and

(b) Is prepared to pay the reasonable cost of the access provided.

(c)Then they should have a right to be connected.

However, we do not believe that such open access now applies under the NER. The TNSPs are not required under the Rules to build the assets needed to provide access (as they are free to classify the service as non-regulated).

We contend that the adverse effects of this implicit monopoly power extend throughout the connection and access regime, regardless of whether or not this veto power is actually used. The implied threat is enough to result in inefficiencies and increase cost.

We therefore propose that in order to deliver an open access regime, the regulatory environment as it affects Network Service Providers needs to be significantly strengthened. [

In addition to providing effective open access, we propose (as noted above) that the access regime should provide the level and location of access chosen by the prospective generator, with both accurate reflection of cost, and reasonably predictable operational consequences

These two aspects are closely related. A generator, in paying for network augmentation to support their chosen access level, would not be acting prudently unless there were foreseeable, ongoing operational consequences which justified the expense. [

The preservation of such defined access does not require that the generator has any specific dispatch rights (ie specific and guaranteed access rights in dispatch timescales). The preservation of defined access can, and we believe should, be defined through transmission planning studies under defined conditions. The preservation of an agreed access level can be objectively measured in this context. [This is also analogous to reliability standards on the demand side, whereby demand is not guaranteed supply at all times, but is ensured supply under specified planning conditions.]

Such an arrangement would leave the generator with the risk of reduced access from time to time as network capability varies from the defined conditions used in the planning studies, due for example to network outages or ambient conditions. Such risks are reasonably foreseeable by a prospective generator. While these residual risks are clearly undesirable, and will cause the generator to seek a risk adjusted return, there is no other obvious party that is better placed to manage them under the current industry structure. So whilst undesirable, such an arrangement is probably most economically efficient. Therefore we propose the more limited objective of protection of agreed access in the planning context.

In relation to the question of enhanced access rights, we propose a simple solution. This is to change the Rules to allow a generator to negotiate a level of network access which exceeds the capability of the plant installed. (This would require changes to 5.4A(d) which limit the level to the generator output level)

The additional capacity of the network would provide a reserve of network capacity thus making congestion less likely and/or would facilitate future generator expansion (eg future conversion of a OCGT plant to CCGT). To gain this benefit, the generator would pay the additional cost of providing the higher access level. Under our proposal for the protection of agreed access, the TNSP in negotiating subsequent network connections would be obliged to allow for the agreed access level despite this value exceeding the plant capacity. This would ensure that the intended spare capacity would be preserved.

The generator would thus have the option of paying for increased network capability, with the subsequent reduction in congestion. If no other measures were instituted then other nearby generators would also gain benefits from this spare capacity, but would gain only limited benefits unless they paid for full network access for their own plant (this assumes that the Rules are changed as we have proposed to give a rational meaning to the concept of partial access).

2.1 Financial access rights regime

We are concerned by the discussion of financial access rights. As discussed, this concept can be applied in the intra-regional context only if the market settlement were changed from regional to nodal settlement.

The first concern is that all generators now in the NEM entered with a reasonable expectation that they would continue to have a right to settlement on a regional basis [albeit up to the level of their current “non-firm” access level]

Furthermore many generators have entered hedging contracts in this same expectation. However previous discussion implies that generators may be deprived of this right without compensation [ie auctioning of the rights].

In contrast, in advocating a congestion management regime, we have been careful to specify that any departure from this right to regional settlement should be accompanied by the free provision of an alternative right that is as close as possible to the right foregone while still providing the benefits of congestion management

We commend this approach to you, as we contend that the un-compensated loss of this settlement right would constitute an unprecedented regulatory risk imposed on existing participants in this competitive market.

We also have serious doubts regarding the application of financial transmission rights in the Australian context. As noted in your paper, FTRs can be self-funding only if the rights are “simultaneously feasible”. But in order to achieve this, the capability of the network needs to be known when the rights are determined.

In the Australian context, with long transmission distances, and relatively small numbers of alternative paths, the transmission capability is highly variable, and hence is unsuited to serve as a basis for any prior allocation of rights.

We believe that any attempt to distribute such rights in advance would fail to deliver the benefits that a congestion management regime can deliver, and would impose much greater costs and risks on the market.

The problem is likely to be compounded by the conservative approach by TNSPs with transmission capacities understated as a result

3. Network charging

We support the observations in the directions paper that network charges should prove an efficient locational signal, and that this signal should be long-term [given that generation investment is long-term proposition]

We note that there is a happy coincidence in that the cost characteristics of transmission network assets is very well matched to the provision of long-term signals.

