Wholesale Advisory Group

National Frequency Keeping Market Recommendations Paper

By the Wholesale Advisory Group

May 2014

Note: This paper has been prepared for the purpose of making recommendations to the Electricity Authority Board. Content should not be interpreted as representing the views or policy of the Electricity Authority.

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Contents

Tables

Figures

The Wholesale Advisory Group

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Electricity Authority request

The Electricity Authority (Authority) has requested input and advice of the Wholesale Advisory Group (WAG) to determine the potential for developing a national market for frequency keeping (FK).

1 Introduction

1.1.1 In October 2013 the Authority asked the WAG to consider the benefits of developing a national FK market and if feasible to develop arrangements to give effect to it.

1.1.2 The Authority had previously identified that a national FK market could contribute to the Authority's statutory objective by:

a) ensuring that the most efficient providers available nationally are selected in each trading period

b) improving the operational efficiency of the service by reducing the overall quantity of FK that is required.

1.1.3 This paper presents the WAG's recommendations following its investigations.

2 Conclusion and recommendations

2.1.1 The WAG concludes that implementing a national FK market would result in a substantial net economic benefit (section 5) and that doing so would be consistent with the Authority's statutory objective and Code amendment principles (Section 3).

2.1.2 The WAG therefore recommends the Authority should progress the national FK market as a priority project. The WAG considers this project should be developed in parallel with the national reserves market initiative. The WAG recognises that of the two projects, the national FK market has a wider technical scope of work, and as a consequence would be commissioned following the introduction of the national reserves market.

2.1.3 The WAG endorses the investigation work initiated by the Authority in engaging the system operator to identify the best options for implementing a national FK market in more detail. The WAG agrees that the Authority and the system operator jointly are best placed to complete this work as it is technical in nature, but the WAG would like to remain involved in the following key aspects of the national FK market design:

a) The method of frequency keeper selection - The WAG has received advice from the secretariat that full co-optimisation with energy and reserves is the preferred method and would not introduce unintended pricing consequences. The WAG would appreciate seeing a report from the Authority, incorporating independent advice, to confirm that this is definitely the case. Of particular interest to the WAG are convergence of the SPD model and the establishing of provably marginal prices. If any pricing complications were to be found in the co-optimised markets that affect the cost benefit analysis, the method of selection should be referred back to the WAG for further consideration.

b) Technical representation – The WAG requests it be invited to nominate a member to represent the WAG on any technical group established by the Authority to support this work.

c) Regular updates – As provided for in the advisory group charter and the WAG terms of reference, the WAG specifically seeks regular updates, particularly in the event that the Authority proposes to make a substantial change, or approaches a significant milestone.

2.1.4 The WAG notes that the national FK market design should include consideration of the following:

a) the extent to which enabling Code provisions for a national FK market are centralised in part 13 of the Code to create alignment between the energy, reserves and FK markets

b) the extent to which the new HVDC bi-pole control system functions including round-power and FKC[1] can be utilised to support a national FK market.

2.1.5 Additionally, the WAG notes that it has an interest in pursuing the future FK cost allocation work that the Authority has already identified as a project following on from the development of a national FK market.

3 Problem definition

3.1 Authority's statutory objective and Code amendment principles

1.1.1 The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

1.1.2 Principle 2 of the Authority's Code amendment principles states that the Authority and its advisory groups will only consider using the Code to regulate market activity when either:

a) it can be demonstrated that amendments to the Code will improve the efficiency of the electricity industry for the long-term benefit of consumers

b) market failure is clearly identified, such as may arise from market power, externalities, asymmetric information and prohibitive transaction costs

c) a problem is created by the existing Code, which either requires an amendment to the Code, or an amendment to the way in which the Code is applied.

3.2 Current market inefficiencies

3.2.1 The WAG identified three areas of inefficiency in the current FK market:

a) competition in the island-based FK markets is limited[1]

b) the selection of frequency keepers is not co-optimised with energy and reserves in SPD and constrained on/off payments for frequency keepers in the energy market arise as result

c) the MW quantity of island-based FK procured by the system operator is larger than would be required if FK was co-ordinated nationally.

3.3 Improvements in efficiency possible

3.3.1 A national FK market would improve the overall efficiency of the FK market by:

a) increasing the productive efficiency of the market by allowing FK to be purchased from the lowest cost providers in a national pool rather than in two separate island-based pools

b) increasing the allocative and productive efficiency of the market by co-optimising the selection of energy, reserves and FK to allow the lowest overall cost selection of alternatives

c) increasing productive efficiency of the market by reducing the MW quantity of FK required to regulate frequency on the power system

3.3.2 An additional dynamic efficiency gain can be obtained in the energy market by deferring investing in peaking capacity as a result of any reduction in the MW quantity of FK purchased.

[1] The related Multiple Frequency Keepers Project addresses this inefficiency on an intra-island basis only by reducing barriers to entry for smaller FK providers such as load aggregators. The project provides for central co-ordination of FK so that the MW band required can to be split and allocated across multiple providers in the same trading period.

4 Current arrangements

4.1 Procurement

4.1.1 In accordance with the frequency principal performance objective (PPO) in part 7 of the Code, the system operator is required to act as a reasonable and prudent system operator with the objective to maintain system frequency in each island between 49.8 Hz and 50.2 Hz - the normal band.

4.1.2 The objective to maintain frequency in the normal band is a quality-based objective intended to achieve the optimal trade-off between quality and the cost. The system operator acts to achieve this quality objective by procuring FK services from providers in half-hour markets separately in each island. Providers are currently generating companies[2] that have sufficiently responsive plant and adequate spare capacity to be able to vary their output to maintain island frequency within the normal band, for normal demand/supply imbalances.

