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Options paper: Price discovery in a renewables-based electricity system

We appreciate the opportunity to respond to the MDAG options paper *Price discovery in a renewables-based electricity system* published December 2022.

We commend the comprehensive approach to the research, analysis and communication that has provided a substantive backdrop to the consultation. Specifically, the library of options[1] paper that underpins the consultation, provides helpful statements about whether an option is useful for transition and the indicative level of net benefits.

Through our dual roles as grid owner (GO) and system operator (SO) we are committed to:

- enabling new connections and least regrets timely investments
- building, operating and maintaining the National Grid safely and efficiently
- operate the power system, and
- run the wholesale electricity market.

Our focus in this consultation response is on those options most likely to support the reliable transition to a renewables-based electricity system. As the SO, we are uniquely placed in the industry with practical experience in operating and understanding the power system and the electricity market.

The SO is available to investigate market enhancement options - leveraging its deep operational expertise into the design thinking – through the Technical Advisory Service (TAS) arrangement with the Authority.

[1] Library of options (ea.govt.nz)

Resource inadequacy and high prices for consumers pose a significant risk to a successful transition and meeting decarbonisation targets

Aotearoa New Zealand is at a pivotal point in the transition to decarbonise its economy. The changes required to achieve a highly renewables-based electricity system will set the direction for the country for at least the next decade, and many changes will need to occur across the energy sector and economy.

Consumers will, in the long-term, benefit from the emissions reductions and anticipated lower prices a market-led renewables based electricity system should bring. However, a transition that brings high prices and risks to security of supply invites political intervention before the benefits can be realised. Both high prices and reliability risk are the symptoms of uncertainty about the composition and availability of generation, development of demand-side flexibility and the potential exercise of market power.

To get to a well-functioning renewables electricity market there will be transition trade-offs, for example, an objective for "efficient operation" may necessitate a degree of friction (or inefficiency) while the market adjusts to changed operational parameters needed for security of supply. The tolerance of consumers for an unreliable electricity supply is not infinite and the real possibility of ad hoc intervention exists when faced with risk of electricity supply blackouts from insufficient generation or grid capacity.

A greater focus to ensure reliable electricity supply should align with a sustainable and affordable future. Advancing all three aspects of the energy trilemma (delivering sustainable, reliable and affordable energy) will ensure we have a successful energy system that can deliver long-term benefits for consumers.

Energy-only price signals appear insufficient as the only means to incentivise the right resources early in the transition

We agree with MDAG's description that with more intermittent generation in the mix (solar, wind), the supply variability increases the potential for unexpected large reduction in supply from intermittent sources during a trading period.

A well-functioning market in a highly renewable system needs to deliver reliable supply and competitive energy prices. While we believe that markets are a highly effective tool for ensuring efficient outcomes, sole reliance on market solutions particularly during periods of significant transition may not generate the outcomes required to drive confidence in electrification.

Specifically, we consider reliance on efficient energy price signals on their own may not guarantee a desirable market response to address the anticipated winter generation capacity constraints and lack of flexibility resources.

The Authority has also just released its own analysis on "*New Zealand's electricity future: generation and future prices*[2] where it identifies growing uncertainty about what generation

[2] 14 February 2023 *New Zealand's electricity future: generation and future prices* Electricity Authority

will be online for each winter 2024 – 2026. It writes "*There is ~2,600 GWh/year of new renewable electricity generation3 expected to be online between now and 2026*"…*[but] "Many build projects are facing covid-induced supply chain issues, long consenting times and increasing costs. Hence, there is growing uncertainty about what generation will be online for each winter."* The analysis also raises the issue that some fossil-fuelled generation stations are close to retirement or if operating, require more maintenance (hence outages). This context will exacerbate uncertainty in the availability of firm energy. Faced with a lack of adequate peaking capacity today and assurance of generation peaking capacity in the future, the risk of supply shortage increases. We agree with the conclusion that uncertainty is growing and posed the same conclusion for winter 2023 from our analysis of the 2023 peak capacity challenge.[3]

Recognising these conclusions, options that provide the SO with mechanisms to reduce uncertainty and increase resource availability to manage supply variability during the transition are urgently required.

