8th March 2018

Energy Security Board

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Finncorn

National Energy Guarantee – Submission to the Energy Security Board in response to the Draft Design Consultation Paper

Please find attached a public submission for the consideration of the ESB and the Commonwealth Government.

Yours sincerely,

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National Energy Guarantee
A scrambled NEG

Finncorn Consulting's response to the Draft Design Consultation Paper

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Introduction

Why are we submitting?

Finncorn is commenting on the NEG Draft Design Consultation Paper ("DDCP") based on our current roles advising renewable energy developers on commercial structuring (including the utilisation of the contract market in its range of forms), advising an international trader and an international generator / retailer on potential NEM market-entries, as well as our continuing involvement with Energy Consumers Australia in providing advice on the competitive generation and retailing segments of the electricity market, and assisting ECA in their effective advocacy for the long-term interests of energy consumers in that market.[1]

Finncorn's past experience includes the management of energy trading operations in Asia for an investment bank, as well as investment experience as both equity research analysts and as an investor in the electricity sector. Finncorn principals have worked directly within large energy corporates who are the key participants to be impacted by the NEG.

We therefore offer a broad perspective to the ESB in considering both fundamental aspects and detailed design, and their impacts on the long-term interests of consumers and the competitive health of the NEM.

A scrambled NEG

As a single overarching theme, we note the NEG is a novel policy which has been proposed very suddenly, with extremely short timeframes indicated for consultation, design and implementation. **The ESB is seemingly taking the view that it is required to scramble an emergency response to an imminent crisis**.

However, we observe **the NEM is in many areas is adequately functional** or (at worst) likely to improve its performance due to **other effective measures being taken** by the ESB, the regulatory bodies, and the participants. This is evidenced by progress since the ESB's "Health of the NEM" report was published:

- Good generation and transmission reliability over the past summer, validating the ESB and AEMO's preparation and response.
- The emergence of numerous credible dispatchable and firming capacity investments across a range of technologies including coal (Bayswater upgrade), gas (Barker Inlet and others), and a variety of pumped hydro and battery storage projects, both independent and associated with intermittent renewable projects.
- The moderation in forward market prices towards efficient new-entrant long-run marginal costs, in the face of oncoming (albeit policy-delayed) supply under the LRET.

The haste and premise of 'crisis conditions' brings very high risks of poor outcomes, compared with a more normal process where broad support for the policy design would be developed based on open analysis and comparison with alternatives. Instead, stakeholders are presented with a policy concept which lacks that foundation, asked to simply accept the NEG is the best feasible policy to pursue, and join the effort.

In preparing this submission and offering our constructive responses to the ESB's questions, in essence this is exactly what we are doing – but not without first challenging the premise in this introduction!

We encourage the ESB to take a step back, review the current state of the NEM, receive the stakeholder feedback, and contemplate whether some key aspects of the NEG design are overly-complex, unnecessary and inadvisable. We understand the ESB was constituted to be independent. In our view, it should be prepared to push for the NEG to evolve into a better policy than it appears to be now, despite the complex political environment (and the position the ESB occupies as the originator of the idea).

We support the objectives of the ESB in coordinating emissions-reduction, reliability and affordability in a durable framework under the NEG. We agree that a lack of clarity has impacted all three aspects of the "trilemma" negatively – **the need for resolution is clear, but not at any cost.**

[1] For example, our submission to the current ACCC enquiry, available at http://energyconsumersaustralia.com.au/publication/state-play-quantifying-competitive-outcomes-retailing-nem/

Eight high-level areas of concern

In reviewing the DDCP, we have nothing to say regarding the level of ambition of the emissions-reduction target set by the Commonwealth, and we understand the NEG is a mechanism to deliver that target. We focus on the mechanism.

In homage to the DDCP's 'eight high-level steps' towards reliability, we offer our **eight high-level areas of concern for the health of the NEM and the long-term interests of consumers** in achieving a low-cost and effectively competitive electricity market:

1. Competition impacts are improperly deferred from consideration

In the work we have done with ECA on the **long-term interests of consumers** and the competitive health of the NEM, we have formed the clear view that two main factors are necessary conditions for the market to operate in the consumers' long-term interests:

1. **Total industry cost levels that are efficient**: as low as possible in aggregate, since they must all be recovered through either consumer prices, or unsustainable loss-making by participants; and
2. **A sufficiently-competitive market structure** to allow consumer prices to in fact (rather than in theory) be set based on costs plus adequate profitability to provide a return on the substantial capital employed – not for the <u>least</u>-efficient tier of competitors, but for the <u>most</u>-efficient.

We have argued previously that neither condition is currently satisfied in the NEM.

While this may be an open question pending the ACCC's final report, given the importance of effective competition to the delivery of efficient cost outcomes for consumers, we **do not think it is advisable for a policy change of this magnitude to be pushed forward to a detailed design phase WITHOUT the impact on competition being a key input to design at the earliest stages.**

In our view, there are a number of ways in **which the NEG could drive worse outcomes for the long-term interests of consumers**, by undermining both conditions above:

- **adding material costs** (both deadweight compliance costs, and the more subtle costs of less-efficient price signals from less-transparent contract markets with higher frictional costs); and
- **creating or reinforcing anti-competitive structural outcomes** by demanding a form of contracting which is impractical for smaller participants, and so reinforcing the already-formidable advantage of the very few largest participants.[2]

2. The contracting problem for reliability has been asserted, but not defined

In targeting greater levels of contracting under the reliability aspects of the NEG, the ESB has implied that current levels of contracting are inadequate for reliability, and that greater levels of contracting will lead to greater reliability.

This is presented as axiomatic, but we do not accept that it is. There is no evidence presented to support this assertion, no suggestion as to the "correct" level of contracting the ESB appears to target, and no explanation as to what sub-segments of the market are failing to contract adequately in the ESB's view.

In reading the DDCP we expected to receive the ESB's analysis of:

- Which classes of dispatchable generator are considered to be insufficiently contracted?
- Which classes of retailer are considered to be insufficiently contracted?
- Despite their intermittency and consequent difficulty in firmly contracting, what portfolio-level reliability does the current variable renewable energy fleet contribute, now and in future?
- How far out from spot delivery is the under-contracting considered a problem – years, months, days?

[2] We defined these in Table 1, page 25 of our "state of Play" report, available at http://energyconsumersaustralia.com.au/publication/state-play-quantifying-competitive-outcomes-retailing-nem/

- What are the trends – getting better or worse?
- Why are participants behaving as they do in relation to contracting (or not) given the clear economic risks and incentives they already face if they fail to manage this risk?
- What is a reasonable upper limit on contracting to expect under any conditions, given the risk of generator outages and uncertainty about retail load in the future faced by participants?

If the data to answer the questions above does not yet exist, we suggest it be gathered and considered before decisions are taken – the problem should be properly defined and understood before solutions are deployed. Without analysis of this type to support the NEG's premises on reliability, it is very difficult to judge whether the NEG design is likely to achieve that objective at all, or at reasonable cost.

Evidence should support not only the ESB's views that its policy is likely to be effective, but in fact more effective and less costly than alternatives.

