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Jess Boddington
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Australian Energy Market Commission
PO Box A2449
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Dear Ms Boddington

RE: Coordination of Generation and Transmission Investment – Access reform – Directions Paper

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission ('Commission')'s Directions Paper on access reform, as a component of the Coordination of Generation and Transmission Investment (COGATI) Review.

About ERM Power

ERM Power is an Australian energy business for business. ERM Power provides large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fuelled ERM Power's growth, and today the Company is the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. ERM Power also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.
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General comments

Adequate transmission network capacity is essential for the safe delivery of energy to consumers and secure operation of the power system. The National Electricity Market (NEM) is clearly undergoing a shift in the provision of electricity supply, as investment in asynchronous renewable generation reaches historic levels. Direct pressure has been placed on existing transmission assets due to the changing market dynamics of generation investment. This is particularly evident from the increasing numbers of new generators locating assets at the grid edge, connecting to network that was not originally designed to accommodate generation output. This trend has driven transitional issues related to generator network access and dispatch outcomes.

It is important that the transmission network is funded and constructed to deliver energy to consumers at the lowest cost. As the power system evolves, access reform should be considered and progressed where it is demonstrated that any proposed reform delivers benefits and improved costs for consumers. Considering that consumers currently incur the total cost of transmission investment, any access reform must be comprehensively tested and analysed prior to implementation.

The Commission has indicated that the proposed access reforms will create increased financial certainty for generators, providing incentives for generators to bear a large portion of the costs of new transmission infrastructure. However, the model proposed by the Commission in the Directions Paper highlights many areas of complexity with uncertain risks. A primary risk is that the expected costs of implementing the reform have not been estimated, and the implications of unquantified costs on the market.

[1] Based on ERM Power analysis of latest published information

ERM Power are concerned regarding the lack of supportive evidence and analysis for the proposed access reforms. In considering the proposed changes to generator nodal pricing (locational marginal prices, LMP) and financial transmission rights (transmission hedges), the Commission should provide clear evidence from international power markets of similar transmission pricing and access frameworks to this proposed change. Although NEM market participants consider that access reform should be progressed as a priority[2], this does not suggest that reform should be expedited at the expense of adequate analysis of the costs, benefits and impacts of the reforms on the market.

We believe the reforms proposed in the Directions Paper do not adequately safeguard market participants and consumers against inefficient investment costs and unnecessary risk allocation. In summary, ERM Power believe:

- The proposed access reforms must be assessed with a cost-benefit analysis
- The approach taken to expedite implementation of these reforms should be reconsidered, due to the risk of unintended impacts on market operation and investment efficiencies
- The potential for proposed reforms to negatively impact financial contracts market must be adequately assessed
- The provision of grandfathered rights to transmission access is a priority design feature which must be determined
- Implementation of transmission access reform should be delayed until identified risks and uncertainties have been managed through effective stakeholder consultation

Addressing the need for a cost-benefit analysis is an immediate priority

As the NEM undergoes transition, the regulatory framework governing the market is expectedly undergoing reform to ensure the market rules are fit-for-purpose for the new models of generation investment and consumer behaviour. It is important for the fair operation of the market that regulatory reform keep pace with the scale of the transition underway. However, the reforms to transmission network access and charging proposed by the Commission represent significant changes to the market. It is essential that a market reform of this scale undergo a detailed cost-benefit analysis to ensure that the proposed benefits of this reform outweigh the costs of its implementation. Failure to quantify estimated implementation costs to the market and cost savings to consumers prior to implementation risks producing unintended and inefficient outcomes for participants and consumers.

We recommend consideration of the currently known market costs relevant to the proposed reform. The Commission has suggested that the cost benefits of the proposed reforms are greater than the current costs of congestion on the transmission network, which are at a level to warrant changes to the access regime. ERM Power notes that it is unclear whether the changes proposed are justified by the costs of transmission capacity-related congestion currently observed in the NEM. AEMO's estimated cost of congestion in the Annual Constraints Report CY2018, under the current access regime, was $10.5 million under system normal conditions. The cost impact of network outages was estimated to be $10.7 million. Additional costs of $13.6 million and $30.4 million was allocated to the South Australian system strength asynchronous generation limit and network support agreements, respectively. However, these latter costs of $13.6 million and $30.4 million would not be reduced through the proposed access and pricing regime change.