A large majority of the cost of transmission service lies in the capital charges. Furthermore, a significant part of the remaining cost, the operation and maintenance cost is largely determined by the choice of asset installed. Hence if a generator is required to pay the ongoing cost of a transmission asset installed to provide access at their chosen level and location, then they have a high degree of certainty in relation to the costs they will face.

While we appreciate that the network will evolve over time and that locational signals at any particular location may consequently change, we do not believe that such changes should alter the charges once a generator has agreed the level and cost of access.

Consider for example a generator that locates at a network node where demand dominates, and consequently incurs cost for connection only, with no component for cost on the shared network. Over time, with additional generation connecting at that node, there may be a need for augmentation of the shared network to provide generator access.

We contend that the original generator should not have its charge increased in this circumstance because –

- The new cost relates to events over which the original generator has no control, and
- If a part of the cost were allocated to the original generator, then the locational signal appropriate to a subsequent generator would be diluted, and hence would not be fully efficient

Consider the contrary example, where a generator chooses to locate where a network augmentation is necessary to support their access, and commits to costs based on that investment. It may be that over time there is demand growth such that if the generator were then seeking connection the network augmentation would not be required.

We contend that the original generator should not have its charge reduced because –

- It has not contributed to the reduction in the need for transmission assets,
- The cost of the assets remains as it is largely sunk cost (the asset will likely remain in service because the small savings from discontinuing its use would not justify the loss of reliability that would follow)
- If the charge to the generator were reduced then some other party would need to pay, but would be unlikely to see any benefit for incurring that cost.

We therefore contend that a suitable long-term cost signal comprises an obligation for any new generator to pay the cost of the network assets needed to provide the chosen level of access at the particular time and place of that access [this could also include costs for accelerated network investments].

In summary, we propose that a new generator must adapt to the network at the time of its connection, but once access has been agreed, the network must in future adapt to that prior commitment..]

We appreciate that there are legacy issues relating to the different conditions that applied in the past, where greater or lesser costs may have applied. However, we suggest that the Commission should focus on efficient prospective arrangements and not seek to untangle past charging arrangements.

The major legacy issue to be addressed, we suggest, is the need to now provide protection of all existing access arrangements from any adverse effects due to new entrants.

In the discussion above we treated the cost of network assets to provide a chosen level of access as if this were a sufficient description. We now wish to examine this in more detail and to propose that detailed provisions need to be incorporated in the Rules to define the costs that should be charged.

We note at the start that the Commission has experienced difficulties in the matter of inter-regional TUOS, as a result of inconsistent cost charging regimes in different regions. We contend that the difficulties are much greater for generators facing the monopoly power of a Network Service Provider. This suggests to us that the regulatory regime needs to be much more prescriptive on cost allocation to ensure consistency throughout the NEM.

We propose as a starting point that the appropriate principle is that a generator seeking access should pay the no more than the stand-alone cost of supplying that service.

There are a variety of reasons that a Network Service Provider may choose to construct assets that go beyond a stand-alone satisfaction of the access requirement. For example –

- They may wish to prepare for more convenient later expansion of the network,
- They may see future value in making more extensive use of an easement,
- They may want to provide network capacity for expected future connections

We do not wish to dispute the validity or desirability of such considerations. However, we contend that such decisions, if made by a party other than the connecting generator, should not affect the charges to be paid by the connecting generator.

4. Congestion

4.1 materiality of congestion

The Commission continues to give primary focus in relation to congestion management to the materiality of congestion. This was an understandable position in the context of a proposal for a location-specific and time-limited regime.

However, in the light of our proposal for a complete rather than a partial congestion management regime, we believe that the question of materiality should be considered differently. In any case the discussion of materiality is likely to be inconclusive in the absence of any agreed measure of materiality or of what level would justify action.

We consider that the current emphasis on materiality of congestion should be modified because –

- A complete congestion management regime will be very much cheaper to implement, both in initial cost and in ongoing cost than the partial regimes contemplated so far. Indeed we anticipate that the ongoing costs once the relevant software is developed would be negligible,
- A complete congestion management would affect the market only to the extent that actual congestion occurred, so there is little downside in implementing it, even if there were an unexpected reduction in congestion,
- The timely implementation of congestion management, despite the uncertainty over future congestion, may avoid the pressure for a hasty implementation in the event of increased congestion. The system would be developed and proven before the need became acute.
- A complete congestion management regime can bring benefits beyond the immediate context of intra-regional congestion, by eliminating the need to AEMO to clamp inter-regional flows in the case of settlement deficits (and thus eliminating the uncertainty imposed on participants through the risk of clamping), and by enhancing inter-regional trade by providing a more firm product in support of inter-regional hedging (by providing positive interconnector settlement residues despite counter-price flow).

