Delta electricity

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COGATI Implementation – Access and Charging

Delta Electricity welcomes the opportunity to contribute to the AEMC's deliberations on the frameworks guiding investment in generation and transmission. Delta owns and operates the 1320MW Vales Point power station in NSW and has a retail licence to sell electricity to large customers. Delta has operated coal and gas fired generating plant in the National Electricity Market (NEM) since its start in 1998 and is an active participant in both the electricity and gas trading markets.

Delta engaged Marsden Jacob to provide advice on the questions raised by the AEMC in relation to implementing CoGaTI. The Marsden Jacob report is provided as an attached document for consideration by the AEMC.

Coordination

Delta encourages the AEMC to consider the interactions between the proposed access and charging changes and potential market changes arising from the ESB's post-2025 review. The current pace of regulatory review is creating substantial uncertainty across the market. The timeframe for implementing the proposed access and charging changes begins immediately following the implementation of 5-minute settlement and will immediately precede any changes proposed by the ESB in its post-2025 market frameworks review. It is highly likely that interactions between reforms will clash and require additional changes to ensure the efficiency of the market is maintained.

An assessment of the relevance of the proposed access and charging regime under various market design frameworks would be helpful in considering the extent to which changes may be necessary in the future. This would also help to inform the work of the ESB as it considers the market frameworks that are best suited to the changing investment landscape.

Dynamic Regional Pricing

The dynamic regional pricing model as described by the AEMC appears under-developed. It is clear that the mechanism will create sub-regions within a NEM region when transmission constraints bind and that this will lead to separate pricing and redistribution of settlement residues. However, Delta has not seen enough design detail to properly evaluate the impact on the market. Some example design details that should be considered include:

- how dynamic regional prices will be calculated;
- how residues will be allocated;
- how these prices will relate to the regional node price (e.g. loss factors);
- the potential number of dynamic pricing regions and possible limits on this number;
- interaction with network outages; and
- any materiality criteria for when they would be invoked.

These issues, and more, need to be addressed by the AEMC to allow a thorough assessment of any impact of the proposed changes. It is recommended that the AEMC undertake an assessment of market benefits so that an informed decision can be made about the need to fully implement dynamic regional pricing.

One of the primary benefits claimed to result from implementing dynamic regional pricing is its contribution to informing AEMO's ISP modelling. It is not clear how this additional information will be substantially more beneficial to AEMO than the information currently available. While it is true that there may be additional price information available due to the changed bidding behavior of participants during congestion, the ISP is likely to remain primarily a cost-based modelling exercise which will exclude bidding behavior. Even allowing for a more market-focused ISP, AEMO currently has access to nearly all the information it needs to assess the extent and location of transmission congestion.

Delta would like to see an additional stage in the implementation process that involves releasing the constraint information that would underpin dynamic regional pricing to the market prior to the implementation of dynamic pricing and settlement. This could take place over the two years prior to dynamic regional pricing being fully implemented. As the AEMC has noted in its consultation paper, only minor changes are required to AEMO's systems to enable dynamic pricing which should mean that this additional stage is only a minor addition to the implementation process. Following this "dry-run" stage, a reassessment should be undertaken before moving fully to dynamic regional pricing. This would enable participants and regulators to assess the magnitude of the benefits that are likely to be realised by moving to regional pricing.

The AEMC's proposal places a much greater financial risk on the constraint formulation process. Delta would therefore expect governance, oversight, and transparency of this process to be robust.

Transmission Access Rights

The Transmission Access Rights described have little detail about how transmission access rights would work in practice. Before the benefits can be assessed and the reforms implemented, the form of the rights will need to be designed in much more detail. It is not clear that the AEMC has considered important details, including:

- the level of firmness that the rights will provide;
- the duration of the rights;
- how generation investment timing and transmission access rights are coordinated;
- is this an allocation of surpluses on unconstrained lines;
- what happens during grid outages; and
- would limitations be placed on firmness under certain circumstances?

It is also not clear to Delta how the proposed access regime will interact with the RIT-T. The current cost benefit test requires cost-based modelling to determine net market benefits. It appears from the access proposal that some investment would be undertaken on a commercial basis and would supplant the market benefits test. While generators potentially pay for this investment, the cost is passed on to consumers ultimately and an assessment of the long-term market benefits should still be considered. Alternatively, transmission owners may have to forego regulated returns and rely on market-based returns and their associated commercial risk. There is no guarantee that market pricing of access rights will produce long term efficient transmission investment.

Delta welcomes the AEMC's observation in its supplementary information paper that transmission access rights would need to be grandfathered. Further development of the detailed design features will illuminate answers to some of the remaining questions around grandfathering of access rights. For example, the default duration of access rights may be set at 10 years which would guide a grandfathering arrangement lasting at least as long. Delta considers a long duration access right essential to support efficient investment in long-lived generation and transmission assets.

Delta looks forward to working with the AEMC on developing the details of the access and charging regime to guide further assessment of the model prior to any implementation. To discuss any questions regarding this submission please contact Peter Wormald on (02) 4352 6425.

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MARSDEN JACOB ASSOCIATES

18 April 2019

MJA Submission on Proposed COGATI Access Reforms

Marsden Jacob Associates (Marsden Jacob) is pleased to provide this report to Delta Electricity (DE) in relation to our response to the issues and questions raised in the AEMC paper titled “Consultation Paper, COGATI Implementation – Access and Charging” and dated 1 March 2019.

This review is based on reading of the abovementioned report and the AEMC report titled “Final report, Coordination of Generation and Transmissions Investment: and dated 21 December 2018.

