Consultation Paper

Normal Frequency - Generator Asset Owner Performance Obligations

Prepared by the Electricity Commission

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Executive summary

In 2005, the Commission initiated a strategic project called the Wind Generation Investigation Project (WGIP) to:

(a) assess the likely impact of wind generation development over the next 5 to 10 years;

(b) identify wider power system and electricity market implications of additional wind generation; and

(c) develop options for how these might best be resolved to enable the development of wind generation on a "level playing field" with other generation sources.

The project team completed its work early in 2008 with a report recommending the Commission undertake a number of initiatives, including a proposal to review the Asset Owner Performance Obligations (AOPOs) in three specific areas and the dispensation and equivalence regimes that support them. The Board endorsed the recommendations, including this review, in March 2008.

The three areas on which the review was to focus include the obligations on generation assets to:

(a) support power system frequency (frequency) under normal conditions;

(b) support frequency following an under frequency event; and

(c) provide reactive power.

This paper contains the results of the review of the first set of obligations; the requirement for generators to support frequency under normal conditions (ie in the absence of events that cause the sudden loss of a significant quantity of generation or load). Reports on the other two sets of obligations will be published in due course.

In keeping with the WGIP options paper (and subsequently supported by several submissions received at the time), the Commission's review of the obligations on generation assets to support frequency under normal conditions aims to improve generation investment signals by:

(a) ensuring the standards are appropriate, having regard for the capabilities of all generation types; and

(b) including a clear methodology in the Electricity Governance Rules (Rules) for allocating a share of frequency keeping procurement costs to non-compliant generation (including wind turbines) to simplify the dispensations process.

Note that the second feature of the review is the subject of a separate consultation paper into the allocation of frequency keeping costs.

The AOPOs, dispensations, and equivalence provisions in the Rules together provide investors and asset owners a framework by which the investment ‘playing field’ can be made level with respect to decisions about the choice of generation technology. AOPOs are a standard feature of grid codes around the world. Requiring certain capabilities from the manufacturers of generating units is generally considered to be a low cost way (including compliance costs) to maintain a stable power system.

In New Zealand’s Rules, the AOPOs are a relatively small set of outcome-focussed requirements, reinforced with more specific technical requirements contained in the technical codes. The dispensation provisions allow generation investors to choose technologies that are non-compliant, with the agreement of the System Operator, as long as they are prepared to pay any costs that their non-compliance imposes on others. The equivalence provisions allow asset owners to innovate to meet requirements in other ways. The intent is that all generation investments compete on equal terms in respect of the capabilities required.

The AOPO for generators and the HVDC owner to support frequency under normal conditions is included in rule 2.1 in section III of part C. Rule 2.1 is a general requirement and covers both normal and emergency conditions. Generators must ensure generating units and associated control systems, when synchronised[1], make the maximum possible injection contribution to keep frequency within the normal band[2] (and to restore it to the normal band). Any such contribution by generators will be assessed according to the technical codes.

Rule 2.1 is supported by requirements in both technical code A (Assets) and B (Emergencies) but the relevant requirements are for generators to ensure their control systems and speed governors have various characteristics[3]. The Commission has compared normal frequency requirements in rule 2.1 and technical code A with similar requirements in other grid codes[4] and confirmed that the requirement for generators to support frequency via free governor action continues to be a standard feature. It is also common for grid codes to require generating units to have speed governors (or equivalent mechanisms) that are

1 Asynchronous intermittent generating stations are treated as being synchronised for the purposes of rules in section II of part C.

2 The normal band is defined in Part A of the Rules and refers to 50 Hz ± 0.2 Hz (ie frequencies between 49.8 and 50.2 Hz, inclusive)

3 Rules 5.1 and 5.3 of technical code A concern requirements for control systems and speed governors. Control systems must support the System Operator to plan to comply and comply with the Principal Performance Obligations (PPOs). Generating units must be fitted with a speed governor that:

(a) provides stable performance with adequate damping;

(b) has adjustable droop over the range 0-7%; and

(c) does not have any characteristics that might adversely affect the operation of the grid.

Further, governor settings must be set appropriately with the agreement of the System Operator and may only be changed with its approval. Finally, a generator’s control system operating multiple units should neither adversely affect the ability of the System Operator to meet its PPOs, nor degrade the individual performance of each unit

4 For example, National Grid (UK), EirGrid (Ireland), NEM (Australia), Nordic code (Norway, Sweden, Denmark), E.On (Germany)

stable, adequately damped, and have adjustable droop settings (commonly within a specified range).

In some cases, the requirements for supporting frequency are specified separately for each generation type and/or exclude wind generation. However, the Commission does not favour this approach as it requires officials to make arbitrary decisions about the inherent capabilities of different technologies and can favour one type over another, irrespective of system effects and their associated costs. It is therefore inconsistent with its objective to create a level playing field for generation investors.

Australia's approach provides another alternative as, while the standards in Australia and New Zealand are both generic, there are greater opportunities/penalties in Australia associated with supporting frequency under normal conditions. The requirements for generators to support frequency are relatively basic but they are reinforced with a relatively sophisticated market where those causing frequency deviations pay those responding to correct them. Together, these arrangements appear to provide:

(a) generation investors a clear and level playing field with respect to the choice of generating technology;

(b) generators an incentive to make additional capability available to support frequency; and

(c) other generators and loads an incentive to change behaviours to lessen any adverse impacts on frequency quality (where it is cost effective to do so).

Although the Commission is not considering a frequency deviations market as sophisticated as Australia's at this time, it is committed to specifying generic standards and cost allocation principles that would achieve the same goals.

Having confirmed that the existing approach is appropriate and the existing rules are not out of step with other grid codes, the Commission is considering rule changes that would support what it considers to be the main features of the existing requirements for supporting frequency under normal conditions. These are that:

(a) generating units should operate under free (unrestricted) governor control according to settings agreed between the generator and the System Operator; and

(b) generating units, their control systems, and speed governors (or equivalent mechanisms) should not hold characteristics that reduce the effectiveness of the speed governor.

During the Commission's review of the allocation of frequency keeping costs, it has become known that some generators limit governor response while frequency is within a "dead band". This information is supported by the results of its analysis of generation output data, which shows less response from generators to frequency than expected when frequency is within the normal band.

The Commission is also aware of an interpretation of rule 2.1 that would suggest generators are entitled to restrict injection response within the normal band and therefore do not require a dispensation to do so. However, the Commission considers this interpretation was never intended and proposes changes to make it clear that generators continue to be required to provide unrestricted governor response to all frequency deviations from 50 Hz. Under the rule amendments proposed, generators could continue to restrict the response of their governor to frequency but would have to make the trade off between any cost allocation associated with non-compliance and the internal costs associated with providing unrestricted governor response.

In addition to this clarification, the Commission proposes a number of other changes including:

(a) a number of drafting improvements;

(b) a reduction in the maximum droop setting within which a governor can be set (from 7% to 6%); and

(c) amendments to ensure that the requirements cover all types of generating units, whether or not they are synchronous.

The Commission is now inviting submissions on the findings of this review of the obligations of generation assets to support frequency under normal conditions and on the proposals in this paper, including comments on the proposed rule changes that give effect to the proposal.

The Commission notes that although it will be impractical to implement a rule change before the proposed new Electricity Authority is established in October 2010, it has decided to consult now given the importance of the issues covered in this paper. Following consultation the Commission will make a recommendation to the new Authority. It will be then up to the Authority to decide whether it wishes to proceed with the rule change or what, if any, use it will make of this consultation by the Commission.

The Commission notes that it will not be practical to implement the proposed rule changes before the new Electricity Authority (Authority) is established in October 2010[5]. However, it has decided to consult now given the importance of the issues covered in this paper with the intention that the consultation may be useful to the Authority. Following consultation, a recommendation will be made to the Authority. It will be then up to the Authority to decide whether it wishes to proceed with the rule change and what, if any, use it will make of this consultation by the Commission.

5 As currently proposed in the Electricity Industry Bill.

Glossary of abbreviations and terms

ACS	Asset Capability Statement (as defined in Part A of the Rules)
AOPOs	Asset Owner Performance Obligations
Board	Electricity Commission Board
Commission	Electricity Commission
Dead band	In the context of this paper, a dead band is a frequency range within which a speed governor will not respond to frequency movements
Frequency	Power system frequency
GIP	Grid Injection Point
HVDC	High Voltage Direct Current
Normal conditions	In the absence of events that cause the loss of a significant quantity of generation or load
PJM	Pennsylvania, Jersey, Maryland Power Exchange
PPOs	Principal Performance Obligations (contained in section II of part C of the Rules)
Rules	Electricity Governance Rules 2003
WGIP	Wind Generation Investigation Project

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1. Introduction and purpose of this paper

1.1.1 This paper contains the findings of the Commission's first review of the obligations of generation assets to support frequency under normal conditions. Papers on the other obligations will follow in due course.

