RES
Level 6, 165 Walker Street
North Sydney, NSW 2060
(02) 8440 7400 | info.australia@res-group.com

9th January 2023

Ms Anna Collyer
Chair
Energy Security Board

Lodged via email to info@esb.org.au

Dear Ms Collyer and Senior Government Officials,

RE: Submission in response to ESB Transmission Access Reform Directions Paper

RES is the largest independent renewables company in the world. Established in the 1980s within the Sir Robert McAlpine engineering and construction group in the UK, RES has the expertise to develop, construct and operate renewable generation across the Americas, Europe and Asia Pacific. With a renewables project portfolio over 23GW, RES is driven by our vision to deliver a future where everyone has access to affordable zero carbon energy.

RES was founded in 1981 and remains the world's largest independent renewable energy company. Active in 11 countries, we draw on an experienced global team of experts to deliver projects. We have developed more than 23GW of renewable energy projects across the globe and currently manage over 10GW of assets. We have developed a deep understanding of various energy market structures across these geographies. In Australia, we have developed projects such as Taralga Wind Farm, Ararat Wind Farm, Murra Warra I Wind Farm, Murra Warra II Wind Farm, Dulacca Wind Farm, Emerald Solar Farm and Avonlie Solar Farm. Setting us apart from our peers, we have built a strong team of power systems engineers with in-house modelling capability to carefully select, prioritise and design new entrant generators to mitigate congestion impacts and optimise network utilisation. We have been actively engaged in the transmission access reform over an extended period including our involvement in the ESB's Technical Working Group.

RES support the transmission access reform objectives of investment efficiency, management of access risk, operational efficiency and incentivisation of congestion relief. We acknowledge the considerable work undertaken to date by the Energy Security Board and applaud the collaborative approach taken. RES believe that the Reform's objectives can be satisfactorily addressed by adopting a standalone operational access model such as the Congestion Relief Market (CRM) or Congestion Management Model (CMM) in combination with Enhanced Information. A robust operational model with clear documentation outlining the rules and intended operation would have a significant positive impact on the locational decisions made by developers and investors. With an awareness that developers and investors will account for the impacts of the operational market when evaluating project revenue, we have a strong view that there is no need to also add an investment timeframe solution. We also note that developers and investors face strong locational signals through the revised system strength framework, jurisdictional REZ schemes, marginal loss factors and an increasing volume of publications from market bodies. Further, it is likely that future capacity auctions would prioritise projects connecting to transmission assets with spare capacity. In our view, the priority access and transmission fees models each have unforeseen consequences that are not aligned with the Reform's objectives. The cost of these unforeseen consequences would ultimately be borne by consumers.

In this submission we have provided our feedback on:

- the ESB's transmission access objectives,
- specific feedback on each of the access models under consideration,
- a more detailed description of our recommended approach to access reform, and
- detailed responses to the consultation questions posed in the directions paper.

Our feedback on the ESB's transmission access objectives is summarised in the table below:

ESB Transmission Access Reform Objective	**RES Feedback**
1. **Investment efficiency**. Better long-term signals for market participants to locate in areas where they can provide the most benefit to consumers, considering impact on overall congestion.	RES support the objective of incentivising the efficient development of the generation fleet to align with long-term interests of consumers. We also acknowledge that today's transmission access arrangements can lead to profitable individual investments that are misaligned to consumers' interests. However, we do not believe that a specific investment timeframe access model is required to ensure developers and investors make locational decisions that are in consumer's interests. Instead, we believe that an operational model with clearly documented rules and intended outcomes together with Enhanced Information would have significant and sufficient impact on the locational decisions made by developers and investors without introducing the unintended consequences of an investment timeframe model.
2. **Manage access risk**. Establish a level playing field that balances investor risk with the continued promotion of new entry that contributes to effective competition in the long-term interests of consumers.	RES supports this objective. We acknowledge that today's market presents an opportunity for new entrants to make a careful locational decision to minimise constraint equation coefficients to the detriment of incumbent generators. Ideally, an access model can be created where the incumbent and new entrant share fair access to the RRP. This would represent a middle ground between today's "winner-takes-all" NEM and other markets where incumbents are protected from or compensated for curtailment. This would be analogous to a new supermarket opening in the same suburb as an existing supermarket, where the two stores then need to compete for their share of consumer's business.
3. **Operational efficiency**. Remove incentives for non-cost reflective	RES supports this objective. We note that some of the biggest benefactors of disorderly bidding are the thermal generators in Central Queensland. When the Central-Southern Queensland