Executive Summary

The review of the access reforms has shown that the case for implementation has not been sufficiently demonstrated or proved. Key questions not adequately addressed include why are these needed? what will they do? how do they fit in with the other reforms committed or proposed? what are the risks? how will they work? Further there would appear significant risks and issues associated with the access reforms that would need to be specifically addressed (these are noted below) prior to any decision to implement.

This paper addresses the access reforms (and question responses) in the context of other committed or proposed reforms and identifies issues that would need to be addressed as part of any decision to proceed and implementation (on the basis the decision is made). Key matters relevant to the access reforms being proposed include the following.

Reform Contest

The context of the proposed reforms, which is described as the continued development of renewable generation (post 2020) is not consistent with current policy or the market outlook. Evidence of the described context of the reform has not be provided.

Reform value

Assuming the described context (which may eventuate), the value of the access reforms, fundamental to their assessment, has not been demonstrated. A key issue here is the value of firm access to renewable generation and dispatchable generation, and the type of generators that the access reforms would be mainly directed at. This would appear to be renewable generation. which places a lower value on firm access than dispatchable generators (that sells firm contracts).

Total package of reforms

The access reforms must be considered within the total reforms being proposed, their role and any required accompanying reforms. The reforms have the Integrated System Plan (ISP) underpinning major transmission developments. This means that in the absence of an properly working actioned ISP, dynamic regional pricing would be unlikely to address the transmission / access needs and may only add additional risk. The relationship between the “actioned ISP” and dynamic regional pricing would appear essential and should be included when considering value and role of access reform.

The ISP and actioned ISP have not yet been proved. If the access reforms are to reply on the actioned ISP to do the “heavy lifting” then this must be a pre-requisite to access reform. This has not occurred.

Access reform design

A consideration of a complex reform such as dynamic regional pricing requires a level of detail that describes the basis of how this would be implemented and what this would provide. Not to do so makes commentary difficult and possibly meaningless There remains a significant amount of design work which must be done before detailed feedback can be provided and any decision can be made on implementation. Key matters of dynamic regional pricing include:

- Where would the supporting cash flows / residues come from?
- Would access be 100% firm or based on addressing identified constraints?
- What would the typical cost of firm access be?

Economic basis and the RIT-T

The matter of transmission development based on the residues associated with dynamic regional pricing and the economics of the RIT-T would need to be recognised and managed. The AEMC should carry out further work on the interaction between the RIT-T and dynamic pricing.

Need and availability of information

The AEMC papers state that dynamic regional price information can be produced with only small changes to AEMO systems. This information should be produced and provided to the market as soon as possible. This would provide essential information and data that would be important input to the reform decision and design, illustrate the dynamics of dynamic regional prices (which may be quite unpredictable), and assist in participant preparation. Examples of this are:

- The number of subregions and the level of basis risk introduced;
- The codification and criteria required on how dynamic regional prices would be formed;
- The discretion that would be provided to AEMO in determining dynamic regional prices. This refers to the matters such as the influence AEMO constraint formulation (such as discretionary constraints) would have on dynamic regional prices;
- The relationship of dynamic regional prices to certain constraints;
- The predictability of the profile of dynamic regional prices.

Contract supply and pricing risk

Concurrent with access reform is 5-minute energy settlement. Both of these reforms have associated risk to the supply and risk of firm contracts.

- 5-minute pricing may reduce contract suppliers;
- Dynamic regional pricing will increase the risks (i.e. basis) to generators, most of which will have the same transmission access regardless of the access reforms.

The impact of both these reforms together may have a significant impact to contract liquidity and contract prices. This has not been assessed and is essential to retailer risks, supply reliability, and consumer prices.

Reform burden

The total reforms and burden on the market must be recognised. The ability of the market to manage these changes (in additional to other reforms) requires careful assessment. If implemented, the phasing should have the simplest and lowest risk reforms introduced first followed by the more complex and higher risk reforms. This is not being proposed.

1 Approach to this Report

The access and charging reforms need to be viewed within:

- The total package of the reforms being proposed;
- The need for the reforms; and
- The required timeframe for the reforms.

This is essential, as the need and value of any reform must consider existing or proposed arrangements that may overlap and/or influence what is being proposed.

The questions posed in the consultation paper relate primarily to design and risk issues of the proposed access and TUOS reforms, and do not address the matters such as the actioned ISP. They do not address the fundamental issues of how the access reforms augments the "actioned ISP" reforms, the relative roles of each, and the risks of committing to both these reforms.

To address the above issues this report is structured as follows:

- The context of the COGATI reforms as presented by the AEMC are summarised together with the current outlook which is somewhat different;
- The tenants of the reforms are presented and what this means to the role and need for the access reforms;
- Issues associated with the reforms are identified. These matters are referenced in the responses to the questions;
- The consistency of the reform proposals to the established principles are presented. The links between reform and principles are also referenced in the question responses;
- The questions are then addressed in turn.

Appendix 1 presents a concise overview of the COGATI proposals and a summary of feedback from participants on these proposals. This is presented to ensure that the reform environment is understood.

Notes to this Report

Comments are made in this review that are critical of parts of the reforms such as the Integrated System Plan (ISP). This is intended to be constructive, as the authors recognise the value that the reforms will potentially provide.

Abbreviations

Consultation Paper	Consultation Paper, COGATI Implementation – Access and Charging
COGATI	Coordination of Generation and Transmission Investment
Final report	Final report: Coordination of Generation and Transmission Investment
ISP	Integrated System Plan
REZ	Renewable Energy Zones
RIT-T	Regulatory Investment Test for Transmission
VRE	Variable Renewable Generation

2 Reform Context and Assumptions

This section presents the context of the Coordination of Generation and Transmissions Investment (COGATI) reforms and assumptions of the reforms.

