8 March 2018

Energy Security Board
By Email: info@esb.org.au

National Energy Guarantee Draft Design Consultation Paper (the "Consultation Paper")

Telstra welcomes the opportunity to make a submission on the Consultation Paper.

Telstra is one of the largest energy consumers in Australia, and relies on the grid to provide critical telcommunication services to Australian homes and businesses.

Telstra recognises the importance of ensuring that the Australian energy market has in place the necessary systems and procedures to deliver Australia reliable power which meets our energy intensity objective at the lowest feasible and economic cost. The National Energy Guarantee (the **Guarantee**) has the potential to deliver these important objectives if it is implemented well.

In particular we consider it important that the Guarantee be implemented in a manner that minimises administrative burden while still delivering on the above objectives. To achieve this we have proposed an emissions methodology and an approach to the reliability requirement that is clear, simple and effective.

The design of the Guarantee will fundamentally influence behaviour in the National Electricity Market (the **NEM**) and the Australian energy market more broadly. As such many aspects of the Consultation Paper are of interest to Telstra, and by extension to our millions of customers.

We note that the Consultation Paper makes passing references to "day ahead markets". Such a market would be a fundamental change to the NEM. We have not commented on this concept in our submission, and in our opinion the need for such a change should be the subject of a separate extensive consultation process.

Yours Sincerely,

James Gerraty
Head of Telstra Energy

TELSTRA CORPORATION LIMITED

Telstra submission to Energy Security Board's National Energy Guarantee Draft Design Consultation Paper

March 2018

3. Emissions Requirement: Energy Security Board design elements

3.2.1 – Entities covered by the emissions requirement

What are stakeholders' views on whether the compliance year should be a calendar year or a financial year, noting that EITE exemption processes under the RET use calendar years, whereas emissions reporting obligations relate to financial years?

Making the compliance year the year to 30 June has several advantages, including alignment with the NGERS calendar and with network price changes in some States (such as New South Wales). In addition, it would potentially create a new surrender window for Large-scale Generation Certificates (**LGC**), which increases price discovery for a commodity otherwise primarily traded in January.

We believe that these advantages outweigh the disadvantage of being misaligned with the Renewable Energy Target (**RET**) calendar and the network price changes in other States (such as Victoria). Particularly from the perspective of large energy users such as Telstra and our many Enterprise customers, alignment with the NGERS calendar is beneficial.

3.2.2 – Calculation of load

What are stakeholders' views on the process to calculate a retailer's load?

Any administrative burden or cost that retailers take on in order to comply with the Guarantee will mean higher prices for end users (including Telstra and/or our customers). In addition, this administrative burden would disproportionately impact smaller Market Participants (such as large energy users registered as customers in the NEM). As such, to the greatest extent possible it would be preferable that regulators overseeing the Guarantee made use of data already available to them or other regulatory bodies. We believe it is best to eliminate any need for difficult calculation or data manipulation by retailers. The methodology set out in response to question 3.2.3, our Proposed Emissions Methodology, observes this principle.

3.2.3 – Calculation of emissions per MWh – overview

What are stakeholders' views on how a retailer's emissions should be determined?

The methodology set out below (our **Proposed Emissions Methodology**) is designed to eliminate the risk of double counting or under counting, and to minimise the administrative burden on Market Participants. These principles are important to ensuring affordable achievement of the Guarantee's objectives for Telstra's customers.

For a given compliance year:

- Up to date emission factors (as defined in the National Electricity Rules, or **NER**) for each generating unit (as defined in the NER) should be maintained by AEMO, entered into the Guarantee Database (see response to 3.6.2), and made public.
- The output in MWh is known at the end of the year for each generating unit, from AEMO data. This output data should be replicated in the Guarantee Database, and made public.
- The consumption in MWh is known at the end of year for each Market Customer (as defined in the NER), from AEMO data. This consumption data should be replicated in the Guarantee Database, and made public.

- A person who is, in the first instance, entitled to the output of a generating unit (at times referred to in this paper as a **Generator** for simplicity), is free to contract some MWh to third parties (whether specified in the contract as percentage of total output, a flat number of MW across the number of hours covered by the contract, a specified number of MWh, or any other common contract specification). Any MWh from a given generating unit contracted (directly or indirectly) to a Market Customer, is multiplied by the emission factor for that generating unit to determine a number of MWh and a number of tonnes of greenhouse gas emissions to associate with that Market Customer's consumption. Some further considerations that should be made in respect of this aspect of the Proposed Emissions Methodology include:

    - How do we ensure that Market Participants who didn't previously need to hold an Australian Financial Services Licence (**AFSL**) to operate their business (such as because they contracted all of their requirements through the ASX) don't need to obtain one to comply with the Guarantee?