In relation to the perception of materiality, we suggest that private participants see the issue of the wealth transfers resulting from congestion as more significant as it directly affects their bottom line than those participants in a situation where many wealth transfers are between entities with a common, government ownership.

4.2 Network availability

We appreciate the efforts of the AER to incentivise Network Service Providers to make network capability available when it will be most valued by the market. But we note that the cut-off value of $10/MWh only distinguishes trivial from significant congestion. It does not provide for a variable level of significance based on the effect on the market.

This is understandable given that “disorderly bidding” now obscures the real cost of congestion.

We note that congestion management, by eliminating the incentive for disorderly bidding, would enable the AER to enhance its scheme by working with realistic values of the cost of congestion. This in turn would support a more timely provision of network capability, while accommodating the need of Network Service Providers to maintain network assets.

4.3 Generator behaviour

We note the concern expressed in the directions paper in relation to generator behaviour in the presence of congestion. The behaviours mentioned, like disorderly bidding, are incentivised by the current market settlement arrangements.

These behaviours would no longer be incentivised if an effective congestion management regime were implemented.

We suggest that it is better to eliminate the incentives for such behaviours, rather than trying to regulate the consequences of these inefficient incentives.

4.4 Congestion Management mechanisms

The Commission has raised some key questions in relation to a mechanism for congestion management. We suggest that two considerations should be primary in responding to these key questions.

The first consideration is the predictability of network congestion. As a market participant we are keenly aware of the poor performance of the market operator in predicting congestion, even shortly before the event. We say this not as a criticism of AEMO, but rather as an indication of the inherent difficulty of the task.

Our first conclusion is that any congestion management regime which relies on predictions of congestion will be of very limited value and largely random in its consequences. Hence we contend that an effective congestion management regime must base its operation on the actual incidence of congestion rather than the predicted incidence. This supports a regime that is universal and ongoing, and which impacts on the market only when there is actual congestion. Our proposed regime satisfies this description.

The second consideration is the cost of implementation. The major part of the cost of location-specific and time-limited regime would lie in the determination of where and when it should apply and how the impact should be distributed among participants. This would require intensive ongoing input of a regulatory nature.

In contrast, the complete regime that we advocate would be an automated component of the market settlement process. It would draw data from the market dispatch process but not alter it. The changes in settlement would eliminate the incentive for disorderly bidding, thus changing participant inputs to dispatch. Once developed, there would be no significant input required.

An important consideration with our proposal for a complete congestion management regime is that its effect on the market is precisely proportionate to the issue to be addressed, because it has no effect until triggered by the actual incidence of congestion.

4.5 Management of basis risk

We propose that in implementing a complete congestion management regime, the implicit distribution of residues should be on the basis of availability offered to the market.

This is not, in essence, a departure from the current market arrangements, as this distribution basis is implicit in the current operation of the market.

In the current market arrangement there is a strong incentive for disorderly bidding. This directly brings into play the market provision to deal with tied bids. Under the Rules these tied bids are dispatched in proportion to availability and then settled at the regional price.

As noted in the directions paper, regional settlement is equivalent to nodal settlement plus a distribution of residue on the basis of dispatched volume. Hence the market arrangements already provide for the distribution of residues on the basis of offered availability.

Hence the proposal to use offered availability as the basis for distribution in a congestion management regime would not radically change the revenue expectations of generators or their ability to manage basis risk in their hedge contract arrangements.

The major effect on generator risks through hedging would be that with a congestion management regime in place they would no longer face the strong incentive to promptly rebid when unexpected congestion emerges. This change would reduce the risk due to an inadvertent failure to disorderly bid, which is serious risk which currently influences the design of trading systems for generators.

While we support the use of availability as a basis for distribution in a congestion management regime, we note that there a seriously undesirable aspect of the current distribution arrangements which can and should be changed in a congestion management regime.

Under the current regime, generators within a region where congestion limits their output are incentivised to disorderly bid. But where the congestion impacts on an interconnector and hence limits the output of generators in another region, these generators generally do not have the opportunity to compete by disorderly bidding. This is because if there were sufficient disorderly bidding to enable the interconnector to achieve a share of constrained flow, then that remote region would have a highly negative price set and generators within it would likely be disadvantaged by the outcome.

We consider that this aspect of the current market arrangements is an unreasonable discrimination which should not be allowed to persist. It can be corrected in the implementation of a congestion management regime by providing for a share of the residue to be allocated to the interconnector. While it is beyond the scope of this submission, we would be happy to describe the details of how this can be done, by using an existing tool that AEMO has.