The Commission has argued that the case for immediate change to address these costs is material. This case for change is argued as immediately material compared to previous assessments of materiality, where the costs of change have outweighed the benefits. Considering this, we do not believe that the case for change can be credibly made without an appropriate cost-benefit analysis. This is particularly relevant considering the known complexity of

[2] Based on the Commission's summary of stakeholder feedback in the Directions Paper

access reforms, demonstrated through the fourteen major reports and reviews on congestion management and generation access since 1997.

During the Transmission Frameworks Review, which considered changes to the transmission access regime, the terms of reference explicitly stated that the second stage of reporting on the need for access reform should include quantitative analysis, to consider where net benefits would be derived from adopting a transmission framework that would provide for better coordination of investment between the transmission and generation sectors. This COGATI process represents the second stage of reporting, and the Commission has not provided details of any substantial quantitative analysis for the publication of their final report on COGATI published in December 2018. Appropriate quantitative analysis is required to ensure the Commission meets the terms of reference provided by the COAG Energy Council.

The terms of reference also recognised that there were likely to be significant costs and risks associated with the introduction of Optional Firm Access, a previously proposed access reform model. The Commission was required to analyse whether the implementation of OFA was likely to contribute to the National Electricity Objective (NEO). At that time, the costs of OFA were determined to outweigh the benefits. Although the market is currently changing rapidly, as the currently proposed changes to the access regime are on a similar scale to OFA, it is similarly essential that the Commission conduct a quantitative cost-benefit analysis of the access reforms currently proposed to identify whether it is likely to contribute to the NEO.

This is essential to test the assumptions underpinning the Commission's support for this proposal. These assumptions are significant, untested in practice and likely to impact the success of the proposed access reform. The Commission has assumed that the proposed changes should improve certainty for prospective generators, may reduce the cost of capital in the longer term and that lower wholesale prices for consumers are expected, as more generation capacity is expected to be sustainably supported by the increased transmission network capacity paid for by these connecting generators. These suggested benefits are subjective and not supported by evidence or analysis. ERM Power strongly advocate for market reforms of significant scope, such as the proposed access reforms, be supported by evidence and analysis, without which the risks of implementing inefficient reform cannot be appropriately managed.

Recommendation

We strongly recommend that the Commission undertake a detailed cost-benefit analysis of this proposed market reform as a priority before further consideration for implementation.

Impacts of expedited implementation on efficient market operation and investment

Throughout the Directions Paper, the Commission has indicated that the rate of change of generation investment and consumer behaviour patterns in the NEM justifies rapid implementation of access reforms. ERM Power strongly believes that, in the absence of an appropriate and timely cost-benefit analysis, expedited implementation of access reform may produce inefficient and unintended outcomes for market operation and investment.

ERM Power believe inefficiencies in the current approach to regulatory reform is evident from numerous market reforms and rule changes at consultation or implementation stage which seek to address similar issues in the market. These regulatory processes include the implementation of the Five Minute Settlement regime, Transparency of New Projects rule change and recommendations from the Reliability Frameworks Review. The Commission has argued that the proposed access reform is a holistic solution to investment decisions. If the proposed reforms are a holistic and long-term solution to the issues arising from transitioning the power system, then the Commission must also further justify the multiple processes currently being consulted on and implemented as warranted.

Lack of this consideration has the potential to result in highly inefficient regulatory outcomes with cost implications. For example, the implementation of the Five Minute Settlement regime has already accrued costs significantly higher than originally estimated. AEMO's estimates for its own costs to implement the rule change were $30 – $85 million over 10 years. However, AEMO is now forecasting costs of $121 million over 10 years, with significantly higher total implementation costs across the industry now expected. With high costs, efficient market benefits must be realised. Five Minute Settlement was advocated as a solution to the issue of disorderly bidding. The Commission has similarly supported the proposed access reforms as a solution to disorderly bidding. As such, ERM Power does not believe this demonstrates efficient market regulation, and disagrees with the Commission's view in the Directions Paper that there are not any problematic implications associated with transitioning from a 30-minute to a 5-minute settlement process, as 5-minute settlement is expected to remove issues related to disorderly bidding that currently exist on a transitory basis in the NEM.