1.2 Purpose

1.2.1 The purpose of this paper is to consult with participants and persons that the Commission thinks are representative of the interests of persons likely to be substantially affected by the Commission's proposed changes to the rules requiring generators to support frequency under normal grid conditions.

1.2.2 Some of the changes proposed in this paper are made in accordance with section 172F(3) of the Electricity Act 1992 (Act) because the Commission is satisfied that the effect of those changes is minor and will not adversely affect the interests of any person in a substantial way. As such, in respect of those proposed minor changes, it is not required to set out a detailed statement of the proposal, a statement of the reasons for the proposal, an assessment of the proposal and all reasonably practicable options identified by the Commission, and any other information the Commission considers relevant.

1.2.3 However, for the proposed changes that are not minor, this paper sets out a detailed statement of the proposal, a statement of the reasons for the proposal, an assessment of the proposal and all reasonably practicable options identified by the Commission, and any other information the Commission considers relevant.

1.2.4 The Commission invites submissions on the proposals in this paper, including drafting comments on the rule changes proposed.

1.3 Submissions

The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@electricitycommission.govt.nz with Consultation Paper – Normal Frequency – Generator Asset Owner Performance obligations in the subject line.

If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to either of the addresses provided below.

Submissions
Electricity Commission
PO Box 10041
Wellington 6143

Submissions
Electricity Commission
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

1.3.1 Submissions should be received by 5pm on 25 June 2010. Please note that late submissions are unlikely to be considered.

1.3.2 The Commission will acknowledge receipt of all submissions electronically. Please contact the Electricity Commission at the telephone number above or by email at submissions@electricitycommission.govt.nz if you do not receive electronic acknowledgement of your submission within two business days.

1.3.3 If possible, submissions should be provided in the format shown in **Appendix 1**. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

2. Background

2.1 History

2.1.1 Existing market arrangements in New Zealand were developed when the power system was dominated by hydro and, to a lesser extent, thermal generation. However, increasing investment in wind generation in the last decade has raised questions about the effectiveness and efficiency of these arrangements specifically with respect to the intermittent output and technical performance capabilities of wind generator technologies.

2.1.2 Recognising this, the Commission established the WGIP in mid-2005 to:

(a) assess the likely impact of wind generation development over the next 5 to 10 years;

(b) identify wider power system and electricity market implications of additional wind generation; and

(c) develop options for how these could be best resolved to enable the development of wind generation on a “level playing field” with other generation sources.

2.1.3 The WGIP developed wind generation scenarios, assessed the implications of increasing amounts of wind generation and identified potential mitigation options. This work culminated in an options paper, which was published on the Commission’s website on 18 October 2007[6].

2.1.4 Following consideration of the submissions received, the WGIP made recommendations to the Commission. These recommendations were adopted by the Board in March 2008 and included a review of the:

(a) AOPOs (to ensure they are appropriate for the range of generation technologies operating in modern power systems); and

(b) dispensations and cost allocation arrangements associated (to ensure they enable effective and efficient investment decision-making).

2.1.5 The review was to cover the obligations on generators to ensure their generating assets:

(a) support power system frequency under normal conditions;

(b) support power system frequency following an under frequency event; and

(c) provide reactive power.

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[6] http://www.electricitycommission.govt.nz/consultation/optionsanalysis

2.1.6 This paper concerns the obligations for generators to support frequency under normal conditions (ie in the absence of contingencies resulting in the sudden loss of a significant quantity of generation or load). Reports on the other two sets of obligations will be published in due course.

2.2 Role of AOPOs

2.2.1 While terminology differs, the AOPO concept is a standard feature in power systems around the world. Historically, assets connected to the grid have been required by regulation to meet minimum frequency and voltage support technical performance standards. For example, grid codes around the world specify that generators must be able to operate within minimum and maximum frequency and voltage limits and provide free governor action, reactive support capability etc. Including these capabilities in the manufacture of generating units is generally considered to be a low cost option (including compliance costs) for investors/ asset owners to meet the power system’s ancillary needs.

2.2.2 Over time, ancillary services markets have developed to varying degrees, enabling some of these costs to be externalised and trade-offs to be made between competing options. For example, interruptible load competes with generation in the instantaneous reserves market. Markets for ancillary services can also provide incentives for asset owners to invest in additional capability and/ or to make excess manufactured capability available.

2.2.3 Consequently, the existing arrangements are a mix of mandatory technical obligations and net ancillary services procurement (i.e. in addition to the mandated obligations), characterised by:

(a) specifying ‘common levels of service’ (in the form of PPOs) on behalf of shared beneficiaries;

(b) where practical and efficient, establishing markets for ancillary services (for example the instantaneous reserve market);

(c) otherwise, or also, requiring asset owners to meet technical performance requirements (in the form of AOPOs and technical codes);

(d) allocating costs from ancillary services procurement to parties that cause the need to the extent it is practical and efficient to do so (including costs incurred indirectly through non-compliance with AOPOs).

2.2.4 The AOPOs are a relatively small set of outcome-focussed requirements which are reinforced with more specific technical requirements contained in the technical codes. The Rules also contain provisions for asset owners to apply for dispensation or equivalence arrangements.

2.2.5 Dispensation provisions allow generation investors to choose technologies that are non-compliant, with the agreement of the System Operator, as long as they are prepared to pay any costs that their non-compliance imposes on others. Dispensation provisions are intended to mimic the decision-making required by an asset owner in a full two-way market - i.e. asset owners may choose not to meet a technical performance requirement if they determine it is cheaper to seek a dispensation from the System Operator from full compliance, subject to payment of any system costs resulting from an asset's non compliance.

2.2.6 Equivalence provisions allow asset owners to innovate to meet requirements in other ways. The equivalence provisions are intended to provide flexibility for asset owners to devise less costly means of achieving technical requirements.

2.2.7 Mandated AOPOs need to be set at levels appropriate for the likely capability required and be sympathetic to the 'off the shelf' capabilities of generators (shaped by trends in standards, internationally) and to the potential to boost the capability via market-based incentives. Mandating AOPOs may be preferable to a market either for the procurement of large amounts of very low cost/value services or because the supply of a service is likely to be lumpy and cause market power issues. For example:

(a) the incremental capital cost of purchasing a synchronous generator with reactive support capability is typically small as this capability is supplied 'off-the-shelf' and the capability can be shaped by the minimum performance standards required; and

(b) given its localised nature, market concentration issues are likely to prohibit a fully competitive market for the supply of reactive support services.

2.2.8 Conversely, AOPOs might be lower if there are large differences in the cost of supplying the capability between generating types and/or system costs can be allocated to moderate the behaviour of causers.

2.2.9 There are some inherent difficulties with the concepts of AOPO and dispensation approach:

(a) generic technical standards are required but can be problematic because not all generators, or even classes of technology, have the same off-the-shelf capabilities. On the other hand, treating technologies differently risks competing investments facing or avoiding more or less costs, distorting investment decisions;

(b) it can be difficult to:

(i) identify system costs caused by non-compliance (e.g. in relation to generator fault ride-through requirements);

(ii) appropriately apportion ancillary service costs across multiple and different forms of non compliance (e.g. generator reactive requirements and distributor power factor requirements);

(iii) identify a rise in ancillary service costs caused by a dispensation (e.g. extra frequency keeping costs);

2.2.10 Thus, while this review is primarily concerned with AOPOs and technical standards, the Commission is also reviewing the efficacy of the dispensations regime and ancillary services arrangements, especially the cost allocation, where interactions with other parts of the market are identified (e.g. possible interactions between generator reactive requirements and off-take power factor requirements).

3. Scope and framework of this review

3.1 Introduction

3.1.1 As explained earlier in the paper, this review is the first of three recommended by the WGIP and endorsed by the Board. The other two concern generator obligations to support frequency following an under frequency event, and to provide reactive power.