2.1 Context of the COGATI reforms

The context to the COGATI reforms as presented by the AEMC is summarised as follows:

- The generation system is changing as coal generators close and new renewable generators and storage assets are developed;
- The basis for this transformation is emissions abatement and the reducing cost of renewable generation;
- The changing generation profile will change the pathways of electricity flows;
- These changes are happening quickly;
- Generation investment and retirement decisions need to be coordinated with transmission investment (to ensure supply is reliable and secure);
- The rate and size of the changes means that transmission planning cannot be undertaken on an incremental basis. It will require a long-term transmission investment strategy that will provide the transmission system needed under an increasing amount of renewable generation and storage.

We also add the following which is equally relevant to this discussion. This is that based on current policy settings:

- The amount of renewable generation committed for development will have the LRET oversubscribed;
- The outlook for the development of renewable generation post the early 2020's is a significant reduction in the development currently being experienced. This is resulting in many solar projects unable to secure PPA offtake agreements;
- Apart from Liddell closing in 2022 there are no other coal generators scheduled for closure or "earmarked" for closure until post 2030;
- Behind the meter rooftop PV is projected (by AEMO) to continue to increase at the current growth rate;
- The expected outlook for scheduled electricity demand (by AEMO) is very little if any growth.

2.2 Reform basis and assumptions

A concise summary of the COGATI reforms are presented in Appendix 1.

It is assumed that the reforms associated with actioning the ISP will be undertaken. The relationship between the actioned ISP to the access reforms is a fundamental matter and is discussed below.

The key tenants of the reforms have been described as follows:

- An actioned ISP is required to address the strategic transmission developments needed - the COGATI reforms are based on the assessment that the current arrangements are not capable of doing this;
- Strategic developments are required to provide for the transmissions necessary for the envisaged new generators;

- An actioned ISP can address interregional developments, but market driven developments are required for more local requirements;
- Access reform by itself cannot address the strategic grid developments needed. As noted, the thrust of the COGATI reforms are based on this assessment;
- REZs should be implemented through the ISP and improving access.

From the above the following holds:

- The key reform is the actionable ISP, as this will result in the large-scale transmission required;
- Without an actioned ISP, dynamic regional pricing would increase the risk to new generators. This is because the key causers of grid constraints could not be addressed (i.e. strategic developments) which would mean generators facing lower spot prices (from being behind constraints) and reduced dispatch;
- By itself, dynamic regional pricing would result in:
  - increased basis risk of supply contracts which would be expected to reduce contract liquidity and increase contracts premiums over spot price.
  - reduced generation development and high spot prices.

This is because the major transmission developments required, which are interregional in nature, are not capable of being addressed through dynamic regional pricing.

What has not been stated or known are the relative roles that an actionable ISP and dynamic regional pricing would individually play.

Views on the access reforms were summarised in the Final report Section 6.2 as follows:

- Consumers typically support some change to congestion and access arrangements immediately;
- Existing generator participants did not typically favour any change to the status quo;
- Renewable generator participants typically wanted change, but did not want to pay for transmission;
- Network participants generally agreed that congestion is an issue, but most consider that actioning the ISP should be a priority.

Appendix 2 presents supporting references to the above views.

3 Reform Issues

3.1 The ISP

The proposed reforms have the ISP provide the direction and the transmission projects to be developed. The ISP is the foundation of the strategic network plan (and NEM requirements). This means that the ISP should / must reflect:

- The total needs of the market in delivering electricity to consumers;
- Future uncertainties;
- Have no "fatal flaws" in the analysis and recommendations. There would need to be processes to ensure this is the case.

To deliver the above, the analysis, scenario development and modelling must be complete and robust. This should require:

- Modelling approaches suited for the matters being considered;
- Properly address all requirements such as a future secure and reliable power system and the economics of providing this;
- A very high level of transparency;
- Peer review by properly qualified parties.

The following are noted from the 2018 ISP:

- The Group 1 projects are somewhat remote from the large strategic plan and could be assessed under the existing RIT-T. The difficulty with such a process is that the RIT-T process is more rigorous than the proposed ISP process making the hurdle rate higher. The group 1 projects might not pass a RIT-T. There appears to be no evidence provided that these projects would pass a RIT-T assessment;
- Does not address all issues of market operation. Excluded are how retailers / large consumers manage energy purchase risk with assets not suitable to support contract sales. This relates to assets suitable for providing firming services (physical and contractual) ;
- Not described is how the ISP would form a single plan from the range of scenarios it might consider? Executive summary in the Final Report states "The pattern of network flows in the transmission system is changing and forecasts of future needs are increasingly uncertain';
- There are different views on what is considered "high transparency". While the 2018 ISP was stated as highly transparency, the following are noted as examples of transparency issues:
  - details of how the modelling was undertaken were not provided
  - modelling to ascertain reliability was not described. It is not clear that such modelling was undertaken
  - there was no quantification of required reserve margins or assessment of the contribution to firm capacity provided by batteries and other assets;
- There has been no statement of what confidential data was used and how this would be managed in the future;
- There has been no discussion on how the ISP process would address significant varying ISP modelling results between ISP publications.

General observations from the 2018 ISP:

- There has been one ISP released and the ISP process as is being proposed is untested and not proven;
- There are many matters that are required to be addressed including approach and how the modelling would be undertaken. The 2018 ISP did not make comment on any encountered issues.