Similarly, the Transparency of New Project rule change currently under consultation seeks to alleviate risks associated with the volume of new generator connection enquiries and improve locational outcomes for new connecting generators through enhanced access to market information for developers. In the access reform Directions Paper, the Commission argues that current locational signals, namely transmission losses, congestion and inter-regional price variation, do not provide a sufficient incentive for efficient generator location, as generators do not incur the costs of their locational decisions on the network augmentation required to deliver their generated output to consumer load centres. The Commission must further develop their justification that these signals are incomplete and imprecise, with information currently available to the market and likely further information available through the Transparency of New Projects rule change.

Due to the complexities of current regulatory reform, ERM Power believe that an expedited implementation of access reforms is likely to result in outcomes not aligned to the design intention of the reforms. In the absence of a cost-benefit analysis, there is potential for a rushed implementation of this reform to create cost allocations that have not been anticipated. Firstly, the Commission intends for the reforms to produce transmission investment in locations which has not occurred under the current regulated investment regime. The current regulated investment regime is designed to augment the transmission network, only where a net market benefit is determined. The proposed reforms may result in the construction of network assets for the connection of remote generators, but which do not produce a net market benefit. Secondly, a network augmentation determined to pass a regulatory investment test recovers costs through strict regulatory processes. It is not clear whether the proposed reforms will be subject to the same regulatory process, and non-regulated network construction under the proposed changes are likely to result in a cost of transmission that is higher than that for a regulated asset. Lastly, it is likely that the proposed change could provide additional market power to vertically-integrated gentailers, due to the difficulty other generators may have in recovering the funding costs of a long-term transmission hedge. It is likely that retailers will be required to underwrite the long-term contract risk of these hedges, which is a barrier to participation for small retailers.

Recommendation
ERM Power recommends the Commission reconsider the need for expedited reform to allow for appropriate assessment and management of the risks of its implementation.

Potential impacts on financial contracts markets

ERM Power holds the view that the proposed access reforms introduces new market risks which have not been fully identified or adequately assessed throughout the COGATI Review. ERM Power believe the Directions Paper and COGATI consultation process does not appropriately consider or provide detailed analysis on the potential impacts of the reform on the financial contracts market, or how these impacts may translate to pricing outcomes for consumers.

We suggest that basis risk is not adequately managed under the proposed model. The introduction of generator nodal pricing (LMP/GNP) and transmission hedges (FTRs) introduces volume and price basis risk into the NEM. This is an increase in risk exposure for participants, who currently only manage their exposure to a known form of volume risk. It is also unlikely that the proposed reforms will improve the current mechanisms available for management of volume risk, as the proposed transmission hedge will also be subject to scaling when network capacity is constrained due to network or potentially market conditions.

Generators may respond to this increased basis risk by contracting only at their generation node. This effectively transfers this basis risk to counterparties[3] who may not be best placed to manage this risk. In addition to the potential for retailers to add sufficient risk premium in retail offers to manage this new risk, this proposed change introduces the need for each individual generator node to be allocated a contract firmness factor to meet the contracting requirements under the Retailer Reliability Obligation (RRO). This unnecessarily increases the RRO administration costs for retailers, the cost of which will ultimately flow through to consumers.

The implementation of FTRs risks negative impacts on liquidity and risk premiums. International markets provide points of reference to assess the potential impacts of GNP/LMP and FTRs on financial contracts markets. In these markets, trading in financial contracts is limited to only a few major nodes and participants tend to offer products to consumers in sub-regions where their internal generation capability exists. Where participants offer products to consumers outside these sub-regions, or in areas with the potential to be impacted by network congestion, sufficient additional risk premium is added. This reduces the level of market competition.