New tools needed for system security and a well-functioning system

We support the MDAG's preferred option A4 *operationally integrated ancillary service product* recognising that its full development may not be feasible for the more immediate needs of winter 2023 and 2024. Further design thinking - such as how a longer-term (e.g. 15 minute) standby reserve product would work with the current real-time[4] dispatch process – plus building, testing, implementing and procuring all need to be worked through as part of this ancillary service development. In the interim as a stepping-stone the design may require more straightforward procurement approaches to ensure firm resource is available to support reliable supply. No approaches should be ruled out.

We also support improving forecasts under option A1 and agree with the MDAG thinking[5] about introducing *sensitivity analysis* on those forecasts, to improve information about the range of forecast spot prices for participant actions. Acknowledging that "more" information will only improve generation commitment decisions up to a point.[6]

Improved system performance can also come from strengthening asset owner performance obligations (AOPOs) such as requiring grid forming inverters, generator ride through, or new standards for designing standalone or integrated ancillary services or products. These options are complementary to market design options raised by MDAG and a workstream under the Future Security and Resilience (FSR) project.[7] We consider the MDAG and FSR projects have shared outcomes that would benefit from joined up thinking. We support developing guiding principles for FSR proposals.

In addition, some market/technical options that have been indicated as "not preferred" by the MDAG should, in our view, remain on the table for further investigation (indicated below) as we consider there are benefits of these enhancements given the recent winter challenges

[3] System Operator Winter Review Paper
[4] This is typically done every 5-minutes.
[5] Library of options para. 2.5
[6] Refer SO submission to the Authority's consultation Consumer Interests Winter 2023
[7] Covering-Paper-FSR-Final-Roadmap-and-Phase-Three.pdf (ea.govt.nz)

with increased renewable and low-priced generation and expected changes to the power system.

Our view of the options to recommend and those to not recommend to the Authority

In the box we list the options we propose are recommended for immediate implementation (A1, A2, A4 and E4); options that require further investigation (A3, A6, A8; A9, B3, C10 and D1) and two options we conclude should not be recommended (A5 and C12).

Our rationale for each is described in the appendix.

We would encourage MDAG to ensure focus is given to a shorter list of the highest priority reforms for an acceptable transition.

Options we support for recommendation and implementation now

- A1. Improve short-term forecasts of wind, solar, and demand [MDAG preferred]
- A2. Strengthen governance for next phase of FSR project [MDAG preferred]
- A4. Reserve product for intermittency [MDAG preferred]
- E4. Enhance conduct monitoring [MDAG preferred]

Options we support recommending for further investigation

- A3. Update shortage price values [MDAG preferred]
- A6. investigate and develop day ahead market [MDAG preferred]
- A8. Negative prices [MDAG *not* preferred]
- A9. Complex offers [MDAG *not* preferred]
- B3. Publish aggregated information on pipeline of new developments, energy and capacity adequacy [MDAG preferred]
- C10. Emergency reserve trader [MDAG partial support]
- D1. Dashboard of flexibility competition [MDAG preferred]

Options we do not support being recommended

- A5. Change gate offers after closure [MDAG preferred]
- C12. Extend locational marginal pricing (LMP) to Distribution networks [MDAG partial support]

Coordination with transmission investment that underpins the market

While the MDAG brief was the electricity market only we consider an omission for its context is the role of transmission capacity. Sufficient grid capacity is a key enabler of competitive price-discovery processes. A reliable and resilient grid becomes even more important to market operation, under the environmental and economic disruption from increasingly severe weather events.

To leverage the benefits of generation and technology in the transition to a highly renewable system requires coordination with investment in grid infrastructure to support the wholesale market.