4.1.3 The two island power systems presently operate as independent a.c. systems loosely coupled by the stabilising influence of the HVDC link. The link effectively transfers a degree of balancing and reserve between the islands, but this benefit is neither recognised nor paid for under the current procurement arrangements for FK or instantaneous reserves.

4.1.4 Procurement arrangements in the North and South Islands differ while a transition is taking place from single FK (SFK) to multiple FK (MFK). The North Island MFK market started on 1 July 2013 and MFK is scheduled to be introduced to the South Island late 2014.

4.1.5 The respective arrangements in the two islands can be summarised as follows:

North Island – MFK

a) providers offer up to 5 FK bands, each between 4 MW and 50 MW in size

b) the system operator selects the lowest cost combination of offers to make up a cumulative band of 50 MW and dispatches the providers

c) the system operator controls frequency using a central frequency controller that issues raise/lower set point controls to dispatched providers every 2 s.

[2] A recent Code amendment permits demand side participation of FK

South Island – SFK

a) providers offer up to 5 FK bands of at least 25 MW

b) the system operator selects the lowest cost offer of 25 MW or more and dispatches a single provider

c) the dispatched single provider controls frequency using its own local station or area based frequency control system

d) responsibility for frequency control moves from one provider to another whenever there is a dispatch change.

4.1.6 At present, only four generating companies meet the system operator's technical requirements for MFK and SFK:

a) Mighty River Power Limited using the Waikato hydro block (North Island)

b) Genesis Energy Limited from four Huntly thermal units, the Tokaanu hydro station, and the Waikaremoana hydro block (North Island)

c) Contact Energy using two Stratford thermal units and the Clutha hydro block (North Island and South Island)

d) Meridian Energy Limited using the Waitaki hydro block and the Manapouri hydro stations (South Island).

4.2 Payment and cost allocation

4.2.1 MFK and SFK providers dispatched by the system operator are currently paid the following:

a) the provider's offer price (the availability fee)

b) to-the-band constrained on or off compensation, if required, to move the frequency keeper from its natural dispatch point so that its control maximum or control minimum operating points are not exceeded within the dispatched FK band

c) in-band constrained on or off compensation, if required, to compensate the provider for any difference between actual and dispatched quantities of output, for example:

i) if a generator produces a lower energy output than its dispatched quantity (to compensate for an increase in system frequency) when the energy price is above its energy offer price, it receives a constrained off payment

ii) if a generator produces a greater energy output than its dispatched quantity (to compensate for a decline in system frequency) when the energy price is below its energy offer price, it receives a constrained on payment

d) in addition, providers are paid in the energy market for any generation produced at the final price, although this is not treated or reported as part of the FK costs.

4.2.2 FK ancillary service costs are allocated monthly to purchasers (those parties that purchase energy through the spot market from the clearing manager). The total cost of FK for each trading period of the previous month is pro-rated to purchasers according to the quantity of electricity purchased in each trading period. The allocation is carried out on a national basis even though the service is procured separately in each island. A degree of cross-subsidisation arises because of the price diversity and procured quantity difference between islands.

5 Cost benefit analysis of implementing a national FK market

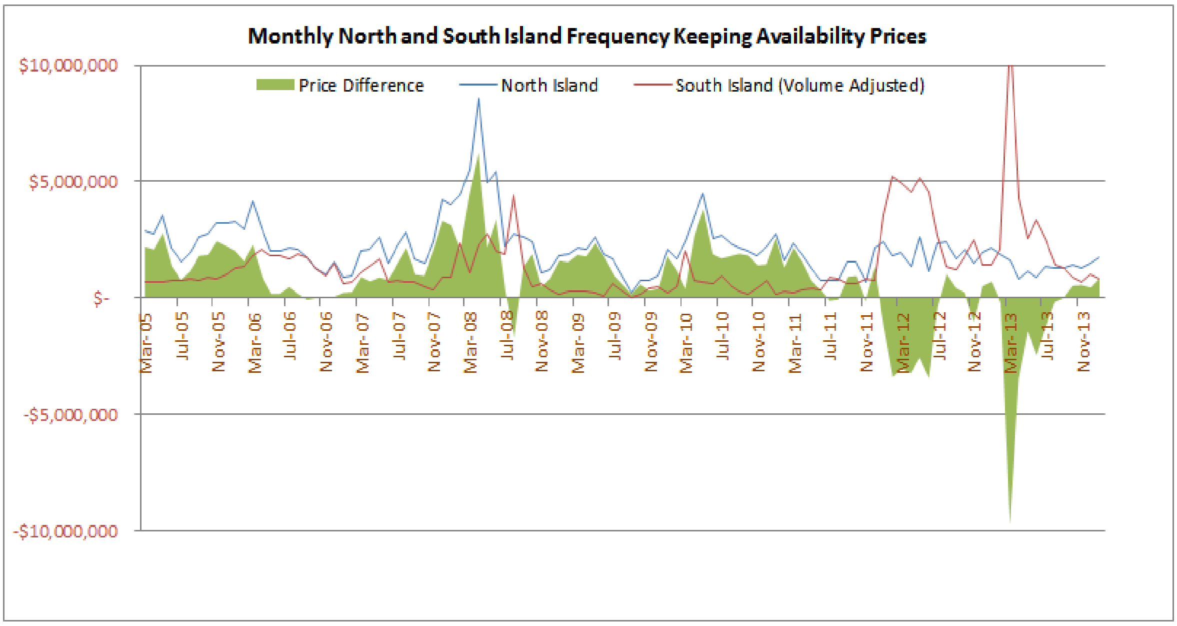
Economic Benefits

5.1 Price diversity between islands

5.1.1 FK prices include a significant energy cost component that has a degree of inter-island diversity. This is evident in the historical FK price differences between the North and South Islands. Since 2005, South Island prices (adjusted for the volume difference between the two islands[3]) have averaged about 64% of North Island prices. The historical price differences since this time are represented by the green area shown in Figure 1.