    - Contemplate that a Generator may continue to sell "unlinked" ASX or Over the Counter (**OTC**) contracts to manage the financial risk associated with their generating units, but at the same time may sell "floating for floating plus fixed premium" contracts that are linked to their generating units for Guarantee compliance purposes.

- A Generator selling more MWh under a contract linked to a generating unit than that generating unit actually produces in the relevant compliance year would be obliged to pay their contract counterparty a compensation amount. This would be calculated based on the difference between the emission factor of the contracted generating unit and the Residual Intensity Factor (see next bullet point) – that difference multiplied by the number of MWh of the shortfall would give the resulting shortfall in tonnes of greenhouse gas emissions, which would be multiplied by the Shortfall Price (see response to 3.6.4) to give the final compensation amount.

- Any MWh actually generated by a generating unit during the compliance year and not contracted to a Market Customer in a contract which specifies the generating unit (or otherwise specifies emissions intensity and then is linked to a generating unit ex post facto) is used to calculate the emissions intensity of uncontracted consumption. That intensity factor for a compliance year which is completed (the **Residual Intensity Factor**), should be entered into the Guarantee Database, and made public.

- Each Market Customer's emissions intensity should be calculated by the regulator after the fact, using the Guarantee Database, by taking into account any contracted MWh at the emission factor for the relevant generating units, and then any uncontracted MWh at the Residual Intensity Factor.

- The regulator should deduct from a Market Customer's load, one MWh for each EITE certificate surrendered by the retailer (as created under the RET). The deducted MWh will be assumed to be uncontracted consumption at the Residual Intensity Factor, and the Market Customer's obligations to comply with the emissions requirement will only apply to the balance of their consumption. The RET legislation should carry forward to allow continued creation of EITE certificates under the already well understood framework (or else that framework should be replicated identically in the Guarantee legislation).

- A Market Customer whose emissions intensity exceeds the target should be required to pay a Shortfall Payment (see response to 3.6.4) for that compliance year.

- A Market Customer whose emissions intensity is better than target will have "overcomplied" by a number of tonnes, and that number of tonnes should be carried forward into the next compliance year or subsequent years without limit.

- The scheme should ensure that large energy users who have directly contracted with Generators for low emissions MWh can contract with a Market Customer to sell that output and for it to be counted against the Market Customer's low emissions targets. These contracts needn't transfer material financial risk, and could be "floating price for floating price" if the only intention was to transfer the entitlement to the emission factor. In this sense, large customers are no different to traders who have bought output from a Generator and sold it to a Market Customer (or to another trader).

3.3.1 – Contracts that specify a generation source

What are stakeholders' views on the methods for determining the emissions to assign to contracts where the generation source is specified?

As noted in our Proposed Emissions Methodology (see response to 3.2.3), each generating unit should have an emission factor maintained by AEMO, and published to the Guarantee Database (see response to 3.6.2).

If the contract specifies a portfolio of plants and the plants have differing emissions profiles (eg some are zero-emissions plants and some are gas plants, used for firming the variable renewable energy), how should the emissions per MWh under the contract be determined?

This should be done in accordance with the Proposed Emissions Methodology – if a specific portfolio of generating units is identified, then the emissions from those generating units can be calculated after the fact (for example if a contracted portfolio of gas and renewables ultimately generated 100 MWh from renewables and 0 MWh from gas, the emission factor of those 100 MWh would be zero).

3.3.2 – Contracts that specify emissions per MWh but not a generation source

What are stakeholders' views on how to determine the emissions per MWh to assign to contracts that specify an emissions level but do not specify a generation source?

Emissions intensity is a physical characteristic and as such, a party contracting to provide energy with a given emissions intensity can only prove delivery against that contract by reference to a physical generating unit (by specifying which MWh from a given generating unit were used to meet the contractual obligations). As such, the contract counterparties must demonstrate after the fact that they secured and transferred entitlement to MWh from a specific generating unit.

