30 July 2014

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

Via email

Re: Normal frequency asset owner performance obligations – Consultation Paper

Contact welcomes the opportunity to comment on the Electricity Authority consultation paper, 'Normal frequency asset owner performance obligations'.

In addition to our responses to the Authority's questions which can be found on page five, we also make the following comments:

1. Previous submissions on the change to dead band requirements

In Contact's previous submission on the Electricity Commission's consultation paper '*Normal Frequency - Generator Asset Owner Performance Obligations - Frequency keeping Cost Allocation 2010'* Contact made its views clear on unrestricted free governor control (FGC); essentially a reduction in dead band. Our comments were:

- While the provision of unrestricted FGC from hydro generation is likely to be feasible in the majority of cases (for existing hydro plant), unrestricted FGC from geothermal or CCGT generation could increase the risk of plant tripping, affecting security and reliability of supply.
- Older thermal plant in particular may not be able to respond without significant consequences for reliability and maintenance costs. The cumulative impacts of this requirement will also accelerate major plant maintenance costs.
- Where geothermal and thermal plants are operating at maximum levels there is limited scope for FGC and is limited to only one direction (i.e. would only back off when load reduces).
- It does not seem reasonable to impose additional obligations beyond what is already effectively provided for through the reasonable endeavours of the operators of those assets within the normal band for frequency.

Contact's views on this matter, i.e. that we did not support the change, remain unchanged. In our view the statement made on page 17 of section 4.2 in this consultation that '*earlier submissions around dead band reduction where other views were expressed*' is an understatement as four out of the five generator submissions at the time opposed this change. There are practical reasons as to why asset operators have existing settings in place and these are discussed further in this submission.

2. Evaluation of costs and benefits

Contact has concerns on the assumptions around the costs and benefits of the proposal. Specifically:

- Sections 5.6.10 and 5.6.11 state that the Authority acknowledges that the full costs are not known and this is a high level assessment. We feel that without considering the cost to asset owners in this analysis (which will have a flow on effect to spot price for marginal plant) the cost/benefit analysis is invalid.
- Section 5.4.5 states that 'other' costs are difficult to estimate. We feel that it would have been useful for the Authority to approach asset owners prior to consultation to gain feedback on the inputs into the cost benefit analysis (CBA).

Costs

In order to determine the effect of the proposal on costs to test compliance and the ongoing costs to assets due to the accelerated use of equivalent operating hours (EOH) Contact employed an external consultant to undertake analysis on our behalf. The results of this analysis are contained in the accompanied confidential report. Based on these results the EOH costs for our thermal plant will increase by around $3.5m per year. The implications of these costs to purchasers would be two-fold:

- Firstly this cost would be reflected in the marginal price through offers;
- Secondly, there will be increased periods where the units will be on outage. This is likely to result in a reduction in supply and higher spot prices that will further increase purchaser costs and reduce system security. In addition to this, as mentioned in section one above, there is an increased risk of a trip when operating at a reduced dead band.

We do not agree with section 3.2.2 which attributes a reduction in wear and tear costs or EOH to decreasing movement in primary plant. Initial wear and tear is incurred to get to that state. Our view is that this decreasing movement is unlikely to occur as plant that do not comply currently, are unlikely to comply in the future as the asset owners are likely to seek dispensations. Geothermal plant face an additional cost associated with the proposal. As these units are base loaded, they will only react downwards reducing market supply and potentially operating these units in a range that the plant is not designed to, again reducing reliability.

Benefits

Section 2.1 mentions a reduction in total frequency keeping (FK) costs to $41m in 2013, these costs are down from $80m in 2008 and will decrease further with MFK nationally. Our view is that the effect of the proposal on reducing these FK costs will be secondary to the other initiatives already in place as discussed above. Section 5.4.4 identifies cost savings to FK of $1.5m year. Based on our external assessment this benefit will easily be outweighed by the additional summated cost EOH costs borne by generator market participants that would be passed onto purchasers through an increase in marginal costs.