3.2 Scope

3.2.1 In keeping with the WGIP options paper, the Commission’s review of the obligations on generation assets to support frequency under normal conditions aims to improve generation investment signals by:

(a) ensuring the standards are appropriate, having regard for the capabilities of all generation types; and

(b) including a clear methodology in the Rules for allocating a share of frequency keeping procurement costs to non-compliant generation (including wind turbines) to simplify the dispensations process.

3.2.2 Note that this paper focuses on the first objective (ensuring the standards are appropriate). The Commission has prepared a separate rule change proposal that considers options for the appropriate allocation of frequency keeping costs (including an allocation to dispensation holders). However, as both subjects are linked, submitters are encouraged to read the Commission proposals for allocating frequency keeping costs when preparing their submission on the rule changes proposed in this paper.

3.2.3 The AOPO for generators and the HVDC owner to support frequency under normal conditions is included in rule 2.1 of section III of part C. Rule 2.1 is a general requirement and covers both normal and emergency conditions. Generators must ensure generating units and associated control systems, when synchronised, can and do make the maximum injection contribution to keep frequency within the normal band (and to restore it to the normal band) to the full extent to which they are capable, considering the circumstances. Contributions by generators will be assessed according to the technical codes.

3.2.4 The technical codes that directly support rule 2.1 include requirements in:

(a) technical code A (Assets) for generators to have control systems and speed governors with various characteristics; and

(b) technical code B (Emergencies) for generators to take specific steps to correct extreme frequency deviations .

3.2.5 However, as this review is focused on the requirements under normal (not emergency) conditions, it does not include a review of the requirements in technical code B.

3.2.6 Also, as the objective of the review is to examine the appropriateness of generator requirements, the scope does not include a review of the obligations of other parties such as consumers/retailers and the HVDC owner to support frequency. It is also more appropriate to consider changes to the requirements for the HVDC owner during the introduction of the new HVDC control system, expected to be delivered as part of the commissioning of pole 3 in 2012.

3.2.7 Finally, this review does not cover the specification and procurement of the frequency keeping ancillary service, as another Commission work stream is overseeing the development of an automatic generation control (AGC) system and frequency regulation market.[7]

3.3 Review framework

3.3.1 The review of the AOPOs for supporting frequency under normal operating conditions contains the following sections:

Section

4. Description of frequency management under normal conditions
5. Review of the appropriateness of the existing requirements
6. Rule change proposal being considered
7. Assessment of options
8. Conclusion and next steps

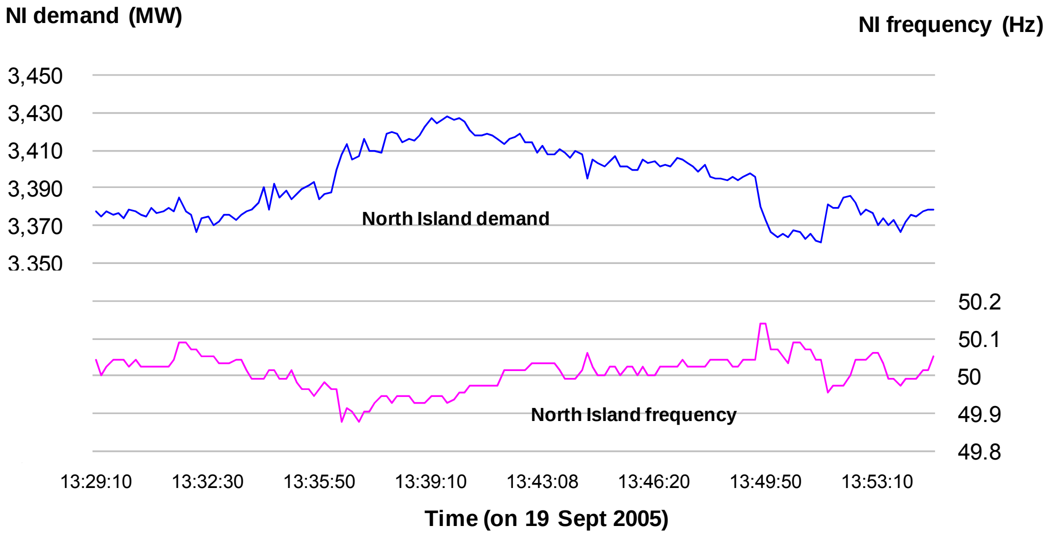
[7] Improving the frequency market is a priority project in the Market Development Programme. See http://www.electricitycommission.govt.nz/opdev/mdp

4. Description of frequency management under normal conditions

4.1 Introduction

4.1.1 As Figure 1 (below) shows, electrical load changes continuously as people and automatic processes switch electrical devices on and off. Variations in load affect frequency as frequency is a measure of the degree of balance between electrical generation and load. In New Zealand, generation and load are in perfect balance when the frequency of the power system is equal to 50 Hz. If the frequency increases above this nominal figure then load is lower than generation and vice versa.

Figure 1: North Island demand and frequency



4.1.2 The existing arrangements for maintaining frequency quality reflect historical practice and are based on the following assumptions:

(a) mandating generators to automatically correct small demand and supply imbalances is more cost effective than equivalent mechanisms for controlling consumer load;

(b) electrical power is generated by synchronous machines; and

(c) market arrangements are less cost-effective than mandated requirements (to greater or lesser degrees, depending on machine capability).

4.1.3 Under normal system conditions (ie outside of events that cause more significant generation/load imbalances), generation and load remain relatively well balanced due to the operation of three controls:

(a) the automated governor response of generators to any demand/supply imbalances on the margin (primary frequency control);

(b) a dedicated frequency keeping ancillary service (secondary frequency control); and

(c) ‘dispatch’ of electricity generation to match daily demand patterns (tertiary frequency control).

4.1.4 The System Operator relies on these mechanisms to maintain power system frequency within a ‘normal band’ of 50 Hz ±0.2 Hz (i.e. 49.8 Hz to 50.2 Hz). Sections 4.2, 4.3 and 4.4 explain the three mechanisms in more detail.

4.1.5 The three controls are inter-linked to some extent. Individual decisions by generators about the response of their governors (or to fit a governor at all) affect power system frequency quality and the cost of the frequency keeping ancillary service. If choices by individual generators reduced the collective performance of governors (e.g. by the introduction of dead bands) then the frequency would move further away from 50 Hz for every given generation and demand imbalance. A significant change in performance could cause any of the following to occur:

(a) frequency quality could decrease (as normal frequency imbalances would become more severe);

(b) the demands on the frequency keeping service could be increased (frequency keepers could be made to increase/decrease output further and, perhaps, faster to correct larger frequency deviations experienced on the power system); or

(c) the System Operator could be required to dispatch generation more frequently to keep the frequency keeping station within its control limits.

4.2 AOPO to provide free governor action (primary frequency control)

4.2.1 The primary mechanism by which frequency quality is managed is via an automatic counteractive response by generators to frequency deviations from 50 Hz known as “free governor action” (also known as “unrestricted governor control”). Traditionally, speed governors are fitted to generating units and these devices automatically respond when frequency moves away from 50 Hz, increasing output on a generating unit in fixed proportion (according to speed droop/regulation settings[8]) with decreases in frequency and vice versa.

[8] Speed regulation is the percentage decrease in frequency required to cause the governor to increase generation of the unit to full output (eg a 4% speed regulation setting would cause generation to increase from zero to full output if frequency dropped from 50 Hz to 48 Hz). Speed droop is similar and is the percentage

4.2.2 The combined effect of free governor action by generators reduces the fall in frequency caused by real time fluctuations in generation and demand. Increasing the amount of generation that operates under governor control (or sharpening the response via the droop settings of existing governors) would arrest frequency falls faster. Conversely, restricting the performance of governors or reducing the number of generating units operating under governor control would reduce the collective response by generators to frequency imbalances, causing the frequency to fall further for a given demand/generation imbalance.

4.2.3 Note that the collective response of governors to frequency deviations does not return the frequency to 50 Hz. This action is the job of the frequency keeping ancillary service (between dispatch intervals) and the real time dispatch process (see the following sections for an explanation of these services).

4.2.4 The Rules do not directly refer to free governor action. Instead, rule 2.1 of section III of part C contains a requirement that generators ensure their generating units and associated control systems, when synchronised, make the maximum injection contribution to keep frequency within the normal band to the full extent to which they are capable.

4.2.5 This requirement is supported by rules in technical code A, the most relevant of which include requirements about speed governors, rate of change on generating units, and control systems.

