Attachment A A potential alternative access regime

A.1 Purpose of this attachment

This attachment aims to outline how the idea of a locational connection fee could potentially be developed into a workable access framework that would be acceptable to Shell Energy, the ESB, consumers and other industry stakeholders. The primary intent is to focus on the potential new access framework itself. However, in order to address consumer concerns relating to costs being equitably shared, the reform ideas in this attachment also extend to how new regulated network infrastructure (much of which will be required to support state and federal government policy objectives) gets funded. This is consistent with the principles outlined in Section 4.1.2.

This framework in this attachment is not a 'finished product' — there are a range of details that need to be worked through for the idea to become fully developed (see Section A.5). However, Shell Energy considers the concept to be at a point where the ESB cannot dismiss it outright in favour of LMP/FTR. We believe this attachment provides an example of the kind of option that should be explored in depth as part of a consultative process to develop a workable long-term access framework. As discussed in Section 4.4, we consider it likely that, with an appropriately consultative process, our idea could be improved, or another idea could be developed that would be far superior to an LMP/FTR regime. To be clear, we believe this consultative process should occur over the medium term, rather than whole-of-system access reform being implemented in the medium term. Additionally, we believe that, before developing any long-term access regime (including this one), the ESB/AEMC should first collaborate with industry and consumers to reach broad agreement on what objectives the access regime should aim to meet (see Section 4.4.1),

We present more detail in this attachment than the ESB has published to date on the concept of a locational connection fee. This demonstrates our willingness to engage constructively when thinking about a future access regime. We ask that the ESB takes the same approach, with meaningful engagement on alternatives to LMP/FTR. As noted throughout our submission, we observe that engagement to date appears to have discounted stakeholder feedback opposing LMP/FTR.

A.2 Connection fee concept overview

A locational connection fee regime could provide a strong locational signal for co-ordinated investment in new generation and transmission infrastructure. Conceptually it can be thought of as a 'do low harm' requirement (discussed further in Section A.5.2) for new generators seeking to connect to the transmission network.

It would have several steps as follows.

- As part of the application process to connect a new generator to existing or proposed network infrastructure, the applicant (in consultation with the TNSP) would first undertake detailed modelling to identify all scenarios where the new generator could 'do harm' (based on a threshold) to the generators already connected to the transmission network.
- The proponent would then work with the TNSP to assess the physical network augmentation, generation asset capabilities and/or operational behaviours necessary to address these impacts. The TNSP would calculate the cost of undertaking any physical augmentation on the basis of it being a regulated or negotiated network asset paid for by the connecting generator. This calculation would take into account the new asset's capabilities and agreed operational behaviours.
    - For example, if the new entrant agreed to be constrained off at all times (via an automated generator runback or tripping scheme) where it would otherwise have negatively impacted the access of existing generators, then the physical augmentation cost would be low. Alternatively, if the new entrant wanted firmer connection, then it would need to bear the cost for physical augmentation that would reduce the number of situations the generator would need to be constrained off/down. The larger physical augmentation required, the higher the cost to the new entrant. In addition to operational behaviours and physical augmentation, the new entrant could potentially enter into commercial contracts with existing generators, under which those existing generators could agree to being 'harmed' under specific circumstances.
- This cost would be the 'locational connection fee' for the new-entrant generator[56]. After the generator agreed with the TNSP on the financial terms of the connection agreement, the TNSP would complete

[56] Note that the locational fee would be separate to the normal costs relating to building and connecting a connection asset.

the augmentation (or facilitate any operational schemes) and the generator would be approved for connection.

- It is possible that a new entrant might prefer to be connected before all the necessary augmentation was completed. In this case, the new generator would need to modify its operations to 'do low harm' to other generators during the period where the broader network augmentation was being completed. The exact details would be negotiated on a case-by-case basis.

There are no 'transmission rights' per se in this type of access framework. Instead, the access regime creates an environment where:

- all generators can be confident that their transmission access won't be materially compromised by new entrants
- new entrants have clarity over locational costs and certainty associated with their connections.

A.3 Funding new/upgraded transmission infrastructure

A.3.1 Privately funded transmission assets

Section A.2 focussed entirely on new-entrant generators seeking to connect to the existing shared network[57]. In this scenario, the new entrant pays for their own connection asset, whilst doing low harm to generators connected to the broader network.