3.2 Access

Dynamic pricing

- The COGATI reports refer to generation and does not distinguish between Variable Renewable Energy (VRE) and dispatchable generation. The two type of generation have very different roles, economics and requirements. There needs to be a clear value assessment regarding the value of dynamic pricing to VRE and dispatchable generation. The access proposals are silent on this;
- What are the priority issues for VRE and dispatchable generation (such as MLFs, constraints);
- Is the introduction of dynamic pricing essential? What would the impact be given that the major transmission developments are proposed to be addressed from an 'actioned ISP?
- There is no information of how dynamic prices will be calculated, except that residues will be between the local and regional spot prices. The COGATI proposals read as if the arrangement might be Constraint Support Pricing (although this may not be consistent with providing a firm hedge between the local and regional spot price). If this is the case AEMO changing constraints would be a major issue;
- Changing pattern of flows and constraints that bind – there may be little pricing patterns;
- Will this apply mainly to VRE generator developments;
- Do VRE and dispatchable generators place different values of firm access? If so, does this need to be accounted for? (Generators wanting to sell contracts are likely to value access higher);
- Impact to contract liquidity. This has been a major issue in the past;
- Overlap with 5-minute energy settlement. This is a significant issue, if not in terms of reform overlap, but in terms of what the market can accommodate in a limited amount of time;
- Why did previous attempts of dynamic pricing fail? Why is it different now?
- Time required for consideration and implementation.

Access rights

- Require a specific description / specification of what is to be provided. There are many questions in this regard, such as:
  - is it access to surpluses on specific constraints?
  - how firm is the access?
  - what happens during grid outages?
  - what about other constraints that may appear that limit flow and access?
  - would firm access be provided under certain limitations?

- would the surplus be paid from a specific constraint surplus or from the total regional surplus?

Information

There appears to be the assumption that dynamic pricing information can only be provided once implemented (i.e. is being used in settlements). This is not the case. This can be obtained regardless (it would just not be used in settlements) and there appears to be no reason why this data cannot be made available well before the proposed introduction dates. Section 6.3.2 of the Final report notes the following in relation to dynamic regions for pricing generation:

> No changes to the TNSP planning, investment or operational arrangements would be required to give effect to this. Some changes to AEMO's dispatch and settlement processes and systems would be required, but we understand that these would be relatively small. Therefore, we consider that this would be relatively straightforward to implement from the perspective of market systems.

- This would mean that the staging should have this information provided prior and not after dynamic pricing is introduced (on the assumption this does occur). This would provide important data to any decision to proceed and importantly would assist with market preparation.

Very quick timetable

The proposed timetable is not reflective of the issues involved, the need, or the time that has been required in the past for lesser reforms. The following are noted:

- The reforms are very considerable;
- This is proposed to occur with 5-minute pricing reform – which in itself will have significant market impacts;
- Similar proposals have failed before;
- There is no supporting evidence on how this could be undertaken in the timeframe proposed.

4 Consistency of Proposals to Agreed Principles

The Final report presented two sets of principles. These were principles that:

- All stakeholders agreed to for achieving the best outcomes for consumers when implementing the ISP (section 3.3.2); and
- The AEMC was guided by in developing its recommendations (section 2.4.3).

The adherence of the COGATI reforms to these principles was reviewed and is summarised in Table 1 below

Table 1 Adherence of the COGATI Reforms to Stated Principles

Stakeholders agreed principles (1)	Assessment
Robust cost benefit analysis	Not met. Reduced RIT-T independent analysis
Effective and meaningful consultation	We are assuming this refers to this process. Greater information on the 2018 ISP is required to assess the potential and robustness of this process
Placing risks with the party best able to manage them	Risks – congestion This would not appear to be satisfied.
Balance between strategic versus local perspectives	The COGATI arrangements would appear to have central planning for strategic solutions and market solutions for local issues. However strategic developments influence local issues Unclear what this balance is.
Incorporate public policy	This has not been demonstrated to date. The 2018 ISP made assumptions on emissions policy not implemented.
AEMC stated principles (2)	**Assessment**
Efficient investment in transmission and generation	ISP is not demonstrated or proven. To demonstrate requires increased transparency.
Efficient operation of the network and market dispatch	This statement need clarification. Does this mean dispatch in SRMC order, or does it include the wider considerations of spot market dynamics and contracts sales for risk management.
Appropriate allocation of risks to parties best placed to bear them	See comments above. The major risks are that of the group 2 and group 3 developments and AEMO is not exposed to any risk.
Maintaining a secure and reliable power system	ISP modelling of reliability and security not tested. The 2018 ISP plan was not demonstrated as reliable. This is a key issue and requires a lot of work not yet attempted.
Transparency through the provision of timely and accurate information	The 2018 ISP process was not transparent. Not details provided on modelling or detailed results. This need to be comprehensively addressed.

Notes

(1) COGATI Final report section 3.3.2

(2) COGATI Final report section 2.4.3

5 Comments on Consultation Paper Questions

Before addressing the questions in turn, the following observations are made in relation to these questions.

The questions are based on the assumption that the reforms will proceed, and the only matters for consideration are the design and timing details. The fundamental issues of the basis of the reforms, reform requirements and other options, are not included in the questions.

Further the design of the questions does not provide for a logical progression of issues:

- Design of phasing - issues impacting this are part of later question;
- Dynamic regional pricing – the information and value available should be the first issues addressed. From this detail design matters can follow. Treatment of storage is a separate issue and should be one of the first matters addressed;
- Generator funding of transmission development is the fundamental issue of dynamic regional pricing and should be addressed prior to the detailed reform issues;
- The timeframes should relate to the needs of the market and not just what is doable. The needs of the market as expressed through unsupported assumptions have been noted as matters that require clear and supported analysis. This includes the uncertainties involved;
- TUOS reforms need to address all the issues associated with TUOS and should not be confined to the matters here.

Question 1: Phases of Access Reforms

1 Is our proposed approach to phasing access reforms appropriate?

As previously noted, this question presupposes the reforms are needed and that the issue is how they are to be introduced.