4.3 Frequency keeping ancillary service (secondary frequency control)

4.3.1 The frequency keeping ancillary service is procured by the System Operator from generators (block dispatch groups, stations, or units) with sufficient spare capacity and responsiveness to vary their generation to help keep frequency within an island at or near 50 Hz for normal demand/supply imbalances. Generators operating to keep frequency not only provide free governor action to respond to supply and demand imbalances, but also continuously seek to restore the frequency to 50Hz and to keep frequency time error within prescribed limits[9].

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decrease in frequency required to cause the prime mover control mechanism to move from fully closed (no change in output) to fully open (highest change in output). Both are subject to the operational limits of the generating unit.

9 Rules 2.2.5 and 2.2.6 of section II of part C require the System Operator to take reasonable and prudent steps to ensure frequency time error does not exceed 5 seconds of New Zealand Standard Time and must be eliminated at least once a day

4.4 Dispatch of generation (tertiary frequency control)

4.4.1 The dispatch of generation is the last control the System Operator employs to manage frequency quality. The System Operator uses its real time dispatch process and software to send generators any changes to the generating "set points" of their generating units and stations in anticipation of daily demand trends to keep the frequency keeper and other generators from straying too far from their scheduled generation levels.

5. Review of the appropriateness of existing requirements

5.1 Introduction

5.1.1 The Commission has looked at some other grid codes, examples of which appear in Appendix 3, primarily to assess the level of consistency of requirements for generators to support frequency under normal conditions (and directly associated technical codes). It has also taken the opportunity to look at how New Zealand's approach to managing the standards (generic requirements with options for exemption, dispensation, and equivalence) compares with other approaches.

5.2 Findings

5.2.1 The requirement for generators to support frequency by operating under unrestricted governor control appears to be a standard feature of grid codes. It also appears common for codes to require generating units to have speed governors (or equivalent mechanisms) that are stable, adequately damped, and have adjustable droop settings (often within a specified range).

5.2.2 In some codes, the characteristics of the response required are specified separately for each generation type, and/or exclude wind generation. However, the Commission does not favour moving to this approach as it:

(a) requires officials to make arbitrary decisions about the inherent capabilities of different technologies;

(b) can create differences in standards that tilt the playing field toward or away from particular generation technologies, with uncertain associated system effects and costs;

(c) is inconsistent with its objective to create a level playing field for generation investors and the risks that could distort investment decisions.

5.2.3 The Commission also notes that, while the standards in Australia and New Zealand are both generic, there are greater opportunities/penalties in Australia associated with responses to frequency deviations. The minimum standards for generators to support frequency are relatively basic in Australia but they are supported by a more sophisticated market in which those causing frequency deviations pay those responding to correct them. Together, these arrangements appear to provide:

(a) generation investors a level playing field with respect to the choice of generating technology;

(b) generators an incentive to make additional capability available to support frequency (where it is cost effective to do so); and

(c) unresponsive generators and loads an incentive to change behaviours to lessen any adverse impacts on frequency quality (where it is cost effective to do so).

5.2.4 However, the Commission is not considering a frequency deviations market as sophisticated as Australia's at this time as it considers that the existing rules can be changed to achieve the same goals at much reduced cost, albeit in a less precise manner.

5.2.5 The Commission notes that some grid codes provide for frequency insensitivity ranges or generator dead bands and that this feature is absent in the Rules in New Zealand. The Commission is also aware that some participants appear to have interpreted the Rules in a way that would entitle them to restrict governor response within the normal band and do not require a dispensation to do so. This finding is supported by the results of recent analysis of generation output data that shows surprisingly less response from generators to frequency than expected when frequency is within the normal band (refer to the Frequency Keeping Cost Allocation Consultation Paper published on the Commission's website at: www.electricitycommission.govt.nz/consultation/freq-keep-cost-allocation).

5.2.6 The Commission considers such an interpretation of the Rules is inconsistent with the intent of the Rules. As indicated in the previous section, generators that restrict the performance of their governors reduce the ability of the power system's primary mechanism for maintaining frequency at 50 Hz. Therefore, providing for a minimum dead band in the Rules has the potential to reduce the power system's resilience to frequency disturbances and increase frequency keeping and reserve requirements (and the costs associated).

5.2.7 Consequently, the Commission proposes to confirm and clarify the existing arrangements. The Rules should not provide for generators to restrict the operation of their governor with a dead band or by any other means without an approved dispensation or equivalence arrangement. Decisions to limit the performance of a governor (or whether or not to provide an equivalent response to frequency deviations) should appropriately require generators to make economic tradeoffs between the internal and external costs incurred by restricting the performance of their governor (below that expected by the droop or regulation setting agreed with the System Operator).

5.2.8 The Commission also understands that there are a number of generators holding dispensations because they are not compliant with the requirements of rule 2.1 of section III of part C of the Rules. However, the System Operator has not identified any associated costs with their non-compliance. As mentioned previously, the Commission is therefore considering changes to the allocation of frequency keeping costs (including an allocation to dispensation holders) in a separate consultation paper.

Q1.	**With respect to normal frequency management, are there features of other grid codes you think the Commission should consider?**

6. Rule change proposal being considered

6.1 Statement of reason for proposal

6.1.1 Having confirmed the approach and that the main thrust of the existing requirements remains appropriate, the Commission is considering rule changes that would ensure the drafting of the requirements is sufficiently clear for the sake of investors, asset owners, and the System Operator. The Commission considers rule changes are necessary because of possible ambiguities in the wording of some requirements.

6.2 Objective of proposal (non-minor changes)

6.2.1 The objective of the proposed rule change is to improve generation investment signals by setting appropriate requirements for generators (having regard for all generator types) to support frequency under normal grid conditions.

6.2.2 Section 172F(1)(c) of the Act requires the Commission to consider whether the objective of the proposed rule change could be satisfactorily achieved by any other reasonably practicable means, other than making a rule change, for example, by education, information, or voluntary compliance. This only needs to be considered for the non-minor amendments proposed in this paper.

6.2.3 As the requirements are already contained in the Rules, and that more than one interpretation of the relevant rules is possible, the Commission considers there is no alternative but to amend the Rules.

6.3 The Commission's proposal

6.3.1 The Commission's proposal is to amend the Rules to clarify the present requirements for generators to ensure their:

(a) generating units operate under unrestricted governor control according to settings agreed between the generator and the System Operator; and

(b) generating units, control systems, and speed governors (or equivalent mechanisms) have characteristics that support the effectiveness of the speed governor's response to frequency changes.

6.3.2 The balance of this section:

(a) explains the minor and non-minor changes being proposed to the rules concerned (paragraphs 6.4 to 6.7);

(b) provides a discussion into the Commission's consideration of changes to the 'catch-all' provisions (paragraphs 6.8); and

(c) describes how the proposal may help achieve the Commission's objectives and outcomes (paragraphs 6.9).

6.4 Minor changes proposed

6.4.1 The table below lists the minor changes the Commission proposes to make to the requirements in technical code A of schedule C3 of part C of the Rules.

Rule	Amended rule	Description
Rule 5.1.1.2	~~**Is able to synchronise**~~ Is able to ~~**synchronise**~~ connect to the **grid** to begin generating **electricity** or **reactive power** at a stable frequency within the frequency range stated in the **asset capability statement** for that **asset**.	Changes marked.
Rule 5.1.2	**Rate of change in output** ~~The rate of change in the output of any of its **generating units** does not adversely affect the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations.** The rate of change must be adjustable to allow for changes in **grid** conditions;~~ The rate of change in the output of any of its **generating units** – 5.1.2.1 does not adversely affect the **system operator's** ability to plan to comply, and to comply, with the **principal performance obligations**; and 5.1.2.2 must be adjustable to allow for changes in **grid** conditions;	Split requirements in two without changing the wording.
Rule 5.1.3.3	~~**Is able to synchronise**~~ Does not adversely affect the operation of the **grid** because of any of its non-linear characteristics;	Changes marked.

Rule 5.3	**Multi-generating unit control** Where the output of more than one **generating unit** is controlled by a common **control system**, the **generator** must ensure that: ~~**5.3.1 Achieve the PPOs**~~ ~~The common **control system** does not adversely affect the ability of the **system operator** to plan to comply, and to comply, with the **principal performance obligations**; and~~ ~~**5.3.2 Combined output**~~ ~~The combined output from the **generating units** performs as though it were from one **generating unit**; and~~ ~~**5.3.3 Individual performances not degraded**~~ ~~Such **control system** does not degrade the individual performance of any one **generating unit.**~~ 5.3.1 the common **control system** does not – 5.3.1.1 adversely affect the ability of the **system operator** to plan to comply, and to comply, with the **principal performance obligations**; or 5.3.1.2 degrade the individual performance of any **generating unit**; and 5.3.2 the combined output from the **generating units** performs as though it were from one **generating unit.**	Deleted duplicate text and split requirements without changing the intent.

