alintaenergy

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Simon Middleton
Program Director
Program Management Office of the Electricity Market Review
Public Utilities Office
Albert Facey House 469 Wellington Street
Perth WA 6000
Via email: electricitymarketreview@finance.wa.gov.au

Dear Simon,

Position Paper: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms – 14 March 2016

Alinta Energy (Alinta) appreciates the opportunity to comment on the Public Utilities Office's (PUO) Position Paper: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms (Paper). The Paper sets out major reforms to address perceived inefficiencies in the supply of energy and ancillary services in the Wholesale Electricity Market (WEM).

A key construct underlying the proposed reforms is the adoption of the national framework for network regulation of Western Power's network scheduled from 1 July 2018. This change, coupled with the appointment of the Australia Energy Market Operator (AEMO) as the WEM system manager, provides a good opportunity to change the WEM design to improve its efficiency.

Alinta understands the proposed core reform proposals for the WEM involve:

- adopting a security constrained market design;
- requiring facility bidding by all participants;
- implementing co-optimisation of energy and ancillary services; and
- moving to a later gate closure and a shorter dispatch cycle.

Implemented as a package, the Paper estimates the present value of savings to be in the order of $100 million. These significant savings potentially available to customers through improved market efficiencies, especially in regard to ancillary services, suggests the reforms should be implemented.

Summary response

Alinta largely supports the reforms proposed in the Paper. In particular Alinta has the following views:

- implementing a security constrained market design is seen as a necessary and inevitable consequence of the decision to move to a constrained access model. When combined with the capabilities of the proposed dispatch engine – NEMDE – adopting a 5 minute dispatch cycle and implementing co-optimisation of energy and ancillary services will very likely result in substantial improvement in dispatch efficiencies and a consequent savings in ancillary service costs ultimately to the benefit of customers. However in the absence of information on transition arrangements in regard to generator access rights embodied in current Arrangements for Access made under the Electricity Network Access Code, Alinta cannot support the proposal to abolish constrained-off compensation;

- underpinning these changes will be the requirement for all participants to bid by facility which Alinta supports. However it's noted this change will impose more costs on some participants than others, but collectively the efficiency improvements from co-optimisation and shorter dispatch cycle should deliver net benefits to the market. Given the magnitude of the costs involved the PUO may wish to consider whether this cost / benefit should be tested through a properly conducted and comprehensive analysis;
- retaining a single pricing node (albeit that it is reassigned to a central load point) based on a hub-and-spoke network representation of the network is preferred as it avoids unnecessary complexity and minimises costs and implementation risks of what will be the most significant change program since the implementation of the balancing and LFAS markets in July 2012; and
- implementing the market settlement packages associated with the proposed dispatch engine requires the merit of retaining or changing/expanding STEM functionality be reviewed. Alinta considers the STEM to be a legacy system and given the emergence of new hedging instruments, not present at market start, the trend of declining trades and noting its retention will increase implementation costs, Alinta views the case for the STEM transitioning to the new market design is not sufficiently strong to justify that it be retained.

In addition, Alinta proposes the Short Run Marginal Cost bidding obligations should be reviewed in light of the significant reforms proposed in the Paper and the changes being made to the Reserve Capacity Mechanism. The review should consider whether the obligations remain necessary and if so, which generators the obligations should apply to, and what the single bidding cap should be.

Risks to implementation

As with any major reform there are implementation risks. In particular, Alinta considers the WEM reforms represent an ambitious proposal to be implemented in a tight timeframe. Consultation with market participants should be undertaken to ensure prioritisation of changes and a staged implementation is undertaken to allow the reforms to be rolled out in an orderly manner.

Detailed response

More detailed comments and responses to requests for comment are included in the Attachment.

If you would like to discuss this submission please don't hesitate to contact myself on 9486 3762 or John Rhodes on 9486 3306.

Yours sincerely

M Shepherd

Michelle Shepherd
General Manager Regulatory and Government Affairs

Attachment

Request for comment – submissions providing feedback on the essential reforms – the implementation of a security-constrained market design, facility bidding for Synergy and co-optimisation of competitive energy and ancillary service markets – are encouraged.

Alinta's views:

- ***Alinta supports implementation of a security constrained market design and co-optimisation of energy and ancillary services, and a requirement for all participants to submit bids on an individual facility basis.***

The Paper makes a strong case that current arrangements based on an unconstrained market design must be reviewed given the Government's decision to transfer regulation of Western Power's network to the Australian Energy Regulatory. Adopting the national framework for network regulation will have implications for the current unconstrained access model underpinning the WEM's market design.

Furthermore, Western Power's actions in developing connection arrangements through a collective process (Competing Access Groups) foreshadow that the network will become increasingly constrained, even during pre-contingent conditions, requiring more frequent system manager intervention in dispatch processes. Ultimately, this will lead to pre-dispatch schedules being poor indicators of dispatch outcomes due to increasing network congestion and an associated increase in constraint payments, a non-transparent cost imposed on customers that they are unable to avoid.

The current simple cost-based dispatch merit order, that fails to consider network congestion, if left unchanged, will increasingly deliver sub-optimal dispatch outcomes and higher costs to customers.

Given this context, the Paper proposes the adoption of a security-constrained energy market design, the benefits being improved transparency and efficiency of dispatch processes while safeguarding system security. It will also be a better indicator of network constraint points, suggesting network or generator capacity augmentation investment opportunities, and result in reduced manual intervention in dispatch processes by the system manager.

Alinta appreciates the current unconstrained market design is only viable providing constraints bind infrequently requiring limited intervention by the system manager. If advice unambiguously and consistenly indicates that constraints will in future bind more frequently, increasingly disrupting automated dispatch processes and result in growing constraint payments, then Alinta will support the proposal set out in the Paper to switch to a constrained access market design in which network constraints are factored into dispatch processes to produce an efficient dispatch solution. This will better ensure dispatch processes remain efficient while reflecting the practical realities of the network as it accommodates increased generator connections and customer load.