A particularly relevant counterfactual position regarding reliability would be doing nothing other than the existing non-NEG steps of strengthening AEMO's operational and forecasting capabilities and providing it with the other key tools it seeks including enhanced demand response markets, a day-ahead market, and an efficient strategic reserve process as a genuine and effective backstop for reliability if required.

3. Dispatchability already has a clear price signal, and renewables do pay for firming

The ESB notes that intermittent renewables cannot easily supply hedge contracts, and so provide lesser reliability than equivalent dispatchable capacity – no doubt contributing to the perception of inadequate contracting. The NEG is claimed to address this by placing a value on dispatchability.

In fact, this value is already clearly reflected in the **lower price received by non-firm renewables when they do contract, compared with dispatchable plant**:

- **If selling generation-following PPAs to a retailer**, an intermittent renewable asset will receive a price very materially less than the price for dispatchable supply, to compensate for the retailer accepting and managing the intermittency risk (i.e. using its portfolio to firm the supply to the point it is acceptably "dispatchable" to the retailer's load).
- **If using ASX-style hedge contracts as a more merchant-style alternative**, the renewable asset may need to buy cap protection in concert with selling futures, to manage the risk of being unavailable when the wholesale pool prices setting the hedge settlement are high – reducing the net revenue received compared with dispatchable plant (who may safely sell the futures alone).

In both cases, the discount in value received by the non-firm renewable asset contributes to reliability, by funding the ability of a retailer to arrange firming, or by directly creating demand from firming capacity in creating demand for the cap products they sell.

Given this price signal, **renewables investors are increasingly considering their own investment in firming as part of the project, as an alternative to the discount they otherwise suffer** – whether by building or contracting with firming assets or demand response.

As a result, we wonder whether **the NEG is trying to solve a problem which is busily solving itself through existing market-based means, and likely at an efficient cost compared with a regulatory interventionist approach.**

4. The threat to contract liquidity is very large

We are concerned with the largely-unsupported assertion that the NEG will 'increase contracting in deeper and more liquid contract markets' and lead to 'reduced prices'. Unless a great deal of care is taken, we suspect the opposite outcome is more likely.

Liquidity thrives on (1) standardised contracts (such as the existing ASX traded instruments, and over-the-counter variants closely related to them), **and (2) a broad range of participants both willing and able to trade** (particularly, by possessing the financial resources to support the obligations of the contracts).

By contrast, while power purchase **agreements ("PPAs") have an important role, they are far more bespoke to each counterparty, rely on strong credit support for long-term obligations, and as a result are illiquid.**

Liquidity allows participants of all types to manage their risks at relatively low cost, in the face of changing business and market conditions. The forward curve it reveals allows new entrants to establish a transparent benchmark for their revenue expectations whether they use hedges, PPAs, or remain merchant-exposed, and thus helps them to make more efficient decisions.

If the NEG drives participants to more bilateral PPA-style contracting at the expense of standard hedge-style contracts, these benefits will be lost. The outcome will be a less-transparent market with less-efficient price signals for investment, less-effective risk management, and fewer participants with the appetite or financial capability to contract.

This would be a recipe for higher, not lower costs for the industry and therefore consumers.

5. The administrative costs are high for the more credible design choices

The DDCP makes clear the ESB faces crucial design choices between:

- Apparently-simpler approaches (such as 'deemed' levels of emissions intensity for various classes of contracts, or 'choice' regarding which contracts are submitted for assessment of compliance) which carry substantial risk of gaming, inaccuracy and unintended consequences; and
- More thorough approaches which offer participants and other stakeholders the assurance of robustness, fairness and accuracy (for example, by fully mapping emissions intensity and "dispatchability" through from each generating unit to each retailer on a 5-minute basis).

Stakeholders should demand the latter, but the price of that is, in our opinion, likely to be very high compliance costs for every participant as well as the regulatory bodies.

Those high costs are driven by the fundamental decision to use the much more abstract medium of retailer contracts as the currency of the mechanism, rather than separate fungible certificates representing emissions intensity and dispatchability, created at the point of generation.

Those costs are ultimately borne by consumers, and so should be clearly associated with incremental benefits over a simpler, cheaper design. We see no suggestion of what those benefits may be.

6. The reliability trigger risks much ado about nothing, but higher prices

As we considered the eight-step process in the DDCP, we imagine how the process might unfold:

- A forecast reliability gap has persisted or emerged, the requirement is triggered, and all retailers and (we think) generator participants need to take action: establishing their contract positions in the registry and keeping that up-to-date. This will likely involve material compliance costs, to be recovered through higher prices at some point given they are faced by all competitors.
- Retailers will be motivated (for pure compliance reasons) to quickly buy up the limited supply of eligible firm hedge contracts, beyond those they currently hold under their risk-management policies, knowing all other retailers will do the same. This drives up forward futures and cap prices and thus the residential and C&I contract prices which are based on the forward curve.
- After what may be a very short period, one or more participants commits to build or contract with new firm capacity (or demand response) ahead of the reliability gap period commencing, thereby closing the gap and (we expect) removing the compliance obligation, as the problem is solved.
- Participants down tools and get back business as usual, possibly selling down their excess hedge positions back down to normal levels, and providing some price relief to consumers.

To us, unless it can be clearly established that participants **would not have built the new capacity but for the process above**, this seems like a largely pointless activity which will potentially contribute to greater consumer contract price volatility, periods of higher prices, and adding deadweight compliance costs.

7. Reliability mechanism risks solving yesterday's problems (again)

By all appearances NEM participants are working successfully through a 2022 reliability gap process right now, without either the threat or assistance of the NEG. **The price signals are now present, and appear to be effectively encouraging new capacity** – participants know the 2022 supply-demand balance will be tight – and so:

- AGL, having given more-than-adequate notice, has proposed a range of actions it intends to take as necessary to replace Liddell capacity with equivalently firm supply;
- Energy Australia yesterday firmly noted that (contrary to the highly-directive approach AGL have experienced) incumbent generators were never intended to be responsible for replacing their own capacity, and that a market-based process exists where it (and others) have the opportunity to build the **most efficient** replacement capacity;
- A bow-wave of committed new renewables will add substantial new energy into the market, much of it encouraged by the recent high forward prices for medium-term electricity.

In general, **many of the recent obstacles to capacity investment have been or are being removed**, including greater assurance of domestic gas availability (and improved contract price transparency), maturing of storage and demand response alternatives, reducing capital costs for renewables, and greater clarity on integration of climate and energy policy in future.

Hazelwood's closure was announced in November 2016, only 16 months ago. The high-price signal is relatively recent – there is an inevitable lag in investment response (and that is why we agree the new requirement of three-year notice of withdrawal of capacity is appropriate to ensure the market can operate as it should to replace capacity in a timely manner).

Taken together, we doubt the extraordinary circumstances following the relatively sudden withdrawal of Northern and Hazelwood (at a time of near-paralysis on replacement investments) are likely to re-occur, and so we wonder whether the interventionist aspects of the reliability mechanism of the NEG is solving problems of the past instead of considering the likely circumstances of the future.