In contrast, the current NEM market design has delivered deep and liquid financial contracting markets which have facilitated the entry of small retailers and generators and increased the level of competition to consumers for the supply of electricity. In our view, this proposed pricing and access regime change will result in a significant disruption to the NEM's financial contracting markets and increase risk premiums, which will then flow through to increase retail price offers for consumers.

In addition, with the physical supply assets in the NEM changing from scheduled to a more intermittent form of supply, firm (scheduled) supply assets with flexible output capability (e. hydro, gas turbines or batteries), which are able to respond to meet consumer reliability and power system security requirements, will be in increased demand. This demand will be driven by both the supply of physical output and power system services, as well as the provision of risk management tools in the contracts market to provide price risk management and compliance with the RRO. However, actual output from these flexible resources will be uncertain. As such, the capability of these critical resources to underwrite the cost of transmission hedges will be reliant on their ability to fund such investment. The proposed access and charging regime would impact the ability of these resources to offer firm contracts at competitive prices which will negatively impact the price outcome to consumers. This may result in a significant barrier to entry for new flexible resources to enter the market due to increased capital costs associated with the purchase of transmission hedges.

The impacts of access reform on contracting volumes and risk premiums must be analysed. In undertaking the cost benefit analysis for the proposed change, it is critical that the Commission consider not just the costs and benefits which may occur in the physical dispatch market, but also the additional costs which will occur in the financial contracts markets in the form of additional risk premium or reductions in contracting volumes offered. The Commission also needs to consider the impact of such changes on the fledgling RRO obligations, as a significant change of this magnitude may make the practicalities of compliance with these new retailer obligations unworkable for a large number of retailers.

[3] This could be a retailer or a large end-use customer

Grandfathering as a key issue

There are key design principles which are critical for the implementation of access reform in the NEM. A primary design consideration must be grandfathered rights for existing generators for transmission access. ERM Power propose that a condition of equity under the proposed regime is the inclusion of grandfathering rights for existing generators.

There are several conditions of grandfathered rights which must be considered. ERM Power believe that grandfathered rights should be implemented, and take into account:

- What contribution generators have already made to network assets for connection, particularly where funding has been provided to upgrade shared network assets
- Any generator/network management (runback/tripping) schemes to increase network capability and who provides these services
- Remaining life of asset
- Strategic value of asset from a reliability or secure power systems operating perspective
- Generators which add value to the power system should receive grandfathered rights first otherwise these could withdraw early and add to overall system costs
- Generator classification

Currently in the NEM, generators have made payments for transmission assets. It is essential for existing generators who have financially contributed to the construction and strength of existing transmission assets to be entitled to full grandfathering in perpetuity. Grandfathering of transmission hedges should consider payments already made by generators for deeper connection assets. If a generator has funded network augmentation, it should not be required to additionally pay for a transmission hedge. New generation connecting to an existing connection point should not be allocated grandfathered rights, where they did not financially contribute to the development of the transmission asset.

Network capability will impact access to grandfathering rights. When considering dynamic allocation of grandfathered rights based on actual network capability at the time of dispatch, grandfathering should be based on reported maximum availability for scheduled generation and the uninterrupted generator forecast for semi-scheduled generation.

Non-scheduled market generators should not receive grandfathered allocation of transmission hedges, as generally, non-schedule market generators do not contribute to the secure operation of the power system through market dispatch. This would provide an incentive to non-scheduled market generators to consider reclassification to scheduled or semi-scheduled generation, with the potential to assist with secure operation of the power system.

Recommendation

Grandfathered rights for existing generators should be allocated under proposed reforms

Implementation should be delayed

The proposed access reforms are significantly complex, with the scale of the proposed market reform presenting the potential to create a significant market impact. In addition to the complexity, ERM Power are concerned that the proposed reforms do not achieve an outcome to meet the primary objective of the COGATI process, which is to coordinate generation and transmission investment. The Directions Paper has primarily provided a proposal for a transmission investment model. However, it does not provide insight into how the proposed transmission investment model will achieve the aim of coordination of investment between generators and TNSPs.