Clearly, the proposal to adopt a constrained access market model is a key issue for the market - network congestion will become an increasingly important factor in dispatch outcomes that may affect some participants more than others. However, to date there has been an absence of information or advice as to the practical implications for participants and how the dispatch of their generators may be impacted.

To clarify these uncertainties so that participants can consider one of the Paper's central underpinning proposals on a more informed basis Alinta urges the PUO to release as soon as possible information related to credible scenarios that identify the likely locational incidence, frequency and duration of network congestion. Furthermore, Alinta suggests that such network congestion modelling be updated annually and made available to the market via for instance the RCM's Requests for Expressions of Interest document. This information will certainly be relevant to new investors considering entering the market and also to existing participants planning capacity enhancements or considering retirements.

Changing to a constrained access market design raises the issue of whether the current dispatch engine, designed for an unconstrained market, will remain workable as the incidence of constraints rises over time. It also provides the opportunity to review what other dispatch engine capabilities should be considered to ensure WEM dispatch processes are as efficient as possible.

In this regard Alinta notes the potential for increased efficiencies through dispatch processes concurrently solving energy and ancillary service dispatch outcomes. This process, referred to as co-optimisation, is widely used in competitive energy markets to ensure least cost dispatch outcomes. Co-optimisation drives economic efficiency by ensuring market processes can select the most efficient combination of energy and ancillary service components from participating participants as well as ensuring that energy and ancillary service outputs are optimised between those participants.

Alinta notes the large disparity in the costs of regulation ancillary services between the national and Western Australian energy markets, costs in the latter being relatively much higher, with a significant component of the difference due to disjointed Load Following Ancillary Services (LFAS) and energy markets in the WEM. Savings in LFAS costs in order of $100M are indicated in the Paper if co-optimisation, together with shorter dispatch cycles, is implemented in the WEM. Alinta notes this figure does not take into consideration participant costs in transitioning to a co-optimised market, nevertheless, in Alinta's view the savings will very likely outweigh the costs.

The Paper proposes that the spinning reserve ancillary service become contestable as part of the implementation of co-optimisation, as is the case in the NEM. This is a change from current arrangements where spinning reserve service is provided by Synergy unless a cheaper service is available under contract from another participant. Synergy is compensated via administratively determined margins which may or may not reflect the actual cost of providing the service.

In principle given the dynamic nature of spinning reserve requirements a market where there is adequate competitive tension will more likely result in efficient cost outcomes than one where values are administratively determined. Furthermore, a co-optimised approach with a common gate closure will present participants with ready access to additional revenue streams that they might otherwise not have considered.

Once technically qualified to provide spinning reserve services, participants can bid as and when they perceive opportunities arise, which will be an improvement over current fixed term contract arrangements. This should encourage the development of a more competitive market for spinning reserve ancillary services and reveal the efficient costs for providing the service.

To facilitate the adoption of a constrained access market design and implementation of co-optimised energy and ancillary services the Paper notes it will be necessary for all participants to make bids on an individual facility basis; a portfolio basis where facilities are grouped for the purpose of bidding will be unfeasible. This is a necessary requirement of the constrained market design where, for the purpose of effecting economic dispatch taking into account constraints, facilities must be associated with particular transmission elements. Also in regard to the co-optimisation of energy and ancillary services it will better distinguish facilities providing regulation ancillary services as opposed to balancing. This should enable a more definitive assessment and justification of the quantity of regulation service required resulting in savings through a lower requirement or time based sculpting of the requirement.

For most participants a facility bidding requirement will mean little change, however it is acknowledged that it will have implications for Synergy with over 30 facilities in its portfolio. Synergy will likely be required to invest in a new trading platform to accommodate its diverse portfolio of plant and fuels. This will certainly add to the cost of transitioning to a security constrained energy and ancillary service co-optimised market, however Alinta expects such costs to represent a fraction of the savings estimated in the Paper.

Based on these considerations, Alinta also supports the Paper's proposals to implement co-optimisation of the energy and ancillary service competitive markets with a common gate closure and a facility bidding requirement for all participants. However, given the market dominance of the Synergy and the proposal that it remain the default provider of ancillary services, Alinta recommends that suitable and effective market power constraints be considered to ensure the efficiency benefits are not captured by the dominant participant diminishing the benefit of reform to customers.

Request for comment – the Electricity Market Review proposes later gate closure for the energy and ancillary service markets, five-minute dispatch cycle and ex-ante price determination.

Submissions providing feedback on these proposed reforms, including alternative options, are encouraged.

Alinta's views:

- ***If co-optimisation is introduced then Alinta also supports implementation of the suggested 5 minute dispatch cycle to ensure dispatch efficiencies and ancillary services savings are maximised.***

- ***Alinta supports adopting ex-ante pricing as it allows generators to determine their co-optimised energy and ancillary services revenues based on known prices.***

- ***Alinta recommends a staged implementation of the reforms and supports a common gate closure of no more than 30 minutes to apply from 1 July 2018 and a requirement that the net benefit of further reducing gate closure be subject to regulatory review within 3 years.***

Electricity demand is constantly fluctuating reflecting changing customer consumption decisions. The function of the wholesale market is to match generation supply with customer demand such that the system remains reliable and secure. Generators participate in wholesale markets by making price based offers to supply various amounts of electricity. Offers are ranked by price with the lowest cost generators dispatched to meet forecast load before more expensive generators such that demand is met and the market cleared at least cost. A similar dispatch process applies to the competitive provision of ancillary services with requirements forecast by the system manager in advance of the start of the dispatch cycle.