The outcomes of this proposal would be –

- Marginal generation in the remote region would be able to compete on price with generators subject to the constraint, or
- If generation with the affected region were sufficiently economic with sufficient volume to give dispatch of counter-price flows on the interconnector, a positive settlement residue on the interconnector would nevertheless result and hence there would be no reason for AEMO to clamp the flow (as they do now in the case of significant accumulation of negative residues)

We note that this outcome both removes the uncertainty over whether or not AEMO will intervene to clamp counter-price flows, but also restores open competition without discrimination in circumstances where discrimination now intrudes.

In summary, we believe that the concerns that have held back the Commission from implementing congestion management will be overcome by the particular proposal that we support, and that there are additional benefits available which support inter-regional trade as well as intra-regional trade.

5. Planning

IPRA sees a need for the planning of transmission investment to be separately considered for different circumstances. In the following discussion we will make suggestions in relation to three different circumstances.

5.1 Network investment to support generator access

As we have noted above we believe that efficient investment in transmission in support of generator access will be achieved if the basis is an informed choice by the prospective generator on the place and level of access.

To allow an informed choice the prospective generator needs to know prior to this decision –

- The costs that they will incur as a result of that choice, and
- The operational consequences of that choice, as far as they can be reasonably forecast

We have further proposed that the costs faced by the generator should be those necessitated by that choice of location and access level. We recognise that there is a role for the Network Service Provider in making design choices to facilitate the anticipated further development of the network, but recommend that such choices if made by any party other than the generator should neither increase the cost to the generator nor delay their connection.

5.2 Investment to support interconnector capability

We have provided evidence in our earlier submission to this review of very restricted interconnector capability. We have attributed this poor performance to the regional segregation of transmission network planning.

The recent introduction of a National Transmission Plan might be expected to improve this situation. There has not yet been sufficient experience to indicate whether or not this will improve the situation as it is currently structured. However, we believe that there is already evidence available which suggests that a refinement to the process is desirable.

Our concern is that the National Transmission Plan, of necessity, must deal with the transmission network in a “broad-brush” manner, focussing on the major transmission paths. In contrast, our experience in actual market operations leads to the conclusion that limitations on interconnector flows are commonly due not to limitations within these major transmission paths, but rather to limitations associated with plant embedded deep within one of the connected regions.

Hence we see a significant risk that the real limitation on interconnector flows will be “below the radar” in the context of the national Transmission Planning.

We propose that rather than the NTP seeking to indicate where investment is needed to give desirable interconnector capability, the NTP should rather indicate the level of reliable interconnector capability it considers desirable for each interconnector and flow direction.

It would then be the responsibility of the relevant TNSPs to ensure in their planning that they did not encroach on that capability.

We see this as giving the need for interconnector capacity and reliability (as determined by AEMO) an equal status with jurisdictional planning standards. It also supports the different planning approaches between TNSPs provided the indicated level of interconnector capability and reliability are satisfied.

5.3 Investment to support reliable supply to customers or market benefits

The issues of investment to support reliable supply to customers or to gain market benefits are clearly the focus of RIT-T test and we anticipate this if the issues for which this test is unsuitable are segregated then the test will service its intended purpose.

In saying this we are not assuming that the RIT-T is now fully developed, but rather we are suggesting that for these particular purposes the path for improvement lies in refining the test rather than replacing it with another mechanism.

6. Connections

In the earlier parts of this submission, we have commented on the meaning of access and the charging principles for connection which we believe best support the NEO in their effect on the competitive generation sector. We suggest that substantial clarification and strengthening of the Rules is necessary to ensure the universal application of these concepts throughout the NEM.

Specifically in relation to the process of connection we believe that separate clarification and strengthening is necessary.

The primary focus in relation to the connection process should be to put in place additional measures to counteract the monopoly power that inherently resides with Network Service Providers. We believe that monopoly power, even where not explicitly or openly exercised, has serious and adverse effects throughout the connection process.

The size and sophistication of generation companies has been suggested as mitigating the monopoly power of Network Service Providers. However, we do not believe that any significant mitigation arises in this way. Furthermore, the market Rules should operate in an even-handed way for all those seeking entry as a generator, and should not rely on generation entrants having any particular characteristics. There should be a rapid and economical means available to resolve any disputes in relation to connections, with sufficient expertise to overcome any information asymmetry.

We also note that even the availability of an alternative supplier of connection services would not resolve the issue of monopoly power. This is because any such alternative service provider would need themselves to seek connection to the network of the incumbent TNSP.

Hence the incumbent TNSP retains an indirect power to impose conditions on the prospective generator.

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