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19 October 2020

Attention: Russel Pendlebury
Australian Energy Market Commission
SYDNEY NSW 1235
Submitted online to: www.aemc.gov.au

Submission: Consultation on Transmission Access Reform Interim Report

CS Energy welcomes the opportunity to provide a submission to the Australian Energy Market Commission (**AEMC**) on its *Interim Report Transmission Access Reform Updated Technical Specifications and Cost-Benefit Analysis*, September 2020 (**Interim Report**).

About CS Energy

CS Energy is a Queensland energy company that generates and sells electricity in the National Electricity Market (**NEM**). CS Energy owns the Kogan Creek and Callide B coal-fired power stations and has a 50% share in the Callide C station (which it also operates). CS Energy sells electricity into the NEM from these power stations, as well as electricity generated by Gladstone Power Station.

CS Energy also operates a retail business, offering retail contracts to large commercial and industrial users in Queensland, and is part of the South-East Queensland retail market through our joint venture with Alinta Energy.

CS Energy is 100 percent owned by the Queensland government.

Executive summary

CS Energy commends the extensive work undertaken to date by the AEMC to advance reform of the current access and charging arrangements. Access reform is complex and the challenges to resolve the issues emerging with the shifting characterisation of the NEM from centrally located dispatchable generation to small and geographically dispersed variable renewable energy (**VRE**) generation, connecting to parts of the network with insufficient capacity, should not be underestimated.

The objectives of the AEMC's reform have shifted significantly since commencement of the *CoGaTI implementation – access and charging review* in March 2019 (**Second CoGaTI Review**). The AEMC's proposed locational marginal pricing (**LMP**) - financial transmission rights (**FTR**) model for transmission access reform is no longer about the coordination of generation and transmission investment, its revised objective being the management of congestion and improved locational signals for generation. Access reform requires a

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holistic consideration of the issues to be resolved, and the new narrow focus of the AEMC's proposed reforms as set out in the Interim Report are concerning.

CS Energy does not support the AEMC's current proposal for the LMP-FTR model for transmission access reform:

(a) CS Energy's previous in-principle support was conditional upon several concerns including that the design was appropriately resolved. These concerns have not been addressed.

(b) The materiality of network congestion suggested by the AEMC is not supported by recent network constraint data published by AEMO[1], which shows the overwhelming majority of network constraints are non-thermal, and the market cost impact of binding constraints across the NEM arises predominately from system strength or frequency control concerns; that is, constraints caused by insufficient transmission capacity are not significant. The Coordination of Generation and Transmission Investment review (**CoGaTI**) reforms as proposed in the Interim Report will not resolve these technical issues.

(c) CS Energy disputes that the proposed design will address the purported "missing" locational signals.

(d) CS Energy considers the modelling and assumptions in the NERA Economic Consulting (**NERA**) report to the AEMC[2] (**NERA Report**) are flawed, and disputes the scale of benefits claimed by NERA.

(e) The proposed access model will introduce a level of complexity into the market that is not warranted given the network congestion problem it purports to solve.

(f) CS Energy believes the identified network congestion and locational signals can be addressed under other mechanisms, including major reforms yet to commence such as five-minute settlement (**5MS**), the wholesale demand response mechanism (**WDRM**) and market design changes arising from the Energy Security Board's (**ESB**) post 2025 market design process (**P2025 Process**).

CS Energy suggests:

(a) The AEMC's transmission access reforms be properly integrated with the ESB's P2025 Process, allowing the ESB to holistically consider the ability of other market design changes to address the problems CoGaTI is seeking to address and evaluate the risk of introducing the AEMC's proposed LMP-FTR at this stage in the reform process; and

(b) Introduction of some form of LMP-FTR should be revisited only after the other major reforms and post 2025 design changes have been implemented and adequate time has been allowed for the reforms to establish and reveal any residual gaps, which may then require addressing through further mechanisms, which may not necessitate an LMP-FTR mechanism.

CS Energy is of the view the AEMC has not demonstrated the urgency of implementing a fundamental change to the market design at this time and implores the AEMC to conclude its work on CoGaTI, referring consideration of transmission access reform to the P2025

[1] AEMO's monthly constraint reports can be found here
[2] NERA Economic Consulting, *Cost Benefit Analysis of Access Reform: Modelling Report*, September 2020

Process, where it can more appropriately be considered within the landscape of market design initiatives that may address transmission issues.