This is relevant to the phasing question, as phasing should as a minimum have pricing data released prior to the introduction of the reforms and not after. While this would normally be a critical input to the assessment of reform needs and design, it is also essential to participants in their preparatory work prior to any reform introduction.

The reference to the small amount of work required by AEMO (in section 3.2 of this paper) means that this should be able to be commenced well before the proposed date of the reform introduction.

The provision of such data would be very insightful and would likely raise many questions and issues essential for the proper consideration and design of such reform. These issues include:

- The number of subregions and the level of basis risk introduced;
- The codification and criteria required on how dynamic regional prices would be formed;
- The discretion that would be provided to AEMO in determining dynamic regional prices. This refers to the matters such as the influence AEMO constraint formulation (such as discretionary constraints) would have on dynamic regional prices;
- Whether the actions or formulations undertaken by different TNSP's could influence constraint formulation and dynamic regional prices;
- The relationship of dynamic regional prices to certain constraints;
- The predictability of the profile of dynamic regional prices
- The level of access that could be provided and the cost of providing such access;
- Including dynamic regional pricing in all future ISPs (the basis this would be presented would require consideration). This would appear to be essential;
- Obtaining actual evidence on what this will provide and whether the benefits would outweigh the costs and risks.

These are just a small sample of the issues that would need to be addressed prior to the introduction of dynamic regional pricing. The number of issues and the time that has been required on less complex reforms would strongly suggest that the timetable is too short.

This then raises the issue of a phasing strategy that has arguably the most difficult phase first. Such a strategy carries the risk of delays in the following phases.

2 Are the number and nature of the phases appropriate? How might access reform be phased differently?

The above answer has explained the reasons why the phasing approach proposed questionable, the most significant issue being not publishing data, which we would understand can be made available, prior to the commencing date of dynamic regional pricing.

The phasing has three large phases, commencing with the complex introduction of dynamic regional pricing. As a general comment, it is good practice:

- To start with the simplest developments;

- Have more and smaller developments per phase;
- Provide as much information as possible prior to each phase.

Consistent with the above, an improvement to the phasing would be as follows:

- Present the details of the proposed design including (but not limited to):
  - how dynamic regional prices will be calculated
  - the potential number of dynamic pricing regions and possible limits on this
  - any criteria for when they would be invoked
  - relationships to other matters such as AEMO constraint management;
- Publish the dynamic regional prices based on the criteria initially established;
- Provide for improvements / amendments to this including how this interacts with other processes;
- Include dynamic regional prices in some form in future ISPs;
- Identify models for dynamic regional pricing;
- Commence with a simplified form of dynamic regional pricing and with a development timeline.

3 What interactions with other market design reforms throughout the sector, and the energy transformation more generally, should be considered when developing and assessing transmission access reforms?

While this was not presented as a phasing issue it does impact on how the phasing should be designed.

There are many interactions and many of these have been previously identified in this paper. These interactions should be considered in this reform. These include:

- What the actioned ISP will provide and how access would complement this;
- How dynamic regional pricing would impact the efficiency of the NEM including how wholesale electricity is procured, retailer and generator risk management, and energy prices;
- Contract liquidity;
- Interaction with AEMO systems and operations, and how operating decisions by AEMO may / would impact dynamic regional price outcomes;
- Predictability of dynamic regional prices and relationship to constraints and identified transmission works;
- Level of firmness that can be provided and the risks of providing this.

4 What should be taken into account when considering how to transition to these new arrangements?

While the answer to this question has largely been encapsulated in the responses above, the following general matters are considered essential to any reform transition:

- Identifying what is essential and justified. This means actually and accurately presenting the outlook for the NEM and the basis for this outlook, and not basing this on what has happened over the past few years;
- Understanding what the market can digest. This does mean:

  - increased transparency and explaining in full what is proposed and how it is proposed to be done
  - Recognising other reforms scheduled such as 5 minute energy settlement;
- The need for the market to have data on the reforms prior to commencement. This has been addressed above;
- Appreciating the value / risk trade-off of the various reform components. For example, it may be that an actioned ISP achieves 80% of the developments required, and that dynamic regional pricing introduced to soon would simply add complexity with little value.

Question 2: Phase 1: Dynamic Regional Pricing

1 What is the nature of the risk on generators from being settled at the dynamic regional price in the event of congestion? To what extent is this risk different from (and greater or less than) the current risk to generators of being constrained off/down in the event of congestion? What impact may these changing risks have on the contract market, both in terms of products, liquidity, and risks businesses are exposed to?

Firstly, the observation is made that many of these matters have been studied in previous NEM papers in detail before, and there would be value in the AEMC briefly presenting the logic and reasoning from these previous papers. In other words, let's not re-invent the wheel.

Settling at the dynamic regional price

The issues are clear here and have been well expressed many times:

- Dynamic regional prices introduce basis risk to the regional spot price that consumers are settled on and that contracts would reference. By itself this has the effect of reducing contract liquidity, increasing seller risk, and increasing contract prices;
- The abolition of the Snowy region is a case study on how the AEMC viewed the importance of contract liquidity. There is a question that needs to be answered in this regard. This question is this, has the AEMC perspectives on this changed?
- There is no evidence to the extent generators would be willing to pay for transmission. The current economics of solar and wind generation is marginal, and such plant would not be economic if additional transmission is required to be paid. This appears at odds with the underlying assumption of the reforms that solar and wind generation will continue to be developed at the rate observed over the last say 3 years;
- With no other change, generators face higher risk due to congestion under dynamic pricing. Congestion under dynamic regional pricing would mean both lower dispatch and substantially lower spot prices. Spot price impacts can be more sensitive than volume / dispatch level impacts due to prices being marginal prices. As previously noted, this increased risk would be reflected in contract prices when selling contracts;
- New generators in areas of "thin" transmission are mainly VRE generators. These generators do not value 100% firmness to the same extent as generators that sell firm contracts. There greatest risk issue tor VRE generation from transmission are reducing MLFs;
- Storage is a non-network solution to VRE generators to address (i.e. not totally address) "duck curve" impacts and grid constraints.