[3] Between 2006 and 2012, the system operator progressively reduced the quantity of FK purchased in the South Island from 50 MW to 25 MW.

Figure 1 - Price diversity between islands



5.1.2 For the purposes of analysing the economic benefit that could be achieved by selection of FK in a national FK market, the historical pay-as-bid block offers ($ per 25 MW or $ per 50 MW band) were assumed to reflect the marginal cost of production. As this is generally not the case due to the pay-as-bid design of the current market, the analysis set out below represents the upper bound of cost reduction that could be achieved through selection in a national FK market.

5.1.3 The Authority simulated national FK market selection using a modified version of its vSPD model of Transpower's SPD clearing engine software. The Authority carried out the analysis using both unmodified block offer prices and block offer prices converted to equivalent uniform offer prices ($ per MW). The converted uniform offer prices were analysed to measure improvements possible in the run time of the solver software.

5.1.4 The Authority used a set of historical FK offers in the simulation taken after the introduction of Multiple FK in the North Island in July 2013 to capture a period when the most recent market arrangements have been in effect.

5.1.5 The upper bound cost reduction over the 6-month simulation period was assessed to be $4 m, or $8 m annually.

5.2 Reduction in frequency keeping quantity

5.2.1 The system operator's current practice is to purchase FK bands of +/- 25 MW in the South Island and +/- 50 MW in the North Island. The bands are sized to cover:

- the impact of non-dispatchable generation
- the intra-trading period variability of load
- errors in forecast load
- generation not exactly meeting its dispatch target.

5.2.2 Under a national FK market, it is expected that the total national FK band requirement is expected to reduce to less than +/- 75 MW due to increased inertia and load diversity between the two islands. The system operator requires operational experience to determine the extent of the band size reduction, but a conservative estimate is a reduction of 10 MW.

5.2.3 The Authority's vSPD simulation identified a cost reduction of $1.5 m over the 6-month simulation period, or $3.0 m annually for a quantity reduction of 10 MW (accepting the limitations of this analysis described in paragraph 5.1.2)

5.3 Co-optimisation of FK with energy and reserves

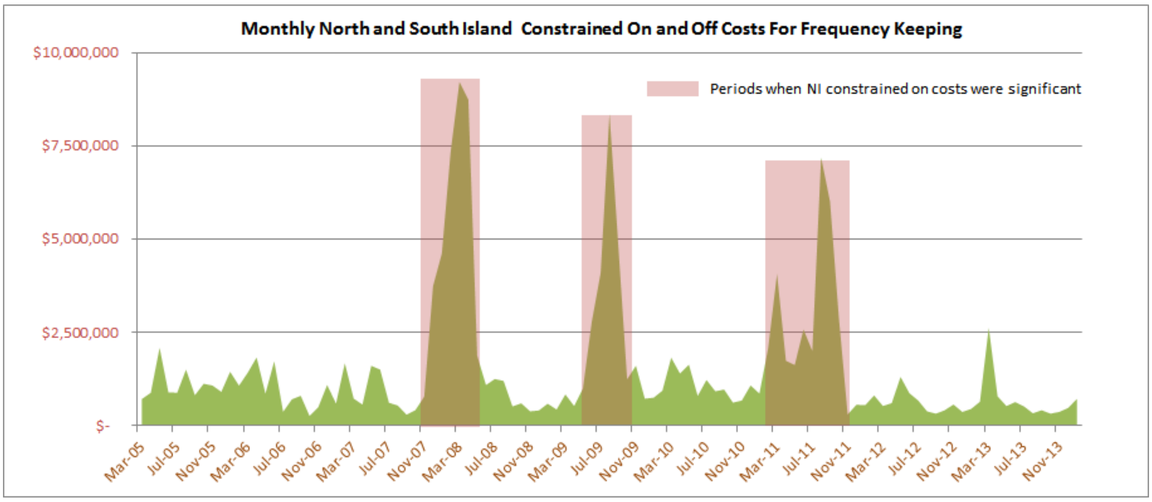
5.3.1 FK selection can have an impact on energy prices. For example, if a generator that is dispatched for FK is constrained on or off to provide the dispatched FK band, the cleared price of energy may change.

5.3.2 While the constrained on and off costs are taken in the current FK selection algorithm, no optimisation is carried out in SPD to minimise the total cost of:

- FK availability cost
- FK constrained on and off costs
- energy cost
- reserves costs.

5.3.3 The inefficiency of the current selection of FK, energy and reserves is evident in the magnitude of constrained on and off payments made to frequency keepers. Historical constrained on and off payments are shown in Figure 2[4].

Figure 2 Constrained on and off costs for frequency keeping



5.3.4 Full co-optimisation as proposed under a national FK market inherently offers efficiency gains by minimising the constrained on and off payments made to frequency keepers, and additionally minimising the effect of FK selection on energy prices. The Authority's vSPD simulation identified a cost reduction of $1 m over the 6-month simulation period, or $2 m annually.