What are stakeholders' views on how the contract market may evolve to support this type of compliance with the emissions requirement?

The contract market for LGCs (a single type of certificate used to meet a well-defined regulatory obligation) is limited almost exclusively to contracts for spot physical delivery, contracts for future physical delivery, and options over future physical delivery. That is the extent of evolution over a decade. The emissions requirement contemplated for the Guarantee is much more complex, but the market will attempt to find simple and consistent ways to comply. Generally speaking, to minimise costs Market Participants will attempt to leave their practices unchanged other than to the extent necessary to comply. An ability to do this effectively will be important for keeping down costs for end users like Telstra and our customers.

3.3.3 – Contracts that specify neither emissions per MWh nor a generation source

What are stakeholders' views on the appropriate emissions level to assign to contracts that do not specify an emissions level or generation source?

Contracts are not generally used to provide energy – they are used to provide financial protection against price volatility. As such, emissions are not relevant to these contracts other than in relation to the Guarantee. Unless a Market Customer has chosen to use a contract to manage its Guarantee emissions intensity obligations, a contract should be disregarded in calculating intensity. This is consistent with our Proposed Emissions Methodology (see response to 3.2.3).

What (if any) impact would these approaches to determining the deemed emissions level have on the liquidity and availability of those types of contracts?

We expect that contracts which do not specify a generation source or an emissions intensity would continue to be the most common form of contract, so long as the Guarantee emissions obligations are carefully designed.

3.3.4 – Retailer owned generation

What are stakeholders' views on how to deal with internal non-contractual arrangements between the retail and generation arms of a gentailer, for the purposes of the emissions requirement?

Each MWh from those generating units should be allocated to a single Market Customer or else not allocated to any, and used to determine the Residual Intensity Factor. A "gentailer" does not exist in the NER. There are generators and customers. Emissions intensity obligations under the Guarantee will sit with Market Customers, who would need to contract with their related-party Generators if seeking to comply with their Guarantee obligations using those assets.

What are stakeholders' views on how to determine the emissions level to assign to contracts between the retail and generation arms of a gentailer?

Based on the emission factor of the relevant generating units, as per our Proposed Emissions Methodology (see response to 3.2.3).

3.3.5 – Unhedged load

What are stakeholders' views on how to determine the emissions level to assign to unhedged loads?

This should be based on the emission factor of each generating unit for any MWh not contracted by them to a Market Customer, as per our Proposed Emissions Methodology (see response to 3.2.3). Any other approach would render ineffective the exercise of tracking the emissions intensity of contracted generation.

3.4.1 – Carrying forward overachievement

Should the emissions requirement allow for unlimited carry-over of overachievement or specify limits on the carry-over of overachievement?

As noted in our Proposed Emissions Methodology (see response to 3.2.3) there should be no limit on the carry-over of overachievement. Market Customers should be given the flexibility to comply ahead of time. Basic economic drivers would discourage over-utilisation of this option, and greater flexibility is desirable in keeping down costs for end users.

3.4.2 – Deferring compliance

What are stakeholders' views on the deferral of compliance?

Compliance deferral is perhaps an alternative option to permitting the use of offsets, but in our view an approach to offsets as set out in response to 3.4.3 would be preferable.

3.4.3 – Use of offsets

Should limits on individual retailers' use of offsets be set at an absolute level, regardless of retailer size? An absolute limit would represent a greater proportion of a smaller retailer's emissions than a larger retailer.

Or, instead, should limits on individual retailers' use of offsets be based on the size of retailers' loads, such that offsets represent the same proportionate share of retailers' emissions regardless of retailer size?

What are the pros and cons of each of the above approaches?

If limits on use of offsets are independent of retailer size, how should the risk of large retailers splitting into several smaller entities for the purposes of increasing their overall offset limit be addressed?

As noted in response to 4.4, the use of offsets should be permitted because Market Customers may not be able to forecast their requirements accurately when determining what long term contracts to enter into with Generators.

The threshold for offsets should be set low enough to ensure that it is not treated as a mechanism to avoid contributing to the need to invest in new generation in Australia.

Smaller Market Customers will have greater difficulty forecasting their requirements, as they will often be growing rapidly. An appropriate threshold may be linked to a fixed number of MWh each compliance year plus a percentage of any MWh above that fixed number. For example – for each compliance year Market Customers are allowed to use offsets to meet the emissions intensity target for their first 300,000 MWh, plus may use offsets to meet their emissions intensity target for 5% of any MWh above 300,000.