Noting the generally positive relationship in energy markets between the length of dispatch cycle being forecast and forecast error, the latter tends to reduce in line with shorter dispatch cycles. Applied to the provision of ancillary services, effectively a market overhead to ensure the system remains reliable and secure, a shorter dispatch cycle translates to reduced ancillary service requirements resulting in reduced costs ultimately paid by customers.

Given some generators participate in both energy and ancillary markets, efficiencies are maximised where both markets are cleared, i.e. co-optimised, simultaneously. As noted previously, Alinta supports the introduction of co-optimisation of energy and ancillary services in the WEM (i.e. same gate closure) as it will provide benefits to generators and customers: generators benefit from improved plant utilisation and potential additional revenue flows and customers benefit from more efficient dispatch outcomes that reduce ancillary service charges and required load following ancillary service capacity levels.

If co-optimisation were introduced, then in view of the dispatch efficiency and cost savings reasons outlined above, Alinta also supports implementation of the suggested 5 minute dispatch cycle. In light of the proposal in the Paper to adopt the National Electricity Market Dispatch Engine (NEMDE), which has 5 minute dispatch cycle capability, Alinta sees no reason to retain the current 30 minute dispatch cycle with its attendant higher load/ancillary services forecast error and resultant higher requirement for frequency control ancillary services.

Alinta notes that changing from a 30 minute to a 5 minute dispatch cycle will result in more frequent dispatch instructions being issued. This will better align end of interval dispatch targets with ramp rates resulting in savings in the level of frequency control ancillary services required to ensure system stability. The increased granularity of system operations will likely impact some generators more than others. For instance, it's likely that the marginal energy generator will be instructed to move more frequently, within its price offer bands than is currently the case, however generators with offers below the market clearing price in any interval will be largely unaffected by a change to a 5 minute dispatch cycle.

In regard to pricing, ex-ante pricing is strongly preferred by Alinta as it allows generators to determine their co-optimised energy and ancillary services revenues based on known prices. It removes an element of uncertainty from the offer pricing process (apart from when prices are recalculate ex-post due to errors) allowing risk premiums to be reduced resulting in lower offer prices which are more reflective of expected actual underlying costs.

In respect of gate closure, Alinta notes that different markets, perhaps reflecting the stage of their development, size, or market design, often have different gate closures. For example, in the Ireland's Single Electricity Market, gate closure is 10AM on day before; in the UK's British Electricity Trading and Transmission Arrangements (BETTA) market it is one hour prior; in the National Electricity Market of Singapore it is 5[1] minutes before trading/dispatch interval start; while in the NEM there is no formal gate closure[2].

Clearly, the variation suggests there is no convergence on what is an appropriate gate closure, there is "no one size that fits all": market design, structural competitiveness, size and sophistication would most likely all be relevant considerations. However, given the dynamic nature of electricity supply and demand, it's reasonable to conclude that a shorter gate closure allows pricing offers to reflect more recent information as to load variations and plant capabilities. Rebidding in response to updated forecasts and changes in expectations about dispatch prices forms part of price discovery which in competitive markets leads to efficient prices.

If NEMDE is adopted, then scope exists for the WEM to have a very short gate closure or none at all. Given the current gate closure of 2 hours, the skewed structural competitiveness of the WEM and proposed adoption of co-optimised bidding of energy and ancillary services, Alinta posits a staged approach to reducing gate closure would be appropriate to allow participants to manage what amounts to a set of very significant changes to market operations.

Accordingly, at this juncture, Alinta supports a common gate closure of no more than 30 minutes to apply from 1 July 2018. However, provision for a formal review by the Economic Regulation Authority within 3 years of the net benefit of further reducing gate closure should be included in the market rules to ensure the opportunity to further improve efficiencies is not unnecessarily postponed.

[1] NB: offers within 65 minutes of dispatch period start are subject to market surveillance review.
[2] To be accepted and processed by NEMDE a rebid should be made at least a minute prior to gate closure.

Request for comment – submissions providing feedback on the proposed retention of the STEM are encouraged.

Alinta's views:

- ***Alinta does not support retaining the STEM; it is a legacy feature of the WEM that participants are finding increasingly less useful as evidenced through declining trades.***
- ***In addition to the existing bilateral market, new products have emerged that provide liquid hedging opportunities ranging from bespoke arrangements to platform based standard products.***
- ***If the STEM is removed Alinta posits that demand will drive an accelerated development of fit-for-purpose products benefiting both buyers and sellers that will prove to be a superior hedging solution to retaining the STEM, which by its nature is rigid and expensive to change.***

The Short Term Energy Market (STEM) is an energy-only forward market operated by the market operator on the Scheduling Day to primarily facilitate trading around Bilateral Contract positions. The STEM is run for every Trading Interval of the Trading Day and determines a single clearing price for each Trading Interval as well as the quantities that participants have been cleared to sell to or purchase from the market operator.

Daily average STEM traded quantities, as measured by a 12 month moving average[3], have been in decline since January 2014. Average March 2016 quantities were 35% less than those of January 2014. The consistent decline in traded quantities over time indicates participants are finding alternatives to transacting in the STEM – its usefulness to the market is diminishing and its retention certainly warrants review.

Participants seeking hedge arrangements now have a wider choice of products than at market start. For instance, Synergy offers bespoke contracts as well as its mandated standard products while others offer bilaterals and even products that directly compete with Synergy's standard product offering. These products cover longer time periods (bilateral tenors are negotiable) and thus are more flexible than the simple day-ahead STEM. They also signal forward price trends, promote liquidity and the on-market components improve transparency within the market.

While it is acknowledged that transacting through the STEM is low cost (transactions cleared by the market operator at minimal credit risk and settled weekly) it nevertheless imposes material costs on generators through the daily submission process, undertaken to avoid net STEM shortfall penalties. Arguably, given the requirement for generators to make balancing submissions covering their maximum sent-out capacity, the STEM is redundant in respect of the obligation for generators to make their capacity available. Furthermore, the STEM no longer plays a role in physical generation obligations as since July 2012 dispatch is decided through the competitive balancing market process.