5.3.5 The WAG notes that full co-optimisation carries a potential risk of unintended pricing consequences at times when system capacity becomes scarce or constrained. The WAG suggests the Authority carries out additional modelling work to assess this risk and reviews any studies completed to date on this subject.

5.4 Deferred investment in peaking capacity

5.4.1 Reducing the band requirement for FK by 10 MW would make some contribution to meeting North Island capacity requirements and allow investment in peaking capacity to be deferred (or allow existing capacity to be retired earlier) - thus providing an additional economic benefit.

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4 FK providers found ways to exploit the FK selection algorithm in 2008, 2009 and 2011 when constrained on payments rose to high levels. The system operator and the Authority have progressively improved the selection algorithm to the extent that such exploitation has not re-emerged since 2011 when the last changes were made. Only recent offers between July and December 2013 when constrained on costs were in the 'normal' range were used in the vSPD simulation to calculate cost reductions.

5.4.2 The WAG assessed a similar benefit in relation to the national instantaneous reserves market to the extent that a national reserves market also allows investment in peaking capacity to be deferred. While New Zealand is currently in a period of limited demand growth, it is expected that new peaking capacity may be needed from around 2018 assuming demand increases in line with the long-term rate of growth. Peaking capacity is assumed to cost approximately $145/kW per year.

5.4.3 A 10 MW reduction in the FK band would not always contribute 10 MW to peaking capacity in the North Island. The reduction would occur over both islands and exporting additional capacity from the South Island to the North Island is subject to a number of constraints such as the HVDC capacity and water storage.

5.4.4 As a conservative estimate, a 10 MW reduction in the FK band nationally is assumed to avoid the need for approximately 5 MW of North Island peaking capacity investments.

5.4.5 The economic benefit of the NIRM (through deferral of capacity investment) is therefore estimated as $700 k per year, or $5 m PV over 20 years (using an 8% discount rate).

5.5 Summary of economic benefits

5.5.1 The economic benefits assessed above are summarised in Table 1 below in both annual and 20-year PV terms using an 8% discount rate.

Table 1: Economic benefits of implementing a national FK market

Item	Annual Value	Present Value
Price diversity between islands	$8 m (upper limit)	$59 m
Reduction in FK quantity	$3 m	$22 m
Co-optimisation of energy and reserves	$2 m	$15 m
Deferred investment in peaking capacity	$0.7 m (from 2018 onwards)	$4.7 m
Total	**$12.7 m (before 2018)** **$13.4 m (from 2018)**	**$101 m**

Economic Costs

5.6 Market systems

5.6.1 The technology platform required to co-ordinate and control FK in a single market spanning both islands has been provided within the scope of the Multiple Frequency Keepers Project and Transpower's new HVDC bipole control system.

5.6.2 The main costs to develop a national FK market that utilises this technology platform are associated with the changes to the system operator and NZX market systems to accommodate a new form of FK offer and to carry out FK selection in SPD. The system operator has investigated these costs and the results are summarised in Table 2 below.

5.7 Changes to FK provider systems

5.7.1 FK providers would need to modify their trading systems to accommodate a new form of FK offer and would need to familiarise staff with new market arrangements. This cost is expected to be in the order of $0.5 m per provider or $2.0 m in total.

5.8 Code amendments

5.8.1 Enabling Code provisions and changes to the procurement plan and the system operator's ancillary services contract are required to support a national FK market. The cost of this regulatory work is estimated to be in the order of $0.15 m

5.9 Summary of costs

5.9.1 The economic benefits assessed above are summarised in Table 1 below in both annual and 20-year PV terms using an 8% discount rate.

Table 2: Cost of implementing a national FK market

Item	Cost
System operator and market system changes	$5.2 m
Changes to FK provider systems	$2 m
Code, procurement plan and ancillary services contract changes	$0.15 m
Total	**$7.35 m**

6 Approach to the project

6.1 Process followed by the WAG

6.1.1 The WAG met three times between October 2013 and February 2013 to discuss the national FK market. The WAG recognised that the Authority has already developed the Multiple Frequency Keepers Project as an enabler for a national FK market. The technical and market solution options for a national FK market are necessarily limited by this pre-cursor project.

6.1.2 The WAG considered publishing a discussion paper to seek feedback from the wider industry. However, it decided to proceed directly to making its recommendations to the Authority on the basis that the project has substantial net benefits and is largely uncontentious. In addition, the project, if approved, would require the Authority to seek feedback from the wider industry as part of the Code amendment process to finalise and confirm the detailed design elements, and create enabling regulatory provisions.

6.1.3 The next stage of the project will be technical and, in the WAG's view, can best be progressed by the Authority working in conjunction with the system operator. However, the WAG would like to be kept informed of progress with the project.

6.1.4 The WAG is of the view that implementing a national FK market is feasible and endorses the work already started by the Authority to investigate market designs, costs and timelines.

6.2 Proposed solution

Selection of national FK market providers

6.2.1 The system operator has advised the Authority that the performance of the existing FK selection tool is barely adequate to support island-based MFK. Accordingly, it will need to be replaced as part of any national FK market implementation.

6.2.2 It is proposed to extend the current co-optimisation of energy and reserves in SPD to include FK, i.e. to perform the selection of frequency keepers in SPD. The cost benefit analysis in section 5 indicates full co-optimisation using SPD has an additional present value benefit of
\$15 m.