We ask that the MDAG reflects the critical dependency on transmission for a competitive market in its recommendations to the Electricity Authority.

Transpower supporting the MDAG and the Authority for the next stages

The transition to a highly renewables-based electricity system in a highly uncertain future is likely to be iterative so solutions must be flexible and practical for a fast-changing context. We consider the right options and solutions will be found in a co-ordinated and collaborative approach. Some options may need to be temporary, acting as stepping-stones until the transition is complete. A periodic review cycle for future options implementation would have merit to help align the transition with contextual changes unlikely to be linear in nature.

As the SO will ultimately be operating the market and system including any changes delivered, we believe our inclusion in the delivery in any changes can help deliver better outcomes for consumers and the safe and secure operation of the power system.

The recommendations to the Authority could also convey the MDAG's view on any extent that government-led policy developments (the Energy Strategy, Gas Transition Plan, and NZ Battery) have influenced, or could influence, the options being recommended.

We trust this submission is helpful to the MDAG's consideration of the options to recommend to the Authority. We believe our expertise and independence can assist the MDAG and the Authority in the next phases of this work. We welcome closer involvement and engagement going forward.

Yours faithfully,

Joel Cook

Head of Regulation

Appendix – Transpower options analysis

Options we support for implementation

A1. Improve short-term forecasts of wind, solar and demand

Under the current market rules, intermittent generators provide offers to the market indicating their expected generation output for each half-hour 36 hours into the future and within 2 hours the intermittent generator offers must be based on a persistence forecast, unless otherwise agreed with the Authority. The Authority's winter 2023 consultation[8] highlighted that the increasing amounts of intermittent generation can make the market forecasts more uncertain. One of the options in this paper was provision of additional information to the market based on an external wind forecast. While providing increased information to the market based on an external wind forecast would provide additional information on potential wind variability and uncertainty, we believe that any large-scale improvement in the quality of intermittent generation forecasting will depend on the outcome of the project the Authority is currently working on to improve the accuracy of intermittent generation forecasts/offers[9]. We encourage the MDAG to recommend urgency given the increasing quantity of intermittent generation coming online (e.g. Turitea, Kaiwera Downs, Harapaki and various solar projects[10]) and the impact this uncertainty and variability can have on co-ordinating resources to maintain system security.

In regard to the load forecast, the SO has procured the Tesla load forecast and has seen significant improvements in the quality of the load forecast (reduced forecast errors) used in the market forecast schedules. Based on our trials to date, our current thinking is that further accuracy gains are likely to deliver smaller improvements for higher effort (diminishing returns). Nevertheless the SO will continue to monitor the forecast and identify potential areas for further improvement.

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[8] Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023.pdf (ea.govt.nz)

[9] This project should recognise that there might need to be different potential solutions for the different types of intermittent generation types. As an example, solar generation sites could be smaller and more distributed compared to wind generation sites. Furthermore, where persistence offers could be seen as a reasonable estimate in some instances for wind generation, it is less likely to be so for solar (especially during the sunrise and sunset periods).

[10] Connection enquiry information | Transpower

Providing sensitivity schedules can help participants understand the potential variability in forecast spot prices. While some more resourced market participants might be able to do this themselves currently, providing a price sensitivity forecast to all market participants can help competition by removing information asymmetry. This option was explored with the Authority several years ago, with approximate costs and timeframes for investigation and implementation being ~$1.7m and 16 months. These would need to be reviewed in terms of current costs and the SO's current work plan.

- Agree with MDAG proposed timing 2023 – 2024.

A2. Strengthen governance for next phase of FSR project

We appreciate the MDAG's consideration of ways to strengthen governance around the FSR project, given the project's importance to developing the technicalities of future system coordination. We agree that strong engagement with the SO and GO is critical (for GO specifically, the role of the resilience of grid infrastructure) and that obtaining high quality input from wider stakeholders will become even more important.