To ensure that the threshold is not abused, in addition to a limit of 5% in a single year, there should be a limit of 10% over a rolling 5 years (in aggregate).

Related bodies corporate should be treated as one Market Customer for threshold purposes, and the regulator should be able to deem certain entities to be related for this purpose. Any related parties should be noted in the Guarantee Database (see response to 3.6.2), and this should be public.

Offsets should be high quality offsets – they should qualify under a scheme such as the UN CER programme, and the best indication of quality is price. Offsets used to meet Guarantee obligations should be targeted to have a cost no less than 50% of the Shortfall Price (see response to 3.6.4). Each retailer should be required to submit to the regulator the price paid for each offset (to be entered into the Guarantee Database, but not to be published), and should certify that the purchases were at arms' length and that for the price paid no other benefits were gained in addition to the offset. This should be subject to potential audit.

What (if any) requirements to use within-NEM opportunities before using offsets are appropriate?

Provided a mechanism such as that described above is used, there should be no specific requirements.

3.5 – Interaction with voluntary 'green' programs

What are stakeholder views on the interaction between the emissions requirement of the Guarantee and voluntary programs such as GreenPower?

Clearly voluntary programs need to remain additional to any mandated obligations, whether that is under the RET, the Guarantee or otherwise. For GreenPower this should be possible simply by ensuring that LGCs surrendered voluntarily cannot be utilised towards any Guarantee obligation (which should be the case if adopting our Proposed Emissions Methodology – see response to 3.2.3).

In addition, a new voluntary programme should be established which allows a Generator to voluntarily omit its generating unit's output and emissions from the Guarantee calculation if the generating units emission factor is below the target.

3.6.2 – Compliance registry

What are stakeholders' views on the need for a compliance registry? What are stakeholders' views on its design?

Are there alternative schemes that would allow retailers to monitor and verify compliance with the emissions requirement? How could these alternative schemes work?

Are there any additional features which the registry should have?

Should any of the data in the registry be made publicly available?

A database (the **Guarantee Database**) should be used to store all information needed to determine compliance with the Guarantee, which in the case of the emissions requirement would include at least that information specified as part of our Proposed Emissions Methodology (see response to 3.2.3). The design should allow for the regulators to gather all required data without having to request anything from Generators or Market Customers if possible – drawing on sources such as NGERS data, AEMO data, and so on.

All data should be publicly available (other than the price paid for offsets). Any commercial sensitivity it arguably has is outweighed by the benefits of transparency, as transparency will ensure efficient market outcomes in meeting Guarantee obligations.

The Guarantee Database should perhaps be hosted by AEMO, given that it will in many respects mirror data in the market management systems (as defined in the NER) hosted by AEMO. That being said, some aspects of the market management systems and AEMO data are not publicly available other than to Market Participants. This is problematic for large energy users like Telstra who are not Market Customers. We may require information to determine whether to enter into long term contracts, and as such it should be publicly available.

3.6.3 – Reporting requirements for emissions requirement

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?

The Guarantee Database should be populated by the regulator where at all possible, rather than by Market Customers or Generators. For a given compliance year the data required would include: emission factor of each generating unit; MWh generated by each generating unit; MWh from given generating units contracted by each Market Customer; MWh sold by each Market Customer; and MWh voluntarily excluded. In responses to previous questions, various data points are noted.

Is information on generators' contracting positions also required to be entered into the compliance registry, for the purposes of reducing the chance of either double-counting or attributing generation output to the wrong retailer?

Yes, definitely. Whether or not it is made publicly available, it must be in the Guarantee Database.

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

No. Furthermore, requesting this information could (given the implications for confidentiality) discourage Market Customers and Generators from contracting if those prices may have to be disclosed. It has no bearing on tracking emissions and so can be ignored.

3.6.4 – Enforcement tools for emissions requirement

What are stakeholder views on the proposed approach to compliance with the emissions requirement and particular:

Whether this approach provides the appropriate drivers of compliance.

The type of information the AER will need to access to ensure compliance.

Other possible enforcement tools, such as increased prudential requirements or restrictions on accepting new customers while emissions requirements remain outstanding.