6.2.3 The FK band is currently fixed (50 MW in the North Island and 25 MW in the South Island) but the national band requirement could be made variable in each trading period depending on dispatched generation and load. In such a case, SPD would allow a scheduled quantity of FK to be dispatched in the same way that the reserve products are scheduled and dispatched

Offers and pricing

6.2.4 Under the current market arrangements, providers are paid as offered, and FK is cleared in discrete bands. Frequency keepers are also paid constrained on and off costs and these costs must be added to offer prices to determine total offer costs.

6.2.5 Under selection in SPD it is proposed to adopt a uniform island $/MW enablement price for national FK market with part bands permitted to be cleared.

HVDC controls and interaction with national reserves market

6.2.6 The grid owner completed commissioning of its new HVDC bipole controls on Pole 2 and Pole 3 at the end of 2013. Besides standard HVDC stability controls, the new control system includes a FK and reserves sharing controller (FKC).

6.2.7 The fast acting FKC is designed to minimise the absolute frequency difference between the North and South Islands. It allows both national FK and national fast instantaneous reserves to be sourced in either a.c. island by controlling the HVDC link to behave much like an a.c. link.

6.2.8 Whenever FKC is enabled, it transfers FK and reserves between the a.c. islands, regardless of whether island-based or national markets are introduced. In the absence of national markets, free FK and free reserves would be transferred across the link.

6.2.9 Operation of a national FK market is dependent on the ability to transfer FK between the a.c. islands using the HVDC link. While FKC is not the only control option for a national FK market, it is the default option because FKC is a requirement for the related national reserves market initiative.

HVDC round power

6.2.10 The HVDC link has a minimum transfer level in either direction on the HVDC, which would constrain the link's ability to transfer FK (and reserves) between the islands whenever the link is scheduled at low power transfer levels.

6.2.11 It is possible to reduce this constraint by using round power, where power is transferred in opposite directions on the two poles. Transpower is currently investigating how to offer the round power capability of the HVDC link to the market in order to maximise the number of trading periods when national FK (and national reserves) can be transferred between the islands.

7 Next steps

7.1.1 If the Authority agrees with the WAG's recommendations, it should progress the national FK market project as soon as possible. This is expected to involve working jointly with system operator regarding system design and development, market design, enabling Code development, and consultation with stakeholders.

7.1.2 The WAG undertakes to make itself available to provide advice to the Authority as required through the course of the Authority's future work on the national FK market.

7.1.3 The WAG requests the Authority to keep it updated with progress on this project.

Appendix A Frequency keeping optimisation – Authority report

Frequency Keeping Optimisation

Modelling options

12 March 2014

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Version control

Version	Date amended	Comments
1	14 March 2014	
2	31 March 2014	65 MW National FK added

Contents

Tables

Figures

1 Introduction

1.1 This document is a mathematical description of modification of Transpower's "Scheduling, Pricing, and Dispatch" (SPD) software to optimise energy, reserve and frequency keeping (regulation) markets. This document only present the changes made to current SPD model for this purpose and therefore will not cover the unchanged parts of SPD.

1.2 The modelling options presented in the flowing sections are based on the assumption that frequency keepers are not paid for intra-band constrained on/off.

1.3 In this document, we consider three base models to include frequency keeping markets into SPD optimisation process. The frequency keeping market node constraints are removed in these models.

1.4 The first model (block offer model) is a mixed-integer problem. In this model, frequency keeping providers offer regulation service in block and only one block can be selected from a frequency keeping provider. This regulation offer structure is similar to (more ideal than) current structure. In order to solve this model, a mixed integer model is required. This model can be easily modified to allow multi-blocks cleared from one provider.

1.5 The second model (uniform offer LP model) is a linear problem. In this model, frequency keepers are assumed to have uniform offer ($/MWh). This frequency offer structure is similar to current energy and reserve offer structure. In order to overcome the issue with frequency keeping control min and max, control min/max slopes are introduced to each offer (similar to reserve).

1.6 Model three is a mixed-integer problem (uniform offer MIP model). In this model, frequency keepers are assumed to have uniform offer ($/MWh). Frequency keeping control min/max constraints are applied to the schemes which are selected to provide frequency keeping service.

1.7 All of these models allow frequency keeping service to be shared between islands. Intra-band constrained on/off cost is assumed being removed.

1.8 Table 1 summarises structure, advantages, shortcomings and possible improvements of the three models.

1.9 Table 2 compares the system costs and frequency keeping costs from three different models.

1.10 Section two described the three models in more details. The mathematical formulations of the three models are presented in sections three to six.

Table 1: Regulation optimisation modelling option summary

	Block offer model	Uniform offer LP model	Uniform offer MIP model
General structure	Regulation offered in block ($/block). A regulation scheme can offer multiple blocks of different sizes and prices. No more than one block can be cleared from a regulation scheme. Multiple regulation schemes can be cleared at a time. Actual control min/ max constraints applied for selected regulation schemes. Mixed integer programming required.	Regulation uniformly offered ($/MW). A regulation scheme can offer multiple bands of different sizes and prices. Multiple bands can be cleared from a regulation scheme. Multiple regulation schemes can be cleared at a time. Linearized control min/max constraints applied for selected regulation schemes. Linear programming required.	Regulation uniformly offered ($/MW). A regulation scheme can offer multiple bands of different sizes and prices. Multiple bands can be cleared from a regulation scheme. Multiple regulation schemes can be cleared at a time. Actual control min/max constraints applied for selected regulation schemes. Mixed integer programming required.