bidding to promote better use of the network in operational timeframes, resulting in more efficient dispatch outcomes and lower costs for consumers.	transient stability constraint is binding, these generators can bid at the market floor price and displace lower cost solar generation to access the RRP and maximise profit. This is an expensive constraint to alleviate with transmission augmentation, so the constraint is expected to continue to bind in the medium term as new renewables continue to enter the market prior to thermal retirements. The promotion of cost reflective bidding can lower costs for consumers whilst also reducing emissions. In RES' experience, investors will consider whether or not disorderly bidding can be used to reduce curtailment impacts when connecting within congested parts of the network. Similarly, the risk of subsequent parties using disorderly bidding to the detriment of the project under due diligence is also considered through sensitive analysis. Operational access arrangements are key considerations when determining the financial feasibility of generation investments.
4. **Incentivise congestion relief**. Create incentives for demand side and two-way technologies to locate where they are needed most and operate in ways that benefit the broader system.	RES supports this objective. We agree that today's market incentivises storage to locate close to load centres adjacent to strong transmission to increase the certainty of RRP access during peak price events and maximise discharge MLF. Changes to access arrangements might help incentivise storage to locate closer to VRE resources, optimise network utilisation and reduce spilled energy. However, we note that energy storage investment in REZs would still be risky because revenues could be significantly reduced if even a single competing storage project or flexible load connects nearby. For this reason, we believe that fixed long-term revenue certainty is required to support storage investment within REZs.

Investment timeframe: priority access

RES strongly opposes all variants of the priority access model, including the proposed hybrid with the Congestion Relief Market. We anticipate the following counterproductive outcomes:

1. **Lost incentive for efficient connection arrangement design**. By placing the priority number ahead of constraint equation coefficients in dispatch, the priority access model would significantly dilute the incentive for new entrants to efficiently utilise the network. Developers currently face a strong signal to minimise constraint equation coefficients via locational choice, connection arrangement design, establishment of cost-effective runback schemes. This is an attractive feature of market design because developers are rewarded for efficiently using the existing network and not developing projects that create bottlenecks on the network. The priority access model would remove this incentive and lead to the rushed progression of inefficient projects with cheap single circuit connections which would create future bottlenecks as VRE

penetration increases. We also believe that the priority access / CRM hybrid model would have large gaps between the energy run and the CRM brought about by generators with high constraint equation coefficients and low queue positions. It is unlikely that the CRM can bridge this gap and achieve an efficient dispatch result, particularly if these generators are motivated to achieve physical dispatch (rather than CRM payments) to meet contractual obligations. Given that many corporate PPA offtakers are motivated by climate objectives, we think this type of physical dispatch obligation will be common.

2. **Strengthened incentive for connections race**. With the current high volume of renewable connections and the requirement for detailed system strength impact assessment studies, AEMO and the TNSPs are under considerable strain to process connection applications. The NEM connection process is one of the most complex globally. It requires applicants to prepare very high-quality connection application packages based on mature designs, including having finalised their connection arrangements, made final technology selections and have completed electrical balance of plant designs well ahead of Final Investment Decision (FID). With the implementation of a priority access model, developers would have a strong commercial incentive to rush the design process that currently underpins a Connection Application, as they are driven to secure a queue number ahead of competing projects. This would lead to suboptimal outcomes for consumers and penalise better projects that can deliver lower costs of energy. This would have a detrimental impact on connection processing times as AEMO, TNSP and applicant's resources are consumed with repeated cycles of work on immature projects, and developers constantly escalating issues with AEMO and TNSP leadership teams to expedite progression of projects toward securing priority queue numbers.
3. **Inappropriate allocation of access risk**. The priority access model does not achieve an appropriate balance between investment certainty and the promotion of new entrants, by affording incumbents greater protections than other markets globally. Using the supermarket analogy, the priority access model effectively blocks a portion of customers from entering the new supermarket. As queue allocations are exhausted and transmission congestion grows as forecasted by the 2022 ISP, developers will be forced to areas with poorer quality resources which ultimately increases the cost of energy and hinders emissions reduction, leading to suboptimal outcomes for consumers and penalise better projects that can deliver lower costs of energy.
4. **Grandfathering complexity.** The implementation of a priority access model introduces a significant grandfathering challenge. It would be impossible to design grandfathering arrangements to preserve the status quo allocation of risk. Incumbents would either end up at the front or end of the queue which would be a significant change from the assumed risks at time of final investment decision. Grandfathering arrangements could have unintended consequences in some regions such as Central Queensland where incumbents may gain priority access to the transmission capacity between Central and Southern Queensland, which would jeopardise planned renewable investments in the region. It is important to note that all generators currently have equal coefficients in this constraint, so winner-takes-all is not a realistic outcome in this example. The implementation of priority access would lead to reduced investment in regional Queensland which is inconsistent with objectives of the Queensland Government and this reform. Similar problems are expected to arise in other jurisdictions.