8. Consideration should be given to lower-cost alternatives with equivalent benefits

In the case of **emissions**, the NEG shrouds an emissions-intensity scheme (supported in principle by many stakeholders) in a cloak of retailer contracts, in a manner which may largely obscure the price signal on emissions, while **increasing complexity and compliance costs, and threatening liquidity, economic efficiency of investment decisions, and competitive outcomes**.

The benefits of this unusual feature over a simpler certificated and traded scheme with identical environmental outcomes are entirely unclear to us.

In the case of **reliability**, a combination of improved AEMO operational performance with the numerous other tools either already at AEMO's disposal or proposed to be developed seem likely to drive much of the necessary assurance that 'the lights will stay on'.

The highly-complex aspect of making legally-defendable 'reliability gap' forecasts, allocating responsibility among retailers, establishing retailer compliance and determining fair and robust penalties appear to be almost an afterthought by comparison to those sensible steps.

In our view the ESB should advocate for why this is a better solution than the (relatively) simple alternative of putting the retailer obligation mechanism back in the toolbox, and just equipping AEMO to play its role more effectively (as set out in various Finkel recommendations and the DDCP itself).

In our view (and as well-described in section 5.3 of the DDCP) **the mere threat of well-designed emergency AEMO intervention would be highly-effective**. Note that it would give BOTH generators (who would not wish to compete with AEMO capacity for dispatch) AND retailers (who would not wish to be allocated AEMO's crisis-response cost recovery) a stronger incentive, in tandem with existing price signals, to bring on dispatchable capacity as needed to close any gap AEMO may identify.

Should AEMO ever again need to make good on the threat, reliability will be maintained but there will be inefficient cost consequences. However, it isn't clear to us that this contingent outcome would be any worse than the clear and certain disadvantages we see in the retailer obligation mechanism which MIGHT forestall that need.

In both emissions and reliability design, the ESB (as proposer of this novel mechanism) should establish arguments why there are additional benefits to outweigh the costs in excess of the simpler solutions. In our view, it has not done so at this point.

A simpler reliability mechanism

While we have made comments in the body of this submission on the specific questions asked about the eight-step reliability process, we also wish to propose a simpler version for the ESB's consideration.

In our view, there are extremely complicated commercial and administrative issues associated with allocating and assessing compliance with a theoretical reliability gap which will (if the mechanism works) never translate to a physical lack of reliability (since it will be met by either participants or AEMO). This is highlighted by the discussion about ex-ante versus ex-post approaches, and the reliance on forecasts and "business as usual" counterfactuals of contracting positions.

Producer of last resort as the main focus

Instead, we believe there should be more focus on the AEMO "producer of last resort" function as the primary source of incentives and penalties.

Under the reliability mechanism as proposed, there comes a point (in our model, relatively close to the gap similarly to the long-notice RERT) where AEMO takes this urgent action because it deems participants have not addressed the gap in time. At that point, real costs are incurred by AEMO and (as noted by the ESB) the incentive for participants to arrange their own short-term dispatchable capacity in competition with AEMO's actions is greatly reduced.

Consequences based on actual contracts when invoked, actual load during gap

The allocation of (*ex-post*) costs associated with that function should be based on a factual examination of which retailers were actually under-contracted at the time a reliability gap became acute enough for AEMO to exercise its procurer of last resort function (perhaps a year to six months prior to the gap), compared with the actual peak loads each retailer served during the gap period. This only requires contract disclosure at a single point in time by all retailers – still a considerable task, but relatively minor compared with alternatives discussed.

Retailers would be well-aware of the looming action by AEMO and would have the opportunity to assemble what they believe to be an adequate hedge and contract position for their load, perhaps sooner than they would otherwise have done, and perhaps at somewhat higher levels, in anticipation of disclosure. In doing so in the lead-up, the demand this creates transmits a price signal which may in fact cause capacity to be built, and forestall the need for AEMO to procure some or all last-resort capacity.

Priced to retailers as a retrospective cap contract (at a high cost)

One way to allocate costs may be to price the full procurer of last resort capacity costs like a cap contract, in other words, a cost per MW over the period of the gap where AEMO has the capacity available. AEMO therefore acts as a developer of temporary peaking capacity (which may or may not need to be dispatched) with the power to impose caps over that capacity on retailers to cover the costs.

Retailers who did not contract sufficiently to cover their peak load would be retrospectively allocated the cost of those cap contracts, in proportion to their share of the overall under-contracting.

The costs would be relatively high compared with typical market-based cap contracts, because of the urgent short-term nature of the capacity arrangements.

Material incentive, with limited risk of pass-through to consumers in price

It would be a significant disincentive to under-contracted retailers if they were to be allocated these costs, because their better-contracted competitors would therefore enjoy a cost advantage.

Because the costs are levied in arrears and are directed at particular retailers (not socialized over the entire retailer industry), there is more likelihood the costs will be absorbed as lower profitability by that subset of retailers, rather than passed through to consumers in prices.

We note that an incentive applies as much to generators (who would prefer not to be competing with AEMO assets for dispatch at time where otherwise, they might be enjoying higher prices) as it does to retailers. This is appropriate, as ultimately it is generators who build new capacity – retailers are only an indirect means to encourage that to happen.

Emphasising the strongest, least costly aspects of the NEG reliability mechanism

The advantage of this approach is that the simpler elements of the reliability mechanism (as well as its fundamental objective of guaranteeing reliability) are maintained:

- Better industry-level forecasting improves foresight and decision-making by both AEMO and participants;
- The concept of an adequate warning period for participants to take action voluntarily is preserved, (and in this case, it is as long as possible);
- The incentive of an AEMO-led book-build process may have a useful role to play in stimulating capacity investment within the warning period;
- A procurer of last resort function to achieve the fundamental objective of keeping the lights on is effective;
- The ex-post assessment of "what actually happened" regarding contracts and peak load avoids the difficulties in relying on *ex-ante* approaches; and
- A valid basis for allocating costs where they were driven (in a manner least-likely to be simply passed on to consumers in price) is facilitated.

By contrast, the most difficult, commercially-intrusive and administratively costly elements are largely avoided.

We recommend the ESB seriously consider this slimmed-down version of the reliability mechanism.

Response to the Draft Design Consultation Paper questions

In the remainder of this submission, we follow the sections of the DDCP, and respond to relevant questions.

DDCP Section 3 – ESB design elements for Emissions

Q: How a retailer's emissions should be determined?

Even the most direct-seeming contracts in electricity are essentially derivatives – usually settled in cash against the wholesale spot price for the region. A key issue will be distinguishing between a (derivative) contract obligation between legal entities, and actual generation. There is nothing to stop a generator 'contracting' its physical capacity multiple times in this way, provided it can cover the settlement of the value.

While the concept of applying a residual emission intensity to any load which cannot be associated with a contract is pragmatic, it gives rise to a particular risk of gaming under a model of limited or voluntary disclosure of contracts.[3] The incentive would be for any contracts with generation of intensity greater than the likely residual to be kept hidden.[4] This would be an unacceptable outcome in our view as it would undermine the fairness of the scheme to all participants, and encourage a race to the bottom on disclosure.