The details of the guiding principles outlined in the "Library of Options" (para. 2.10) might need some refinement to ensure they are practical and feasible to apply and make the Code change process more efficient. The principles need to adequately balance the issues of system security, resilience and market efficiency and not act as an impediment to decision making in a context of rapid changes in technology development and their commercialisation. Guiding principles could support alignment of decisions under this (and other) projects but care should be taken that in applying these principles they do not act as a layer of compliance that could unnecessarily slow progress.

Our understanding of the role for a "reference group" is more circumspect.[11] The Authority's FSR project is following a typical regulatory change process i.e. through discussion, issues, options and decision steps. The regulatory process requires engagement with, and invites views from, all industry participants and any other interested parties. The regulatory consultation would cover economic and technical matters and conflicts of interest would likely be called out through the submission process. Would the reference group be in the FSR project process, involved in drafting papers, analysing submissions, holding workshops; or would the role be modelled similar to an advisory group? We note the

[11] Library of options para. 2.13 "*We also propose an external reference group to help: (a) Identify and address key economic and technical trade-offs, (b) Oversee that application of the guiding principles; (c) Examine issues where Transpower (or the Authority) may be perceived as having potential conflicts of interest – such as the best division of responsibility between national and 'local' system operation, or the merits of an independent system operator model ; and (d) Support periodic stakeholder engagement*."

Authority's proposal for a new advisory group responsible for "*advice on draft issues papers, option papers or other Code amendment papers… and, as appropriate, to assist in considering and reconciling views presented in submissions.*[12]

- Agree with the proposed timing (2023).

A4. Reserve product for intermittency

A well-functioning market in a highly renewable system needs to deliver reliable supply and competitive energy prices. While we believe that markets are a highly effective tool for ensuring efficient outcomes, sole reliance on market solutions particularly during periods of significant transition may not generate the outcomes required to drive confidence in electrification.

Specifically, we consider reliance on efficient energy price signals on their own may not guarantee a desirable market response to address the anticipated winter generation capacity constraints and lack of flexibility resources,

The SO winter review paper[13] highlighted the need for flexible generation capacity to meet growing winter peak demands. This is in part due to the reduced incentives for inflexible thermal generation to commit plant as well as increased generation uncertainty with increasing quantities of installed intermittent generation. The current market products are not providing the necessary incentives for sufficient residual capacity to cater for these and other supply/demand imbalance risks.

We agree with the MDAG that a new ancillary service product should be progressed **as a priority** to provide additional incentives for flexible resources to manage balancing supply and demand given the increasing uncertainty (e.g. due to intermittent generation, unexpected increases in demand or other resource unavailability). Designing such an ancillary service however could require significant development and system changes by the SO depending on the complexity of the solution. The design thinking - such as how a longer-term reserve product works with the current real-time dispatch process – plus building, testing, implementing, procuring and all the associated Code development would need to be worked through for an integrated/co-optimised ancillary service implementation. In the interim as a stepping-stone the design may require more straightforward procurement approaches to ensure firm resources are available to support reliable supply as the transition progresses. No approaches should be ruled out. The SO needs to be engaged early to ensure the effort required for the development and

[12] Review of the consultation and feedback processes section 5
[13] SO Winter Review Paper November 2022

implementation of the systems and processes, as well as procuring the resources, are adequately taken into consideration to meet the tight timelines outlined in the MDAG paper.

- Agree with intent for MDAG proposed timing 2023 – mid 2024 but consider high risk of missing the date if the solution is complex.