2 Is generator capacity an appropriate metric on which to allocate the settlement residue which arises from dynamic regional pricing? If not, what alternative metric should be used? Which particular measure of capacity should be used (e.g. nameplate capacity, maximum output in previous X years)? How might the use of capacity or another metric create distorted incentives for generators and/or storage devices?

While the matters raised in this question are important, there are two matters that need to be addressed before this question can be answered. These two matters are as follows:

- Firstly, how would dynamic regional prices be calculated, the criteria for having a dynamic regional price developed, whether once a dynamic regional price commences it remains, and how variable would such constraints and prices be;
- Secondly, what precisely has been meant by generator capacity in this reform proposal has not been made clear. Consequently, this question will be addressed by not making any assumptions this regard.

The issues to this question relate to:

- Existing and new generators;
- Generator type - VRE and dispatchable (usually thermal) generation. This relates to the value placed on firm access between such generator types;
- The committed status of the generator;
- The actual level of generator dispatch;
- The availability for the generator to increase generation;
- The contract status of a generator. For example, if "NEG" type arrangements were introduced that require retailers to show contract status (i.e. to some body), would this be a consideration in access priority.

Noting the above we make the following comments:

- The prime purpose is to align access value to parties that will invest, and for the value of such investments to be captured by the investing party. However, the specifics of this appear missing;
- The capacity referenced should relate to the incentives and market value of increased transmission from that location. Generators without contracts or that do not contract have a lower need and a lower value for firm access. This should be an issue to this reform.

3 Should storage, when importing from the grid, be settled at the dynamic regional price? What might the effects of this be?

While this question involves dynamic regional pricing, it relates to the separate issue of a storage participant category.

The key issue of a storage participant category is whether storage is treated either as a generator or has as a load and a generator.

Well known is that moving from fundamentals, such as having storage imports treated as negative generation and not demand, introduces gaming and arbitrage opportunities. For example, a site with storage, solar and load would have opportunities to manipulate load and storage charging.

The effects of this can include:

- Incentives to influence the economics of behind the meter storage over in front of the meter storage (apart from cost);
- Greater difficulty in the costs required for a body such as AEMO to coordinate large scale storage.

Considerations to move from the fundamentals of the energy market require great care, and without a very clear argument for, storage should be treated as demand and generation.

4 What issues or unintended consequences might arise?

This question is taken to be the unintended consequences of the proposed reforms of dynamic regional pricing and the treatment of storage.

These issues have been covered in the previous questions. However, the following broad consequences are a risk:

- Increased prices for contracts. This would increase the value of thermal firming generation (i.e. generation capable of selling firm contracts);
- Reduced market operating efficiency;
- A potential stand-off and /or between transmission development by TNSPs and market driven transmission development participants (that would each value transmission developments differently);
- Reduced development of renewable generation;
- Reduced supply reliability;
- Higher cost of emissions abatement;
- Higher risk and high costs to consumers.

5 What are the nature and extent of implementation costs, such as system changes (e.g. settlement reallocations), that would be required to implement phase 1?

Phase 1 is the introduction of dynamic regional pricing. The consultation paper states that “the access arrangements would be changed to implement dynamic regions for determining the price payable to generators”.

To address this question requires additional detail on what is proposed (i.e. it is not possible to describe the nature and extent of the implementation costs without a detailed description pf what is being proposed). However, what can be said is this:

- Implementation would involve extensive changes by AEMO and market participants;
- Market participant issues include:
  - education and training
  - participants re-evaluating risk, updated systems and reporting;
- AEMO issues include:
  - the mechanism, for calculating dynamic regional prices – a number have been proposed over the last 10 or so years (such as constraint support pricing)
  - NEMDE changes and reporting (it is understood that the changes to NEMDE would be minor)
  - rules for when a dynamic region should be created
  - AEMO and TNSP risks.

Question 3: Information from Dynamic regional Pricing

In summary the answers to these questions are self-evident must be guided by the following, as per the principles previously presented in Table 1 of this submission:

- We do not know exactly what this information / data will show. This is one reason why the information is being collected. Like all reforms, the more information that can be used into the decision process, and not after, the better the outcome;
- The dispatch and pricing process should be fully transparent, and should be revealed in the same manner of other associated data;
- The information should be used by TNSP / AEMO / AEMC in a transparent manner and in ways that links with established economics and processes.

1 What information is likely to be revealed through dynamic regional pricing?

The information likely to be revealed through dynamic regional pricing would depend on how dynamic regional prices are calculated and what is reported.

This information should be provided at least a year prior to any decision on its introduction. During that period the information that should be revealed includes:

- How the criteria for a dynamic regional pricing works;
- How many potential dynamic regions there potentially are, how many are just short of the criteria to be a dynamic region, how many locations move in and out of this class;
- The pattern and level of price changes;
- The level of basis risk;
- The value and incentive to fund transmission development and obtain firm access;
- The firmness of the access payments. For example, how are periods of grid outages when access is reduced managed.

Based on the reforms that have the information released after the reforms, the information likely to be revealed is as follows:

- The pattern of dynamic prices is irregular, and it is difficult to gauge value;
- Projecting the future will be very difficult;
- MLFs in many cases will be the key issue and these reforms will not address that issue;
- The optimum grid constraints will not match the access value required and there will be a mismatch. Parties will still seek to free ride such developments;
- Transparency will be low in relation to ISP outlooks;
- The reforms would be unlikely to provide the level of market development in transmission development required.