For transmission assets that are funded by a private proponent, we believe it's appropriate for the funding proponent to have a property right to that specific asset (but not the broader network), as per the ERM Power submission to the AEMC's recent consultation on dedicated connection assets[58]. This would result in a slightly different access regime for third parties seeking access to the privately-owned transmission asset (c.f. the rest of the network), because they would need to reach an agreement with the asset owner (in addition to complying with the broader 'do low harm' concept).

Discussing the intricacies of dedicated connection assets and designated network assets is out of scope of this paper. The primary point of the previous two paragraphs was to highlight that it is reasonably easy to apply locational connection fee regime for new entrants seeking to connect to the existing shared network, or privately funded transmission assets. It becomes slightly more complex when considering new regulated transmission infrastructure built to facilitate generation (e.g. REZs), however, the principles of a property right in return for funding network augmentation remains the same.

A.3.2 Regulated network upgrades/extensions

A key concern of consumer groups is that consumers pay for the entirety of regulated transmission projects via transmission use of system (TUOS) charges. This means consumers are allocated all the risks associated with the projects despite generators receiving some of the benefits and creating some of the risks. Under the current framework, the TUOS cost to consumers will increase as more actionable Integrated System Plan (ISP) projects are developed.

As per principle 6 in Section 4.1.2, it is important that the transmission access framework facilitates an appropriate allocation of costs and risks between generators, consumers and TNSPs. For new transmission projects that receive regulated revenue, Shell Energy considers that it would be fair for TNSPs to recover revenue from both consumers and generators, in proportion to the benefit that they receive.

The cost-benefit analysis (CBA) of a project under the regulatory investment test for transmission (RIT-T) process provides a mechanism to establish the proportion of benefits that accrue to consumers vs. generators.

In our view, it is reasonable to expect that a substantial proportion of the benefits of actionable ISP projects will accrue to new-entrant (and potentially existing) generators. Based on the access framework described in Section A.2, once actionable ISP projects are built, new-entrant generators could benefit from them without contributing to their costs. This starts to appear particularly inequitable if the actionable ISP projects are specifically built to facilitate additional generation — especially where the new infrastructure provides little in the way of reliability benefits to consumers.

[57] Note that the logic is also applicable for connection to an existing REZ network.
[58] ERM Power, *RE: Connection to dedicated connection assets*, 28 January 2021. Accessed from: https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0294_-_erm_power_-_20210128.pdf

To address the issue of equitably apportioning transmission costs, Shell proposes the following mechanism that remains consistent with the locational connection fee regime model described in Section A.2. It is effectively a reform of the existing TUOS regime for new-build transmission infrastructure.

- Consider a scenario where AEMO identifies an actionable ISP project. Assume that the project successfully progresses through each approval/development stage, and is constructed.
- During the CBA as part of the RIT-T, require the TNSP to estimate (based on a pre-determined calculation framework) the proportion of benefits that would accrue to customers, existing generators, and new-entrant generators that locate in the network such that they benefit from the project. The Australian Energy Regulator (AER) should carefully review this apportioning of benefits when it assesses the RIT-T. For the rest of this explanation, consider the example of a 30% (consumers) vs. 10% (existing generators) vs. 60% (new-entrant generator) split of benefits
- For that specific transmission project, require the TNSP to have three notional and separate 'cost recovery buckets' – one each for customers (30% of project costs), existing generators (10%) and new-entrant generators that locate in the network such that they benefit from the project (60%). It is possible that costs increase between the finalised RIT-T and the AER approving the contingent project application (CPA). If the cost changes, each cost recovery bucket should be scaled to remain in proportion to the benefits estimated during the RIT-T processes (30% vs. 10% vs. 60%). Cost recovery would work as follows.
    - The TNSP would recover 30% of the project costs from consumers as per regular TUOS charges.
    - The costs in the 'existing generator' bucket (10% of project costs) would be smeared across existing generators that benefit in the form of a new GTUOS charge.
    - Initially, the TNSP and/or an underwriter (e.g. a state government) would hold the risk of the 60% of project costs[59]. However, in addition to the 'do no harm' locational connection fee described in Section A.2, the TNSP would be allowed to charge new-entrant generators that would benefit from the project a TUOS fee proportional to the new-entrant's requested access capacity. If there is as much connecting capacity as the ISP/TNSP had planned for, then the TNSP would recover sufficient revenue to cover the entire 60% bucket (for either itself or the underwriter). In the case of a transmission project built to facilitate new generation in a REZ, a government could potentially underwrite the risk of the 60% bucket by guaranteeing a yearly TUOS payment to TNSP. The government could recover these costs via the REZ coordinator recovering costs from generators connecting to the REZ infrastructure. Section A.4 considers the special case of REZs in more detail.
    - If a generator retired before the TNSP had recovered all costs in the relevant 'generator cost bucket', the capacity (and accompanying costs) released by the retiring generator would be offered to new or existing generators who wanted to increase their level of firm access. Any residual cost (that would have been paid by the retiring generator) would be reallocated such that generators that did not retire do not have their GTUOS fees increased. There are a range of options for how the residual costs would be reallocated. For example, they could be smeared across all generators, all consumers, or a combination of the two. Alternatively, they could be reallocated to a new cost-recovery bucket for new-entrants that would benefit. This is an example of a design aspect that needs more work (see Section A.5)