E4 Enhance monitoring with more autonomy

We support enhanced monitoring of wholesale energy market participants. Our submission to the Authority's consultation[14] on competition in the wholesale market stated "*We support the proposal to continue proactive monitoring and enforcement of trading conduct in the spot market, but we consider the monitoring could need "beefing up" as identified by MDAG. We also consider that the Authority should consider whether monitoring should be undertaken by an independent third party. Monitoring from the same party that created the rules to be monitored could risk optimism bias into what is being observed. Confidence in the monitoring could be improved through the use of an independent service provider*." [15]

We consider the MDAG has made a strong case that market power risks will increase as the penetration of intermittent, unfirm generation grows. Alongside conduct monitoring, the MDAG could also recommend the Commerce Commission and Authority work together to require information disclosures from participants that enable the regulator to monitor for any issues under section 36 of the Commerce Act.

[14] Electricity Authority Promoting competition in the wholesale electricity market in the transition toward 100% renewable electricity October 2022
[15] Transpower submission *Promoting Competition 100% Renewable Market* 14 December 2022

- Agree with MDAG proposed timing mid 2024 – 2026.

Options we support for further investigation

A3. Update shortage price values

Shortage-price values are key to the scarcity pricing regime under RTP. The shortage pricing values should be reviewed as soon as practical by the Authority to ensure these are fit-for-purpose. This update will need careful considerations taking into account the interaction of the different elements of the spot market scarcity pricing regime which could require significant effort. This will also need to take into account any interaction with the additional ancillary service considered as part of A4.

- Agree with MDG proposed timing 2023 – 2025.

A6. Investigate + develop ahead market

We propose this could be considered a next phase project for the MDAG: to research, engage, develop an ahead market design for the Aotearoa New Zealand context and propose it to the Authority. We consider there are close linkages between A4, A6 and A9 and their interactions need careful consideration to ensure that any options are not excluded too early without adequate assessment.

Under our current market arrangements all forecast market schedules are indicative. Only the real-time dispatch schedule provides the dispatch instructions for energy and instantaneous reserves. This framework relies on market participants using the forecast price signals to co-ordinate their resources across time. When this co-ordination does not deliver sufficient capacity there can be shortfalls in trying to balance resources in real-time. With the increases in intermittent generation and, increasing uncertainty in thermal commitment (lumpy generation decisions) this co-ordination issue is becoming more acute as we transition to a more renewable system with resources available in real-time deviating from those expected to be available thus making balancing supply and demand more challenging in real-time.

A solution to cater for this co-ordination issue is the provision of more flexible capacity in real-time (to allow for coordination mismatches under the current scheduling and dispatch process – e.g. as outlined in option A4).

A complementary and longer-term solution could be the development of an ahead market to provide firmer schedules for resources ahead of real-time settled at the forecast prices with deviations from the forecasts dispatched in real-time at real-time prices. As noted by MDAG, an ahead market approach would help provide participants with greater certainty ahead of real-time which could be beneficial for those resources that require longer lead times to schedule resources (e.g. some less flexible generation and some demand-side resources) as well as provide greater incentives for improving forecast of intermittent resources.

There are also benefits to the SO. Providing firm schedules to resources ahead of real-time with only balancing deviations from these schedules in real-time reduces the uncertainty coming into real-time relative to the status quo which will assist the SO in its security planning.

In addition to Code development, this option would represent a significant change to the market with consequences for existing market participants. Such a significant change would need to be assessed against other options. Depending on the solution that is used for the ahead market, there could be significant development for the market system and downstream settlement systems. The SO would need to be engaged early to ensure the implications on tools and processes, security planning and real-time operations are taken into account early in the assessment process.

- Considering the effort that could be required for this option the investigation into the design should start sooner than 2025 to meet the MDAG proposed timing of mid-2027.

A8. Negative offers / prices

The MDAG is correct in outlining the complexities negative offer prices could introduce with the current market clearing engine. This issue can be resolved but would require investigation.