6.5 Non-minor changes proposed to rule 2.1 of section III of part C

6.5.1 The AOPO for generators and the HVDC owner to support frequency under normal conditions is included in rule 2.1 of section III of part C:

Existing rule:
2.1 Contribution by injections to overall frequency management Each **generator** (while **synchronised**) and the **HVDC owner** will at all times ensure that their **assets**, other than any **generating units** within an **excluded generating station**, make the maximum possible **injection** contribution to maintain frequency within the **normal band** (and to restore frequency to the **normal band**). Any such contribution will be assessed against the **technical codes**.

6.5.2 Despite the intent of rule 2.1, it may be interpreted to mean that generators are required to make the maximum possible injection to maintain frequency within the normal band only when frequency deviates outside the normal band.

6.5.3 To clarify rule 2.1 the Commission proposes changes which would:

(a) separate the requirements of both generators and the HVDC owner so the wording of the requirements for each can be made specific and more clear;

(b) better describe what is required of generators to maintain frequency within the normal band; and

(c) ensure that the requirement does not just apply to synchronous generating units.

6.5.4 The changes proposed are as follows:

Proposal:
~~**2.1 Contribution by injections to overall frequency management**~~ ~~Each **generator** (while **synchronised**) and the **HVDC owner** will at all times ensure that their **assets**, other than any **generating units** within an **excluded generating station**, make the maximum possible **injection** contribution to maintain frequency within the **normal band** (and to restore frequency to the **normal band**). Any such contribution will be assessed against the **technical codes**.~~

2.1 Contribution to overall frequency management

2.1.1 A **generator** must ensure its **generating units** when **injecting electricity** into the **grid** or a **local network** (other than a **generating unit** within an **excluded generating station**) operate under unrestricted governor control when frequency is within the **normal band** and make the maximum possible **injection** contribution to restore frequency to the **normal band**. The **system operator** must assess each contribution against the **technical codes**.

2.1.2 The **HVDC owner** must at all times ensure the **HVDC link** when **injecting electricity** into the **grid** makes the maximum possible **injection** contribution to maintain frequency in both **islands** within the **normal band** (and to restore frequency to the **normal band**). The **system operator** must assess any such contribution against the **technical codes**.

6.5.5 Splitting the requirements for generators and the HVDC owner into two paragraphs allows the requirements for each to be worded more clearly. Rule 2.1.1 describes what would be required of generators and rule 2.1.2 does the same for the HVDC owner and the HVDC link.

6.5.6 Rule 2.1.1 would require generators to operate under unrestricted governor control while frequency is within and outside the normal band. This would mean that all generating units would be required to increase or decrease their output in proportion with the size of any frequency deviation, according to their droop settings. If rule 2.1.1 is amended, generators could continue to restrict the response of their governor to frequency with dead bands or similar but would have to make the trade off between costs:

(a) allocated as a condition of the dispensation they would need to obtain from the System Operator; and

(b) incurred by providing unrestricted governor response.

6.5.7 Note that the requirements for the HVDC owner are little changed in the proposed rule 2.1.2. As the focus of this review is on generator requirements, the Commission does not propose to change the requirements for the HVDC owner at this time. It intends revisiting them as part of the commissioning of the new HVDC control system, expected to be introduced as part of the commissioning of the new HVDC pole.

Q2. Do you agree with the proposal to clarify rule 2.1 so that generators must ensure their generating units operate under unrestricted governor control?

6.6 Non-minor changes proposed to rule 5.1.3 in technical code A of schedule C3

6.6.1 Rule 5.1.3 requires generating units to be fitted with a speed governor and outlines what is required of them. The requirements for speed governors are consistent with other grid codes. They must:

(a) provide stable performance with adequate damping;

(b) be capable of having their droop[10] adjusted within the range 0-7%;

(c) not have any non-linear characteristics (eg dead band or hysteresis), inherent or introduced, that would reduce the speed governor's effectiveness in responding to frequency deviations.

6.6.2 Rules 5.1 and 5.1.3 are worded as follows:

Existing rule:

5.1 Requirements for frequency response and control

Each **generator** will ensure that:

...

5.1.3 Generating unit has a speed governor

Each of its **generating units** has a speed governor which:

5.1.3.1 Provides stable performance

Provides stable performance with adequate damping; and

5.1.3.2 Has adjustable droop

Has an adjustable droop over the range of zero percent to 7 percent; and

5.1.3.3 Is able to synchronise

Does not adversely affect the operation of the **grid** because of any of its non-linear characteristics;

6.6.3 It has also considered changes to the droop range required in rule 5.1.3.2. Some grid codes require droop to be set within a specified range while others simply require the generating unit to operate under unrestricted governor control in accordance with declared or agreed droop settings. The droop range over which a governor must be adjustable in New Zealand (0-7%) appears to be wider than many others.

10 Droop is the percentage change in frequency that would cause the main prime mover control mechanism to change from fully closed to fully open

6.6.4 A 6% droop setting would cause the prime mover control mechanism to be completely open once frequency dropped to 47 Hz (i.e. 6% below the nominal frequency of 50 Hz), the lowest permissible frequency in the North Island. Accordingly, 6% appears to be a more optimum upper limit than 7% for the droop setting range. The Commission is interested in receiving submissions on the appropriate upper limit for the droop range.

6.6.5 The Commission also proposes to amend the wording of the requirement so it is clear droop must be capable of being set at a level somewhere within this range. An extreme interpretation of the existing rule is that all governors must be adjustable within the entire range specified and that even governors with a wider range would be non-compliant. This interpretation was never intended.

6.6.6 The new drafting proposed is as follows:

Proposal:

5.1 Requirements for frequency response and control

Each **generator** will ensure that:

...

5.1.3 Generating unit has a speed governor

Each of its **generating units** ~~has~~ is fitted with a speed governor or equivalent mechanism which~~:~~ –

~~**5.1.3.1 Provides stable performance**~~

5.1.3.1 ~~P~~provides stable performance with adequate damping; and

~~**5.1.3.2 Has adjustable droop**~~

5.1.3.2 ~~Has an adjustable~~can have droop ~~over the range of~~ set between zero percent ~~to~~and ~~7~~6 percent; and

~~**5.1.3.3 Is able to synchronise**~~

5.1.3.3 ~~D~~does not adversely affect the operation of the **grid** because of any of its non-linear characteristics;

Q3. Do you agree with the proposals for speed governor requirements?

6.7 Non-minor changes proposed to rule 5.1.4 in technical code A of schedule C3

6.7.1 Rule 5.1.4 concerns the requirements surrounding the speed governor settings before, during and following commissioning and is worded, as follows:

Existing rule:

5.1 Requirements for frequency response and control

Each **generator** will ensure that:

...

5.1.4 Appropriate speed governor settings

Appropriate speed governor settings to be applied before commencing **system tests** for a **generating unit** are agreed between the **system operator** and the **generator**. The performance of the **generating unit** is then assessed by measurements from **system tests** and final settings are then applied to the **generating unit** before making it ready for service after those final settings are agreed between the **system operator** and the **generator**. **Asset owners** will not change speed governor settings without **system operator** approval.

6.7.2 The Commission is proposing to separate the requirements in rule 5.1.4 into three sub-paragraphs to make it clear that the initial governor settings and every subsequent change to them should have the prior approval of the System Operator. The proposed rule is as follows:

Proposal:

5.1 Requirements for frequency response and control

Each **generator** will ensure that:

...

5.1.4 Appropriate speed governor settings

~~Appropriate speed governor settings to be applied before commencing **system tests** for a **generating unit** are agreed between the **system operator** and the **generator**. The performance of the **generating unit** is then assessed by measurements from **system tests** and final settings are then applied to the **generating unit** before making it ready for service after those final settings are agreed between the **system operator** and the **generator**. **Asset owners** will not change speed governor settings without **system operator** approval.~~

<u>It obtains prior written approval from the **system operator** for –</u>

5.1.4.1 the initial settings of the speed governor fitted to a generating unit being commissioned before the generator conducts any system tests; and

5.1.4.2 the final settings of the speed governor fitted to a generating unit being commissioned before requesting and obtaining a final assessment under rule 2.3; and

5.1.4.3 every change to the settings of the speed governor following commissioning.