[3] ERA: Issues Paper: 2015 Wholesale Electricity Market Report to the Minister for Energy, page 28.

Maintaining STEM functionality within market trading systems is not without cost for both the market operator and participants. Also, if the proposal to adopt AEMO's Market Settlement and Transfer Solution (MSATS) proceeds to settle the WEM then changes to these systems would be needed to accommodate STEM transactions. These costs will be borne by participants.

In Alinta's view, retaining the STEM is not justified; it is a legacy feature of the WEM that participants are finding increasingly less useful as evidenced through declining trades. In addition to the existing bilateral market, new products have recently emerged that provide liquid hedging opportunities ranging from bespoke arrangements to platform based standard products.

Moreover, as the market continues to evolve and the general sophistication of participants increase, in the absence of the STEM, Alinta posits that demand will drive an accelerated development of fit-for-purpose products that benefit both buyer and seller. Dynamic demand driven product development will be a superior hedging solution to retaining the STEM which by its nature is rigid and expensive to change.

Request for comment – submissions providing feedback on the proposal to implement market reforms using NEMDE, a hub-and-spoke network model and single reference node pricing are encouraged.

Alinta's views:

- ***Alinta supports implementation of the proposed hub-and-spoke network model.***
- ***Implementing full nodal pricing for the SWIS is not supported as it would unnecessary complexity and cost for little benefit at this stage.***
- ***If the hub-and-spoke model is implemented then Alinta supports adopting NEMDE as the WEM's dispatch engine on account of it being fit for purpose, low cost and due to AEMO's operating experience likely to result in the least implementation risk.***

If the Application Bill to transfer electricity network regulatory functions from the Economic Regulatory Authority to the Australian Energy Regulator passes into law then a constrained network access model will apply to the South West Interconnected System (SWIS) from 1 July 2018. Alinta understands this to mean that the dispatch process will no longer be based on a simple ranking of bid prices but that network constraints will be factored in such that dispatch outcomes resolve to the least cost solution also taking into account the loading and maintenance circumstances of the network.

A key issue for the dispatch process and dispatch price outcomes model is whether to design for full nodal network pricing or a single price pertaining to a region noting that interconnection arrangements may result in a number of regions being incorporated within a single electricity market as is the case with the NEM. Full nodal pricing has certain attractions (signals dispatch prices at each network element such as a connection point or a zone substation transformer) but requires the network be comprehensively described in the dispatch engine. Unless settlement is effected on the same nodal prices it gives rise to basis risk and requirement for associated hedging instruments.

In contrast, a hub and spoke network model resolves to a single nodal price for a designated region. However, network constraints are incorporated in the model to indicate areas of congestion. This approach is far simpler (and therefore much less costly) to implement than full nodal pricing and removes basis risk and the associated need for sophisticated hedging products.

In Alinta's view, implementing full nodal pricing for the SWIS is not warranted at this juncture; it would add unnecessary complexity and cost and it is questionable, in the context of the lightly constrained SWIS, whether generator or load locational decisions would change merely because of small nodal price differentials. In the SWIS, other factors such as access to or availability of fuel for generators and similarly access to or availability of key inputs for loads such as raw materials or labour would likely dominate locational decisions.

If a single reference node hub and spoke network model is to underpin the dispatch process for the SWIS, as is the case in the NEM, albeit that it has five interconnected regional nodes broadly reflecting state boundaries, then it would be sensible to incorporate the NEM Dispatch Engine (NEMDE) in to the WEM.

Benefits of this approach are perceived to be:

- Simplicity: SWIS represented as a single region with a single reference node and corresponding dispatch price (no basis risk);
- Low cost: NEMDE is well proven and while some changes and development costs will be incurred they are likely to be much less than for another dispatch engine; and
- Operator experience: WEM market operator, AEMO, has extensive experience in running and maintaining NEMDE.

In sum, Alinta's view is that the SWIS can be adequately represented through a hub and spoke model and designated as a single region that resolves to a single nodal reference price. This solution paves the way for NEMDE to be adopted in the WEM. Alinta is reasonably confident AEMO's experience in developing and operating NEMDE for the NEM will reduce development cost and implementation risk as it is transitioned to the WEM.

Request for comment – submissions on whether the Wholesale Electricity Market should adopt the National Electricity Market's cost allocation method for system restart ancillary services are encouraged.

Alinta's views:

- ***There is no reason to change the current cost recovery regime in the WEM rules (i.e. based on consumption share); Alinta does not support cost recovery being expanded to include metered schedules for Scheduled and Non-Scheduled Generators.***

Electricity markets exist to generate and supply electricity for use by customers. When electricity is unavailable to meet consumer demand, end use activities are curtailed resulting in significant economic costs being incurred by customers.

For resource allocation and investment assessment purposes this economic cost is often expressed using terms such as Value of Customer Reliability (VCR), Value of Lost Load (VoLL) or Value of Unserved Energy. Typically, VCR is estimated through consumer surveys which seek to determine the value customers place on having supply available; that is it is indicative of their willingness to pay to avoid loss of supply.

AEMO's most recent survey[4] indicated residential customers have a VCR in the order of $26,000/MWh while for business customers it is higher at around $45,000/MWh but is much lower for transmission connected customers at about $6,000/MWh (mostly reflecting access to back-up supply). These figures clearly indicate customers place a very high value on a reliable supply.

System restart ancillary services encapsulate arrangements to restart the system following a major supply disruption and loss of supply to customers. This critical ancillary service exists to minimise the economic loss to customers (i.e. the community) of loss of supply.