Section 2.3.2 mentions a regulatory cost due to uncertainty in generator investment. Our view is that at present there are minimal issues with clarity on technical compliance. Requirements are clearly known and when new equipment is specified or if there is any uncertainty, the SO is consulted with. This cost is insignificant and it is speculative to say generator compliance costs will be reduced as the cost to comply with the proposal would outweigh this significantly.

This section also mentions that the SO would benefit by having more clarity on asset owner information in order to better assess system security. We believe that this is not a reason to change the Code and the most efficient way to achieve this would be through a change to the asset capability statement (ACS). If the SO are unsure what the gain settings, droop, or dead band are, then additional fields can be added to request that information.

Section 5.2 mentions enhanced competition amongst generators competition. As mentioned above, the situation is unlikely to change from the status quo.

3. Dispensations and Transition Period

Sections 4.4.2 and 4.4.7 refer to dispensation related costs or costs that may be imposed in the future. Our view is that if the asset is unable to comply, then in order for the asset owner to make an informed decision to apply for a dispensation for the lifetime of the plant, they would need to know these costs in advance. An indication of what these costs would look like would be very useful and in our view is an important input into the CBA. These additional operating costs would be reflected in the marginal price through offers.

When introducing new technical requirements we think that it is unreasonable to assume that the AO has a choice to comply or to dispensate, as these requirements were not specified at the time of build. This may be more reasonable for new connections as these can be specified in advance. We would suggest a grandfathering clause for existing plant which would exonerate that plant from complying and requiring a dispensation.

The eight month transition period is not reasonable. If it is possible to make the required plant changes to become compliant then the lead time for achieving this may be in excess of two years. For minor changes and testing, it would be more sensible and efficient to do these during scheduled maintenance periods to avoid additional outages of generation thus reducing supply and imposing additional costs to purchasers. We would suggest a transition period of two to five years.

4. Compliance with dispatch instructions

The proposal will have an adverse effect on generator asset owners when complying with a MW dispatch instruction. In the past there have been queries from the SO as to why fast acting plant is off dispatch. The mismatch between actual and the dispatched amount was due to fluctuations in system frequency and therefore reducing the dead band, increasing gains, and reducing droop settings will only aggravate this issue. The SO will need to account for this when monitoring and enforcing compliance.

5. Summary

Contact believes that the assumptions and inputs into the cost benefit analysis are incorrect and would need to be revised to include the flow on costs to purchasers. As it stands asset owner costs that significantly affect the outcome of the CBA have not been considered, while the stated benefits, which we believe are questionable, could be achieved through more efficient means.

We would like to see:

- The transition period extended by a minimum of two years.
- Code changes affecting plant to apply to new (proposed) generation only.
- The dispensation costs made known, so an informed assessment can be made.

Finally in the future it would be useful if proposals such as this could be consulted on through workshops as were the AUFLS changes.

If you would like to discuss any of the points above please contact me.

Yours sincerely

Gerard Demler
Transmission Manager, Market Services

Specific answers to questions

No.	Question	Contact Energy response
Q1	Do you have any comments relating to the drafting of the proposed Code amendment? Please provide comments and suggested drafting improvements with reference to specific parts, schedules and clauses of the draft proposed Code amendment set out in Appendix A.	Please see sections one to four above.
Q2	What comments do you have on the Authority's proposal for an eight-month transition period?	As per section 3 above we suggest a minimum of two years to align with maintenance outages and lead times for equipment.
Q3	What costs do you anticipate that affected parties, particularly generators, may face in transitioning to the new regime if the proposed Code amendment was to proceed?	Contact estimates $764k for compliance testing. Transition costs are unknown at this stage (if applicable).
Q4	What on-going costs, relative to the status quo, do you anticipate that that affected parties, particularly generators, might incur if the proposed Code amendment was to proceed?	EOH costs for our thermal plant will increase by around $3.5m per year. This amount would be added to the marginal cost of plant increasing cost for purchasers. There will be increased periods where the units will be on outage resulting in a reduction in supply, again increasing purchaser costs.