Investment timeframe: transmission fees

RES strongly opposes all variants of the transmission fees model, including the potential hybrid with the Congestion Relief Market. We anticipate the following counterproductive outcomes:

1. **Increased influence of centralised planning**. The transmission fees model seeks to penalise new entrants that connect in locations or volumes which differ from those envisaged in the ISP. The ISP is a techno-economic exercise designed to solve for the cheapest cost for consumers but ignoring or greatly simplifying significant factors such as:

    - Resource availability
    - Environmental impacts
    - Social and political factors
    - Land use
    - Cultural heritage impacts
    - Transport connections
    - Construction costs and constraints
    - Local supply chains

    Giving developers and investors such a strong commercial incentive to align their plans to the ISP would be inappropriate and will lead to unintended outcomes inconsistent with the factors above. New entrants already face a very strong signal to minimise their system strength costs by selecting locations electrically close to system strength nodes declared by AEMO.

2. **Increased costs for new entrants**. This model introduces a new cost for new entrants that will be returned to consumers. In return for the fees, proponents are expected to gain comfort from the higher fees faced by second movers and benefit from reduced cost of capital. However, this benefit may be diminished as deep pocketed investors elect to pay fees and cause curtailment on the first mover. This issue could be improved by providing a refund of fees to reflect curtailment on generators and avoid generators being penalised twice. Nonetheless, in our view, it is unlikely that the reduced cost of capital will offset the quantum of transmission fees, leading to higher energy costs for consumers.

3. **Strengthened incentive for connections race**. With the implementation of a transmission fees model, developers would see a very strong signal to rush the connection process in order to secure a low transmission fee. This would have a detrimental impact on connection processing times as resources are ill-spent on immature projects and developers constantly escalate issues with AEMO and TNSP leadership teams as they face significant commercial pressure to secure low fees.

4. **Inappropriate allocation of access risk**. The transmission fees model does not achieve an appropriate balance between investment certainty and the promotion of new entrants, by affording incumbents greater protections than other markets globally. Using the supermarket analogy, the transmission fees model places an escalating entry fee on all new supermarkets. As low fee locations are exhausted and transmission congestion grows as forecasted by the 2022 ISP, developers will be forced to areas with poorer quality resources which ultimately increases the

cost of energy and hinders emissions reduction. The transmission fees model is not fit for the future state of the NEM where generation is significantly overbuilt compared to transmission capacity. The model simply builds in escalating costs for new entrants which will lead to an increased dependency on a capacity mechanism for revenue.

5. **Inaccuracies in fee estimation**. The estimation of transmission fees would be based on a single ISP scenario and optimised development path. As with any complex forecasting exercise, the forecast is inevitably inaccurate. The proposed approach runs the risk of aligning generation buildout with a single ISP scenario and reduces the market's ability to quickly respond to changing conditions. For example, the 2022 ISP is already out of date following the announcements in the Queensland Government Energy and Jobs Plan. Whilst a refund on fees for projects facing increased levels of curtailment would help with investment certainty and inaccuracies in estimating, this would still force generation build out to align with a single scenario, despite changes to underlying demand or costs.

Investment timeframe: enhanced information

In RES' view, enhanced information could help investors make better locational decisions. However, "hosting capacity" is a problematic metric because it requires too many subjective assumptions from TNSPs and is not easily utilised within financial models. In our view, it would be better to publish indicative curtailment percentages for all major nodes across the transmission network. Further, percentage curtailment could be plotted against incremental increases in project size which would provide stakeholders with a good indication of when a network becomes saturated with generation. These plots could be generated for selected future years using location specific wind and solar generation profiles. The plots would be generated utilising AEMO's ISP PLEXOS® model for the optimum development path. This information would provide prospective investors with inputs for their financial model. This approach better reflects the future state of the NEM where increasing levels of transmission curtailment is normal and some investment in generation beyond the "hosting capacity" is efficient. Please refer to our question responses for further detail on this concept.

Operational timeframe: RES Recommended Approach

In RES' view, all four transmission access reform objectives can be achieved by combining an operational timeframe model with enhanced information. It is important to recognise that investors will account for the structure of the market when forecasting energy revenues. Taking past learnings into account, investors typically engage experienced consultants to provide revenue forecasts that take wholesale prices, loss factors and congestion into account. In RES' experience, these forecasts have considered competitive bidding, constraint equation coefficients, generation runback schemes and the potential for announced or theoretical competing projects. As a result, projects with high curtailment risk have been abandoned or significantly modified before FID to mitigate risk. However, the winner-takes-all risk on meshed networks remains as an issue, preventing investors from making assumptions that further projects will not crowd into a congested area when assessing the probability of competing projects progressing.