The Commission has recognised that the proposed change will create winners and losers in the market. This complexity and ambiguity indicates that extensive analysis of costs and benefits of the proposal must be undertaken. If access reform is to be successfully implemented in the NEM, the positive and negative impacts of the change must be fully understood prior to implementation.

The proposed implementation date also coincides with the implementation dates of other significant reforms, including Five Minute Settlement and the Wholesale Demand Response Mechanism. Major rule changes are being set for implementation in 2021 and 2022, with a fundamental review of the NEM market design post-2025 currently underway. It is unclear whether the Australian Energy Market Operator (AEMO) or market participants have the capability to facilitate the volume of reforms slated for implementation at the same time.

ERM Power believe that implementation of the proposed reforms should be delayed until an adequate cost-benefit analysis is undertaken. After completion of a cost-benefit analysis, the timing of the change should account for the time required for new generation to access transmission hedges. We suggest a minimum time requirement of four years, with a post-2024 implementation date. In terms of the implementation of grandfathering provisions, we suggest that this should be based on generation currently in service at the time any rule change is determined.

Recommendation

We recommend that implementation of access reform be delayed until these costs of implementation are considered and a plan is presented for appropriate management.

Conclusion

We provide detailed feedback on the design of the proposed access changes for consideration. We also propose an alternative model of transmission access reform for the Commission's consideration.

We would welcome the opportunity to discuss this further.

Yours sincerely,

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Design principles of access regime

Market price setting

There are many design principles related to the setting of locational marginal prices (LMPs) and regional reference prices (RRPs) for generators and loads respectively that will determine the efficacy of the proposed reforms.

ERM Power does not support the proposal to cap the generator nodel prince (GNP) or LMP at the relevant RRP. We believe this may impact both investment signals for new generation or load and transmission investment, and an existing generator's ability to recoup their long-term cost of capital. This has the potential to cause both a barrier to entry for new investments, and act as a driver of early retirements for existing generators. The market price cap should continue to serve as a sufficient measure against excessive market prices.

However, we recommend that the AEMC consider the constraint formulation which applies nodal pricing to generators and whether generators which do not significantly impact on network congestion be subject to the proposed pricing constraints. This is suggested in order to ensure that allocation of costs are fairly distributed across the market.

We believe that whether categories of market participants access these respective nodal prices should be determined based on their registration classification, in order to ensure the right economic incentives are created for participants:

- All scheduled and semi-scheduled participants should access the GNP/LMP
- All non-scheduled market generators should access the GNP
- All non-scheduled non market generators and all non-scheduled load should access the RRP

With the NEM undergoing significant change and increasing levels of distributed energy resources, ERM Power believe that the GNP should apply to both transmission and distributed connected generation.

Transmission hedges

The Commission has assumed the success of the proposed access reforms on the principle that transmission investment will be driven through the purchasing of transmission hedges. ERM Power believe this principle must be tested and demonstrated, as the process mechanisms expected to drive transmission hedges through the purchase of transmission hedges (financial transmission rights, or FTRs) are unclear. It is difficult for stakeholders to grasp the proposed investment process, as there are no international examples of transmission hedge or FTR products dictating merchant transmission investment in overseas markets. To assist stakeholders in providing appropriate feedback, the Commission must provide greater detail on how the investment process is expected to operate. This process framework must be defined and consulted on prior to the implementation of transmission hedges as a product.

If transmission hedges are introduced as a product, uncapped purchasing levels of hedging products will ensure fairer operation of the market. ERM Power supports the principle that the TNSP have the option to allow the purchase of an uncapped amount of hedging products, if the condition that the GNP/LMP is not capped at the RRP is met. This would allow for both TNSPs to provide sufficient transmission investment to support the level of hedges purchased, and allow generators with excess hedges to sell their products to new generators if it was financially preferable to do so. This will also promote the adequate sizing of transmission assets over the long term by facilitating speculative investment by parties who would be willing to take such investment.