Q5	What comment do you have on the Authority's evaluation of the alternatives and the cost-benefit assessment of the preferred Code amendment (the proposal) set out in Sections 5.4 and 5.5?	Contact has concerns on the assumptions contained in the proposals CBA. While the Authority acknowledges that the full costs are not known and this is a high level assessment we feel that in order for the output of the cost/benefit analysis to be valid, even at a high level, the cost to asset owners must be considered. We believe this is significant. Section 5.4.5 states that "other" costs are difficult to estimate, we feel that this could have been quantified by the Authority approaching asset owners prior to consultation to gain feedback on the inputs into the CBA. Cost savings to FK of $1.5m year are stated. We believe this benefit will easily be outweighed by the additional summated cost EOH costs borne by generator market participants that will be added to the marginal cost of plant, ultimately increasing the cost for purchasers. FK costs have halved in the last five years and these will decrease further with MFK nationally. Our view is that the effect of the proposal in reducing FK costs is secondary to other initiatives already in place.
Q6	What comment do you have on the Authority's assessment of the proposed Code amendment against the requirements of section 32(1) of the Act?	Section 5.2 mentions enhanced competition amongst generators. We believe the current situation is unlikely to change. While hydro will be compliant, large thermals will not be, and geothermal will not be applicable. Based on this, these benefits are irrelevant. An increase in EOH due to increased wear and tear results in increased maintenance outages and an increased risk of trip which reduces reliability of supply. The EOH cost increase and a reduction of supply in the market will increase purchaser costs reducing efficiencies in the market and any perceived gains in FK cost reduction. There are no efficiencies to be gained from removing ambiguity in generator obligations. Obligations are largely known at present and if not, are clarified with the SO on a case by case basis.

Q7	What comment do you have on the Authority's assessment of the proposed Code amendment against the Code amendment principles?	*Principle 2 – Clearly Identified Efficiency Gain or Market or Regulatory Failure*: As per our response to Q6, our view is that there are no efficiencies to be gained around obligations and reduction in purchaser costs with this proposal. *Principle 3 – Quantitative Assessment:* As per Q5 response, our view is that without considering the cost to asset owners and the flow on effect of these, an accurate CBA cannot be made.

Clause Reference	**Submitter's Comment**	**Submitters Alternative Drafting**
Schedule 8.3 (c)(iv)	Contact is of the view that requiring units to operate with governor gains that are set "as high as practical" is not sensible. For example, in the context of hydro-units it is usual to select governor gain parameters such that the frequency/speed control loops have sufficient gain/phase margin. This is often achieved via Nyquist testing (only applicable to hydro-units). Furthermore, the identification of the actual proportional and integral gain parameters/values in a modern digital governor (particularly of thermal units) is difficult. And in some cases governor vendors take the view that the governor code is proprietary.	is tuned to provide swift response to frequency changes; and does not adversely affect the plant
Part I, Preliminary provisions 1.1	Contact is of the view that the proposed definition of droop remains ambiguous, as it does not indicate whether the droop value is inclusive/exclusive of a frequency dead-band.	**Droop** means the ratio of the steady-state change in **frequency**, expressed as a percentage of 50Hz (from the edge of a frequency dead-band), to the steady-state change in the power output of a **generating unit**, expressed as a percentage of the

Clause Reference	Submitter's Comment	Submitters Alternative Drafting
		generating unit's rated gross output (MCR)
Schedule 8.3 (d)	The new clause requires generators to obtain approval of actual governor settings, in the form of proportional/integral gain and droop. Given the complexity of modern governors the discovery of these settings is often difficult and it is usual for generators/ vendor's to supply simplified power system models. Contact is of the view that the original clause (d) of *The Code* is more practical than the proposed change.	None. Retain the current code.
Schedule 8.3.5 (1)(b)(iii)	none	none