Ultimately, customers are the prime beneficiaries of system restart ancillary services and surveys indicate they place a high value of a reliable supply. System restart ancillary services can be characterised as insurance against sustained outages and potentially very large economic loss. As customers are the prime beneficiaries of this insurance, it is reasonable that they fund the associated costs.

In Alinta's view there is no reason to change the current cost recovery regime in the WEM rules (i.e. based on consumption share). Accordingly, Alinta does not support cost recovery being expanded to include metered schedules for Scheduled and Non-Scheduled Generators.

[4] AEMO: Value of Customer Reliability, Final Report, September 2014.

Request for comment – submissions are encouraged on the likely effects on stakeholders of a change to the reference node for the South West Interconnected System from the Muja 330 kV busbar to a network location in the Perth metropolitan region (such as Southern Terminal).

Alinta's views:

- ***Alinta supports reassigning the reference node from Muja to a major load centre near Perth.***
- ***Reassignment should result in a lower level of constraint payments and potentially slightly higher market prices better indicating the full cost of supplying an increment in demand at a point in time.***
- ***To ensure a smooth transition and minimise errors trial loss factors reflecting the node reassignment should be published a minimum of 12 months before they apply***.

As noted above the system reference node for the SWIS is at the Muja 330 kV busbar. This has been the case since market start in 2006 and likely reflects the fact that the Collie/Muja area contains a significant proportion of the system's low marginal cost installed generation capacity. Also the area is well supported by transmission capacity; it is rarely constrained on account of congestion, major transmission maintenance activities excepted.

In contrast the main load centre for the SWIS is Perth and its immediate surrounds. Given electricity markets are designed to discover the marginal cost of energy, it seems sensible that the reference node, at which the market is cleared, is located closer to a major load centre in a constrained market model. The cost of supplying an incremental unit of demand, expressed through the market clearing price, is more likely to reflect the full or true marginal energy cost. This is because generators closer to the load centre will more likely be despatched than otherwise and more frequently set the market clearing price.

Reassigning the reference node will likely result in reduced incidences of constrained on payments, which are generally not transparent, in a locational sense, to the market. Also, as constraint payments tend to vary reflecting a number of factors such as weather (proxy for demand) as well as network maintenance plans, they are difficult hedge with the result that retail price margins are increased to cover the risk.

The arguments for reassigning the reference node from Muja to major load centre near Perth appear sound and are supported by Alinta. Other things equal, it should result in a lower level of constraint payments and potentially slightly higher market prices better indicating the full cost of supplying an increment in demand at a point in time.

Alinta notes, however, that reassigning the system reference node will impact published loss factors. Loss factors closer to the reference point will tend to be lower while those further away will tend to be higher. This will have implications for customer contracts which take loss factors into account when pricing contracts especially those that may straddle the change implementation date. To ensure a smooth transition and minimise errors, Alinta recommends that trial loss factors, reflecting the reassignment of the node, be published a minimum of 12 months before they apply.

Request for comment – submissions are encouraged from stakeholders on the circumstances, if any, under which a formal gate closure limit should apply to generator rebids.

Alinta's views:

- ***Alinta supports a gate closure of 30 minutes applies to energy and ancillary service bids.***
- ***The merits of further shortening the gate closure or removing it completely should be subject to periodic regulatory review.***

The following comments assume recommendations to replace the WEM's dispatch engine with NEMDE are accepted and that the market is settled on a 30 minute trading interval that comprises six five minute contiguous dispatch intervals with dispatch interval prices set by the dispatch solution immediately prior to dispatch interval start i.e. the NEM's dispatch engine and settlement regime are adopted in their entirety.

Given this scenario, it would be possible to dispense with a rebid gate closure, as is the case in the NEM. Electricity markets are dynamic: demand is in constant flux and physical plant underpinning the market can suffer outages. The absence of gate closure promotes efficient outcomes through the flexibility of suppliers to respond to changing market conditions; price outcomes should reflect underlying demand and supply conditions. However, there is a concern that rebids close to dispatch can disproportionately influence price outcomes through the inability of competitors to respond within the time available.

Other energy markets have gate closures of varying times after which rebids are restricted to certain circumstances, such as plant outages. However, deciding the appropriate gate closure and post gate closure rebid restrictions requires regulators to consider the trade-off between the efficiencies of an iterative price discovery process, the flexibility of the market to respond to evolving market conditions and changing expectations, and curtailing the ability of participants to rebid.

Alinta notes the issue of gate closure in relation to the NEM was considered by the ACCC when it was responsible for approving changes to the National Electricity Rules and by its replacement the Australian Energy Market Commission (AEMC).

In considering the issue the ACCC[5] noted that rebidding may give rise to inefficient outcomes and contemplated a 90 minute gate closure. Ultimately, however, it elected not to make any change to rebidding arrangements, other than require quarterly monitoring by the regulator of price outcomes being significantly different than forecast, as it took the view that to do so would introduce distortions to the market and impose costs on participants.

In its development of the bidding in good faith rule change[6], the AEMC carefully considered the arguments in respect of implementing a gate closure in NEM bidding processes noting that its implementation would involve a compromise between competing efficiencies. On the one hand, restricting late rebids would better enable efficient responses for other participants (e.g. from fast

[5] ACCC, Amendments to the National Electricity Code – Changes to bidding and rebidding rules, 4 December 2002.
[6] AEMC, National Electricity Amendment (Bidding in good faith) Rule, 10 December 2015.

start generators or demand side capacity) but on the other hand would restrict the flexibility for the market to reach efficient outcomes that reflect changing conditions.

In making the rule, the AEMC decided against imposing a gate closure regime on the basis that it had not been sufficiently demonstrated that the potential costs associated with restricting efficient rebids close to dispatch would be outweighed by the benefits of preventing generators submitting deliberately late rebids.