Transmission assets are long-lived investments, and hedge lengths should be appropriately designed in accordance with these time-based risk profiles. ERM Power believe that it is essential that transmission hedges are available for long-term purchase. This would provide generators with the option to manage their risk associated with the transmission hedge for the potential life of asset. This optionality is important to ensure that generators are not restricted to short-term hedge products, and potentially exposed to the risk of operating with an unhedged position if transmission hedges are not available for purchase at the expiration of short-term products.

The proposed access reforms focus largely on the purchasing of transmission hedges. ERM Power believe that if a generator funds transmission investment through a hedging arrangement, acquiring the risk associated with this funding arrangement, then it should be provided with the right to on-sell that hedge at their discretion. We also recommend that the Commission consider the outcome of generators who do not purchase transmission hedges. As only generators with transmission hedges receive a payout when the GMP/LMP diverges from the RRP, the TNSP retains funds from generators who have paid to connect to the transmission network but do not hold transmission hedges. We suggest that these surplus funds are banked and used to pay out on transmission hedges during network outage conditions.

It is currently unclear how transmission hedges would include price and volume adjustments due to transmission losses and in effect who would pay for these losses. There is the potential for their inclusion in a transmission hedge to opaquely increase the costs of transmission hedges for generators, as TNSPs would be required to absorb the risk of variations in transmission losses over time. We believe the Commission should carefully consider if real time dynamic transmission losses should be contained within the transmission hedge.

Proposed incentives for coordinated transmission investment should be reconsidered

A key principle of the proposed reforms is incentivisation. The basis of the Commission's proposal for access reform is that generators will be incentivised to invest in transmission at locations where it is needed. The Commission has made a number of assumptions to support their view that generators will be provided with the appropriate incentives to deliver this investment. For successful operation of any reforms, these assumptions need to be tested. To date, the Commission has not provided analysis or evidence to provide confidence that the assumptions are robust.

Assumption 1: Expectations of TNSPs

Stakeholders require an outline of a robust process detailing how the Commission will ensure their expectation that the financial proceeds from the purchase of transmission hedging products will be used to underwrite transmission investment will be met. Detail on the nature of the mandate applied to TNSPs must be provided, based on the Commission's assertion that transmission businesses would be obliged and financially incentivised to provide a level of network access consistent with the amount of transmission hedges that were held by generators.

Assumption 2: Linkages to network planning

The Commission should explicitly define how the level of transmission hedges that generators purchase will inform the transmission planning process. The Commission states that, with a 'generator access standard', the transmission network would need to be planned to provide the 'agreed level of capacity consistent with the amount of transmission hedges that are sold. The planning standards conditions would be designed so that network capacity would be provided when generators value it the most'.

However, the Directions Paper does not adequately dictate the explicit locational incentives for generators and TNSPs to collectively develop the most efficient areas of the network. It is unclear whether the implication of the proposed change is that areas of network, not previously identified by TNSPs as warranted for a RIT-T application, will now be identified as appropriate for network investment based on the purchase of a transmission hedge. This relies heavily on the assumption that a prospective generator will locate in the most efficient location, given the sum of generation and transmission costs and that any errors or inefficiencies would not be subsequently passed through to consumers as higher prices.

Assumption 3: Network performance

Regarding incentives for network investment, we believe the proposal to impose penalties for network performance on TNSPs will not provide a sufficient financial incentive for TNSPs to maintain adequate levels of performance. We believe the level of currently proposed penalties will be insufficient to impact TNSP's operational decisions. ERM Power suggest the currently indicated level of imposed financial penalties are unlikely to be effective unless they are set at a significant level, close to the value of generator loss from network performance outages.

The preference for access reform to open access regimes should be reconsidered

The absence of adequate analysis through the COGATI process has likely impacted the identification of potential solutions. There are currently options available within different types of access models that provide similar outcomes to the proposed reforms. It is likely that due to the long-lived asset life of transmission networks, that a TNSP will seek a minimum 20-25 year transmission hedge, with network augmentation taking approximately 4 years to design, construct and commission prior to the activation of any new transmission hedges. We believe that this results in few practical differences between a congested access regime and the proposed continuation of a modified open access regime (Table 1).