2 How valuable is the information from dynamic regional pricing likely to be in the various transmission planning processes? Will it have other uses?

This question presumes that this data is not available without the reforms. This information is available can be produced with only small modifications / additions to the AEMO systems.

In the past TNSPs have not used this data, but instead have focused on the actual constraints and have valued these constraints not on spot prices but on the economic costs of these constraints (as required by the RIT-T).

If this data were of high value, there is a question about why the TNSPs are not requesting this data and using it.

There is an conflict of planning based on dynamic regional pricing and the requirements of the RIT-T.

The conclusion to this is as follows. While this data may be of value, it is unlikely to be of primary value.

3 How should the information revealed by dynamic regional pricing be revealed to the market?

This is a surprising question. The answer must be with full transparency. Not to do so would reduce the incentive for generators to act on this data. This means it should be revealed in the same manner as regional spot prices.

5 How might AEMO, TNSPs and the AER integrate the information into their processes?

This question relates to the criteria used for transmission investment and how this supports and adds additional information to what is already provided and used.

TNSPs

Dynamic regional pricing values constraints at bid prices (not the economic cost) which is different than the criteria used in the RIT-T. Given that there are no reform proposals to move away from the RIT-T economic criteria, from the perspective of TNSPs, the data may be of secondary value.

However, it would indicate the potential investment actions of parties that might consider investment into transmission upgrades, that is market driven investment. The process to include this can be no different than how TNSPs consider market driven generation investment. Both impact transmission operation and constraints.

AEMO

For AEMO this is related to the production of the ISP.

Like TNSPs, this information would need to be treated on the same basis as market driven generation development.

AER

There is likely to be little value to the AER.

6 Should the rules be modified to require these parties to take this information into account, and if so, how?

The answer to this question must be clearly no. These parties have obligations under their charter, and this does not include what data must be used.

To do so would risk these parties being required to use data that does not support their obligations.

Question 4: Generators Fund Transmission Investment

Phase 3 relates to generators funding transmission infrastructure.

First, an interpretation of what is being provided and given in return.

The consultation paper states that "generators' collective decisions to purchase transmission rights would guide the preparation of AEMO's ISP's and TNSPs' planning decisions due to an obligation placed on TNSPs to provide sufficient transmission capacity consistent with the rights purchased by generators."[1]

However, the reforms have been described and can be understood to be the "other way round". The executive summary of the Final report stated:

> "This final phase of access reform involves generators having the option to pay for transmission in return for firm access rights."

This has generators purchasing access rights through funding a particular transmission upgrade. The transmission upgrade provides for a calculated increase in transmission flow limit to the regional reference node. Based on this increase, additional access provided by the upgrade, and TNSPs provide a financial access based on the increased transmission.

It is unclear what model is being proposed:

- TNSP sell access and then undertaken the transmission works required; or
- Participants pay for transmission works based on a level of access this would provide.

This needs to be clearly expressed.

1 What issues and considerations should the AEMC take into account when developing and assessing phase 3?

There are many issues to be accounted for in phase 3:

- The actual model is of how this would work (as describe above);
- How access rights and investment are matched;
- The level of firmness of access provided. Would there be varying levels based on individual agreements;
- Can any party purchase access or does this need to be a physical generator at that location;
- The level of risk carried by TNSPs. Given that firmness can never be 100%, either TNSPs accept risk, the level of firmness is less than 100%, or access is supported by other market surpluses;
- The impact different models would have on the willingness of generators to invest in transmission;
- The impact market driven investment may have on the optimum development of the transmission system.

[1] Table 3.1

Question 5: Access Reform Timeframes

1 Are the timeframes suggested for the access reforms appropriate?

This question requires a full appreciation of:

- The extent of the proposed reforms;
- The potential reform impacts across the market;
- The changed risk positions of participants;
- The effectiveness of the reforms to achieve their objectives.

The timing requires the details of what would be implemented to be provided at least a year prior to introduction, and data and information to be provided based on the detailed reform proposals.

Having an overly ambitious timetable would carry the risk of an unprepared market with potentially high costs and abandonment of the reforms either before or after their introduction. The net result would be very poor for consumers and market development.

The suggested timing and phasing are not consistent with these requirements.

Question 6: IR-TUOS

The questions posed were as follows

1 How should IR-TUOS be refined?

2 What are the answers to the specific questions raised above, or how might the AEMC go about answering these questions? What other considerations should the AEMC take into account when refining IR-TUOS?

This is not seen as a critical issue among the issues discussed above. However, it is important that the principles stated be adhered to, and that the value of inter-regional transmission reflect the value provided across the regions involved.

Question 7: TUOS Framework

The question posed were as follows:

1 What insights do you have with regard to the above components of TUOS which you consider the AEMC should take into account when assessing TUOS reform?

2 What other components of TUOS should be considered?

There are many issues associated with the proposed TUOS reform. The reply to this question is limited to the issues and risks associated with TNSP’s providing firm access.

The arrangements proposed have the potential to introducer additional risk to TNSP (the precise design has not been described). These additional risks could be managed outside of the TUOS arrangements or may have the risks absorbed.

The principle should be that TUOS addresses regulated assets with regulated risks and the risk associated with market driven transmission development and access rights are addressed outside of the TUOS framework.

Question 8: TUOS reform Timeframes

1 Are the timeframes suggested for the TUOS reforms appropriate?

The issues associated with TUOS reform and overlap with the COGATI reforms strongly suggests the proposed timetable is considerably too short.

Appendix 1 Overview of the COGATI Proposals

The proposals presented in the Final Report consist of:

- The proposed reforms;
- How the reforms are introduced (i.e. staged);
- The desired outcomes.

These are summarised below.