	Block offer model	Uniform offer LP model	Uniform offer MIP model
Advantages **Vs.** **Disadvantages**	Regulation offer structure unchanged. Block offer not preferable in dynamically calculated regulation. (over purchase) Optimal solution. But may over-purchase because of block offer. Regulation is paid as it is cost	Regulation offer structure changed. Uniform offer preferable in dynamically calculated regulation. LP optimal solution may not be optimal if control Min/Max constraint violated. Regulation price can be underestimated.	Regulation offer structure changed. Uniform offer preferable in dynamically calculated regulation. Optimal solution. Uniform offers guarantee optimal regulation purchase. Multiple price solutions may occur.

	Block offer model	Uniform offer LP model	Uniform offer MIP model
<u>Notes</u>	Block offer model can replace the current process to pre-select frequency keepers. Block offer model can also be used for final pricing schedule. This model is not preferable for real-time schedule. Hard market node constraints still needed in real time schedule. We can resolve the problem with LP giving regulation solutions is pre-determined.	LP model may be preferable option for real time dispatch but have the issue of under-purchased or underestimated constrained-on cost. One of the operational solutions is to modify the rule so that regulation providers will not get paid for constrained-on/off. However, the issue with control max constraint still exists. Ex: a scheme that has control max much lower than generation max can be selected to provide regulation based on linearized control max constraint. If the linearized control max constraint is bound, this scheme will be constrained off to meet the control max constraint. Therefore, a significant amount of energy is lost from this scheme and need to be supplied from somewhere else. During the energy scarcity period, this will be a critical issue.	Uniform offer model can replace the current process to pre-select frequency keepers. Uniform offer model can also be used for final pricing schedule. This model is not preferable for real-time schedule. Hard market node constraints still needed in real time schedule. We can resolve the problem with LP giving regulation solutions is pre-determined. The regulation marginal price defined by this LP model can be underestimated.

Source: Electricity Authority

Notes: 1.

Table 2: Simulation results

	System Cost (Including Frequency Keeping Cost)				Frequency Keeping Cost Only			
	Island FK	**National FK (50 MW)**	**National FK (65 MW)**	**National FK (75 MW)**	**Island FK**	**National FK (50 MW)**	**National FK (65 MW)**	**National FK (75 MW)**
Block offer model	$76,660,114	$68,005,719	$70,724,880	$71,725,629	$13,273,093	$5,700,230	$8,248,995	$9,204,826
Uniform offer LP model	$75,740,139	$67,641,864	$69,683,508	$71,141,518	$13,016,972	$5,495,741	$7,458,914	$8,859,399
LP model with constrained-on/off	$77,718,674	$68,292,694	$70,539,277	$72,153,414	$13,016,972	$5,495,741	$7,458,914	$8,859,399
Uniform offer MIP model	$76,435,712	$67,822,712	$69,933,564	$71,442,769	$13,149,712	$5,679,360	$7,678,354	$9,191,665
Current selection process	N/A	N/A	N/A	N/A	$11,810,598	$7,954,552	N/A	N/A

Source: Electricity Authority

Notes:
1. Island FK means NI and SI separately and respectively require 50 and 25 MW of frequency keeping.
2. National FK (50 MW) means there is only one national market for FK with FK requirement of 50 MW. Similarly for National FK (75 MW & 65 MW).
3. Simulation based on historical data from 24 Jun 2013 to 18 Dec 2013.
4. The regulation (frequency keeping) offer data are modified so that a block offer can be equally converted to uniform offer.
5. Modified vSPD model is used for the simulation with FK optimisation part added.
6. The national frequency keeping cost for current process is calculated by removing the SI frequency keeping cost from Island frequency keeping cost. Therefore, this is just the upper bound of national frequency keeping cost.

1.11 When converting historical regulation block offer to uniform offer, we often encounter cases where the average price of the bigger size block is lower than average price of smaller size block. In this case, we need to increase the cost of bigger size block so that its average price is greater than that of the smaller size block. By doing this, we can equally convert block offer to uniform offer.

1.12 For example, a scheme offers regulation in two blocks. The first block offers 10 MW at $100/block. This is equal to $20/MWh in uniform offer. The second block offers 20 MW at $150/block. This is equal to $15/MWh in uniform offer. In order to equally convert block offer to uniform offer, the cost of second block will be adjusted to $200.01/block. The uniform offer will be 10 MW @ $20/MWh for first offer band and 10 MW @ $20.002/MWh.

1.13 Table 3 shows the historical frequency keeping cost from 2009 to 2013. If we assume that national frequency keeping requirement is equal to NI frequency keeping requirement, the frequency keeping cost in SI is the lower bound of saving we could get if national frequency keeping market were in place.

Table 3: Historical frequency keeping cost

[insert caption subheading]

Year	NI	SI	Total
2009	$17,831,765	$2,605,890	$20,437,654
2010	$30,049,306	$5,983,058	$36,032,364
2011	$18,121,427	$4,701,039	$22,822,466
2012	$26,381,455	$16,499,521	$42,880,976
2013	$20,844,089	$12,405,957	$33,250,046

Source: Electricity Authority

Notes: 1.

2 Regulation optimisation modelling options

2.1 Regulation block offer – mixed integer programing model

(a) In this model the regulation is offered in blocks. One regulation scheme can offer multiple blocks of different sizes (MW) and prices ($/block). Frequency keeping providers offer the service in block with the price (cost) in $/block. For each regulation scheme, no more than one block can be selected. Regulation can be provided by multiple schemes at a time. Intra-band constrained on/off cost is removed. This model produces optimal solution.