Q4. Do you agree with the proposal that initial and all subsequent changes to the speed governor settings be agreed by the System Operator?

6.8 Consideration of changes to "catch-all" rules

6.8.1 The Commission has noted that there are a number of "catch-all" rules in technical code A of schedule C3 of part C of the Rules that require generators to ensure their generating units, control systems, and speed governors either:

(a) support (rule 5.1.1.1) the ability of the system operator to plan to comply, and to comply, with its principal performance obligations; or

(b) do not adversely affect (rules 5.1.2 and 5.3.1) the ability of the system operator to plan to comply, and to comply, with its principal performance obligations.

6.8.2 Such a general requirement covers any act or omission by a generator that causes the generating unit to operate in a manner detrimental to the maintenance of a stable power system. In the context of this paper, these requirements would ensure generating units, their control systems, and speed governors (or equivalent mechanisms) do not have characteristics that would reduce the effectiveness of a generating unit's response to frequency changes below that which would be expected by the speed governor settings agreed in rule 5.1.4. As there are other ways in which a generating unit might operate in a manner detrimental to maintaining a stable power system (eg production of reactive power), it is necessary to generalise the requirement.

6.8.3 The Commission's initial inclination is not to change these 'catch-all rules'. Although there have never been any allegations that generators have breached these rules, the Commission is inclined to accept that they provide a net positive benefit by:

(a) deterring generators from making imprudent innovations that compromise the reasonable and prudent operation of the grid;

(b) providing a mechanism by which the System Operator can alter generator behaviour should it detect any adverse effects on system operation, either during commissioning or after generating units are in service.

Q5.	**Do you agree with the Commission's analysis regarding the "catch-all" rules?**

6.9 How proposal gives effect to Commission's objectives

6.9.1 Section 172X of the Act requires the Commission, in formulating recommendations for electricity governance rules, to outline how the proposal will give effect to its principal objectives and specific outcomes as set out in section 172N of the Act and to its GPS objectives and outcomes.

6.9.2 Appendix 2 contains a table which lists the objectives and outcomes as specified in section 172N of the Act and the GPS and outlines how the proposal may help achieve the relevant objectives and outcomes.

Q6.	**Do you have any comments on the proposed rules?**

7. Assessment of options

7.1 Other reasonably practicable options

7.1.1 Section 172F of the Act provides that unless the Commission is satisfied that the effect of the recommendation is minor and will not adversely affect the interest of any person in a substantial way, before making a recommendation to the Minister on a rule, the Commission must seek to identify all reasonably practicable options, assess those options, ensure that the objective of the rule is unlikely to be satisfactorily achieved by any reasonably practicable means other than making the rule, and prepare a statement of the proposal.

7.2 Reasonably Practicable Options

7.2.1 In its review of the appropriate requirements for generators to support frequency under normal conditions, the Commission has assessed the proposal against two reasonably practicable alternatives:

Option	Description
A (Proposal)	Clarify existing requirements in rule 2.1 of section III of part C and rules 5.1.1.2, 5.1.2, 5.1.3, 5.3.1, 5.3.2 and 5.1.4 of technical code A of schedule C3 of part C for generating units to operate under unrestricted governor control according to governor settings agreed with the System Operator.
B (Alternative)	Clarify requirements in similar manner as proposal but explicitly provide for a delay/dead band in the response of governors
C (Status Quo)	Stay with existing rules, which are ambiguous about the possibility of a delay/dead band in the response of governors

7.2.2 The Commission considered and rejected an option to create separate requirements for different types of generation as it did not meet its objective to create a level playing field for generation investors and the risks that could distort investment decisions. It also considered the option to create a sophisticated frequency deviations market similar to the one that operates in Australia but did not consider it to be reasonably practicable.

7.2.3 Option B is not preferred as any additional frequency keeping costs arising from delays or dead bands in governor response would be shared across all purchasers as the payers of the frequency keeping ancillary service. The Commission is currently consulting on proposed changes to the frequency keeping cost allocation rules (refer to the Frequency Keeping Cost Allocation

Consultation Paper published on the Commission's website at: www.electricitycommission.govt.nz/consultation/freq-keep-cost-allocation). The changes proposed in this paper provided a similar outcome to Option B, but in a manner that allows additional costs arising from delays or dead bands in governor response to be allocated to causers.

7.2.4 Option C, the status quo is not preferred as it fails to achieve the stated objective of improving the clarity of requirements for generators (having regard for all types of generator types) to support frequency under normal grid conditions.

Q7. Do you think there are other reasonably practicable options the Commission should consider?

7.3 Benefits and costs

7.3.1 The nature of this rule change proposal does not lend itself to a quantitative analysis[11] of the relevant costs and benefits. A qualitative analysis of the costs and benefits of the reasonably practicable options is given below:

Option	Costs	Benefits
A (Proposal)	Implementation costs for the proposed changes to the Rules.	More consistent application of the Rules by removing the ambiguity in the present wording of the Rules.
	Indirect costs for generators responding continuously to normal frequency fluctuations (to the extent that these costs are currently being avoided)	Reduction in the amount of frequency keeping procurement necessary to achieve the normal frequency standard, assuming some generators choose to remove dead bands they have applied to their governors.
B (Alternative)	Implementation costs for the proposed changes to the Rules.	More consistent application of the Rules by removing the ambiguity in the present wording of the Rules.
	Possible increase in demand for the frequency keeping service.	
	Difficulty for the Commission to set the maximum dead band that would	

[11] A quantitative assessment would involve, amongst other things, making assumptions about the likely percentage net increase or decrease in market efficiency for each option. The error associated with estimating the quantities involved is likely to exceed the margin between the options.

Option	Costs	Benefits
	minimize the sum of free governor action costs and the cost of the frequency keeping service.	
C (Status Quo)	Increased demand for the frequency keeping service.	Avoided cost of implementing proposed changes to the Rules.
	More frequent dispatch of generation to keep the frequency keeping station within its control limits.	
	Gradual decrease in the quality of normal frequency.	

7.3.2 As discussed elsewhere in the paper, the ambiguity of the present wording of the Rules requiring generators to support frequency under normal grid conditions has the potential for generators to reduce the effectiveness of their governors when frequency is within the normal band. A delay in the response of governors to frequency reduces the effectiveness of the primary frequency control, increasing the frequency deviation for any given imbalance between generation and load.

7.3.3 Comparison of the options boils down to a judgment about which option has the best potential to minimize the sum of free governor action costs and the cost of the frequency keeping service. The Commission considers that option A (the proposal) has greater potential to produce an optimal economic outcome than options B or C assuming that the additional rule changes proposed in the Commission's Frequency Keeping Cost Allocation Consultation Paper are also made.

7.4 Assessment against the objective

7.4.1 The Commission considers the proposal best meets the objective of the rule change. The other options do not meet the objective as:

(a) Option B's set of requirements (same as proposal but includes an allowance for a delay or dead band) is inappropriate as it has less potential to produce an optimal economic outcome (see previous section on costs and benefits); and

(b) Option C's set of requirements (the status quo) is inappropriate as the requirements are not clear and are therefore also less likely to produce an optimal economic outcome.

7.5 Assessment of all options

7.5.1 Having considered the options, their costs and benefits, and their chances of achieving the objective, the Commission considers that the assessment supports the proposal.

Q8.	**Do you have any comments on the Commission’s assessment of the options?**

8. Conclusion and next steps

8.1 Conclusion

8.1.1 The Commission has reviewed the appropriateness of the existing rules associated with the requirements for generators to support frequency under normal conditions. After consideration, the Commission plans to confirm the existing standards but proposes to reduce the droop setting range and amend the drafting in the places identified to make the requirements clearer.

8.1.2 In summary, the rule changes being considered would require generators to:

(a) ensure their generating units operate under unrestricted governor control;

(b) fit a speed governor or equivalent mechanism to their generating units that is stable with adequate damping, can adjust its droop setting within the range 0-6%; and

(c) have written, prior approval of the System Operator before making initial, final, and subsequent changes to speed governor settings.

8.1.3 The Commission is now inviting submissions (see Appendix 1 for suggested format) from participants and persons who are likely to be substantially affected by these proposed amendments to the Rules.