CS Energy's detailed comments on the Interim Report are set out in the Attachment.

If you would like to discuss this submission, please contact Teresa Scott (Market Policy Manager) on M 0438 665 056 or tscott@csenergy.com.au.

Yours sincerely

Teresa Scott
Market Policy Manager

ATTACHMENT

1. Transmission access reform agenda

CS Energy's submission to the AEMC's October 2019 Discussion Paper[3] highlighted two key concerns with the design proposal upon which CS Energy's support for the implementation of an LMP-FTR model was conditioned:

(a) the AEMC proposing fundamental changes to the market design to address transmission access and congestion may not be a prudent step in the context of the broader reform agenda; and

(b) the AEMC was not making the optimal design choices in respect of some of the fundamental features of the proposed LMP–FTR model.

The updated model proposed by the AEMC in the Interim Report fails to alleviate these concerns.

(a) CoGaTI's objectives have progressively narrowed since commencement of the Second CoGaTI Review. The LMP-FTR model for transmission access reform is no longer about the coordination of generation and transmission investment, its revised objective is the management of congestion and improved locational signals for generation. Access reform requires a holistic consideration of the issues to be resolved, and the narrow focus of the AEMC's reforms are out of step with the broader market reform that is currently occurring through the P2025 Process and other processes.

(b) While CS Energy has agreed with the AEMC that the introduction of LMP-FTR should in theory facilitate efficient levels of supply and demand, its agreement was always dependent upon the design features being appropriate.

(c) The AEMC is not adequately considering industry feedback as to the impact on the forward contract market, dismissing concerns raised by industry as mere transitional issues that will disappear once the LMP-FTR reform has matured. CS Energy cannot overemphasize the ongoing impact LMP-FTR will have on liquidity in the forward contract market; FTRs will place a significant barrier to generators being able to offer forward contracts to retailers, which ultimately will likely lead to increased costs for consumers.

2. CoGaTI's purpose

2.1. Materiality of the problem

The AEMC's proposed LMP-FTR model for transmission access reform has two primary purposes – to help generators manage congestion risk and to improve locational signals for generators. CS Energy agrees that these are two of several difficulties emerging with the shifting characterisation of the NEM from centrally located dispatchable generation to smaller and geographically dispersed VRE generation. Appropriate reforms are necessary to address these emerging issues.

[3] CS Energy, *Submission to AEMC Discussion Paper*, November 2019

However, the proposed LMP-FTR model is a fundamental change to the NEM and the materiality of the issues the AEMC is seeking to address with these reforms must be proportional to the significant disruption and costs that will occur across the NEM if the LMP-FTR model is implemented.

(a) Congestion

CS Energy challenges the materiality of the congestion problem that will be addressed by the current LMP-FTR model. Monthly network constraint data published by AEMO[4] shows the overwhelming majority of network constraints are non-thermal (above 90%) and the market cost impact of binding constraints across the NEM is higher by several orders of magnitude for system strength or frequency control concerns; that is, the level and cost of constraints caused by insufficient transmission capacity is not material. CS Energy has extrapolated in Figure 1 below AEMO's monthly constraint data to calculate average constraint data for the 2019-2020 financial year.