(b) One of the disadvantages of this model is that mixed integer programming is required because of block offer structure. However, with the small number of frequency keeping providers and enhanced computational power, this model can be solved very quickly.

2.2 Regulation uniform offer – linear programming model

(a) In this model regulation is offered in the form of $/MWh, similarly to energy and reserve.

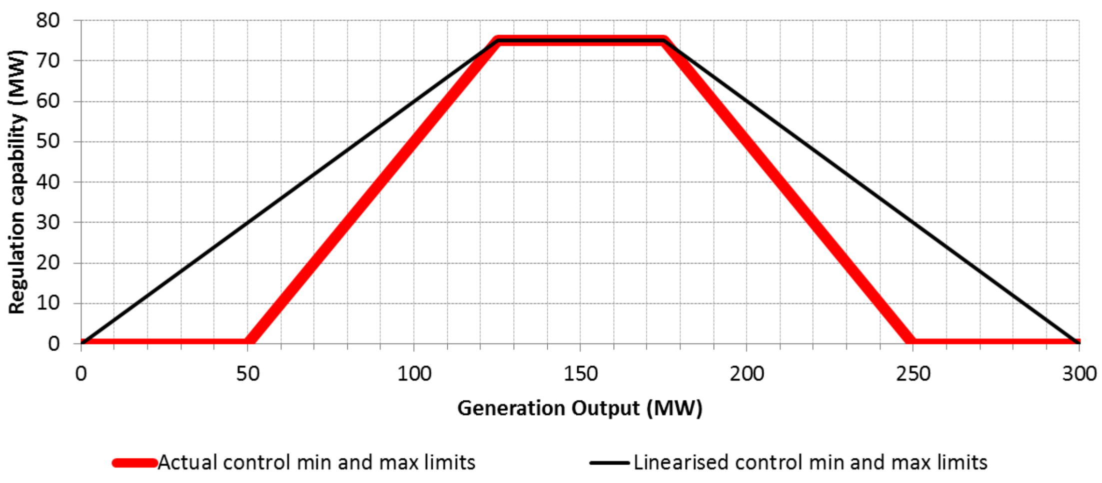
(b) In general, a scheme that is selected to provide regulation is required to have minimum and/or a maximum output limits. The scheme's generation has to be greater than or equal to the minimum limit plus the amount of frequency keeping supplied by the scheme. Similarly, the scheme's generation has to be less than or equal to the maximum limit minus the amount of frequency keeping supplied by the scheme.

(c) If these minimum and maximum limits are equal zero and the plant/scheme's generation capacity respectively, the relationship between generation and frequency keeping is linear and the problem is a straightforward linear programming problem (LP).

(d) In many cases, the minimum is much greater than zero and/or the maximum limit is much less than generation capacity offered. In this situation, the problem becomes a mixed integer linear programming problem (MIP).

(e) In order to solve the problem using LP, the relationship between generation and regulation of a scheme need to be linearized. Let's call this linearized relationship "soft constraint". Figure 1 demonstrates one of the ways to linearize this relationship.

Figure 1 Linearization of control min and max limit of frequency keeping



Source: Electricity Authority

Notes: 2. Generation capacity 300 MW, regulation capacity 75 MW
3. Control min limit 50 MW and control max limit 250 MW

(f) An issue with this approximation is that the amount of frequency keeping supply is overestimated if one of these constraints is binding on either side of the slopes (the black line is always above the red line along the slopes). This means that the regulation provider may be required to constrain on/off its generation output in operation (real time) and the solution is suboptimal. The suboptimal issue gets worse if the control min and/or the gap between control max and generation capacity are larger.

(g) In order to overcome this issue, the following approaches can be considered.

(i) Requesting regulation providers to submit very low price generation offer to meet the minimum generation limit. This approach may help to reduce the occurrence of this issue but does not completely solve the issue with control min limit. Furthermore, this approach does not touch on the control max limit.

(ii) Amending the code so that regulation providers are not paid for constrained-on/off generation to meet regulation control min/max requirements.

(iii) Using MIP to resolving the problem if LP solution violates control min and/or max limits. The MIP problem will be used re-solved with actual control min and max limits being applied for selected frequency keepers. This approach makes sure that control min and max limits are not violated and guarantee the optimal solution but requires mixed integer programming. This approach is described in more details in the following section.

2.3 Regulation uniform offer – mixed integer programing model

(a) In this model regulation is offered in the form of $/MWh, similarly to energy and reserve.

(b) The control min and max limits ("hard constraint") is modelled using mixed integer programming.

(c) A binary variable is introduced in the model so that if a scheme is selected to provide frequency keeping, the actual control min and max limits will be applied for this scheme. For the unselected scheme, frequency keeping offer will be forced to zero and therefore cannot be cleared.

(d) One of the issues with this approach is that it is very likely to have multiple pricing solutions (degeneracy in dual problem). Currently, the frequency keeping requirement is easily predicted, a frequency keeping provider may offer exact amount. If all the offers of this frequency keeping provider are cleared and that is enough to meet the frequency keeping requirement all other offers will be forced to zero. The problem will then have multiple pricing solutions with the extreme price is infeasible price.

(e) This issue can be resolved by reducing the frequency keeping requirement by a very small amount (Ex: If tolerance is 1e-6, we can reduce the frequency keeping requirement by 2e-6). Another option is to add a very small amount (2e-6) to regulation offer MW. This will make sure that the frequency price will be defined by the highest cleared offer price.

(f) This issue may disappear if regulation requirement is dynamically defined based on cleared demand, generation and reserve.