Shell Energy acknowledges that the above process introduces complexity and implementation questions that need to be investigated further (see Section A.5). However, it would also deliver substantial benefits. For example:

- There would be a more equitable allocation of costs between consumers and generators to reflect who benefits from new-build transmission infrastructure.
- By default, the TNSP or government underwriter would hold some stranded asset risk due to less-than-expected new-entrant generation. As a result, they would be more incentivised to keep costs down than they are currently. Given that actionable ISP projects/REZs should only be constructed where there is a demonstrated benefit to consumers and/or generators (accompanied by confirmed interest to connect), this risk should be manageable.

[59] The argument for the TNSP to hold the risk is to disincentivise transmission 'overbuild' during the design phase (because the TNSP would be exposed to the stranded asset risk). However, this may impact the TNSP's WACC, which would ultimately increase the cost of the project. Therefore, a government may be well-placed to take the role of 'underwriter', noting that taxpayers (rather than electricity consumers) would be exposed to the stranded asset risk.

- The locational connection fee regime described in Section A.2 means that generators (both existing and new-entrant) can be confident that their GTUOS fees are underwriting value (i.e. they won't be paying a GTUOS fee only to have a new entrant negatively impact their transmission access). We consider that the (effectively) firm access provided by the proposed regime would be of value to generators, and may even encourage investment. As a high-profile (albeit speculative) example, the proposed Sun Cable project values firm transmission access to the extent that it is willing to underwrite substantial new transmission infrastructure. Walcha Link is another example that demonstrates the private sector values firm access to new transmission infrastructure.

Shell Energy envisions that the above process would only apply to new/upgraded transmission assets (i.e. it would not be retrospective). The existing regulatory asset base of each TNSP would continue to be paid for by consumers, via TUOS.

A.4 Vision for how the proposed reforms could interact with REZs

Section A.3 flagged how the proposed access and TUOS reforms allow for government-facilitated REZs as part of the process to fund regulated transmission assets. Section A.4 examines in more detail how REZs could interact with the proposed reforms.

A.4.1 Planning the REZ

Consider a scenario where a government is facilitating a REZ's development via a REZ coordinator. This is consistent with the concept in the ESB's most recent REZ consultation paper[60], the approach NSW is taking with the Central-West Orana REZ, and early moves from Victoria to establish VicGrid as a new REZ-planning entity.

To comply with the proposed access reforms, the REZ coordinator would need to ensure that the REZ was designed so as not to harm the access of generators already connected elsewhere in the network. This is effectively making sure that the REZ and enabling network infrastructure is appropriately sized and has sufficient technical capabilities. If the ISP provides sufficient guidance, and the REZ coordinator works closely with the TNSP, then this should be relatively straightforward.

Note that the REZ coordinator's optimal REZ design may result in congestion for new entrants connecting within the REZ.

A.4.2 Funding the REZ

Assume that the REZ coordinator eventually agrees with the TNSP on the REZ's size, and the physical transmission augmentation/operational behaviour required to facilitate it (so as not to harm the transmission access of generators already connected in the network). The TNSP would calculate the cost of the necessary physical augmentation.