Table 1. Comparison between congestion access regime and the Commission's proposed open access regime

Congestion access regime	Proposed GNP/FTR open access regime
Generator applies for access to the grid	Generator applies for transmission hedge
Generator signs up for network construction contract	Generator signs up for network construction contract
Generation assets can commission but risks congestion payment to existing generators or being constrained off until network augmentation is commissioned	Generation assets can commission but risks only being paid GNP with no allocation of FTR payments for GNP to RRP risk management until network augmentation is commissioned
Network assets commission, generator now receives unconstrained access to the system and FTR payments	Network assets commission, generator now receives transmission hedge (FTR) payments

We believe the decision to examine potential options under only an open access connection regime should be reconsidered. A congested access or the proposed GNP/FTR open access connection regimes deliver the same outcomes for generator locational signals. However, the congested access regime will potentially deliver a more economically efficient outcome in the long term, as it facilitates a more carefully considered coordination of generator and transmission investment planning.

Renewable Energy Zones (REZs)

The Directions Paper outlines the intention to accelerate development of Renewable Energy Zones (REZs) prior to the final implementation of access reform. ERM Power believes that the cost recovery for the construction of network connection assets to REZs is a crucial issue. While it may be possible to justify the development of a small number of REZ's through the RIT-T process, in conjunction with the development of other shared network assets, this may not be possible for the majority of REZ's In considering this outcome, it should be clearly noted that ERM Power does not support the development of lengthy circuitous shared network assets merely to support lower REZ connection costs when lower cost direct routes for these shared network assets are available This highlights the risk associated with the proposal for expedited development of REZs, when the risk allocation of undertaking such asset development remains undefined.

We believe that consumers should not bear the risk of transmission investment for REZs without RIT-Ts being undertaken for these investments. If transmission hedges are used to fund normal network augmentation, it is inconsistent to have connections to REZs funded by consumers.

To address this uncertainty, ERM Power supports a separate REZ funding model. If transmission assets for a REZ are underutilised, consumers should not be required to underwrite this risk. We suggest that a third party investor would be best-placed to acquire and manage the risk of transmission asset underutilisation associated with the establishment of REZ connection assets. We believe this provides an opportunity for an independent party to manage the risk of asset underutilisation with potential cost recovery from currently contracted and future connecting generators. The overall risks to market funding associated with the development of REZ connection assets could also be mitigated by limiting the number of REZ connection assets under construction or still awaiting connection agreements for efficient utilisation.

Alternative transmission development model

ERM Power recommend an alternative approach to the Commission's proposed access reforms.

Regulated frameworks provide the most common and viable models for transmission investment. The vast majority of international power markets undertake transmission development through the application of a cost-benefit analysis, similar to the RIT-T process in the NEM. As demonstrated by the example of network upgrades in New Zealand[4], regulated transmission investment can be funded by generators. Alternatively, there are examples of regulatory frameworks in overseas markets where network augmentations are funded by consumers, or paid for on a beneficiary-pays basis. Under the latter arrangement, the relative benefits to parties is calculated following the same principles as the calculation of market benefits under the current RIT-T calculation.

ERM Power proposes that a regulated investment model based on a beneficiary-pays basis is the optimal approach for charging reforms. We believe this provides a feasible alternative to the Commission's proposed GNP/FTR access and pricing regime.

As noted by William H Hogan – Transmission Benefits and Cost Allocation[5]

A workable system of cost allocation commensurate with benefits for new transmission investment is within reach using available analytical tools. Cost allocation commensurate with the distribution of benefits follows directly from the information that must be produced as part of the evaluation of the investment. Transmission is inherently about moving electric power between locations, and the analysis of the value of such investment requires calculation of locational impacts on generation and load. A consistent parsing of the benefits allows for estimation of cost allocation shares that make the beneficiaries better off while respecting the principle that those in regions who do not benefit do not pay. The procedures are not perfect, but they provide a workable approximation that makes transmission cost socialization a last, not a first, resort.

[4] Network upgrade construction and commission of transmission between the North and South Islands of New Zealand
[5] William H Hogan - Transmission Benefits and Cost Allocation 31 May 2011