While we agree with the MDAG's articulation of the specific issues of introducing negative offers, we do not agree that this does not warrant further work at this stage. The issue of how to dispatch high volumes of competing low-SRMC renewable generation remains even if the negative offers prices might not be the preferred option. This issue will only grow in importance as more low-SRMC generation and distributed energy resources connect to the grid (sometimes competing to exit from the same location on the grid with constrained transmission). To get ahead of these issues, we propose work should begin as soon as possible to investigate feasible options to address this issue.

We suggest that further work is initiated to better understand feasible options to address this issue, including subject matter experts from the SO.

A9 Centralised commitment based on complex offers (aka temporal offers)

The MDAG describes this option as low benefit and not preferred, but we consider there are benefits of allowing for some complex offers with intertemporal optimisation.

As discussed above, under the current market arrangements all forecast market schedules are indicative and only the real-time dispatch process provides the dispatch instructions for energy and instantaneous reserves. However, the real-time dispatch process only considers the next 5 minutes without any understanding of the future requirements of the power system. This means that the real-time dispatch can dispatch resources off (e.g. in the middle of the night when load is low) without considerations that in doing so, the resource would not be available to generate for the morning peak load period even though it may be needed to ensure the demand is supplied. This lack of forward "visibility" of the current dispatch tools could be addressed through complex offers and intertemporal optimisation so that current decisions are made with some "knowledge" of the implication these decisions have on future periods.

The benefits of intertemporal coordination could increase further with increased proliferation of limited battery energy storage systems (BESS) offering into the market in a highly renewable system. Lack of intertemporal co-ordination can result in resources being used inefficiently (at the wrong time) which can impact system security, e.g. if a BESS with 0.5 hour storage is discharged now and so is not available in the next trading period to discharge or provide IR. Thus, the impact of current dispatch decisions can impact the available resources in the next trading period.[16] If we consider a state where there are lots of these limited energy storage resources on the system then it is not clear that self-commitment would enable all these limited energy storage devices to be allocated efficiently across time without greater intertemporal co-ordination.

Thus, we consider that the MDAG may have discounted the benefits of complex offers and intertemporal optimisation too quickly. Further consideration should be given to this in light of the issues the SO is observing currently with the lack of intertemporal optimisation and the expectation of increased limited energy storage systems. We think this issue could be included as part of the day-ahead investigation (A6).

B3 Publish aggregated information on pipeline of new developments, energy and capacity adequacy

Over the past two years Transpower as GO has been working on creating public information about new grid connection enquiries, from initial enquiry through to commissioning. Information is available to the general public on our website in an aggregated view of our forward pipeline of works by count and size (MW) noting connection types and subtypes, their locations (by planning region), need dates (by Regulatory Control Period) and enquiry stages.[17] We consider this work meets the intent for option B3 for pipeline information.

The SO provides an indication of potential generation developments over the next 10 years as part of the annual Security of Supply Assessment (SOSA). This assessment is updated annually.

On the "adequacy" point, the SO publishes daily the New Zealand Generation Balance (NZGB) which is an update of a 200-day look ahead of potential generation capacity relative to peak demand (considering some sensitivities). The SO through the annual Security of Supply

[16] This is similar to the current dispatching off of inflexible plant overnight as discussed in the previous paragraph.
[17] Connection enquiry information | Transpower

Assessment (SOSO) process also provides a 10-year indication of forecast energy and capacity margins relative to the standards. If these energy and capacity margins are expected to be produced more frequently, the SO would need to investigate the feasibility of this and if so, the resourcing implications under the SOSPA. The standards used for these capacity and adequacy checks are developed by the Authority and defined in the Code. Given the expected changes in the system with increased electrification of the economy, the increased role intermittent generation is going to play in the supply mix and the changing resource costs, we believe the adequacy standards should be reviewed by the Authority to determine if they are still fit for purpose. While we consider this is an important measure to reflect to industry stakeholders how the future capacity and energy margins compare relative to the standards, we consider options A1 and A4 above as more time critical for the secure operation of the power system. Therefore, we consider the update of the adequacy standards should be undertaken as part of its planned review cycle by the Authority and not detract from the delivery of options A1 and A4.