If the REZ is 'regulated' as envisaged by the ESB in its January 2021 REZ consultation paper (i.e. the REZ has been identified "as an actionable ISP project and… has passed a RIT-T"),[61] then costs would be recovered as per the process described in Section A.3.

If the REZ was government-driven (not regulated), then the cost recovered from different parties would depend on the government's appetite to fund infrastructure itself, vs. a desire to recover costs from different parties. At one end of the spectrum, the government could fund the infrastructure in its entirety. At the other end, the government may want to recover all its costs.

Assuming the government wanted to recover costs in an equitable fashion, an independent entity[62] could assess the proportion of the benefits from physical augmentation that would accrue to consumers, existing generators and new-entrant generators to the REZ[63]. The proportion of benefits accruing to new REZ generators would dictate the costs that the REZ coordinator would seek to recover from them (see Section A.4.3). The government could pass on proportional costs to consumers and existing generators by other means. This is consistent with the *NSW Electricity Infrastructure Investment Act 2020*.

[60] ESB, *Renewable Energy Zones, Consultation paper*, January 2021, Chapter 4. Accessed from: http://www.coagenergycouncil.gov.au/publications/stage-2-rez-consultation-energy-security-board

[61] ESB, *Renewable Energy Zones, Consultation paper*, January 2021, pp 5. Accessed from: http://www.coagenergycouncil.gov.au/publications/stage-2-rez-consultation-energy-security-board

[62] Shell Energy expects that the Australian Energy Regulator (AER) would be a suitable entity, given that the assessment of benefit distribution be similar to the assessment the AER would perform as part of a RIT-T for any new-build regulated project (see Section A.3).

[63] If the physical augmentations had passed a RIT-T, then this step would be superfluous, because it would already have been undertaken by the AER as described in see Section A.3.

A.4.3 Establishing the REZ

The REZ coordinator would be responsible for filling the REZ with generators. The ESB has previously suggested an auction or tender process to do so. The REZ coordinator would be free to take this approach, but may consider whether to implement a reserve price to guarantee at least some cost recovery. Alternatively, the REZ coordinator may choose to charge each REZ connectee an administratively calculated, TUOS-like fee designed to guarantee full cost recovery. However, if either the reserve price or the administratively calculated fee is too high, then the REZ coordinator may be left with a stranded asset.

A key point is that the REZ coordinator would be responsible for ensuring it didn't 'overfill' the REZ to the extent that it did material harm to existing generators on the network. Similarly, prior to the auction/tender/similar process, the REZ coordinator would need to make clear to all prospective REZ participants the operational requirements and/or congestion that they would face as part of a REZ designed to minimise whole-of-system costs[64]. If the REZ and facilitating infrastructure was appropriately designed in the first place, Shell Energy considers that these conditions are unlikely to be onerous. If they were not appropriately designed, the REZ coordinator would likely bear the costs of a stranded asset.

Box 1 provides a worked example for the rough order of magnitude that a REZ generator might expect to pay if the REZ coordinator charged a $/MW TUOS fee.

Box 1: Exploring the costs that a REZ coordinator might pass through to generators

Scenario 1

Consider a scenario where a REZ is an actionable ISP project, and passes the RIT-T. The REZ has an average capacity factor of 30%. Capital costs for physical transmission augmentation are $500M. Benefits are split between consumers (25% or $125M), existing generators (5% or $25M) and generators that would connect within the REZ (70% or $350M).

The relevant state government agrees to accept the stranded asset risk by committing to paying a yearly TUOS fee to the TNSP. The REZ coordinator plans to pass on this costs to new generators as they connect via an auction, or via an administratively-calculated fee. Table 3 below shows the yearly cost for generators in Scenario 1A (7% yearly cost recovery) or Scenario 1B (10% yearly cost recovery).

Scenario 2

Scenario 2 is the same as Scenario 1, except that there is a different REZ that is more remote than in Scenario 1 (network capital costs are higher at $800M), but has a higher average capacity factor (35%). Even though the capacity factor is better, the higher capital costs mean that generators pay more to connect to the REZ. This provides a locational signal for proponents lobbying for different REZs.