There should be a simple dollar figure (the **Shortfall Price**) for any shortfall against obligations. This would be multiplied by the number of tonnes of emissions associated with failing to meet the emissions target, to determine the penalty to be paid (the **Shortfall Payment**). This is much like the shortfall mechanism in the RET. Anything else would make it unclear to Market Customers how to price the risk associated with non-compliance, and that will drive higher costs to consumers.

3.7.1 – Competitive markets

What are stakeholder views on how the Guarantee may impact on competitive market?

Any compliance mechanisms that put a burden on Market Customers will impact smaller Market Customers more than large ones, even if the overall cost of compliance is greater for larger Market Customers. In addition, new entrants will be put off by any burdensome compliance arrangements. As such, improper scheme design will reduce competition, and increase prices to end users.

3.7.2 – Jurisdictional considerations

What are stakeholder views on the operation of the emissions requirement in particular jurisdictions?

If the emissions requirement applies across the whole of the national market, then any jurisdictional targets could be incorporated by using the voluntary method noted in response to 3.5 (that is, generation built purely to meet a State-based target could be voluntarily excluded from Guarantee compliance calculations).

4. Emissions Requirement: Commonwealth Government design elements

4.2.2 – Form of the emissions target under the Guarantee

Stakeholder views are sought on options for setting the emissions targets under the Guarantee.

The target should be set in tonnes per MWh for each year, and this should be set at a NEM level for NEM connection points, and at a non-NEM national level for non-NEM connection points. The targets should be set based on current forecasts of load and EITE load (to determine **non-EITE load**).

4.2.3 – Forecasts and adjustments to the target

Stakeholder views are sought on:

Whether, and in what circumstances, electricity emission targets already set should be adjusted.

The process for making any such adjustments to electricity emissions targets.

Efficient energy investments require long term policy certainty. The principle that should be observed here is that changes to targets will only be made if absolutely necessary, and that a stable target which is imperfect at aligning to the original policy objectives is preferable to a regularly changing target which perfectly aligns with the original policy objectives (within a tolerance). Once every five years the target should be reviewed if the non-EITE load forecast is different to the forecast used when setting the target, by at least 10%. If a review takes place, it should be limited to an independent expert re-forecasting non-EITE load so that a corresponding change to the target can be made.

4.2.4 – Timing and process for setting the electricity emissions targets under the Guarantee

Stakeholder views are sought on the proposed timing for updating the electricity emissions targets, including a five-year notice period.

Consistent with the principles noted in response to 4.2.3, the targets should be set indicatively 15 years in advance, and locked in 10 years in advance, subject to review as noted in response to 4.2.3. The RET was set in 2009, with targets out to 2030 (with 21 years to run), but has seen significant investment in the last two years (with 13 years to run). Efficient investment in energy generation involves an investment horizon of at least 25 years, which means that regulatory certainty and stability are both crucial to efficient investment.

4.2.5 – Geographic neutrality

Stakeholder views are sought on the proposed approach to setting the electricity emissions targets under the Guarantee and interaction with state renewable energy schemes.

As noted in response to 3.5, a voluntary scheme should exist where a Generator can voluntarily exclude a low emissions (emissions below the annual target) generating unit's output and emissions from the Guarantee calculation. Some State-based schemes may make use of this to ensure that their low emissions generation is incremental to the policy objectives of the Guarantee, but that is a question for State legislators.

4.4 – External offsets

Stakeholder views are sought on whether retailers should be allowed to use external offsets to meet a proportion of their emissions requirement. In particular, views are sought on:

Whether there is a strong rationale for the use for offsets within the Guarantee

The impact allowing offsets would have on investment under the Guarantee

If offsets were to be used to help achieve compliance with the emissions requirement, what would be an appropriate limit for their use?

The use of offsets should be permitted because Market Customers may not be able to forecast their requirements accurately when determining what long term contracts to enter into with Generators. Offsets should not otherwise be permitted.

Please see response to 3.4.3 for further detail on our proposed methodology.

5. Reliability Requirement

5.6.1 – What contracts will be eligible?

What are stakeholder views on the types of contracts that should be considered eligible for the purposes of the requirement?