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Appendix 1 Format for submissions

Question	Response
1. With respect to normal frequency management, are there features of other grid codes you think the Commission should consider?	
2. Do you agree with the proposal to clarify rule 2.1 so that generators must ensure their generating units operate under unrestricted governor control?	
3. Do you agree with the proposals for speed governor requirements?	
4. Do you agree with the proposal that initial and all subsequent changes to the speed governor settings be agreed by the System Operator?	
5. Do you agree with the Commission's analysis regarding the "catch-all" rules?	
6. Do you have any comments on the proposed rules?	
7. Do you think there are other reasonably practicable options the Commission should consider?	
8. Do you have any comments on the Commission's assessment of the options?	

Appendix 2 Consideration against objectives and outcomes

Objectives and Outcomes under section 172N of the Act	**Response**
The Commission's principal objectives are:	
(a) to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner; and	This proposal has the potential to increase the efficiency with which electricity is produced by providing clear standards for generators to support frequency under normal conditions, enabling generators to make choices regarding the operation of their governors according to the costs associated with those decisions.
(b) to promote and facilitate the efficient use of electricity.	This proposal does not materially affect the achievement of this objective
The specific outcomes that the Commission must seek to achieve are as follows:	
(a) energy and other resources are used efficiently;	This proposal does not materially affect the achievement of this objective
(b) risks (including price risks) relating to security of supply are properly and efficiently managed;	This proposal does not materially affect the achievement of this objective
(c) barriers to competition in the electricity industry are minimised for the long-term benefit of end-users;	This proposal does not materially affect the achievement of this objective
(d) incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment;	The proposal specifies standards that are neutral in respect of the type of generation chosen by investment decision makers
(e) the full costs of producing and transporting each additional unit of electricity are signalled;	This proposal does not materially affect the achievement of this objective
(f) delivered electricity costs and prices are subject to sustained downward pressure; and	This proposal does not materially affect the achievement of this objective

(g)	the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables, and distributed generation.	This proposal does not materially affect the achievement of this objective

Appendix 3 Examples of requirements in other grid codes

3.1.1 The table below provides examples of the relevant standards required in six other grid codes.

Summary of requirements in other grid codes

Code	Features
NEM (Australia)	• Connection is automatic if a generator can meet a minimum positive contribution to normal frequency management[12]. If the generator cannot meet the automatic standard, it must show its generation will make a positive contribution in line with what is possible for the type of generation concerned. At a minimum, generation must not increase in response to a frequency rise and must not decrease by more than 2% if frequency falls. • There is no requirement to have a speed governor or for droop settings • Capability is required at the point of connection (standards apply to generating system with one or more units on generator's side of grid connection point)
National Grid (UK)	• Generating units, except older and smaller wind farms[13], must be fitted with a fast acting proportional frequency control device (or turbine speed governor) and unit load controller or equivalent control device to provide frequency response under normal operational conditions. • The frequency control device (or speed governor) must be capable of being set so that it operates with an overall speed droop of between 3-5%, must operate stably over the entire operating range of the unit, and must not have a dead band greater than ±0.015 Hz. • Obligations are input-focussed but acknowledge alternatives to a speed governor: o refers to fast acting proportional frequency control device or turbine speed governor and unit load controller or equivalent control device o performance is required of each generating unit or power park module (collection of intermittent generating units joined together at single point of connection to the grid)
EIR Grid (Ireland)	• Generating units must be fitted with a fast acting proportional turbine speed governor and unit load controller or equivalent control device to provide frequency response under normal operating conditions. • Generators other than wind generators must operate under the control of a governor control system and provide unrestricted governor action in response to frequency deviations without time delays and with a dead band no greater than ±0.015Hz. • If frequency goes outside the normal band, generators are required to check that the response of their units is as it should be and make changes if it is not. • Wind farms have separate requirements and do not have to respond to

[12] Eg: Generation must not rise when frequency rises, nor fall when frequency falls and must be capable of increasing its output by 20% of its maximum operating level times the percentage difference between the lower limit of the normal frequency band and system frequency or 5% of its maximum operating level (whichever is lower) when frequency falls below the lower limit of the normal frequency band

[13] Excludes Power Park Modules (wind farms) in Scotland with a Completion Date before 1 July 2004 or Power Park Modules in a Power Station in Scotland with a Registered Capacity less than 50MW

[14] However, controllable wind farms must hold 5% of output in reserve and ramp up when frequency falls below the normal range's lower limit and ramp down when it rises above the normal range's higher limit

	frequency while it remains within the normal band.[14]

PJM (USA)	• Generators must operate on unrestricted governor control or, if a governor is not available, should not fluctuate from scheduled output unless directed. Wind farms have separate requirements. • Obligations are input-focussed
Nordic grid code	• Generating units except wind turbines must be capable of automatically contributing to frequency regulation of the electric power system with a frequency response in the range 0.25-1 p.u. power/Hz, which corresponds to a droop of 2-8%, at a frequency variation of 50 ± 0.1 Hz. Load following requirements are specified for each plant type (oil and gas, coal, PWR nuclear, and BWR nuclear). • Wind requirements are dealt with separately. Wind turbine output must vary automatically as a function of the system frequency. The control function must be proportional to frequency deviations and must be provided with a dead-band. The detailed settings are provided by each TSO (Finland, Sweden, Norway). • National rules apply to hydropower plants that are not covered by the Nordic Connection Code. In Norway there are national requirements for hydro power plants. In Finland, general requirements for thermal power and hydropower are used.
E.On grid code (Germany)	• Every generating plant with a rated capacity of ≥ 100 MW must be capable of supplying primary frequency control (wind farms are excused), whereby: o Droop must be adjustable o Plant must activate full control power range available to a frequency deviation of ± 0.2 Hz evenly within 30 seconds and be able to sustain it for at least 15 minutes o The insensitivity range (ie dead band) must be less than ± 0.01 Hz

Extract from* S5.2.5.11 (Frequency control) of *National Electricity Rules (Australia)

(b) *Automatic access standard:*

(1) Each *generating system's active power* transfer to the *power system* must not:

(i) increase in response to a rise in *system frequency*; and

(ii) decrease in response to a fall in *system frequency*

(2) Each *generating system* must be capable of automatically reducing its *active power* transfer to the *power system*:

(i) whenever the *system frequency* exceeds the upper limit of the *normal operating frequency band;*

(ii) by an amount that equals or exceeds the least of:

(A) 20% of its *maximum operating level* times the percentage *frequency* difference between *system frequency* and the upper limit of the *normal operating frequency band;*

(B) 10% of its *maximum operating level*; and

(C) Subject to the *frequency* recovering gradually, the difference between the *generating unit's pre-disturbance level* and *minimum operating level,* but zero if the difference is negative.

(iii) Sufficiently rapidly for the *Generator* to be in a position to offer measurable amounts of lower services to the *spot market* for *market ancillary services.*

(3) Each *generating unit or generating system* must be capable of automatically increasing its *active power* transfer to the *power system:*

(i) whenever the *system frequency* falls below the lower limit of the *normal operating frequency band;*

(ii) by the amount that is equal or exceeds the least of:

(A) 20% of its *maximum operating level* times the percentage *frequency* difference between the lower limit of the *normal operating frequency band* and *system frequency:*

(B) 5% of its *maximum operating level*; and

(C) Subject to the *frequency* recovering gradually, one third of the difference between the *generating unit's maximum operating level* and *pre-disturbance level*, but zero if the difference is negative; and

(iii) sufficiently rapidly for the *Generator* to be in a position to offer measurable amounts of raise services to the *spot market* for *market ancillary services.*

(c) *Minimum access standard*:

For each *generating system, active power* transfer to the *power system* must not:

(1) Increase in response to a rise in *system frequency;* and

(2) Decrease more than 2% per Hz in response to a fall in *system frequency*

(d) Each *control system* used to satisfy clause S5.2.5.11 must be *adequately damped.*
A *Generator* proposing a *negotiated access standard* in respect of clause S5.2.5.11(c)(2) must demonstrate to *NEMMCO* that the proposed increase and decrease in *active power* transfer to the *power system* are as close as practicable to the *automatic access standard* for that *plant*.

Extract from UK Grid code

CC.6.3.7 (a) Each **Generating Unit, DC Converter** or **Power Park Module** (excluding **Power Park Modules** in Scotland with a **Completion Date** before 1 July 2004 or **Power Park Modules** in a **Power Station** in Scotland with a **Registered Capacity** less than 50MW) must be fitted with a fast acting proportional **Frequency** control device (or turbine speed governor) and unit load controller or equivalent control device to provide **Frequency** response under normal operational conditions in accordance with **Balancing Code 3** (**BC3**). In the case of a **Power Park Module** the frequency or speed control device(s) may be on the **Power Park Module** or on each individual **Power Park Unit** or be a combination of both.