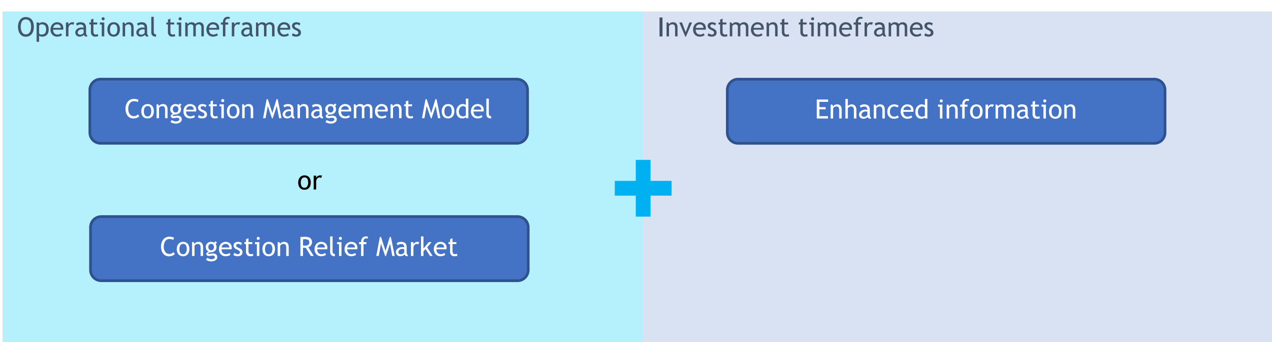
RES recommends the design of an operational timeframes model to prevent winner-takes-all outcomes. This would significantly improve investor confidence whilst removing the ability for new entrants to displace incumbents by connecting in congested areas. This model may be based on either the Congestion

Management Model (CMM) or the CRM. The design of the model and its intended impact would need to be clearly documented so that consultants could adapt revenue forecasts to account for the impacts of the new model.

The CMM could be designed as a standalone option to meet the transmission access reform objectives with pro-rata rebate entitlements based on a combination of constraint equation coefficients and offered availability. This would remove the winner-takes-all problem whilst retaining a slightly softer incentive for developers to minimise constraint equation coefficients via locational choice, connection arrangement design, establishment of cost-effective runback schemes.

Similarly, the CRM could be designed as a standalone option to meet the transmission access reform objectives by pro-rating access to generators with tied bids in the initial energy market run based on constraint equation coefficients. Congestion relief would then be traded on the CRM to converge on a physical dispatch outcome that minimises overall curtailment on low-cost generators as per today's market. The optional nature of the CRM would help to reduce the need for contracts to be renegotiated in the short term. In the long term, generators would still be expected to opt-in to the CRM to maximise profit. There is one key downside with this approach: if a large portion of generators opt out in the short term, wholesale prices are likely to increase (when compared to the CMM option) because the removal of winner-takes-all outcome would lead to increased levels of curtailment to generators lower in the bid stack which could exhaust the capacity of the marginal generating unit in some dispatch intervals.

RES recommends that the ESB and senior officials consider a pure operational timeframe model supplemented with enhanced information provision as discussed above. In our view, the decision between CMM and CRM will come down to a trade-off between the need to prevent contract renegotiation against short term wholesale prices. Our recommended approach is depicted in the figure below.



For further information regarding RES' position on transmission access reform, please contact Martin Hemphill (Manager – Grid Connections) via email at martin.hemphill@res-group.com.

Sincerely,

Matt Rebbeck

CEO RES Australia

RES
Level 6, 165 Walker Street
North Sydney, NSW 2060
(02) 8440 7400 | info.australia@res-group.com

Response to consultation questions

Section	Question	RES Response
3.3 Implementation considerations	Q1. Should the core elements of the hybrid model be implemented on a staged basis and if so, what factors should inform the decision with respect to staging?	Q1. RES does not support the introduction of the hybrid model as presented in the Directions Paper, notably RES does not support inclusion of Priority access or transmission fees frameworks. In our view, an operational solution can be implemented which by itself achieve the transmission access objectives (when coupled with Enhanced Information), balancing investment risk with the continued promotion of new entrant generation.
4.2.1 Parties subject to the arrangement	Q2. Do you agree with the proposed scope of market participants included in this access reform? Q3. Should different treatments apply to any particular categories of market participant?	Q2. RES agrees that scheduled and semi-scheduled generators, bi-directional resources, and loads should be included in the operational timeframe solution (noting that CRM participation is a generator choice). RES agrees that these participants should be included in the operational timeframe solution regardless of their connection to transmission or distribution assets. Q3. RES suggests that further work is required in detailed design to ensure that an operational timeframe solution does not create an inefficient opportunity for out of merit order generation to be dispatched.
4.2.2 Alternative distributions of congestion risk in the energy market	The ESB has proposed a decision option to round constraint coefficients in the energy market. Q4. Do you agree with the assessment of risks and opportunities for these design options? Q5. What is your preferred option and why?	Q4. RES does not support the decision to round constraint equation coefficients. The proposal would not address the reform objectives and would introduce considerable uncertainty for new entrants. In meshed networks, it is understood that small differences in constraint coefficients can lead to winner-takes-all outcomes. However, these outcomes would persist if coefficients were rounded. In today's market, a new entrant can gain dispatch over an incumbent by connecting as little as 1km further along a transmission line. The rounding of coefficients would only increase the physical distance required to impact the rounded coefficient. This would lead to inefficient and more costly