Any swap, base, peak or $300 cap contract should be eligible. A retailer holding an option over a swap, base, peak or $300 cap contract could be taken to have complied also. Any ASX traded base, peak or cap contract should be eligible, and for OTC contracts there should be template contracts which are eligible, but also a process where a Market Customer or trader can have their standard contract terms (such as their ISDA Schedule and template Confirmation) reviewed by the regulator and confirmed to be eligible (as in practice each Market Participant will have bespoke terms for their hedges). Provided that the regulator is satisfied that the contract has equivalent firmness to an ASX traded contract, or better, they would confirm eligibility.

Do stakeholders consider eligible contracts should be financial, or have a link to physical capacity?

What do stakeholders think of the approach to certify financial contracts back to a physical asset?

We do not believe that physical linking is necessary, and feel that financial contracts should be sufficient. This is because prudent Market Participants would typically not sell capacity they could not rely upon, nor buy a contract from a counterparty they could not rely upon to deliver financially.

To what extent does the design choice about eligible contracts influence different types of retailers, and so market structure?

Of the most critical importance is that smaller Market Participants are not penalised by being forced to obtain an AFSL if they previously had relied upon exchange traded contracts.

What are stakeholder views on the proposed approach of determining the generation source in a vertically integrated business?

Each Market Customer should be required to obtain the requisite amount of capacity, regardless of whether they own generating units or not. This could be ensured by requiring an internal OTC contract between generation and retail arms of these vertically integrated businesses.

5.7.3 – What forecasts should be used for the allocation?

What are stakeholder views on the proposed method of allocating the gap to retailers?

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

How should C&I load be treated?

Firstly, the total capacity requirement should be the subject of contracts rather than just the increment. Then, for a given region and period each Market Customer should be required to contract swaps, base, peak or caps (or a combination) for a set number of MW for each MWh of residential consumption, as well as a set number of MW for each MWh of consumption from different categories of C&I customers (or individually identified customers where they consume above a threshold). This would then put the burden of forecasting total consumption in that period onto Market Customers, and it would be up to them to ensure that they contracted adequately for that period. Any costs of activating RERT or other mechanisms to address shortfalls could be allocated to Market Customers who fell short of their contracting obligations (provided that the cause of an overall market shortfall was not due to AEMO mis-forecasting).

So for example, if we had a 500MW forecast shortfall in SA, and we needed to increase to 5000MW of capacity, 5000MW would need to be allocated across all Market Customers. Assuming for simplicity that all consumption was forecast to be by residential consumers, and assuming we forecast 22 TWh of load, Market Customers would need to demonstrate that they had contracted 0.228 kW of capacity for each MWh consumed by their residential customers in SA during that year.

In practice, the required MW per MWh for individually identified C&I customers would be determined first, and those MW and MWh would be removed from the total, following which the required MW per MWh for other C&I categories would be determined, leaving only the MW and MWh to be allocated to residential and small business load. Thresholds for compliance should also apply as per our response to 5.7.4.

In addition, it is likely appropriate that the targets be set quarterly (as some quarters will have a higher requirement than others).

How should load met by interconnectors be treated?

AEMO should determine an overall MW capacity figure required for each State, and should specify how much of that can reliably be assumed to be provided by interconnectors, with the residual being the amount that Market Customers must contract.

5.7.4 – Who is required to respond?

Should a different level of compliance and/or reporting requirement be required for large energy users who are registered Customers?

What are stakeholder views on extending the reliability requirement to large energy users that are not market customers?

If the reliability requirement should be extended to large energy users that are not market customers, what would be an appropriate definition of 'large energy user'?

Any Market Customer consuming above a threshold should be required to comply. That threshold should be set at a level that allows new entrant retailers and non-retailer customers sufficient time to comply. The same approach to related bodies should be taken as with offset thresholds noted in response to 3.4.3. An appropriate threshold might be consuming less than circa 300,000 MWh per annum across all regions (equivalent to the fixed component of the offsets threshold) or if that test is not met, consuming less than 50,000 MWh in the region where the reliability requirement is applicable.

Non-market customers should not have compliance obligations under the scheme, as their retailers would hold that obligation. Non-market customers could, however, elect in future to enter long term contracts with dispatchable generation which they could then novate or sub-contract to their retailer (which may increase the number of retailers willing to bid to supply them). For this reason, large customers who are not Market Customers (such as Telstra) should be given visibility of any market data associated with the reliability obligation.

5.8.1 – Ex ante vs ex post approach to compliance

What are stakeholder views on an ex ante or ex post approach to compliance?