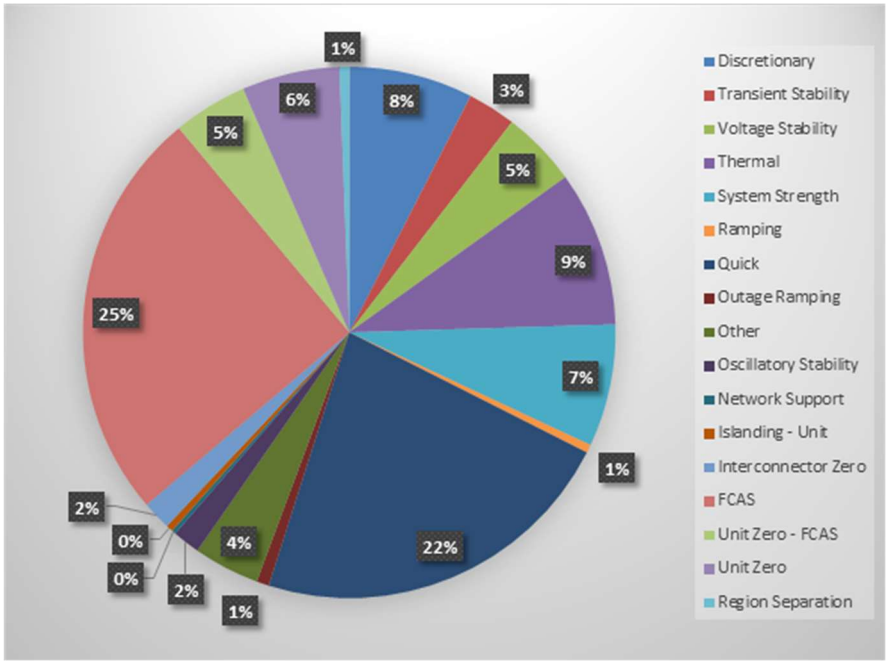

Figure 1 NEM Constraint binding limit by type average for FY2019-20

Congestion arising due to insufficient transmission capacity is not significant. In proposing solutions to the identified issues, the AEMC is overstating the extent to which network constraints arise due to insufficient network capacity and is conflating this with the more critical system security issues (and the resulting network constraints which arise because of system security issues). CS Energy acknowledges the current design blueprint reflects all binding constraints that are included in the NEM dispatch engine (**NEMDE**) and FTRs will hedge the price difference between all constraints. However, CS Energy believes the AEMC has not adequately considered the interactions with the market design initiatives (**MDI**) in the P2025 Process.

The provision of system services has a projected shortfall as they are not currently valued and the Essential System Services (**ESS**) MDI is seeking to value these

[4] AEMO, *Op Cit*

services and develop appropriate mechanisms to incentivise investment in technologies to procure these services. Industry is supportive of the general aim of the ESS MDI, as evidenced by the six recent Rule change requests received by the AEMC on system services, and it is expected that mechanisms will be established to procure system services. Once these mechanisms are established, network congestion issues which arise predominantly from system strength or frequency control concerns, are likely to alleviate. Implementing an LMP-FTR model that requires the market to value FTRs which will payout predominantly on non-thermal constraints implicitly creates a tension with a mechanism that is implemented to value and procure system services.

(b) Locational signals

CS Energy disputes the current LMP-FTR model will provide the "missing" locational signals that will incentivise new entrants to make the best use of new and existing transmission capacity. The AEMC appears to have formed the view that, on introduction of LMP, locational decisions would be driven almost entirely by the local price and disregards industry advice that price, whilst a key factor, is weighed against other equally important locational signals such as high availability of fuel resource, land availability, prospects of obtaining necessary planning approvals and access to existing network infrastructure.

Participants already see strong locational pricing signals through marginal loss factors (**MLFs**) and yet, even with the recent deterioration in MLFs for VRE generation, new entrants continue to make decisions to locate in weaker areas of the network and far from load centres.

It is concerning that the AEMC has not sought to gain a better understanding of the complete range of factors underpinning generator locational decisions, and then assessed whether LMP-FTR will change this behaviour. CS Energy agrees with the AEMC that the current locational signals are incomplete and, if considered through the lens of pure economic theory, LMP will result in more efficient price signals for locating new investment. However, because of the competing factors taken into consideration when making locational decisions, CS Energy does not consider the introduction of LMPs will significantly change generator behaviour vis-à-vis locational decisions and LMP will not deliver benefits of a scale warranted to proceed with the reform.

CS Energy is also of the view the recent "poor" locational decisions arose because of the rapid influx of development following return of policy certainty on the Renewable Energy Target in 2016. The "investment mistakes and learnings" from this period have now had the opportunity to filter through the market and are being taken into consideration by new entrants in their investment making decisions (including consideration of additional expenditure on equipment required by Transmission Network Service Providers (**TNSPs**) to connect). These "poor" decisions are unlikely to continue to repeat, and to the extent they do, the risk will be appropriately borne by the relevant project.