		connection assets as developers seek to connect far enough away from incumbents to gain a lower coefficient in constraints that are forecast to bind. Today's market design is also predictable – the key factor to consider is the relative order of constraint equation coefficients, not the absolute value. The proposed change would introduce uncertainty and reduce transparency. The rounding would require developers and investors to consider the absolute value of coefficients more accurately. Further, the rounding of coefficients is likely to increase energy costs for consumers as additional energy would be required from the marginal generator to offset the additional curtailment brought about by not curtailing the generator with the largest impact on the constraint first. Q5. RES prefer the option of keeping the existing energy market design regarding the formulation of constraint equation coefficients.
4.2.3 Arbitrage opportunities between the energy market and CRM for out-of-merit generators	Q6. Do you agree with the analysis of key risks and opportunities for each design option to respond to the new arbitrage opportunities between the energy market and the CRM? Q7. Are the design choices more applicable to certain categories of market participant? Q8. Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?	Q6. In RES' view, further detailed design is required to reduce the opportunity for out-of-market generators to arbitrage the energy market and CRM. The wealth transfers away from in-market generators would introduce investment uncertainty and hinder the business case for new entrant renewables. We agree that this is a valid risk for further consideration. Q7. The design choices would apply to scheduled generators, loads and bi-directional resources with a non-zero short run marginal cost. Q8. RES prefers option 3 – excluding out-of-merit generators from energy market dispatch based on the participant's bids in the CRM relative to the forecast RRP because an automatic system is a much stronger safeguard than option 2. Noting that out-of-market generators could respond by amending their CRM bids below RRP, we would prefer if the AER had a role to monitor, investigate and prosecute bidding behaviour intended to create an arbitrage opportunity for out-of-market generators.

4.2.4 Treatment of storage acting as a generator and as a load	Q9. Do you agree with the underlying assumptions for the respective incentives of storage acting as a generator and as load? Q10. Do you agree with the analysis of key risks and opportunities for each design option? Q11. Do you have a preferred design choice (either standalone, or combination of options) and what is your rationale?	Q9. RES agrees with the incentives for storage acting as a generator and load; however, a further scenario should also be considered where LMP>RRP due to a load driven transmission constraint such as the forecasted Gladstone load area constraint driven by the retirement of Gladstone Power Station. In this scenario, storage would seek to access to the LMP for generation. Q10. RES agrees with the analysis of risks and opportunities, but we have proposed an alternative for consideration in our response to Q11. Q11. The same design choices cannot be applied to storage as other generators because strategic bidding is likely to lead to wealth transfers and allow storage proponents to achieve financial returns on the energy market that do not reflect the limitation on their storage depth. Whilst a “strike price” concept may reflect the intended use case of some storages under cap contracts, it would not be appropriate for merchant revenue maximising storages that respond purely to estimated opportunity cost. An automatic daily energy constraint should be considered further. We do not foresee any immediate issues with excluding storage from the energy market when acting as a load but this is a relatively new concept and needs to be worked through to ensure that new entrant storage is not disincentivised.
4.2.5 Calculation of RRP	Q12. Do you have a preferred calculation for RRP and why? Q13. Which approach do you prefer for the treatment of FCAS and why? Q14. If the technical implementation plan requires that we adopt your non-preferred calculation of RRP and FCAS prices, what are the risks?	Q12. From RES’ perspective, the long-term benefits of option 2 (RRP based on CRM) outweigh the risks and retains consistency with the concept that RRP is based on physical dispatch. However, further analysis and transitional arrangements may be required to reduce the requirement to reopen existing contracts. Q13. No response. Q14. Refer to Q12.
4.6.6 Settlement of metered output	Q15. Do you agree with the risks and benefits of the two options for the	Q15. RES agrees with the assessment of risks and benefits. Q16. RES prefer option 1 (metered output is priced at RRP) because it is important for many investors and offtakers to avoid exposure to LMP. The risk

	formula of settlements and their materiality? Q16. Do you have a preferred settlement formula and why?	of proponents not following dispatch instructions can continue to be managed via AEMO's non-conformance monitoring. This issue is also outside of the reform objectives.
5.3.1 Form of queue right	Q17. Should the ESB work towards providing as many unique queue numbers as is feasible (given implementation challenges) or is a tiered approach preferable?	Q17. For the avoidance of doubt, RES strongly opposes all variants of the priority access model. Our rationale is set out in the body of our submission. Nevertheless, if the decision was taken to progress to a priority access model, our preferences are ordered as follows: i) Batches ii) Unique queue numbers iii) Tiered access Tiered access is technically flawed because it would require AEMO or the TNSP to assess a single transmission network capacity which would cause problems during transmission outages or changes to credible contingencies brought about by extreme weather events. It is likely that this option would not appropriately reflect the increase in transfer capacity brought about by generation runback schemes. Unique queue numbers are a technically superior option and would provide the most investment certainty; however, this approach would cause developers to race for connections, increasing the strain on an already stressed connection process. Grouping generators into batches (perhaps based on year of connection) would still incentivise 'racing' but would reduce the strain on the connection process when compared to unique queue numbers. The value of a development project could drastically change based on queue position; the ESB should be careful not to incentivise developers to rush the connection process and risk placing unnecessary burden onto NSPs and AEMO.
5.3.2 Allocation mechanism	Q18. What mechanism should be used to allocate queue positions to generators? E.g. first come first served, auctions, a combination or another approach?	Q18. For the avoidance of doubt, RES strongly opposes all variants of the priority access model. Our rationale is set out in the body of our submission. The first come first serve approach is problematic as it would increase the strain on an already stressed connection process. An auction process would be problematic because it relies on a static assessment of transmission capacity and introduces a new process to the project development cycle which would