Table 3: summary of costs to generators in scenarios 1 and 2

	1A	1B	2A	2B
Network capital costs ($M)	500	500	800	800
Costs to be recovered from generators ($M)	350	250	560	560
Assumed yearly cost recovery (%)	7	10	7	10
Yearly cost recovered from generators ($M)	**24.5**	**35**	**39.2**	**56**
Yearly cost per ($/MW)	**7000**	**10,000**	**12,000**	**16,000**
Average capacity factor (%)	0.3	0.3	0.35	0.35
Yearly cost ($/MWh)	**2.66**	**3.81**	**3.65**	**5.22**

A.4.4 Ongoing REZ operations

After the REZ-facilitating transmission infrastructure was completed, it would be treated the same as anywhere else on the transmission network for new generators seeking to connect. I.e. new generators seeking to connect anywhere on the network would have to do low harm to all generators already connected to the network (including the REZ generators).

Additionally, until the REZ was filled to its designed capacity, generators seeking to connect outside of the REZ would either be required to either:

- do no material harm to generators that were planned for inside the REZ

[64] As flagged earlier in this section, we acknowledge that a REZ designed with the objective of minimising whole-of-system costs will likely have some non-zero level of efficient congestion.

- pay the REZ coordinator a TUOS fee equivalent to what an in-REZ new entrant would have paid for taking up the same level of transmission access.

For example, consider a scenario where a REZ was designed for 1 GW of solar capacity, but had only filled 900 MW. A new-entrant solar generator wants to connect outside of the REZ, but the effect of its connection is that the power transfer capability of the REZ during solar hours reduces to 900 MW. In order to do no material harm, the new entrant could either:

- agree to constrain its output in the event that it was causing the REZ to be congested (e.g. if a 100 MW solar farm was to connect within the REZ)
- choose to pay the REZ coordinator a TUOS fee equivalent to the fee a 100 MW solar farm would have paid if it connected within the REZ
- pay for a TUOS fee equivalent to a (for example) 50 MW in-REZ solar farm, and agree to constrain its output if it was causing the REZ to be constrained to below 950 WM during solar hours.

A.5 Outstanding issues to explore as part of a future work program

The ideas in Attachment A have been developed in a timeframe to inform the ESB's mid-2021 recommendations to Ministers. As a result, there are a number of issues that require further consideration. Some of them have been highlighted throughout the course of the attachment. Section A.5 summarises additional issues/questions that should be explored as part of a larger work program, including detailed stakeholder consultation. Section A.5 is not exhaustive, but should provide a useful starting point for the ESB's future thinking.

A.5.1 Questions around central planning

Quality of central planning

Both the locational connection fee access regime and the proposed complementary TUOS reforms are heavily dependent on central planners (AEMO, TNSPs and/or REZ coordinators) doing a good job upfront. For example, if a TNSP gets something wrong when assessing whether a new entrant would do harm (e.g. because of a modelling error or failing to consider enough scenarios), then the new-entrant generators could still cause congestion. Alternatively, the new entrant may be overcharged if the central planner is too conservative.

A tangible scenario would be if the TNSP had not anticipated one or more coal units in the vicinity of the new entrant closing earlier than expected. In this case, system strength may decline to the extent that constraints bind, and existing generators end up being disadvantaged by the new entrant.

A key question is whether the relevant central planners will do a sufficiently good job. If not, how could they be supported to do so?

Who takes on the risk for central planning mistakes?

Even if central planners are highly competent, it seems likely that some mistakes will still be made. As one example, it is important to explore what happens if the TNSP makes a mistake when specifying low-harm conditions, such that a new generator actually does significant harm after it has already made its investment decision. It seems unreasonable for the generator to be required to materially change its operation and/or pay for additional augmentation due to a TNSP mistake. It may be more reasonable for the TNSP to be liable for any additional remediation/compensation. However, this may make TNSPs excessively conservative when imposing 'do low harm' requirements (see Section A.5.2) on new generators. Alternatively, the cost of remediating central planning mistakes could be smeared across the TUOS of consumers if it passed the RIT-T. This is effectively what happens under the current cost recovery framework.

Apportioning benefits to consumers, existing generators and new-entrant generators

The TUOS reforms covered in sections A.3 and A.4 rely on an independent entity (potentially the AER) assessing the proportion of benefits that accrue to consumers, existing generators and new-entrant generators. For this to happen, the RIT-Ts (or equivalent CBAs for non-regulated REZ developments) need to be of a high quality. This will be more difficult for assets like interconnectors or meshed REZs compared with radial REZs. There will undoubtedly be arguments over how the benefits are split. With this in mind, it may be useful to develop additional CBA guidelines for this purpose.