2.2. Alternative approaches to addressing the identified problems

The AEMC has not adequately explored alternative approaches to address the identified problems, and critically whether there are any alternative approaches that could be pursued which would substantively address the identified congestion risk and see improvement to locational signals, yet be simpler, less costly and disruptive in

implementation. CS Energy considers there are several alterative minor reforms which would improve how new entrants make the best use of new and existing transmission capacity:

- Improved market visibility of forecasted transmission congestion, such as constraint information and transfer limits. While this data is currently available, CS Energy considers the presentation and reporting of the data could be enhanced by both AEMO and TNSPs with a requirement to publish this information to the market on a rolling basis.

- CS Energy has previously suggested the development of a "heat map" tool, which could be used by developers to assess the level of capacity that may be available, and allow the identification of network constraints in the vicinity of a proposed project site.

The AEMC has not holistically considered in sufficient detail the interaction of the proposed LMP-FTR model with the broader reforms currently underway in the NEM, which CS Energy suggests negates the immediate need for the introduction of LMP-FTR (in light of its revised objectives):

- Although only implemented in December 2019, the Transparency of new projects Rule change[5] is intended to aid new generation projects in making better investment decisions, including where to locate. While the reform has not been given adequate time to establish, the AEMC should undertake a qualitative assessment of the benefits delivered by the reform to date and the impact on generator locational decisions.

- 5MS is scheduled to commence in October 2021 and will provide sharper price signals on market conditions and constraints; the WDRM which commences 24 days later is intended to facilitate greater participation by the demand side, allowing load to be bid as demand reductions as a substitute for generation.

- CoGaTI does not address the technical barriers, such as low system strength, to improve access for non-synchronous generation. Other work is underway to address these issues. CS Energy is of the view that valuing and procuring system services as part of the market design changes arising from the P2025 Process will significantly alleviate the identified network congestion issues, which as highlighted above arise predominantly from system strength and frequency control concerns.

The AEMC has not evaluated the necessity for CoGaTI in the full context of all the other market reforms, particularly the P2025 Process. CS Energy implores the AEMC to take a step back and allow these reforms to establish and demonstrate their value. Only after adequate time has passed to reveal any residual gaps should LMP-FTR be revisited if appropriate.

3. NERA Economic Consulting Report

3.1. Modelling and assumptions

CS Energy challenges the benefits estimated by NERA, as presented in the NERA Report, which are dependent upon NERA's underlying assumptions and modelling

[5] https://www.aemc.gov.au/rule-changes/transparency-new-projects

which CS Energy considers to be fundamentally flawed. Several key concerns are as follows:

- The modelling is overly simplified; NERA has aggregated its modelling across the NEM without considering variations between NEM regions resulting in a model that is not representative of the physical characteristics of the NEM.

- The assumptions and inputs are based on the Integrated System Plan and Electricity Statement of Opportunities, which are derived from planning models and not commercially solved market models. NERA's modelling overlays market and commercial decisions as the incentives for participant behaviour. The NERA Report does not offer any clarity on whether wholesale price projections calculated on the basis of a planning model would be compatible with FTRs which would be considered on a commercial basis.

- It is not clear whether NERA has assumed a long-term planning model with participants bidding in at their short-run marginal cost (**SRMC**). If this is the case, and NERA has adopted AEMO's methodology whereby wind has a variable cost in the range of $2.70/MWh to $3.60/MWh and solar has a zero-marginal cost, it follows that dispatch of wind would be reduced prior to solar.[6] It appears that this approach may have been taken (as evidenced in Figure 3.7 of the NERA Report) with solar capacity being the predominant technology type being installed, equating to roughly 40 GW of installed capacity in the long run with virtually no change in installed wind capacity. This is of paramount concern given that solar resource is highly correlated at particular times of the day leading to significantly greater potential for dispatch constraint (due to demand levels) as opposed to wind resource, which is available at different times of day and night depending on location.