For these two reasons, we think the emissions requirement (in the absence of the clarity of a generation-driven certification of output which would eliminate the concerns) will need to be a "complete solution" which requires disclosure of all contracts, and then maps every generation unit's dispatch against a contract and thus against every retailer's load for each five minute period (as the ESB identifies as a possible approach).

While that sounds complex (and it probably is), it is at least robust in preventing deliberate gaming, or innocent errors which would equally undermine the fairness of the mechanism. As such it would be the lesser of two evils.

Q: Methods for determining the emissions to assign to contracts where the generation source is specified?

We note that even the apparently-simple case of renewables assets under PPA to retailers can be more complicated than the DDCP anticipates.

- What is the emissions intensity of a PPA where the generator partially firms its supply to the retailer using a battery, which may be charged from the grid?
- What is the emissions intensity of a PPA with an element of guaranteed notional volume for delivery, where the generator may make good on the contract via cash settlement if production is less than committed?

Given the PPA market is evolving and innovating quickly (including the examples above which modify risk and lower overall costs for the contracting parties), we suggest the ESB will face a substantial challenge in attempting to anticipate this and robustly associate emissions intensity with contracts, rather than with generation itself. The emissions mechanism must not stifle this innovation.

Again, we suspect the only viable solution will be to view the contracts less as physical supply agreements (which they are not), more as indicative of linkages between particular generating units and particular retailers, and then fully map 5-minute dispatch to retailers in a manner that ensures the overall outcome for the system is accurate.

Q: Methods for determining the emissions to assign to contracts that specify an emissions level but do not specify a generation source? How the contract market may evolve to support this type of compliance with the emissions requirement?

The ESB is correct to anticipate this type of contracting – portfolio effects among generators can greatly improve their ability to contract more firmly and achieve more favorable value.

[3] We refer to the comment on p16 section 3.3: "Retailers would report contracts of their choosing"… !

[4] This would also create a conflict with the requirement to evidence dispatchability under the reliability element.

We agree that the concept of 'stapling' an emissions characteristic to an existing form of fungible hedge contract has merit to accommodate this, and that the existing processes under the CER is a good base to support the veracity of the emissions and avoid risk of double-counting.

Again, this ties in with a broader design choice which completely maps all dispatch to all contracts, discussed earlier. Conceptually, the CER-managed registry would need to make a virtual transfer of each MWh of generation (with its stapled emissions and reliability characteristics) through to a retailer, likely via intermediaries. This is analogous (but substantially more complex than) the registry of LGCs currently being created, traded, transferred and surrendered.

Since the design must allow for retailers to balance their emissions obligation independent of their wholesale energy supply, the obvious next step is for participants to 'un-staple' the emissions characteristic and trade it separately in an OTC market, which might in turn encourage an ASX futures contract over delivery of the instrument should standardisation and liquidity allow.

Provided this is anticipated and the documentation is developed quickly (for example, via an industry-led preparation of a standard), it could lead to maintained liquidity in the underlying electricity hedge contracts and adequate liquidity in the contractual emissions characteristic.

This would be a good outcome for transparency of the value of emissions intensity, and thus in our view, it would likely be extended to all forms of contract including PPAs, in the absence of a legislated instrument analogous to the LGC or an equivalent under an orthodox EIS design.

Q: Appropriate emissions level to assign to contracts that do not specify an emissions level or generation source? What (if any) impact would these approaches to determining the deemed emissions level have on the liquidity and availability of those types of contracts?

In our view, several of the simpler suggestions run the risk of unanticipated outcomes, whether via deliberate gaming or simply inaccuracy which impact the equity of the mechanism for participants.

Rather, we think the approach should be a transparent cascading of the emissions of generation in a manner that ensures the total result is accurate across the system, on a 5-minute basis:

1. Assign emissions intensity for the contracts with specified emissions intensity (sections 3.3.1 and 3.3.2) in the manner described above.
2. Then, retailer-owned generation which is dispatched uncontracted to external parties should be assigned to the retailer in question (section 3.3.4).
3. Next, determine the quantity of contracted load without an identifiable emissions characteristic such as a futures contract (section 3.3.3) and deem to it the "lowest emissions residual" from remaining generation not assigned in the steps above.
4. Finally, unhedged load would be deemed the final, highest-emissions residual.

In addition to overall accuracy and fairness, this approach has two further benefits:

- An incentive to contract is created DIRECTLY within the emissions mechanism. This is clearly a policy objective under the NEG for reliability purposes, and in our view this may be a better way to achieve it.
- An incentive is created to maintain or enhance contract liquidity – once again, a stated objective of the NEG.

Q: How to deal with internal non-contractual arrangements between the retail and generation arms of a gentailer, for the purposes of the emissions requirement? How to determine the emissions level to assign to contracts between the retail and generation arms of a gentailer?

This is an area where in our view, the question of competitive effects must be considered in the basic design.

We believe that transparency and competition would be enhanced if the NEG required gentailers to formalize their internal arrangements into explicit contracts (which would then be treated equivalently to all other such contracts).

This has the benefit of simplifying the NEG design, while also encouraging greater economic separation within gentailers. This in turn may lead to greater prospects of external contracting and thus the restoration of contract liquidity which has been internalized due to increasing vertical integration over time.

We think it is very important that where possible, the NEG and the competitive analysis and potential actions being led by the ACCC are co-ordinated, and this is one clear opportunity to do so.

Q: How to determine the emissions level to assign to unhedged loads?

We suggested above that unhedged loads should receive the highest-emissions residual after all other forms of contract have been allocated the lower-emissions dispatch, on a 5-mintue basis.

This would be fairer and less-distortive than the other alternatives raised such as backwards-looking weighted averages, or a punitive allocation of the highest-emitting plant in the NEM.

What about contracts which are contingent – like caps?

In our view, a cap contract illustrates why the emissions requirement must elect to focus on real-world, real-time dispatch rather than apparently-simpler metrics like deeming historical or forecast weighted averages.

Caps may be backed by very low (hydro) or moderate (gas) emissions-intensity. However, a cap contract may expire without a single MWh being settled against it, if wholesale pool prices do not settle above the strike.

It seems clear to us the only way to maintain overall robustness and accuracy of outcomes is to match up exactly when (if) the underlying peaking capacity generates to support the cap. Retailers should not be advantaged by being deemed to have contracted with (e.g.) hydro plant under a cap that is never settled and the hydro never dispatched. We can imagine spurious contracting such as very cheap caps with very high strike prices, created solely to influence the NEG emissions mechanism outcome.

Q: Should the emissions requirement allow for unlimited carry-over of overachievement [or not]?

Some flexibility is important for the reasons the ESB outlines, but given there is no end-date to the scheme (unlike the RET), unlimited carry over might cause retailers to “hoard” overachievement for the future, in a manner which may distort outcomes in an unpredictable way.

As one hypothetical, some retailers may have access to an excess of low-cost low-intensity contracts, and see a competitive advantage in forcing their competitors to invest in additional higher-cost supply, with the added benefit of driving down wholesale prices.