Given the above regulatory decisions, on balance, it's reasonable to conclude there are no substantive reasons for the WEM to continue with a gate closure following the implementation of NEMDE or another fit for purpose bidding engine. Retaining current market power strictures for dominate generators will ensure the market functions efficiently and appropriate market monitoring by the regulator will provide a basis to identify and investigate any anti-competitive behaviour.

However, taken collectively, the changes proposed in the Paper represent a large step change for the market. Participants will be faced with significant changes in market operations including constrained market dispatch, co-optimisation of energy and ancillary services with a common gate closure structure, and 5 minute dispatch intervals. Furthermore, the attendant detail underpinning the changes, such as energy and ancillary bid structure and market interface to be compatible with the selected new dispatch engine, are yet to be disclosed.

In this context, Alinta believes a staged approach should be adopted. In particular, Alinta would support an initial gate closure of 30 minutes. This would apply to energy and ancillary service bids and allow participants to gain experience with bidding in both markets. A three yearly review by the regulator could determine the merits of shortening the gate closure or removing it completely.

Request for comment – submissions from stakeholders are encouraged on how, and whether, the Non-STEM settlement timelines should be amended.

Alinta's views:

- ***Alinta supports a staged approach where the non-STEM billing period initially remained a month but a target was set to reduce its associated settlement period.***
- ***An initial target should be ambitious but also viable i.e. based on agreement between key parties that takes into account the improved meter data functionality to be delivered through the Market Settlement and Transfer Solution package and incorporates a credible timeframe.***
- ***Alinta suggests an initial target reduction in the settlement period of one to two weeks be considered. A reduction of two weeks would reduce prudential guarantees by around 20% amounting to some millions of dollars.***
- ***Additional reductions in prudential obligations will result from reducing the non-STEM billing period warranting a review be included in future market evolution plans.***

Settlement processes in the NEM are tight: preliminary invoices for a seven day trading week ending at midnight on Saturday (billing period) are issued after five business days and final invoices are issued after 18 business days with settlement due within two business days thereafter. During the 13 business day intervening period between the preliminary and final invoices participants and AEMO must use reasonable endeavours to resolve disputes. Routine revised statements for a billing period are issued at approximately 20 weeks and again at approximately 30 weeks after that billing period to cover outstanding minor adjustments.

By comparison with the WEM's 6 week non-STEM monthly billing period settlement processes, NEM settlement is efficient. It results in NEM participants funding lower levels of financial guarantees (and security deposits if used to stay within trading limits) which results in reduced market overheads that ultimately translate into lower costs for customers.

Alinta acknowledges the NEM processes rely on Meter Data Providers passing validated metering data, both interval and non-interval, the latter based on load profiles, to AEMO by the second business day after the billing period ends. In contrast, Western Power must provide monthly interval meter data by the first business day of <u>second</u> month following the end of a trading month i.e. Western Power is allowed a full month to assemble and validate meter data. Alinta posits there is scope to reduce this time period.

However, Alinta acknowledges that legacy meter data collection arrangements in the WEM will take some time to change and that a reduced meter data cycle period may increase inaccuracies. Nevertheless, Alinta would find it difficult to accept an outcome where no change is effected to the nearly 6 week non-STEM settlement period. The proposed adoption of AEMOs' sophisticated Market Settlement and Transfer Solution package system, that can convert non-interval meter readings to half hourly profiles based on the net system load profiles, should assist in reducing the non-STEM settlement period.

In regard to reducing the non-STEM billing period to less than a month, Alinta is aware of the implications for the reserve capacity credit allocation process and also acknowledges an attendant increase in administrative overheads for participants in managing settlement processes, and a resultant mismatch between market settlement payments and customer receipts.

Based on these considerations, Alinta would support a staged approach where the non-STEM billing period initially remained a month but a target was set to reduce its associated settlement period. An initial target should be ambitious but also viable i.e. based on agreement between key parties that takes into account the improved meter data functionality to be delivered through the Market Settlement and Transfer Solution package and incorporates a credible timeframe.

In regard to the initial target, Alinta suggests a target reduction in the settlement period of one to two weeks be considered[7]. A reduction of two weeks would reduce prudential guarantees by around 20% amounting to some millions of dollars.

Noting that further reductions in participant prudential obligations would result from reducing the non-STEM billing period to less than a month Alinta suggests it be included as project in the periodically updated market evolution plan.

[7] A reduction of around three weeks or more would require revision of the 15 day outage data finalisation limit.

Request for comment – submissions from stakeholders are encouraged on how loss residues collected by the Australian Energy Market Operator, due to the use of static marginal transmission loss factors and settlement by difference, should be allocated back to consumers.

Alinta's views:

- ***Of the options presented, Alinta favours the third or hybrid option as an appropriate and innovative solution to dealing with loss residues. This is because both loss residues and constrained-on payments are settlement risks that are outside of retailers' control and cannot be cost-effectively hedged.***

- ***Alinta supports implementing the settlement-by-difference approach which can be developed at relatively low cost as part of adopting AEMO's existing settlement systems. Even if FRC is delayed till after July 2018, there is no substantive rationale to reconfigure the adopted settlement processes to defer settlement-by-difference until such time as FRC is implemented. To do so would incur two sets of reconfiguration costs; one to turn it off and one to turn it back on for no substantive benefit.***

Alinta appreciates for the purposes of settling electricity markets it is standard practice for connection point exit or entry energy amounts to be determined by applying static loss factors, typically determined from historical load flow data. Static transmission loss factors represent average marginal losses expected over a period of time, usually a year. As a result they are unlikely to accurately estimate losses at any point in time especially as actual losses are measured as an exponential function (i.e. square) of load.