- CS Energy seeks further clarity on the wholesale price projections. For example, the NERA Report should include Regional Reference Price (**RRP**) by region, dispatch-weighted prices by technology-type and load-weighted prices by region. It is challenging to provide specific commentary without these key pieces of information. From initial inspection on the only piece of wholesale price information available at NERA's Figure 3.3, CS Energy is concerned about the lower bound of prices in the period to 2030, as this price is significantly below current wholesale price forecasts. If time-weighted prices are settling at roughly $30/MWh during this period, it is challenging to understand how 10 GW of solar capacity could obtain the financial investment required to enter the market. Finally, it appears there is no price projection chart provided at all for the No-reform case, let alone at a regional level.

- NERA has assumed a fixed coal closure schedule, but maintained its least-system cost planning approach for other aspects of its model. This assumption is internally inconsistent. Plant will dynamically respond to wholesale outcomes if they are uneconomic, leading to vastly different wholesale price outcomes.

- CS Energy generally agrees with the approach of modelling RRP versus LMP however the modelling does not take into consideration several inputs such as negative pricing, 5MS and, for the Reform scenario, the cost to acquire FTRs and transitional FTR arrangements.

[6] Ernst & Young, *Project Marinus PADR Economic Modelling Report*, November 2019, p59

- NERA assume efficient dispatch, with all generation bid at a generator's SRMC. This is an overly simplistic assumption of bidding practices in the NEM, including for VRE generation which will also bid below its SRMC of $0/MWh (VRE generation is incentivised to bid negative prices as VRE is able to create large scale generation certificates (**LGCs**) which are a discrete revenue stream).

- NERA's modelling process relies on 24 hour "load blocks" which is inappropriate for the changing technology mix as the NEM transitions, failing to gauge the expected future volatility of the market or the impact of storage and peaking plants.

The NERA modelling derives the main cost benefit from the avoided capex of 20 GW of solar build under the Reform model versus the 40 GW of solar build under the No-reform base case. This 20 GW of additional build in the base case is very difficult to justify. NERA have derived this overspend based on economic theory, providing no rational explanation of how there would be an investment case for 40 GW of solar capacity in the No reform case.[7] Given the average NEM demand is historically around 19 GW to 21 GW, CS Energy struggles to see the additional 20 GW of demand that supports the business case for this build. CS Energy also cautions against too heavy a reliance on this estimated benefit, given the estimated benefits only accrue well into the period of assessment where even low levels of uncertainty and investment risk could result in the erosion of any forecast benefit.

3.2. Race to the floor bidding

The AEMC claims that dispatch efficiency will be improved through elimination of race-to-the-floor bidding, which NERA has estimated will provide a substantial benefit through the lowering of system costs as output over time is allocated to the lowest cost generator. CS Energy questions the quantum of the estimated benefit:

- The process outlined in the NERA Report[8] to identify the incentives for different technology types to engage in race to the floor bidding is again overly simplistic and fails to consider the divergent economic drivers for different technology types. For black coal, the NERA Report does not take into consideration the opportunity cost for base load generation to restart if dispatch falls below its minimum generation levels (and then fails to include in its assessment of total system cost the decommitment and recommitment costs of slow start units, or the system cost of being unavailable for sudden spikes in demand requiring an immediate response).[9]

  Conversely, for wind and solar generation, these projects are frequently underpinned by a long-term offtake agreement in the form of a whole-of-meter swap, with an adjustment to the floating price under the swap during periods of negative wholesale prices[10] to dis-incentivise generation below $0/MWh other than to the value of the LGC revenue. This dis-incentive was not as prevalent in the offtake agreements for early renewable projects, which were predominately wind, as these agreements typically did not include this adjustment (so wind will remain on during negative price periods). There is however no consideration in the NERA Report as to how the terms of these offtake agreements may dis-incentivise race-to-the floor bidding behaviour for renewable projects.

[7] Even assuming this solar capacity is charging the 20 GW of battery capacity installed under the No-reform model, there is a remaining 20 GW of solar capacity to fill demand.
[8] NERA Economic Consulting, *Op Cit*, section 5.2
[9] CS Energy has not provided comments on the incentives for hydro to engage in race-to-the-floor bidding. Greater transparency is required as to whether all "hydro" has been grouped as to include the pumping stations located at the majority of hydro power stations within the NEM. Obviously, hydro is incentivised to pump when prices are negative.
[10] Typically, the floating price is taken to be zero so that the offtaker does not have to pay a negative spot price.