- Transpower as the GO already publishes new grid connection enquiries, which supports option B3.
- However, if the SO is required to produce this future pipeline information and/or update the energy and capacity margins more frequently than the current annual SOSA process, the SO would need to assess the feasibility and the resource requirements. The MDAG proposed timing of 2023 – 2024 might be challenging to implement a full solution and so a phased approach may be more appropriate.

C 10 Procurement process for high-scarcity DSF (RERT - Reliability Emergency Reserve Trader)

This option could potentially be developed under investigating approaches for option A4.

- Consider this could be investigated sooner than indicated by MDAG, as part of or as a stepping-stone for A4.

D1 - Develop dashboard of competition indicators for flexibility segment of wholesale market

The MDAG's view is that "*Options D1 and D2*[18] *are proposed for prompt adoption because they are foundational in nature and should be relatively straightforward to implement*". However, the MDAG also identifies that demand side flexibility needs to be lifted, which suggests it may be some time before enough information is available to understand what the indicators are and what they can tell us about the level of competition.

- Agree with MDAG proposed timing (2023 – 2024).

[18] D2 is Greater transparency of hedge info (esp. non-base load) covering offers, bids + agreed prices

Options we do not support being recommended

A5. Offer price reductions after gate closure

The SO uses the forecast schedules to prepare for real-time security and gate closure is part of stabilising the offers available for real-time operation. Allowing some marginal resources to change their offers after gate closure will increase the uncertainty to the SO, as offer changes of marginal plant could impact dispatch and changing power flow patterns, potentially resulting in unanticipated binding constraints on the grid closer to real-time or overloads in real-time for which no constraint was created. Allowing marginal plant to change their offers would make another resource marginal who might also be averse to being on the margin thus resulting in multiple offer changes thus increasing the uncertainty of real-time dispatch conditions relative to what was forecast.

In short, this option only increases, rather than decreases, uncertainty closer to real time which can adversely impact system security.

This option appears to be designed to adjust generic market rules to accommodate the inflexibility of some generation plant. Customising rules to suit the particular operating characteristics of individual generators does not, in our view, send efficient price signals to potential investors. Put another way, to do so would be to socialise the cost of private investment decisions.

We consider the introduction of the additional ancillary service (A4), the day-ahead market approach (A6) and/or the introduction of complex offers (A9) would be more principled ways of addressing the inflexibility of some plant without increasing uncertainty closer to real-time that compromises system security.

C12. Investigate extending LMP into distribution networks

The MDAG proposes "partial support" although identifies that the costs of making this change would be significant and have not been explored. Extending the market model beyond the grid exit point into the distribution network to calculate LMPs in the distribution network will significantly increase the size and complexity of the market clearing engine. LMP would need a network model including circuit limits, loss model, impedances, outages and load shape and if the modelling is poor so too will be the price signals. LMP is already a significant overhead at transmission level before creating the capability from scratch for each distribution network. Market settlement would be at sub-distribution level which would be significant change to the settlement process. The question then becomes whether the benefits outweigh the increased complexity and costs.

The Authority commissioned Sapere[19] to investigate some of the issues towards extending LMP to Distribution networks. The question for its research was about the practical considerations for implementing DLMP, but the report also covered the wider question of "*how to ensure optimised power flow modelling at distribution level with a proliferation of assets and competing control of those assets at distribution level*." The report states "*Whatever the answer is will beg the question of whether there is a positive benefit to doing so*." Interestingly the report considers that "*In many cases the prices consumers see would continue to be fixed price variable volume prices bundled with distribution and transmission costs*" [all quotes page 34].

This option would divert significant industry resource in investigating a complex solution to an issue for which the problem and benefits are uncertain. This option should not be recommended.

[19] An-exploration-of-locational-marginal-pricing-at-a-distribution-level-in-the-NZ-context June 2017