The Proposed Reforms

The proposed reforms reflect moving straight to Option 3 or 4 of the five options presented in the Coordination of Generation and Transmission Investment Option Paper (these are summarised in the box below). Key elements of the solution proposed by the AEMC are as follows:

- For Group 1 projects undertake in parallel the AER's assessment of any dispute lodged, the preferred option, and the contingent project revenue determination. The assumption is that group 1 projects will be developed;
- The ISP is to form the basis of the future development of the transmission system. This basis shall be a single recommended development pathway developed through the modelling undertaken by AEMO in producing the ISP. This "actioned ISP" will progress group 2 and 3 projects (and subsequent projects identified in the ISP);
- TNSP's to continue to undertake RIT-T assessments. These assessments will be required to be based on the needs identified in the ISP and to utilise ISP assumptions and scenarios;
- The above is to be supported by market arrangements that will provide the following:
  - Pricing intraregional congestion (through dynamic pricing) to incentivise generators to invest in transmission for the purpose of capturing the access benefits through financial access to dispatch (i.e. avoid free rider issues). The locational pricing signals obtained would be an input to the ISP
  - Facilitate the development of large-scale storage system through a new registration category.

Staged Implementation

The satisfy the timing required for these to be implemented an accelerated staged approach is proposed:

- Stage 1: advance ISP group 1 projects;
- Stage 2: Embed an actioned ISP in the regulatory framework and integrate large-scale energy storage systems;
- Stage 3: Dynamic regional pricing and inter-regional TUOS pricing to ensure costs are aligned to those who benefit;
- Stage 4: Information from dynamic pricing and used as an input into the ISP;
- Stage 5: Enabling generators to fund transmission infrastructure.

The five options can be described as follows:

Option 1 - TNSP decides on transmission investments but is required to consider ISP identified investment needs in their transmission annual planning reports and regulatory proposals.

Option 2 - TNSP decides on transmission investment but is required to conduct RIT-Ts on its ISP-identified investment needs and options.

Option 3 - in addition to the ISP identifying investment needs and options, AEMO determines the “best” option for transmission investment, but the TNSP is still able to determine how to most efficiently meet that option, e.g. to take into account local conditions.

Option 4 - AEMO determines the “best” option for transmission investment and directs a TNSP to proceed with the “best” option, although the TNSP can still choose the functional specification of that option.

Option 5 - AEMO determines what transmission investment is necessary, including the functional specification, and directs a TNSP to implement the investment.

Source: Final Report, Section 3.2

Feedback on the Options (Final Report section 3.3)

Feedback from stakeholders and the AEMC was as follows;

Stakeholders - reasons for options 1 and 2:

- Preferred market-based approaches and decentralised transmission investment;
- RIT-T should remain the prime CBA process;
- Avoid consumers bearing the risk of a future envisaged by a central planning approach to the grid not eventuating;
- Provide the flexibility needed in the transmission;
- Less costly to implement.

Stakeholder – reasons for option 3 and 4:

- More costs to the market due to a lack of national coordination;
- TNSPs to pursue options that are considered in the ISP to be in the best interests of consumers;
- Completed faster;
- Could drive more efficient network planning.

AEMC ((Final Report section 3.4.4)

The AEMC stated:

> The Commission considers that the decision to invest in a transmission project should be made by the entity (i.e. the TNSP) that is required to implement it. Options 4 and 5 articulated in the options paper, as well as several submissions received from stakeholders, including AEMO, propose that AEMO direct transmission investment decisions. The Commission considers that it is not appropriate for AEMO to direct a TNSP to either make a decision to implement a preferred option, or to actually build a project that AEMO has determined must proceed through the ISP process.

Appendix 2 Supporting References

Final report section 3.4.2):

The actioned ISP has been developed by reference to the following principles:

- Be clear and transparent - transparent and comprehensive analysis, robust consultation;
- Decision-making on a nationally coordinated basis;
- Allow for both a local and strategic perspective;
- Minimise conflicts of interest;
- Allow for flexibility to deal with the transforming market;
- Allocate risk to the party best able to manage risk;
- Provide a streamlined process and minimise duplication of analysis and decision-making.

Final report section 3.4.1

Commission's conclusions and recommendations - There is a need for an actionable ISP

> In order to keep pace with the changing generation mix, there needs to be an enhanced, integrated, system-wide approach to planning, which does not consider transmission investments on a project by project basis. AEMO has created this through its development of the ISP, which delivers a strategic infrastructure development plan that can facilitate an orderly energy system transition under a range of scenarios. The ISP therefore provides the planning arrangements through which the regulatory frameworks for transmission planning and investment can be reformed to meet the needs of the changing energy market.28

Final report Executive summary - Para 17

> Robust and transparent consultation will create confidence in the transmission investment process and minimise the scope for disputes at the end of the cost-benefit assessment process.

Final report Executive summary - Para 32

> Actioning the ISP needs to be paired with the mechanisms necessary to allow generation to contribute to the enhancement of the networks and the management of congestion along it.

Final report REZ

> Measures to action the ISP, as explained in Chapter 3, will facilitate the development of REZs along nationally strategic transmission flow paths, i.e. AEMO's identification of when and where they are needed will be actioned. Furthermore, the RIT-T process (suitably improved through the recommendations made in Chapter 4) provides a mechanism for some other shared transmission projects. This chapter therefore focuses on those REZs that would not otherwise be developed as shared transmission projects following RIT-T or ISP processes.
>
> The Commission considers that the coordination of generation and transmission investment in general, including with regard to REZs, is best achieved by changing the access regime to one which would introduce more commercial drivers into transmission development. Changes to the access regime would enable better trade-offs to be made between the cost of transmission and the cost of generation in the

development of REZs, and would align more of the risk of investment decisions with those who make them, and away from consumers.