- NERA's estimated benefits substantially exceeds the benefits assessed by ROAM Consulting in the AEMC's 2013 Transmission Frameworks Review Final Report[11] (estimated then at $3-15 million per annum), and also exceeds the benefits estimated by NERA in its March 2020 report.[12] CS Energy recommends further quantitative analysis given the sizeable discrepancies with previous modelling, including a peer review of the modelling inputs that might explain the discrepancies.

3.3. Impact on liquidity and risk

CS Energy challenges NERA's conclusions on contract market liquidity:

- NERA's underlying assumption that a generator's incentive to hedge is based on a forward outlook of spot market volatility within a certain period is flawed; a generator hedges to lock in revenue certainty (by managing the downside of wholesale prices and giving up the upside to obtain this revenue certainty) and to facilitate the retail market. NERA's modelling is then based on this flawed assumption.

- NERA fails to demonstrate a practical understanding of how a trading desk operates to manage its forward position by averaging into the market over time to take out the sometimes extreme volatility of wholesale prices.

- NERA have not given any real consideration to one of the key functions of the forward market in the NEM, which is to offer contracts to retailers to allow those retailers to provide firm pricing to end users.

CS Energy remains of the view that the introduction of LMP-FTRs will lessen contract market liquidity:

- The timing of the auctions will disrupt the contracting cycle; retailers will not be able to obtain contracts at the times needed.

- Generators are unlikely to hold the level of FTRs required:

    - Given FTRs will be slowly released into the market over a 10-year period, generators are unlikely to be able to obtain the quantity of FTRs required to offer the contract volume sought by retailers. Risk associated with FTRs that are yet to be purchased will have to be passed through to the customer.

    - As the simultaneous feasibility auction (**SFA**) will seek to maximise the revenue generated through the sale of FTRs (over quantity), generators are unlikely to hold the required FTR volume that is needed, so while the SFA provides revenue adequacy one of the trade-offs is the impact on contract market liquidity.

    - For the transitional period, while incumbent generators will receive transitional FTRs, these FTRs will not be backed by auction revenue. Therefore, they will be less firm. This will further impact on the volume of hedges incumbent generators (particularly baseload generators) are willing to offer into the market during this period.

[11] AEMC, *Transmission Frameworks Review Final Report*, April 2013, p111
[12] NERA Economic Consulting, *Costs and Benefits of Access Reform*, March 2020

- Even if FTRs can be acquired for all volumes sought, there is a lack of firmness to FTRs (in comparison to "firm" under a swap transaction) such that FTRs will not completely mitigate the basis risk introduced by LMP. Trading desks are likely to see a tightening on their trading limits and/or a requirement to add a risk premium.

- If generators form the view these risks cannot be adequately managed, they may only offer contracts at the LMP (and not the volume weighted average price (**VWAP**)) leaving retailers (or the buyer) to manage the basis risk, which would lead to a significant disruption to the current highly liquid regional contract markets.

CS Energy cannot overemphasize the impact LMP-FTR will have on liquidity in the forward contract market. LMP-FTR will significantly disrupt the contract market; and directly or indirectly the impacts will be borne by retailers who will be unable to obtain contracts to firm retail pricing, or unable to obtain contracts at the desired price, which ultimately will lead to increased costs for consumers.

4. Implementation and ongoing costs

CS Energy considers that the cost assessment underestimates the upfront and ongoing costs associated with proceeding with the transmission access reforms. CS Energy appreciates the difficulty in estimating these costs, however has considered the costs incurred implementing other reforms as its basis for assessing the costs it believes it would incur in implementing the transmission access reforms.

- **IT and system changes:** CS Energy estimate this cost to be a minimum of $10 million, based on its costs to implement 5MS. Although 5MS is not directly comparable, as LMP-FTR will require greater system changes to address the complexity, 5MS is the most recent reform which required wholesale system changes.

- **Rebuilding of forecasting models:** CS Energy considers participants will incur material costs to model and forecast LMPs, dynamic MLFs, likely fair value of FTRs, firmness of FTRs, VWAP. The implementation of LMP-FTR will see two decades of NEM spot and contract trading history "wiped". Spot traders will require this new information immediately upon implementation. However, within the forward contract market, some traders may not be prepared to make markets for contracts until there is sufficient history to analyse.