A.5.2 How to implement a 'do low harm' framework

Defining 'low harm'

Throughout this attachment, we have used the concept of 'doing low harm' to existing generators. From an electrical engineering perspective, a true do no harm approach would require extensive system modelling under numerous power system conditions which would include forecasts of future generation and load connection including the type of connecting system, i.e. synchronous or asynchronous. The required level of modelling to cover all conceivable conditions would be challenging to achieve. Therefore, a 'do low harm' principle is more appropriate than a 'do no harm' principle. However, it is difficult to define.

There are multiple different types of transmission-related 'harm' that a new entrant can do to an existing generator. These include increasing thermal congestion, impacting fault level, impacting oscillatory and transient stability, and affecting revenue due to changes in MLF. Any 'do low harm' framework requires thresholds to be defined for each different type of harm. These thresholds require careful consideration.

The definition of these thresholds impacts the practicality of a 'do low harm' assessment for new-entrant generators. Shell Energy anticipates that there would be an increased (but not prohibitive) modelling requirement for new connections. This is likely to add time and/or cost during the connection process. However, connection timeliness could potentially improve overall due to a lower number of connection applications outside of areas (e.g. REZs) where new-entrants can do low harm without substantial physical augmentation and/or restrictions on operability.

Identifying 'do low harm' conditions for specific assets

The generation patterns for some assets (e.g. solar farms) are relatively easy to predict, whereas the generation behaviour of other assets (e.g. wind farms) has much greater variance. This may make it difficult for a TNSP to assess the likelihood of 'harm' prior to connection, and could result in excessively high or low connection fees. It may be necessary for contractual arrangements between the TNSP and generators to ensure operational decisions don't negatively impact existing generators. This requires further consideration.

Trade-off between investment certainty and network utilisation

There may be a degree of tension between providing investors with certainty that their access won't be adversely impacted by others' locational decisions, and minimising total system costs (which would require a degree of 'efficient' congestion). As a result, a 'do low harm' model may lead to more physical network infrastructure than if there was a different approach whereby there was a higher acceptable level of congestion. However, this could likely be addressed by carefully considering the definition of 'low harm'.

A.5.3 Miscellaneous

Potential conflicts of interest

The do low harm framework for new-entrant generators is based on an assessment by the TNSP. However, the TNSP has an incentive to:

- require excessive physical augmentation, if it is the entity undertaking (and getting paid for) the work
- require excessive technical capabilities for the new generator, as this would allow the TNSP to operate the network more easily, but at the cost of the new generator).

To address these issues, it is worth considering whether:

- there could be an appropriate mechanism to challenge the do low harm requirements
- the provision of any physical augmentation could be contestable, so that the TNSP is not the monopoly provider
- an entity that is independent of the TNSP should be responsible for assessing/reviewing a new entrant's requirements to meet the do low harm threshold.

What happens to the 'spare' access when generators retire?

As mentioned in Section A.3.2, consideration needs to be given to what happens to 'spare' network capacity when a generator retires. The answer may be different depending on whether the cost of the transmission infrastructure built to accommodate the retiring generator had been recovered from that generator or initially allocated as a grandfathered right. For example, if the costs of the network had been fully recovered from the retiring generator, would the retiring generator be able to on-sell their capacity rights? Alternatively, would this capacity be shared amongst existing generators (which would effectively increase the firmness of their access), or would it be made available to a new-entrant generator(s) with payments by this generator used to reduced costs paid by the other generators? If the retiring generator was paying costs on a yearly basis, could the yearly payment simply be transferred to the new connecting generator(s), potentially at the same rate? For any of these options, should there be a price on this spare capacity? If so, how would the price be determined and any additional revenue be distributed (e.g. to consumers as a TUOS reduction)?

Sharing the cost of 'efficient' congestion

As part of its Stage 2 REZ consultation, the ESB raised the concept of preventing 'winner-takes-all' outcomes within REZs by introducing a revenue sharing scheme between REZ participants during times of congestion. It would be worth investigating options to apply this concept more broadly as a complementary measure to a whole-of-system connection fee regime.