Targeted MW per MWh contract requirements should be specified by the regulator well in advance of the period commencing, and compliance should be self-reported (subject to potential audit) after the period has ended.

A target would be for a given quarter. If there was a shortfall forecast for multiple quarters, the regulator should notify Market Participants of this as early as possible. Then, Market Customers should be required to notify the regulator of any forecast failure to meet the obligation as early as possible (including before the relevant quarter has commenced). However, there should be no obligation to demonstrate contracted MW for future periods (only to demonstrate compliance for each period as it has finished). This is because there is no appropriate way to deal with churn assumptions.

While there could be some concern that Market Customers will not contract far enough in advance the reality is that Market Customers will be forced to contract for as many quarters forward as is necessary to support the construction of new generation (in the event of a shortfall), as no Generator would offer a contract for a single quarter or year without having contracting certainty for a greater proportion of the asset's life (unless the price offered for that quarter or year was sufficient to support construction, in which case the objective would be met anyway).

What are stakeholder views on the implications for the assignment of the gap, given an ex ante or ex post approach?

What parameters should be taken into account when deciding between these two options?

Specifying the requirement in MW per MWh in the manner suggested above puts the forecasting obligation onto Market Customers, as is appropriate.

Does an ex post or ex ante approach impact different retailer types?

Yes – please see proposed thresholds in our response to 5.7.4.

Could an ex post approach be effectively implemented while retaining a credible procurer of last resort function?

Yes – but there should be a requirement that any Market Customer who forecasts that they will not meet the contracting obligation should notify the regulator as soon as they become aware of that fact, and there should be obligations to have forecasting processes in place.

5.9 – Procurer of last resort

What are stakeholder views on the including a procurer of last resort function in the reliability requirement?

The approach is not without risk. Perhaps one Market Participant could bid to be the procurer of last resort for each region, based on an auction conducted by AEMO well in advance.

How should a significant and enduring gap be resolved?

By ensuring that investors have certainty that the market rules will not change in future, and by ensuring that the market price cap and other market parameters are set to appropriately incentivise investment in generation in that region.

Continued regulatory change and government intervention will increase the maximum spot price required to incentivise investment, but ultimately the maximum spot price should be a sufficient signal to incentivise investment.

Alternatively, consumers may place a lower value on reliable energy supply than is needed to incentivise investment, in which case the enduring gap should be left unresolved. While Telstra places great importance on reliable supply of energy, we understand that affordable supply of energy is equally important for many Australian energy users. For Telstra it is important that we have a reliable supply of energy on the most affordable basis practicable.

5.10 – Penalties

Do stakeholders consider that retailers not meeting the requirement should be charged a penalty or allocated costs or a penalty plus costs?

Are there other enforcement tools that would be appropriate?

If the obligation is specified in MW per MWh, then it will be extremely straightforward to apportion costs and penalties to Market Customers who have not met the obligation. Any costs associated with the procurer of last resort, or RERT, and so on, should be allocated proportionately to Market Customers who did not meet the obligation (to the extent that those costs arose due to the obligation not being met in aggregate, rather than due to AEMO mis-forecast). In addition, if those costs for the period are below a pre-determined level, a penalty should be imposed. The appropriate quantum of penalty should be determined by the AEMC's Reliability Panel, and could for example be by reference to a set number of Cumulative Price Threshold (or **CPT**, as defined in the NER) events occurring during the period (for example the cost of five such events would be $1,084,500 per MW in FY19).

For example, a retailer who procured 180 MW of capacity for 1 TWh (or 0.180 kW per MWh) instead of 0.228 kW per MWh would be 48 MW short, which based on five FY19 CPT events, would mean a ~$52m penalty less costs contributed. This is a cost of circa $52 per MWh – well above the costs of managing the risk ahead of time to ensure the market was reliable, but not so punitive as to exceed the signal necessary to drive compliance.

Other useful enforcement tools could include, for Market Customers who are energy retailers who fall short for a second year, something akin to a RoLR event (as defined in the National Energy Retail Law) to reduce their number of customers below the amount that they would otherwise have been compliant with for the prior period. In the example above, that could mean 21% of that retailer's customers (perhaps selected based on longest tenure first) in the region go to the RoLR (or perhaps compliant retailers could bid to take on those customers, which would see them more likely ending up with a retailer with adequate capacity contracts).