- **Contract reopening costs:** Over-the counter contracts and power purchase agreements with an end date beyond CoGaTI's commencement date will need to be re-opened. As with the introduction of the carbon tax, the re-negotiations will range from straightforward to complex and drawn out (and possibly dispute resolution). For many contracts, it may give rise to a termination event (through market disruption). The AEMC's estimated average cost of between $5,000 and $20,000 is grossly understated. If compared to contract reopening costs on introduction of the carbon tax, CS Energy considers a more realistic estimate of the costs to be as follows:

    - If not contested by the parties, the average cost would be $30,000 to $50,000; and

    - If contested, costs on average of $500,000 (includes advice, negotiations, engaging counsel and experts and preparing to go to mediation or court).

There is also an underlying risk that if a contract is re-opened, a party may seek to put other issues on the table which increases the complexity, risk and ultimately cost of re-opening the contract. For ISDA contracts that are terminated, this will trigger calculation and payment of the termination amount.

- **Ongoing costs in additional analytics/trading/IT staff:** It is difficult to assess the increased staffing levels that will be required to perform the additional analytical, trading and IT functions if LMP-FTR is implemented. At this stage CS Energy estimates it will incur additional ongoing costs of at least $1 million per annum. (This does not include coverage of trading loses that may arise due to the change in risk profile.)

5. Specific design elements

CS Energy acknowledges the changes made to the design elements by the AEMC in response to concerns raised by stakeholders and is supportive of many of these design changes. The AEMC has broadened the type of FTRs that can be purchased (24-hour and time of use); improved the firmness of FTRs through the SFA (although the trade-off for this is the SFA will not maximise the quantity of FTRs available at auction) and delayed commencement of the reforms.

Despite these design changes, CS Energy remains concerned with various design elements. While CS Energy has provided comments below on several of the elements that it remains concerned with, CS Energy does not intend to respond in detail as it is now of the view that the overall objectives of the AEMC's transmission access reform and proposed solution should be considered as part of the post 2025 reform agenda.

(a) Auction participants

The AEMC is proposing that both participants and non-participants can participant in the auction, as this will likely increase the revenue from the sale of FTRs and decrease competition issues.

CS Energy strongly disagrees with this approach, being of the view this design element will place a larger barrier on smaller participants being able to obtain the FTRs they require to mitigate the risk introduced by LMP; non-participants with significantly larger balance sheets are likely to be able to pay a premium to obtain FTRs, their incentive to obtain FTRs being driven by arbitrage opportunities. FTRs are only needed to deal with the introduction of basis risk arising from the reform, and therefore only participants directly exposed to this basis risk should be entitled to participate in the primary auction.

(b) FTRs available only between a limited number of pre-defined nodes

The AEMC is proposing that FTRs will only be available at a limited number of "pre-defined" hubs, determined by reference to the prevalence of congestion. The proposed model exposes all generators to basis risk, not just those at the pre-defined hubs. However, as noted in the Interim Report, generators not located at the pre-defined hubs will not be able to manage their basis risk. CS Energy considers this will increase risk for generators, which again is likely to have flow through impacts to the forward contract market.

(c) Dynamic MLFs

CS Energy agrees that dynamic MLFs are inherently a more accurate reflection of losses on the network as they are calculated in real time. However, the efficiencies that would be gained need to be considered against:

- The additional operational complexity for trading desks with an increase in data and decision points; forecast MLFs for every five-minute dispatch interval will need to be included in the trading decision; and

- The likely negative impact on the forward contract market, as the use of real time losses will increase risk in generator decision making.

(d) Transitional FTRs

CS Energy welcomes the AEMC's proposal to include in the design transitional FTRs to incumbent generators and that the starting point should reflect the steady-state situation. While CS Energy agrees transitional FTRs should be scaled back over time, the five year time period proposed by the AEMC is inadequate and does not reflect the pace at which incumbent generators are evidencing change under the current open access regime. CS Energy has previously advocated it would expect transitional FTRs to be allocated for the remaining term of the generator's connection and access agreement, preserving for these generators the regime at the time of the original investment decision.