The proposal to adopt the AEMO's market settlement systems (i.e. Market Management System and Market Settlement and Transfer Solutions) and treat the WEM as a single region will result in the identification and determination of so called loss residues. Loss residues reflect the difference between energy generated and energy consumed as determined at the reference node through applying the annually determined static marginal transmission loss factors, valued at the market clearing price. Usually, the loss residues are positive, i.e. settlement payments from customers exceed settlement payments to generators, but they can also be negative[8].

Currently in the WEM, these loss residues are embodied in the notional wholesale meter settlement process (i.e. not separately identified) and fall to Synergy. This has been the case since market start and largely reflects the settlement processes and system capabilities implemented at that time. As noted above, adopting AEMO's settlement systems will result in loss residues identification as part of standard settlement processes[9]. At issue is whether the loss residues, which simply arise through the application of marginal loss factors in the settlement process, should continue to be allocated to Synergy.

[8] It is noted the Paper included an analysis suggesting a loss residue of negative $9M for WEM over the 12 months ending February 2015. While in part this will reflect discrepancies between static loss factors and actual losses as at transmission nodes it may also reflect energy consumed but not allocated to a retailer. If negative residues of this magnitude continued post implementation then Alinta suggests it should result in an investigation or recalibration of the loss factor calculation process.

[9] In effect, the distortion introduced through the application of marginal transmission loss factors will be removed and reallocated as otherwise determined e.g. to the TNSP.

In Alinta's view, there is no reason in equity why they should continue to be allocated to Synergy. They result from the settlement process and should ultimately be allocated to customers.

Under the National Electricity Rules, residue losses are allocated to Transmission Network Service Providers (TNSP) and if positive/negative must be applied to reduce/increase network charges.

The Paper suggests three allocation options to deal with loss residues identified in the WEM as follows:

(i) to retailers based on market share;
(ii) to the TNSP as in the NEM; or
(iii) as a hybrid approach where loss residues, if positive, are offset against constrained-on payments with the residual to the TNSP or if negative, directly to the TNSP.

The second and third options both shield retailers from any volatility of the residues (difficult/expensive to hedge) while the third option has the added benefit of reducing and potentially eliminating constrained-on payments funded by retailers.

Alinta favours the third or hybrid option over the others as an appropriate and innovative solution to dealing with the identified loss residues. This is because both loss residues and constrained-on payments are settlement risks that are outside of retailers' control and cannot be cost-effectively hedged.

The Paper notes that introduction of Full Retail Contestability (FRC) will require treatment of loss residues and also a process to settle retailer loads that takes account of non-interval or accumulation metered loads. The Paper proposes that the NEM's settlement-by-difference methodology be adopted in the WEM to settle retailer loads.

The settlement-by-difference methodology provides that a "local retailer" is assigned a geographical area. Settlement for each area proceeds on the basis that all energy in an area is allocated to the local retailer except that consumed by customers supplied by other retailers (referred to as second tier customers and second tier retailers respectively).

At the commencement of FRC it is proposed that Synergy be deemed the local retailer for the SWIS. Half-hourly settlement of the wholesale market will require estimation and profiling algorithms are developed and applied to non-interval and accumulation metered loads supplied by 2nd tier retailers (i.e. all retailers other than Synergy).

Alinta notes a number of distortions are inherent in the settlement-by-difference approach, the main ones arising from data estimation, net system load profiling and the use of static average distribution loss factors. However, in the NEM these distortions have only started to become more substantive in recent years in part reflecting accelerated customer churn[10].

An alternative approach is the "global settlements" model. Under this model, the wholesale market is settled against all metered connection of supply points aggregated for each retailer, including the local retailer. The net residual is not allocated to the local retailer, implicit under settlement-by-

[10] For example, analysis presented to the NEM Wholesale Consultative Forum determined distortions faced by local retailers from distribution network losses were around $9M per year across FY 12/13 and FY13/14, an increase of some 50% or more over levels experienced during the preceding six years – refer NEMW Consultative Forum: Update on Energy Settlement in the NEM; Agenda item 3.3; 26 November 2014.

difference approach, but smeared across all retailers usually in proportion to share of demand and metering type.

Implementation of the global settlements model would be expensive and not justified at FRC commencement in the WEM where the local retailer is the incumbent supplier for newly contestable franchise customers. In fact stakeholder response to AEMO's recent analysis of distortions associated with the settlements-by-difference approach was that it remained fit-for-purpose and that scope remained to improve the accuracy of current settlement processes.

In light of this background, Alinta supports implementing the settlement-by-difference approach which can be developed at relatively low cost as part of adopting AEMO's existing settlement systems. Even if FRC is delayed till after July 2018, there is no substantive rationale to reconfigure the adopted settlement processes to defer settlement-by-difference until such time as FRC is implemented. To do so would incur two sets of reconfiguration costs; one to turn it off and one to turn it back on for no substantive benefit.

Request for comment – the views of stakeholders are encouraged on:

- what matters should be addressed in the proposed guidelines for interpretation of short run marginal cost bidding obligations under the Wholesale Electricity Market Rules;
- the types of costs that should be permitted for inclusion in prices offered into the STEM and the new real-time energy market;
- what matters specific to generators with larger portfolios need to be considered; and
- how and whether the input assumptions should vary in respect of offers made into the two energy markets.

Alinta's views:

- ***A review of SRMC bidding obligations should be undertaken and until such a review is complete, Alinta does not support the publication of guidelines on the current obligations.***

The Paper outlines significant changes to the WEM which coupled with the changes to the Reserve Capacity Mechanism present a significant shift in WEM market design. Accordingly, Alinta recommends it would be timely to also reconsider the current Short Run Marginal Cost (SRMC) bidding obligations, and whether those obligations remain appropriate.

A review of the SRMC bidding obligations is particularly important given:

- the introduction of facility bidding by all participants leading to greater price transparency and improved competition between generators;
- reform of the Reserve Capacity Mechanism, including the introduction of an auction, which will likely shift revenue earned by generators away from capacity payments to the energy market to underpin expected returns; and
- the introduction of full retail contestability.