Another outcome might be outperformance on overall NEM emissions intensity, as other retailers contract new low-emissions supply in the absence of the ability to trade with the hoarders.

We suspect this is not the intention of the NEG, and so a sensible limit on carry-forward will be preferred.

Q: Should limits on individual retailers’ use of offsets be set at an absolute level, regardless of retailer size? Or based on the size of retailer’s loads?

We note there is no explanation in this section as to why such an approach might be considered necessary.

Offsets would only be used if cheaper than within-NEM opportunities, so in essence, if the limit was absolute (and thus a higher proportion of a smaller retailer’s requirement) this would offer a competitive advantage.

While there might be arguments for and against favoring smaller retailers in this way, our view is that the design of the scheme should avoid any such distortions unless the case is very clear that smaller retailers are in some way disadvantaged otherwise, AND that this type of response would be an appropriate balance rather than tipping the scales too far in their favor.

Concessions to encourage competition from smaller retailers is an interesting point, but again one where close co-ordination with the ACCC would be advised, rather than taking an inconsistent and uncoordinated path. This seems to be well outside the already-challenging objectives of the NEG.

Q: What types of information are likely to be required to be entered into the compliance registry in order for retailers to monitor and assess their compliance with the emissions requirement? Is information on generators' contracting positions also required to be entered into the compliance registry, for the purposes of reducing the change of either double-counting or attributing generation output to the wrong retailer?

We stress again that if the NEG is to be robust and fair in relation to the emissions mechanism, it needs to be "complete" – based on a mapping of all centralized dispatch to all load on a 5-minute basis. This is complex, but essentially a data-management problem which the industry is well-prepared to address if it must – albeit at a cost.

Once again, we are concerned with the language suggesting an element of cherry picking: "Each retailer will report … those contracts the retailer **wishes** to count …" (our emphasis). This immediately suggests a strategy of reporting only low-emissions contracts, if a retailer calculated it will be better off being allocated some deemed average rather than the reality. This seems to be clearly unacceptable both in terms of creating competitive advantage via regulatory arbitrage, and in undermining the ability of the scheme to deliver the overall emission-reduction target for the sector.

This implies that on a real-time basis, the compliance registry[5] must contain **all** retailer and generator contracts, with a process to match these up and identify error or fraud. The mechanism is dealing with real value for the participants, and so should be no less robust than a financial registry of assets and liabilities, including all appropriate checks and balances.

The NEG emissions requirement is essentially an EIS – on the generation side, this type of approach is consistent with the manner in which an EIS would be administered.

Any additional complexity is due to the choice to use retailer contracts – which are derivatives, not physical supply agreements for energy in reality – as the medium of exchange, rather than a separate certificate arising directly from generation.

Q: Is there a need for retailers and generators to report contract pricing information as part of the input into the registry?

On the face of it this seems to be a considerable incursion into matters of commercial sensitivity, and the ESB has offered no suggestion as to why this might be advisable – we can think of three possibilities:

1. **Emissions price:** If the intention was to reveal a price of emissions, there are far simpler means to do so, such as (as discussed previously) participants moving to unstaple and separately trade them.
2. **Hedged generation revenue / retailer CoGS:** If the intention was to reveal more about the immediate profitability of the retailer and generator sectors, this would achieve that – but it seems to be outside the scope of the NEG objectives as stated and would be very bold in its ambition to

[5] The DDCP flagged the ability to make use of the CER processes and systems as an infrastructure to support the emissions mechanism, and this is an excellent suggestion in our view. We are not clear how the subsequent discussion of using the AER to manage the registry fits with that.

More broadly, some matters taken up in sections 3.6.2 ("Compliance registry") and 3.6.3 ("Reporting requirements for emissions requirement") seems to overlap with earlier sections 3.3.1 to 3.3.5 discussed above.

turn the NEG to that purpose. This is another area where the ACCC may have useful views for the ESB to consider.

3. **Forward curve:** If the intention was to look beyond the immediate and reveal a contractual forward curve, we suspect the information would either be incomplete and unreliable (only dealing with contracts that are currently settling) OR the ESB intends to require participants to disclose not only current but future-starting contracts and their price paths. That would add another dimension of both complexity and commercial sensitivity.

Of these, we can see the benefits of a more visible forward curve in assisting generators and retailers with investment decisions and efficient contracting. However, we are not confident the emissions mechanism would be an appropriate tool to use for this purpose.

Q: Approach to compliance

A feature of the penalty under the LRET is the fact that the cost of compliance is fixed, clear, directly related to the alternative (being the price of LGCs) and relatively easy to enforce.

In our view this is appropriate, because non-compliance is not just a "technical breach" or a "victimless crime": it places non-compliant retailers at a competitive advantage via lower costs than their competitors.

Therefore we would caution against a compliance regime without sharp teeth. Retailers would find it hard to resist a race to the bottom if they felt non-complying competitors were placing them at a disadvantage in the core business of competing on lowest-cost, and there were only limited consequences such as administrative undertakings.

If the emissions mechanism is adequately designed and implemented (a responsibility of the regulators, not the participants), compliance should not be an unreasonable expectation. If it IS that difficult, the problem likely lies with the design, and will not be adequately addressed by anticipating a forgiving approach to compliance.

Q: Impact on competitive markets

The basic risk here is that the mechanism may favor a form of contracting which some entities are unable to support, due to limited financial capacity – for example, a small retailer does not offer the credit quality to enter into a long-term PPA with a renewable generator seeking project finance.

The same retailer may however be able to manage its supply risk in the shorter term through liquid ASX hedges, and the acquisition of LGCs (in the current environment) on the liquid spot market.

Therefore, the design choices the ESB faces will be very impactful on this question.

In general, the choices which are supportive of traded market liquidity and the easy separation of emissions from energy in contracts (such as stapled emissions characteristics to existing liquid energy hedge instruments being unstapled and traded on) should be favored over those which would place an unjustified premium on long-term, legally-complex, less-standard and credit-intensive bilateral arrangements.

DDCP Section 4 – Commonwealth design elements for Emissions

Q: Interaction with state renewable energy schemes

Within the NEM

It seems inevitable that the policies of the Commonwealth and various states and territories will continue to diverge at certain times, when Commonwealth targets are perceived to be too low, or the states wish to attract greater renewable asset investment locally. This has been a durable feature of the development of climate policy from the earliest days of the 2% Commonwealth MRET and more ambitious state targets, which eventually contributed to the higher level of ambition in the current RET.

In fact, the promises of the ESB that the NEG will ensure reliability may actually have the (unintended?) consequence of further encouraging state-based schemes, given this assurance that reliability will be secured by a national policy overlay. It may become a safety-net for state governments to pursue popular, more ambitious schemes.

Therefore while the objective of a nationally-consistent and coordinated emission reduction policy is worthy, the design should acknowledge likely state behavior and anticipate clearly how it will be managed.

The NEG design contemplates that any state targets may distort investment preferentially to those states, or on a different timescale than the NEG trajectory, without altering the overall NEG emission outcomes.