(b) The **Frequency** control device (or speed governor) in co-ordination with other control devices must control the **Generating Unit, DC Converter** or **Power Park Module Active Power Output** with stability over the entire operating range of the **Generating Unit, DC Converter** or **Power Park**

Module; and

(c) The **Frequency** control device (or speed governor) must meet the following minimum requirements:

(i) …

(ii) the **Frequency** control device (or speed governor) must be capable of being set so that it operates with an overall speed **Droop** of between 3% and 5%. For the avoidance of doubt, in the case of a **Power Park Module** the speed **Droop** should be equivalent of a fixed setting between 3% and 5% applied to each **Power Park Unit** in service;

(iii) in the case of all **Generating Units, DC Converter** or **Power Park Module** other than the **Steam Unit** within a **CCGT Module** the **Frequency** control device (or speed governor) deadband should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the **Steam Unit** within a **CCGT Module**, the speed governor deadband should be set to an appropriate value consistent with the requirements of CC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of **Limited High Frequency Response**;

For the avoidance of doubt, the minimum requirements in (ii) and (iii) for the provision of **System Ancillary Services** do not restrict the negotiation of **Commercial Ancillary Services** between **NGET** and the **User** using other parameters; and

(d) A facility to modify, so as to fulfil the requirements of the **Balancing Codes**, the **Target Frequency** setting either continuously or in a maximum of 0.05 Hz steps over at least the range 50 ±0.1 Hz should be provided in the unit load controller or equivalent device.

Extract from EIR Grid:

OC4.3.4 REQUIREMENTS OF GENERATION UNIT GOVERNOR SYSTEMS

OC4.3.4.1 In order that adequate **Frequency Regulation** is maintained on the **Transmission System** at all times, **Generators** are required to comply with the provisions of OC4.3.4.

OC4.3.4.2 Other than as permitted in accordance with OC4.3.4.3:

(a) **Generation Units** when **Synchronised** to the **Transmission System** shall operate at all times under the control of a **Governor Control System,** unless otherwise specified by the **TSO**, with characteristics within the appropriate ranges as specified in **Connection Conditions**;

(b) no time delays other than those necessarily inherent in the design of the **Governor Control System** shall be introduced;

(c) A **Frequency Deadband** of no greater than +/- 15mHz may be applied to the operation of the **Governor Control System**. The design, implementation and operation of the **Frequency Deadband** shall be agreed with the **TSO** prior to the **Commissioning**.

OC4.3.4.3 The **Generator** may only restrict governor action in such a manner as to contravene the terms of OC4.3.4.2 where:

(a) the action is essential for the safety of personnel and/or to avoid damage to **Plant**, in which case the **Generator** shall inform the **TSO** of the restriction without delay; or

(b) in order to (acting in accordance with **Good Industry Practice**) secure the reliability of the **Generation Unit**; or

(c) the restriction is agreed between the **TSO** and the **Generator** in advance; or

(d) the restriction is in accordance with a **Dispatch Instruction** given by the **TSO**.

OC4.3.4.4 In the event that the **TSO** in accordance with OC4.3.4.3 either agrees to a restriction on governor action or instructs such a restriction, the **TSO** shall record the nature of the restriction, the reasons, and the time of occurrence and duration of the restriction.

OC4.3.4.5 Action required by **Generators** in response to low **Frequency**:

(a) If **System Frequency** falls to below 49.80 Hz each **Generator** will be required to check that each of its **CDGUs** is achieving the required level of response including that required from the **Governor Control System**, where applicable in order to contribute to containing and correcting the low **System Frequency**.

(b) Where the required level of response is not being achieved appropriate action should be taken by the **Generator** without delay and without receipt of instruction from the **TSO** to achieve the required levels of response, provided the **Generator's** local security and safety conditions permit,

OC4.3.4.6 Action required by **Generators** in response to high **Frequency**:

If **System Frequency** rises to or above 50.2 Hz each **Generator** will be required to ensure that its **CDGUs** has responded in order to contribute to containing and correction the high **System Frequency** by automatic or manually reducing **MW Output** without delay and without receipt of instruction from the **TSO** to achieve the required levels of response, provided the **Generator's** local security and safety conditions permit.

Extract from Nordic code:

3.2 General requirements to be met by thermal power and hydropower Requirements:

- Thermal power plants (Norway, Sweden and Denmark > 100 MW, Finland > 50 MW)
- Hydro power plants (Norway > 10 MW, Sweden and Finland > 50 MW)

The national requirements may be stricter than the requirements stated below.

3.2.1 Automatic frequency control

The production plants must be capable of automatically contributing to frequency regulation of the electric power system with a frequency response in the range 0.25-1 p.u. power/Hz, which corresponds to a droop of 8-2 %, at a frequency variation of 50 ± 0.1 Hz. The locally measured grid frequency or the rotation speed of the plant is used as a control signal.

3.2.2 Turbine regulator, set point

The unit controller shall have an adjustable frequency set point in the range from 49,9 Hz to 50,1 Hz. The set point resolution shall be 0,05 Hz or better. For large thermal power plants an adjustable frequency dead band of the unit controller within the setting range of 0-50 mHz is acceptable.

... ...

3.3.2 Power control equipment characteristics

Operational Modes

The change of output power of a thermal power unit at the rates and within the ranges specified, during normal control and during disturbances control, is normally activated as follows:

- By manual operation

- By the unit controller

The unit controller shall have an adjustable frequency set point in the range from 49.9 Hz to 50.1 Hz. The set point resolution shall be 50 mHz or better.

The droop set point shall be adjustable in the range from 2 % to 8 %. The normal operation is generally with setting in the range from 4 % to 6 %.

An adjustable frequency dead band of the unit controller within the setting range of 0-50 mHz is acceptable. It shall be possible to disengage this dead band.

Power Step Change Limiter

The units shall be equipped with adjustable devices for limiting the magnitude and rate of the power change, so that it will be possible to set these set points at any values from zero up to the maximum specified, both for normal conditions and for disturbance conditions.

Power Control - Normal Operation and Disturbances

The required power output during normal operation is the manually preset power output, modified by a frequency-sensing unit controller (or turbine governor) and this power output shall meet the specifications in Section 3.3.3 (Power response capability during normal operation of the power system).

The need for disturbance control shall be governed by frequency-sensing equipment (e.g. consisting of a frequency relay set at a certain value below normal frequency). The power output shall meet the specification in 3.3.4 (Power response capability during power system disturbances) when the unit is operated under these conditions.

Extract from PJM manual 14D

7.1.3 ...The generator shall operate on unrestricted governor control to assist in maintaining interconnection frequency, except for the period immediately before being removed from service and immediately after being placed in service. Governor outages during periods of operations must be kept to a minimum and must be immediately reported to PJM. When a generator governor is not available, the unit output should not fluctuate from pre-scheduled output unless otherwise directed.

Extract from E.On Netz (Germany) grid code:

3.2.3 Frequency stability

All generating plants meeting the necessary technical and operational requirements can be used for the provision of primary control power, secondary control power and minute reserve. To this end, a prequalification process must be passed during which details concerning the control bank, ramp rate of power, period of provision, availability etc will be determined. Consumers can also participate in secondary control power and provision of minute reserve by way of controllable loads.

Every generating plant with a rated capacity of ≥ 100 MW must be capable of supplying primary control power. This is a prerequisite for connection to the grid. ENE is entitled to exempt individual generating plants from this obligation.

Generating plants with a rated capacity of > 100 MW can, by agreement with ENE, also be used to secure the primary control.

The following requirements must be met for the primary control:

- The primary control bank must be at least ± 2% of the rated power.
- The frequency power droop characteristic must be adjustable.
- Given a quasi-stationary frequency deviation of ± 200 mHz, it must be possible to activate the total primary control power range required by the generating plant evenly in 30s and to supply it for at least 15 min.
- The primary control power must be again available 15 min after activation, provided that the set point frequency has been reached again.
- In the event of smaller frequency deviations, the same rate of power change applies until the required power is reached.
- The insensitivity range must be less than ± 10 mHz.

...

3.3.3 Frequency stability

REA generating plants[15] are exempted until further notice from the basic requirements of providing primary control power, including rated power exceeding 100MW.

[15] All generating plant subsidised under the Renewable Energy Act 2004