In reviewing the SRMC obligations it is important to consider whether they remain necessary and if so, which generators the obligations should apply to, and what the single bidding cap should be.

Until such a review is complete, Alinta does not support the publication of guidelines on the current obligations.

Request for comment – the views of stakeholders are encouraged on the feasibility, costs and benefits of early implementation of any of the proposed reforms.

Alinta's views:

- ***Staged implementation of the reform package is preferable where this is achievable.***

Implementing the suite of proposed changes to wholesale market operations all at the same time (to coincide commencement of constrained access in July 2018) presents a substantial risk to effective market operations. Staged implementation is preferable where this is achievable. In particular, proposed changes of a more administrative nature, such as adopting NEM registration framework, could be brought forward and dealt with.

Process changes especially those improving market process efficiencies such as removing the Resource Plan and even extending the STEM window, assuming the STEM remains, should be implemented allowing participants more time, prior to July 2018, to streamline their own processes and free up time to participate in the co-optimisation market trials and gain experience with shorter dispatch intervals and gate closures.

Synergy's adoption of facility bidding will undoubtedly result in a significant change in market dynamics. For the first time participants will observe and be exposed to individual bid pricing for Synergy's 30 plus facilities. It would definitely be to the market's benefit that the proposed guidelines relating to pricing stricture limits where market power applies (following completion of the review recommended by Alinta) be published prior to July 2018 to clearly establish the limits on the pricing behaviour of dominant generators.

If the case for change in regard to reassigning responsibility for determining transmission loss factors from Western Power to AEMO and, more importantly, reassigning the system node to Southern Terminal is justified, then these changes should be effected as soon as reasonably practicable so the market can understand the relative impacts on energy market operations and work the implications through to retail contracts. As previously stated Alinta recommends trial loss factors, reflecting reassignment of the node be published ahead of implementation enabling retailers to communicate and prepare customers for any resultant changes impacting them.

Request for comment – submissions are encouraged that detail the costs that must be incurred by market participants as a result of the proposed changes.

As it is unclear exactly what market operation changes will be implemented within what timeframe, and until a participant determines its likely levels of active participation under the new framework (for example whether it is feasible and economic to participate the expanded ancillary services market), it is difficult to precisely estimate transition costs.

However, initial indications are that changes to Alinta's generator systems, such as reconfiguration of dispatch response and control systems to accommodate more frequent dispatch instructions, will be in the order of $50k to $100k.

Changes to WEM interface systems to accommodate, for example, shorter gate closure, removal of the Resource Plan (and possibly the STEM as well) and integration of energy and ancillary service bidding within a half an hour timeframe based on a 5 minute dispatch cycle will require an evaluation be undertaken of Alinta's trading systems. An evaluation will examine the cost/benefit of leveraging existing systems or upgrading to new fit-for-purpose systems.

At this stage, given the unknowns surrounding the final energy/ancillary service market design and AEMO's attendant systems interface package, it is not feasible to undertake a definitive assessment of Alinta's trading system costs. However, Alinta expects to be in a better position to advise on the scope of its system change and other associated costs, such as staff training and developing rules compliant bidding procedures, as the proposed implementation is progressed over the next 6 to 12 months.

OTHER COMMENTS

Determination of the financially responsible market participant (refer Paper: page 35)

Alinta notes the Paper's proposal to align WEM registration arrangements, as far as reasonably possible, with those of the NEM. This will introduce into WEM settlement processes the concept of the financially responsible market participant for wholesale market transactions in relation to connection points.

In particular, it is proposed that:

(i) capacity credits, in regard to a generating unit, will only be assigned to the registered Market Generator who is the financially responsible market participant for the generating unit's connection point; and

(ii) the financially responsible market participant will not be required to be the holder of the connection agreement with the network service provider for the relevant connection point.

Under current WEM certification requirements an applicant for certified reserve capacity must present evidence of an Arrangement for Access (i.e. an access contract as defined in the Access Code) in regard to the relevant facility. Alinta understands the Elecricity Network Access Code will lapse on 30 June 2018, when it is planned that chapter 5 of the National Electricity Rules be included in the WEM Rules (assuming the relevant application legislation is passed in the WA Parliament). It is unclear, at this stage, how capacity certification requirements will change in the absence of the Access for Arrangement construct embodied in the Access Code.

Alinta seeks assurance, in the context of both proposed changes to WEM registration and capacity certification processes that will no longer reference an Arrangement for Access, that capacity credits will continue to be assigned, as they are currently, to the participant with the right to submit the application for certification of reserve capacity.

Removal of constrained-off compensation (refer Paper: page 57)

The Paper states that as a matter of principle a generator that is otherwise constained off as a result of the adoption of the security constrained dispatch process should not be entitled to compensation. While Alinta understands the NEM has operated on this basis since it commenced, in the absence of explanatory information as to how WEM participants will be impacted by the new dispatch process, Alinta cannot support this principle at this stage.

As far as Alinta is aware no credible information has been released to particpants to explain how current access rights, including the right to transfer power into the network to the Declared Sent-out Capacity limit listed in the Arrangement for Access with the network service provider, will be transitioned and the principles upon which compensation will be payable for relinquishing those firm access rights under the proposed constained access/market design.

Participants committed to generation investments and supply agreements on the basis of the unconstrained access model. The proposed changes to firm access rights, that could for example result in a generator not being dispatched despite its offer price being less than the clearing dispatch price, may adversely affect such investment decisions made in good faith on the basis of the existing legislation.

Alinta will review its position on the proposed removal of constrained-off payments after credible information about the transition arrangements becomes available and in particular how it is proposed to deal with the loss of existing firm access rights established under legitimate Arrangement for Access contracts.