		inevitably increase the timeframe and costs for new entrants to reach the market whilst increasing uncertainty for developers. These additional auction costs are not justified by the perceived benefit of cost of capital reduction.
5.3.3 Duration of rights	Q19. Would stakeholders prefer that the priority access rights (i.e. queue positions) be set for: the life of the participant's asset, a fixed duration, or a fixed duration with a glide path? Q20. If set for a fixed duration, what period of time do stakeholders consider would be most appropriate? Should this period be adjusted if combined with a glide path?	Q19. For the avoidance of doubt, RES strongly opposes all variants of the priority access model. Our rationale is set out in the body of our submission. Nevertheless, if the decision was taken to progress to a priority access model, our preference for the duration of access rights is as follows: i) Fixed duration ii) Fixed duration with glide path iii) Life of asset Our rationale is based on reducing barriers to entry for new entrants, considering the forecast level of long-term transmission congestion in the 2022 ISP. Fixed duration access rights could be aligned with average PPA duration or project debt tenor. Based on our global experience, maintaining access rights for the life of assets is a significant barrier to entry and leads to developers seeking out inefficient projects with relatively poorer renewables resources.
5.4.1 Method used to calculate fees	Q21. Which of the proposed metrics do stakeholders consider should be used as the basis for calculating congestion fees? Are there alternative metrics the ESB should consider?	Q21. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees model. Our rationale is set out in the body of our submission. Nevertheless, if the decision was taken to progress to a transmission fees model, our preferences are as follows: i) Estimate of total cost of congestion caused by connecting generator ii) Estimate the value of access to the RRP iii) Long run incremental cost New entrants could be incentivised to efficient locations if the fee is based on an estimate of the total cost of congestion caused by the connecting generator. We understand that if new entrants are within the forecasted capacities of the ISP, the fee would be zero. This analysis could leverage AEMO's existing ISP PLEXOS® models to estimate the fee. Care would need to be taken to account for proposed generation runback schemes and competitive bidding behaviour. Safeguards would need to be put in place to ensure that

		generators do not pay for congestion twice (via a transmission fee and physical curtailment). It would be worth considering a refund in annual transmission fees to reflect physical curtailment that occurs. We have the view that long run incremental cost is the least optimal option as it would require significant additional resources and lead to lumpy increases in fees where large transmission investments are needed to alleviate congestion. We also echo the ESB's sentiment that it would be important for developers and prospective investors to access the modelling information to assess potential fees prior to investing significant development capital (e.g. 18 months prior to financial close).
5.4.2 Fee calculation process	Q22. Noting the trade-off between investor clarity and accuracy, do stakeholders have feedback on how bespoke the modelling should be?	Q22. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees model. Our rationale is set out in the body of our submission. Nevertheless, if the decision was taken to progress to a transmission fees model, we suggest that AEMO or the NSPs publish indicative transmission fees on an annual basis to help inform site selection. Bespoke transmission fees should then be calculated for each project to reflect the site-specific generation profile, connection arrangement and generation runback schemes. The bespoke process would deliver benefits as developers would be incentivised to collaborate with NSPs to reduce congestion via technology selection (e.g. DC-coupled solar-storage hybrid systems) and connection arrangement design (e.g. connecting into both circuits of a double circuit tower line). The final fee should be locked in prior to the execution of connection agreements and financial close. This provides sufficient investment certainty.
5.6.2 Timing	Q23. At what time within the connection process should the queue position or congestion fee be locked in?	Q23. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees and priority access models. Our rationale is set out in the body of our submission. Nevertheless, if the decision was taken to progress to a transmission fees model, the final fee should be locked in prior to the execution of connection agreements and financial close.