This is only likely to be valid to a point: if the total of several state targets exceeds the NEG target in aggregate, this would presumably lead to emission reduction beyond the NEG target level.

Earlier, we suggested that contract disclosure under the NEG must be complete, and mapped to generation for assurance purposes. This is another reason why: if not, states may be able to create "additionality" from their own schemes by requiring retailers to forego NEG disclosure in order to access state-based incentives which may be of greater value.

Emissions-reductions outside the NEM

We strongly suggest that retailers be free to utilize low-emissions supply derived from outside the NEM, such as remote off-grid generation, and generation in the WA and NT systems.

This seems to be consistent with policy objectives in a couple of respects:

- Firstly, there have been clear concerns about the effect of high levels of intermittent renewable energy penetration within NEM regions. For a given target, it would seem to us that if some of the contributing renewable assets were located outside the NEM (where current penetration is very low) that would assist to lower the overall externality costs of even higher renewables penetration within the NEM.
- Secondly, opportunities outside the NEM may be simply more attractive, partly due to more favourable conditions (e.g. solar PV in WA versus VIC), and partly due to the fact that within the NEM, a "creaming curve" effect will emerge where the best sites (e.g. closest to transmission capacity and load) are increasingly taken. It would be a better outcome for consumers as a whole if the lowest-cost portfolio of assets was built to satisfy the emissions requirement.

Q: Exemption of EITE activities

Questionable policy basis from 2020 onward

The EITE exemption distributes the differential costs of favoring low-emissions energy more heavily onto small consumers and domestic industrial activity. This has been the case under the LRET, where those electricity customers fund the value of LGCs being surrendered on their behalf, while the benefits of lower wholesale prices driven by the increase in capacity of assets with very low short-run costs are enjoyed by all.

While the DDCP cites "policy continuity", it is fairly clear that a lot of things are changing, some of them for good reasons. It is not clear to us that in the current circumstances, such a redistribution to disadvantage non-EITE consumers and businesses remains justified or desirable.

When the RET was developed, it was feasible to argue that Australia's actions were moving ahead of a number of important trading partners, and so the prospect of a competitive disadvantage for exporters was credible.

However, under the Paris Agreement, action is being taken at a much more extensive global level, among a wider range of developed and developing economies including most of Australia's trading partners. It is difficult to sustain a claim that Australia is any longer a leader in emissions-reduction policy.

In our view, the Commonwealth should reconsider the arguments for and against an EITE exemption very carefully, in light of the impact on costs for small consumers who in many other respects appear to be those worst-affected by the affordability issues the NEG seeks to address.

Some impracticalities

There are also practical issues (including the added cost and complexity of compliance) to consider which we think argue against separate treatment for EITE activities.

Recent corporate contracting with (or self-constructing of) renewables assets – including by entities such as Sun Metals, Adelaide Brighton Cement and Arrium – suggests that the premise that low-emissions energy is more expensive than alternatives may be false. In our experience, direct corporate PPAs will become a more regular feature of renewable energy contracting in future.

Given that, if an EITE wished to contract a renewable energy asset under a PPA, would an exemption mean the project was unable to gain any value from the low-emissions aspect of their generation?

If such a relationship proceeded, would that low-emissions generation never be counted within the NEG, thus leading to additionality versus the target?

If an EITE exemption is maintained, the design should be very clear about how this circumstance would be handled.

Q: Rationale for, impact of the use of offsets? Appropriate limit?

We see no reason why international or domestic offsets should not be used by electricity sector participants (or wider emitters in the economy) in principle. In fact, by encouraging this form of trading between the electricity sector's EIS and the ACCUs scheme, the sector could emerge as the nexus of an economy-wide carbon trading scheme in future.

In our view this would be helpful in allowing Australia to meet its economy-wide emissions reduction targets at least cost. However for this to work the opposite would also need to be permitted: that reductions generated by the electricity sector in excess of the NEG target could be monetised (for example by the creation of ACCUs) and traded onwards to non-electricity sectors of the economy.

Given many stakeholders contend that emissions reduction is relatively cheap within the stationary energy sector (even under conditions that assure adequate reliability), such a mechanism would allow this contention to be tested and (if true) free the sector to contribute lower-cost reductions in emissions beyond the NEG target.

DDCP Section 5 – Reliability Requirement

Q: Should AEMO be able to determine assumptions independently, or should responsibility for the accuracy of assumptions be placed on the market participant?

We note the obvious problems here regarding capacity forecasts:

- It seems unlikely that retailers could reasonably be asked to bear the economic and regulatory consequences of inaccuracy in forecasts made by generators.
- However, if generators are somehow asked to accept that risk (which appears to be outside the scope of the design entirely), there will be a clear tendency towards over-conservatism in their forecasts which may well lead to poor outcomes, such as a "phantom gap" being identified and perhaps triggered, and/or gold-plating of capacity supply.

Even in the case of peak demand forecasts where the conflicts of interest are less, retailers have only limited visibility of how their customers may behave. Again, they may tend towards the over-conservative as a result, with the same risk of high-cost outcomes.

Given the mechanism is an interventionist approach which presumes AEMO knows better than the market participants regarding the need for capacity investment, it seems to us that AEMO ought to take full responsibility for the accuracy of the forecasts used, while participants are required to provide the best possible estimates to AEMO without fear.

In general, the NEM would be better served by the best possible forecasting by AEMO, in particular by ensuring there are no inherent biases as described above.

The past experience of AEMO forecasting robust demand growth based on regulated network company inputs is an example of how this could go badly wrong.

Q: How frequently should the forecast be updated?

We disagree that frequent changes in forecasts would deter investment per se, provided the changes are (a) based on new information and (b) derived from a robust and clear forecasting process, as intended.

The stability needed for taking investment decisions relates to external factors such as regulatory stability, not fundamental factors impacting on the investment decision itself, such as the existence or otherwise of a demand for new capacity.

Regardless of AEMO's processes, market participants will take investment decisions based on their own assessments at that point in time. This may be largely informed by AEMO's forecasts, but if those forecasts are patently out-of-date, the most current information available to the participant will be used.

Given that, we think AEMO should aim to maintain the most current source of forecasts – as that would assist all participants to make decisions from a largely shared viewpoint rather then seeking more current information elsewhere. The frequency of updates, or the need for any ad-hoc updates outside a schedule due to material changes, is them simply an outcome of that objective.

Q: What trigger point would be most appropriate … to the identification of the reliability gap?

A period as short as possible would be preferable in our view, or the mechanism risks becoming the dominant driver for a form of centrally-directed capacity investment rather than (in our view) the better outcome of it being at worst an unlikely backstop mechanism, at best off the table altogether.

As noted in the DDCP, announcement of capacity withdrawal a minimum of three years in the future (per Finkel recommendation) should not result in a triggering – the market and the participants should be allowed time to respond of their own volition to this signal to build.

The longer the period between the trigger point and the gap, the greater the lack of faith in market-based responses is implied. We are not convinced there is evidence to support this lack of faith on a forward-looking basis, as opposed to looking backwards at recent exceptional circumstances including periods of large-scale investment strikes due to unprecedented levels of policy uncertainty, and the withdrawal of material capacity with only 5 months' notice.