5.6.3 Managing multiple simultaneous connection applications	Q24. Should there be a process for batching connection applications and jointly establishing connection requirements and fees? Q25. Could an expression of interest process, combined with auctions, be used to manage multiple simultaneous connections?	Q23. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees and priority access models. Our rationale is set out in the body of our submission. Batching of projects to allocate queue positions would still place considerable strain on the connections process and incentivise developers to rush the applications process. Batching may be more suitable for transmission fees, particularly if the fees are zero when the project fits within the ISP's forecasted development of generation. Batching would be useful to group similarly timed projects in congested areas that overbuild the ISP forecast. This approach would incentivise developers to collaborate with each other on technology selection, connection arrangement design and generation runback schemes to minimise the overall congestion impact of the batched projects. Any batching process would need to consider the risk of project withdrawals impacting costs and timeframes for remaining projects. Q25. EOI processes are likely to be problematic as the batch would then be optional. Problems would arise if projects in similar locations opt in and out.
5.6.4 Qualifying criteria	Q26. Should there be conditions precedent which must be met before a queue position or congestion fee is finalised and accepted? If so, what sort of measures would be appropriate?	Q26. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees and priority access models. Our rationale is set out in the body of our submission. If forced to live with either model, it is acceptable that the queue position would be provisionally identified at the time a connection application was made and confirmed at the time the connection agreement was signed. Similarly, the congestion fee should be finally determined at the time the connection agreement is finalised. There are already significant barriers to signing connection agreements such as the lodgement of bonds, commencement of connection fees and issuance of a 5.3.4A/B letter from AEMO confirming the agreement of the generator performance standards and the finalisation of the system strength impact assessment. In our experience, projects that reach this point have never been abandoned.

		Further, the payment of any transmission fee should be aligned with the generation of energy. To reduce debt costs, fees should not commence until construction and commissioning works have been completed.
5.6.5 Use it or lose it	Q27. Once set, parties would be expected to progress to implementation. Should there be time limits or expiry dates for projects which do not progress in a timely manner? If so, what time limit would be appropriate?	Q27. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees and priority access models. Our rationale is set out in the body of our submission. If fees / queue position are not finally confirmed until the execution of a connection agreement, there would be no need for use it or lose it provisions. This is a simpler approach and would avoid creating an incentive for developers to lodge poor quality or incomplete connection enquiries or applications too early in their project development cycle. A longstop date could be considered to account for the unlikely case of project insolvency or abandonment.
5.7 Treatment of incumbents	Q28. Do stakeholders have a preference for any of the options listed regarding the treatment of incumbents in transitioning to the priority access variant? Are there alternative options for the treatment of incumbents under this model that the ESB should consider? Q29. Do stakeholders support the calculation of congestion fees reflecting the protection of incumbents under the model? If so, do stakeholders have feedback on feedback on how to determine the appropriate degree of protection?	Q28. For the avoidance of doubt, RES strongly opposes all variants of the priority access model. Our rationale is set out in the body of our submission. Any protection of incumbents is unacceptable due to the barrier this creates for new entrants that is inconsistent with objectives 1 and 2. Q29. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees model. Our rationale is set out in the body of our submission. The discussion of incumbent protection within the calculation of fees is very brief in the directions paper, so it is difficult to determine if we support such an approach.
5.8 Options to reduce congestion impact	Q30. Should the ESB develop proposals to give generators options to reduce their congestion impact (in	Q30. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees and priority access models. Our rationale is set out in the body of our submission. The existing market already incentivises developers to

	return for a lower fee or worse queue position) as part of its congestion management reform package? If so, what options should be included?	minimise congestion efficiently utilise the network via technology selection, connection arrangement design and implementation of generation runback schemes. By exposing projects to constraint equation coefficients, efficient behaviour is incentivised. Care needs to be taken to ensure this incentive to minimise congestion through engineering is not lost as developers race for queue position or allocation of a low transmission fee. The prospect of lower transmission fees could be used to incentivise efficient technology selection, connection arrangement design and implementation of generation runback schemes. However, this signal would have no impact in uncongested areas. It would be inappropriate to incentivise with queue positions as this would undermine investors' confidence in the queue. Both the priority queue and transmission fees models risk losing an existing signal for developers to maximise utilization of the network.
5.9 Governance	Q31. Do stakeholders support the proposed governance arrangements for providing locational signals?	Q31. For the avoidance of doubt, RES strongly opposes all variants of the transmission fees and priority access models. The best approach for estimating transmission fees would be based on comparing the marginal congestion cost of the connecting generator utilising the ISP PLEXOS® model. If the connecting generator fits within the forecasted build out of the ISP, the fee is zero. The party responsible for determining fees should be experienced in utilising PLEXOS® to avoid the need to apply simplifications in a parallel modelling package and duplication of work.
6.2 Hosting capacity assessment	Q32. Would investors find indicative network hosting capacity values useful for their siting decisions, noting the fundamental limitations of static modelling of the network? Q33. If so, do stakeholders support defining "zones" of the network based on the sub-regions developed by AEMO for its capacity outlook modelling for the ISP? Are there	Q32. In RES' view, enhanced information could help investors make better locational decisions. However, "hosting capacity" is a problematic metric because it requires too many subjective assumptions from TNSPs and is not easily utilised within financial models. In our view, it would be better to publish indicative curtailment percentages for all major nodes across the transmission network. Further, percentage curtailment could be plotted against incremental increases in project size which would provide stakeholders with a good indication of when a network becomes saturated with generation. These plots could be generated for selected future years using location specific wind and solar generation profiles. The plots would be generated utilising

	alternative approaches the ESB should consider? Do stakeholders have feedback on how granular congestion zones need to be to provide useful information to investors? Q34. Should the ESB focus its efforts on an alternative approach, including making underlying data accessible for investors to conduct their own modelling, more granular ISP modelling by the joint system planners or calculating curtailment forecasts? Are there further alternative approaches that the ESB should consider?	AEMO's ISP PLEXOS® model for the optimum development path. This information would provide prospective investors with inputs for their financial model. This approach better reflects the future state of the NEM where increasing levels of transmission curtailment is normal and some investment in generation beyond the "hosting capacity" is efficient. Q33. Refer to our response to Q32. Our suggested approach provides a stronger and more useful locational signal for specific projects compared to the zonal approach suggested. The zonal approach would fail to address asset specific congestion that we have seen in parts of the NEM such as the Manildra/Molong/Parkes/Orange locality. Q34. Refer to our response to Q32.
6.3 Treatment of diversity	Q35. Do stakeholders support hosting capacity assessments that provide investors with a single figure of static capacity under a single set of pre-determined operating circumstances? If so, do stakeholders have feedback on what the assumed operating circumstances for the assessment should capture? Q36. If stakeholders prefer multiple hosting capacity values that reflect a range of scenarios, should seasonal conditions be relied on? Alternatively, Should the information	Q35. Refer to our response to Q32. Reporting hosting capacity based on a single operating condition would be completely useless to investors, particularly as transmission congestion increases over time as the VRE fleet is overbuilt to meet peak demand. Q36. Refer to our response to Q32. By generating nodal curtailment assessments, there would be no need to develop assumptions on operating conditions. The calculation of hosting capacity under a range of conditions would be of limited use for investors. In fact, overly pessimistic assumptions and publication of hosting capacities would almost certainly increase the cost of capital by increasing the perception of risk. It would be better to enable investors to properly quantify the financial risk. Q37. Refer to our response to Q32. Nodal curtailment assessments could also be generated for loads and generators with 100% capacity factors to help

	be presented in terms of technology-specific values? Q37. Do stakeholders have any feedback on how load and storage is best captured in the assessment of hosting capacity? Do stakeholders support assuming peak demand for the assessment? Q38. Should the hosting capacity assessment be based on all types of constraints, and not just thermal, even though this may result in more conservative figures? Q39. Do stakeholders support relying on the notional transfer capabilities for interconnectors identified by AEMO through its ISP process?	inform storage proponents on whether their energy arbitrage opportunity could be impacted by transmission congestion. Alternatively, it may be possible to utilise an assumed daily profile for charging and discharging. Q38. RES prefers that the nodal curtailment assessment should include voltage, transient and oscillatory stability constraints that are expected to persist over a prolonged period and cannot be resolved with efficient transmission investments. System strength constraints should be excluded because these should no longer occur after the implementation of the new system strength framework. We do not support the calculation or publication of hosting capacities. Q39. RES supports the alignment with ISP assumptions on notional transfer capabilities for interconnectors as this is a common scenario considered by the investment community.
6.4 Capacity included in the forecasts	Q40. If indicative hosting capacity values are calculated, do stakeholders support capturing only committed network augmentations, generation and load or should anticipated projects also be included? Q41. Do stakeholders support overlaying network congestion metrics with information about historical and forecast network constraints?	Q40. RES do not support the publication of hosting capacities and instead prefer nodal curtailment assessments. In our view it would be sufficient to consider incremental generation beyond the efficient level in the ISP optimum development path. More frequent updates would create challenges for project financing as new publications may create inconsistencies with project specific due diligence workstreams. Q41. In RES' view, it would be helpful to overlay nodal curtailment forecasts with historical curtailment outcomes for nearby projects.
6.5 Form of information	Q42. Do stakeholders support using existing interactive mapping tools as a basis for developing a NEM-wide	Q42. In RES' view, it would be useful to utilise existing interactive mapping tools to view nodal curtailment assessments.

	central portal of information for investors?	
6.6 Governance	Q43. Do stakeholders support the proposed governance arrangements for the provision of enhanced information? Q44. What additional obligations are required to ensure that the right parties can access the right information, and how can security concerns be managed?	Q43. In RES view, it would be more efficient for AEMO to generate nodal curtailment forecasts utilising their ISP PLEXOS® model. The proposed approach of AEMO setting out a methodology for the TNSPs to apply, using ISP assumptions is overly resource intensive and likely to lead to inconsistencies between AEMO and TNSP models. The investment community typically considers business cases under ISP scenarios and places less weight on TNSP's TAPRs or other TNSP planning outputs. Q44. No response provided.