The shorter the period, the less likely the triggering will occur, and so the lower the deadweight costs of active compliance will be. That is more consistent with the objective of delivering lower rather than higher consumer prices.

A short period nevertheless appears to allow for the primary objective to be met: AEMO has time to take the steps noted in the DDCP to assure reliability in the face of the looming gap, if it comes to that.

The key trade-off is the expense of any such urgent measures ultimately taken by AEMO, compared with longer lead-time but cheaper responses AEMO might otherwise be able to access.

Provided it is clear that both retailers and generators (ultimately responsible for new capacity investment) will bear those costs in a manner which is difficult to simply pass through to consumers, this trade-off would act as an incentive for the participants to close the gap themselves.

Q: Should a multi-year gap trigger a compliance requirement in only the first year of the gap or over the full duration of the gap?

It seems to us the requirement should be a short as possible – perhaps a quarter or a season – given the risks of embedding capacity over the long-term that proves unnecessary.

Participants should be free to make their own commercial judgments as to whether in fact they build or contract longer-term, based on their assessment of the need to do so, and the relative costs of longer or shorter-term arrangements.

This goes to the heart of concerns being raised about the NEG leading to "gold-plating" in capacity.

Q: The types of contracts which should be considered eligible? Should eligible contracts be financial or have a link to physical capacity?

Appropriate types of financial contracts should be considered "dispatchable"

We firmly agree with the arguments made in the DDCP that "firm" exchange-traded and OTC electricity derivative products can be considered to represent dispatchable physical capacity, despite the lack of an explicit link to a particular generating unit. The description provided in section 5.6.1 on this is correct in our experience.

As such we believe it is important that these contracts simply be accepted as-is for compliance.

1. Doing so is a pragmatic choice to simplify compliance for all retailers, but particularly those for whom vertical integration or long-term PPA-style contracting is impractical. The alternative would have material effects on competition in our view.
2. This lends support to maintaining liquidity in these markets, which are very important as a risk management tool for participants and provide a reliable forward curve with associated benefits for well-founded decision making.
3. As noted in the DDCP, the compliance costs for this approach are likely to be far lower than alternatives canvassed, which would involve complex efforts to specifically associate each contract with a generator.
4. In our experience the assumption being made is largely valid. While in theory a speculative trader could take an "uncovered" sold cap or sold futures contract into the settlement period, in practice this would involve very substantial risks given the magnitude of the wholesale pool Market Price Cap, relative to the value available from the trade by (e.g.) selling the cap and receiving a relatively small premium. Risk departments in trading houses would rapidly identify that if an unforeseen generator outage occurs, the trade can go very badly wrong, very quickly. So in almost all cases, by the time these contracts settle they are held by parties with access to generation which can cover the risk. Exceptions to that would be likely to be immaterial (an assumption which may be able to be validated via the ASX should the ESB wish).

5. The ESB notes that sometimes, renewable generators may sell swaps or futures, which appears inconsistent with the above – however the ESB also correctly notes that commonly they also buy caps against that position, in order to cover the risk of their physical intermittency. As a result, there is no net increase in the volume of dispatchable hedge contracts (rather, the hedge activity of renewable generators creates demand for the type of firming capacity which can supply caps and thus physically balance intermittent renewables).

Note the link between contract tenors and trigger point timing

We note that the question here links back to the timing of the trigger point, which we think should be as short as possible prior to the gap. Instruments such as these are somewhat limited in liquidity beyond the first year forward, and the collateral required to establish a multi-year hedge position may be unattractive for participants, especially if they tend to adjust their customer prices on a shorter-term basis as many smaller mass-market retailers do.

Q: The approach to certify contracts back to a physical asset?

Certification of contracts is problematic – take an aggregate approach

The ESB effectively argues against the idea based on the liquidity risks in any case, but we stress that rather than pursuing some of the more complex alternatives such as "certifying" derivative contracts, the ESB would be better-advised to first analyse the open interest in such contracts during the settlement period with the actual dispatchable capacity available to back them. The details of who bought, who sold and how many times they did so prior to that are not relevant.

While the OTC market in particular is currently somewhat opaque, in our view a requirement for more detailed disclosure on derivative positions in aggregate would be far more appropriate than attempting to determine where every derivative contract may have originated from. This information gap has already been raised by the AEMC in their Retail Competition Review.

In other words, the ESB should first determine whether there IS any apparent material problem with double-counting, before designing the NEG to figure out exactly where!

Q: The proposed approach of determining the generation source in a vertically integrated business?

Disaggregating gentailer capacity into identifiable contracts

The ESB notes that "the treatment of vertically-integrated retailers requires further consideration". Unfortunately, this is not a side-issue given the top 4 gentailers own around half of existing generation capacity, and a proportionally larger share of dispatchable capacity!

For the purposes of both the emissions and the reliability design, we suspect the fairest and most robust approach to this class of participant would be to require gentailers to formalise their internal contracting. This would have several advantages:

1. It would reduce complexity, by reducing the number of cases being dealt with by the NEG policy and placing gentailers on an equivalent basis for compliance.
2. It would increase accuracy and fairness, by requiring gentailers to be specific about what dispatchability (and emissions) characteristics are being retained internally, and what are being contracted out externally. This is likely to be more robust than attempting a "residual" approach.
3. The process, by exposing pricing within the gentailer relationship, may encourage divisional management to act more independently, and contract more often with external parties should the terms be more favourable. This would improve contract liquidity and address wider concerns about diminishing availability of dispatchable hedges for non-gentailer participants.[6]

[6] This is a key area where we believe the ESB should take advice from the ACCC in relation to its inquiry conclusions and recommendations.

Q: The proposed method of allocating the gap to retailers?

Serious consideration should be given to the book-build option instead – but with a real intermediation role for the Commonwealth

The ESB notes an AEMO-managed book-build process as an alternative to attempting to allocate the gap to retailers at all.

In our view, this is much more likely to be a workable process, given the range of problems set out in the DDCP in relation to allocating the gap to retailers.

However, we do not see this as being simple by any means. For example, the statement is made that the process would "… have AEMO intermediate new contracts …". In fact, as described AEMO is merely arranging contracts which would be bilateral among the bookbuild participants. This raises complex issues of acceptable documentation and credit support.

Perhaps the ESB might consider whether a Commonwealth-backed entity (which could indeed be AEMO) would be prepared to genuinely intermediate: that is, stand between participants as the counterparty to the bookbuild contracts and take credit risk against them (for a fee), in the manner that the ASX clearing house provides standard and high-quality credit terms to participants trading futures.

If that was the case, a bookbuild process would be much more likely to succeed in our view, as it would offer a genuinely different source of capacity contracting in an area where bilateral credit and risk constraints can be a very material obstacle.

Incremental new contracts against the gap only – the alternative is based on a fallacy

If an attempt is made to allocate the gap to retailers, the DDCP discussion in section 5.7.2 seems to make it obvious that it can only be workable if it matches incremental new capacity contracts (for new-build capacity or new demand response) against the identified gap.

But in case this isn't broadly accepted, we point out that the only advantage offered by the 'total obligation' alternative is that the ESB considers it may lower prices through lower bidding behavior by contracted generators. This is a fallacy. Spot prices resulting from bidding behavior are entirely irrelevant in the case of a fully-contracted market – since the whole market is contracted by definition, what matters would be the prices at which the contracts were struck.[7]

We see no reason to think contract prices would be lower in such a circumstance – quite the opposite given the substantially larger demand against a limited supply of dispatchable contracts!

Allocating incremental peak demand and BAU contracting fraught with practical problems

As the ESB notes, determining the counterfactual "business as usual" contracting position a retailer WOULD have had contracted for the period of the gap is essential, given the time that will pass between the trigger point and the gap itself (during which retailers would be typically adding to and adjusting their hedge positions in the normal course).

Clearly, there are real economic and regulatory consequences associated with this assumption. We wonder how this counterfactual can be established in a manner which is both fair to participants, and also of any practical use as an incentive or compulsion to contract more than the retailer would prefer to do for their own internal risk-management purposes, given the additional costs and risks of ending up over-contracted.

Who will bear the responsibility for costs or losses should the NEG compel a retailer to take out contracts or hedges which it does not in fact need, perhaps due to lower-than-expected load for reasons beyond the retailer's control?

Ex-post assessment of compliance appears much more workable

An *ex-ante* approach to assessing retailer contracting and load has a couple of fundamental weakness:

[7] This is an example of why stakeholders are concerned about the haste of the NEG policy development. Have the modelling assumptions and conclusions been properly exposed to peer review?

1. It may punish a retailer for not being sufficiently contracted against load it did not – in fact – have to serve at the time of the putative gap.
2. It opens the possibility of compliance actions and penalties being invoked when – in fact – the gap did not prove to exist (i.e. the market may have proved to be reliable despite technical retailer non-compliance, because the capacity and/or demand forecasts were wrong) in which case, it is difficult to see how penalties of any type could be justified.

For those reasons, it appears that an *ex-post* assessment of retailer peak load and contracting position at the time of the gap must be the preferred choice. Only if a retailer can be demonstrated in fact to have been under-contracted would any penalty action appear to be justifiable.

This would recognize that at the retailer level, it is likely that retailers will be closer to the details of their business than an AEMO forecast can be. There is already a very strong economic incentive for retailers to ensure they are adequately contracted against their peak load, since the alternative of paying unhedged pool prices in a period of low capacity reserves and consequently high prices can be very severe.

Provided retailers understand the basis of their proportional allocation, we see no reason or benefit in attempting to formalise it in absolute terms as well via an *ex-ante* approach.

Q: Should the gap be allocated based on AEMO's forecasts or on the retailers' own view of their hedge positions?

Responsibility and accountability should follow the forecast used

All forecasts prove incorrect to some extent. If the AEMO forecast were to be used to override the business judgement of a retailer in managing its risk, then it seems to follow that AEMO (not retailers or their capital providers or customers) should accept the consequences if that causes economic harm.

If the mechanism compels retailers to hedge or contract at particular levels which cause such damages, it seems inevitable the retailer will claim (in hindsight) it never would have acted that way left to its own devices, and this will be challenging to disprove.

That should be reason enough to base forecasts on retailers' load.

Mismatches in forecasts should be identified early, minimized systematically, and managed through analysis – not scaling up a retailer's carefully-developed view

To the extent the aggregate of the retailer-derived forecasts does not match the AEMO forecast, we think it is presumptuous to assume the correct answer is to scale up the retailers' forecasts!

Even if it were the right answer, the risk of gaming seems obvious: retailers will have an incentive to under-estimate their peak demand, hoping they will be scaled up to levels less-uncomfortable than their competitors.

It is as likely to be the case that some retailers have a better view of their own businesses than AEMO, and the problem is with the AEMO forecast. Perhaps the reliability gap is illusory – which would be good to know before compliance actions are taken.

A more appropriate response might be for AEMO to examine and resolve the difference in views in the most appropriate manner in each case, be that convincing a retailer to change their forecast (and thereby help them to better understand and manage their risk) or accepting that AEMO ought to adjust their own forecast based on the more detailed understanding they have gained about the retailer in question.

One way to guard against this problem would be to ensure the AEMO demand forecasting process is very closely based on retailer input in the first place, allowing such differences in views to be identified well before the point of allocating a share of a reliability gap.

Q: How should a significant and enduring gap be resolved?

Such a long-term gap would not be well-served by the high-cost procurer of last resort process. However, we do not see how any other attempt to compel market participants to make significant and enduring capacity investments (against their commercial judgements) would work well either.

This is a much more fundamental question, which seems to ask whether the most basic feature of the NEM – its ability to reveal the price signal for new capacity investment – no longer works.

We do not think this is the case, give we see many participants responding to price signals currently.

But if the ESB suspect this might be so, more fundamental response may be called for, such as a formal capacity market and/or direct government support for the costs of new capacity.

Q: How should C&I load be treated? Views on extending the reliability requirement to large energy users?

This is a very difficult question – every alternative to try to fit C&I exposures into this type of model appears to have problems, if (as we infer from the question) the expectation is that firm contracts over the C&I share of NEM load will be struck years in advance to underwrite dispatchable capacity investments:

- Retailers face very substantial risk if they are compelled to enter into long-term hedges against short-term chunks of C&I load which can and does churn away under a highly-competitive market based largely on one or two-year fixed price contracts. If they were forced to do so, it seems likely the risk premium on C&I contracts would lead to much higher C&I pricing – equivalent to retailers embedding the cost of an option to reduce the volume of a supporting supply contract into any deals they might strike with a dispatchable generator.

- C&I customers do not appear to be at fault here – it isn't clear that they should be required to either enter into very long-term contracts with retailers (diminishing the effectiveness of competition), or bear much higher contract costs as above, or accept restrictions on whether they may accept spot price pass-through when they perceive that is a more attractive level than contract prices on offer.

It is quite a fundamental point. Given the size of C&I load, the design of the NEG needs to have a credible answer to this question, and one which is acceptable to a very large and diverse set of C&I stakeholders as well as the retailers which serve them.

From the C&I perspective, it is a very tenuous argument indeed that they are not the victims, but actually partly to blame for energy market imperfections simply because they tend to seek competitive procurement opportunities every year or two, and wish to have some flexibility to refuse a fixed price offer if they believe it is in their economic interests to take a spot-price exposure for a period.

Conclusion on the Reliability Mechanism: be open to a simpler solution

In this section we have identified a number of concerns and expressed our view on some of the least-harmful design alternatives – but overall, we are doubtful that the total eight-step process is workable.

As a result, in the earlier part of this submission we have suggested a slimmed-down version which we think would deliver the same objectives (including both the reliability outcome, and increased incentives to contract for and build new capacity when needed), preserves what we believe are the many good aspects of the proposed mechanism but removes the most problematic parts.

We believe this should be given some serious consideration.

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