(g) Another solution is to resolve using LP model with fixed regulation and generation min/max constraints applied for the schemes that are selected to provide regulation in MIP model. A problem with the LP resolve is that it may underestimate the regulation price.

3 SETS, PARAMETERS AND VARIABLES

Table 4: SETS

Name	Index	Description
Scheme	s	A group of generators that provide frequency keeping service as a scheme.
Energy Offer	g	Represent offer from generator g.
Reserve Offer	r	Represent reserve offer.
Island	i	Represent island (NI, SI).
Trade Block	k	Represent different band in an offer
Reserve Class	c	Represent different reserve class (6s,60s)

Table 5: PARAMETERS

Name	Description
$RegulationMW_{s,k}$	Maximum MW of frequency offer band k from scheme s.
$RegulationPrice_{s,k}$	Cost of frequency offer band k from scheme s. If block offer → \$/Block; If uniform offer → \$/MWh
$RegulationRequired_{i}$	Amount of frequency keeping (MW) required in island i
$RegulationSharedMax_{i}$	Upper limit of frequency keeping (MW) that can be shared through HVDC into island i.
$Capacity_{s}$	capacity rating of generator g.
$SchemeGenrationCapacity_{s}$	Total capacity rating of all generators in scheme s.
$RegulationCtrlMin_{s}$	Minimum generation of frequency keeping provider (scheme) s
$RegulationCtrlMax_{s}$	Maximum generation of frequency keeping provider (scheme) s
$RegulationCtrlMinSlope_{s}$	Ratio of maximum frequency keeping and generation. This is used to approximately linearize the FK control min constraint.
$RegulationCtrlMaxSlope_{s}$	Ratio of maximum frequency keeping and unused but available generation capacity. This is used to approximately linearize the FK control max constraint.

Table 6: VARIABLES

Name	Type	Description
NETBENEFIT	Free	Objective value.
GENERATION_g	Positive	Energy cleared from generator g. This is current SPD variable.
$\text{PLORESERVE}_{r,c}$	Positive	Total partial load reserve class r cleared from generator g. This is current SPD variable.
$\text{TWORESERVE}_{r,c}$	Positive	Total tail-water depressed reserve class r cleared from generator g. This is current SPD variable.
$\text{SCHEMEGENERATION}_s$	Positive	Total energy cleared from all generators in scheme s.
$\text{SCHEMERESERVE}_{s,c}$	Positive	Total reserve class c cleared from all generators in scheme s.
$\text{REGULATIONBLOCK}_{s,k}$	Positive	Frequency keeping cleared from offer block k of scheme s.
REGULATION_s	Positive	Total frequency keeping cleared from scheme s.
REGULATIONHVDC_i	Positive	Total frequency keeping can be imported through HVDC in to island i.
$\text{BLOCKSELECTED}_{s,k}$	Binary	Regulation offer block selected. Only applied in mixed integer model 1
SCHEMESELECTED_s	Binary	Regulation scheme selected. Only applied in mixed integer model 3

4 Block frequency keeping offer model

4.1 Revised objective function

$$\mathrm{NETBENEFIT} = \sum_{p \in \mathrm{BIDS}} \sum_{k=1}^{\mathrm{DemandBidBlocks}_p} \mathrm{DEMANDBLOCK}_{p,k} \times \mathrm{DemandBidPrice}_{p,k} -$$
$$\sum_{g \in \mathrm{OFFERS}} \sum_{k=1}^{\mathrm{GenerationOfferBlocks}_g} \mathrm{GENERATIONBLOCK}_{g,k} \times \mathrm{GenerationOfferPrice}_{g,k} -$$
$$\sum_{r \in \mathrm{RESERVEOFFERS}} \sum_{k=1}^{\mathrm{ReserveOfferBlocks}_r} \mathrm{RESERVEBLOCK}_{r,k} \times \mathrm{ReserveOfferPrice}_{r,k} -$$
$$\sum_{s \in \mathrm{REGULATIONOFFERS}} \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} 2 \times \mathrm{BLOCKSELECTED}_{s,k} \times \mathrm{RegulationPrice}_{r,k}$$

4.2 Scheme generation calculation

$$\mathrm{SCHEMEGENERATION}_s = \sum_g \mathrm{GENERATION}_g$$
$$\forall g \in \text{Energy Offer in Schemes}$$

4.3 Scheme reserve calculation

$$\mathrm{SCHEMERESERVE}_{s,c} = \sum_r \mathrm{PLORESERVE}_{r,c} + \mathrm{TWORESERVE}_{r,c}$$
$$\forall r \in \text{Reserve Offer in Schemes} \quad \forall c \in \text{Reserve Class}$$

4.4 Regulation offer block definition

Maximum only one block is selected from a scheme

$$\sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{BLOCKSELECTED}_{s,k} \leq 1$$
$$\forall s \in \text{Scheme}$$

4.5 Regulation offer definition

$$\mathrm{REGULATION}_s = \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{BLOCKSELECTED}_{s,k} \times \mathrm{RegulationMW}_{s,k}$$
$$\forall s \in \text{Scheme}$$

4.6 Regulation Energy and Reserve Maximum

For each reserve class, the sum of regulation, energy and reserve cleared is less than or equal to capacity rating.

$$\mathrm{REGULATION}_s + \mathrm{SCHEMEGENERATION}_s + \mathrm{SCHEMERESERVE}_{s,c} \leq \sum_g \mathrm{Capacity}_g$$
$$\forall g \in \text{generators in Scheme s}$$

4.7 Regulation Control Min Definition

$$\begin{aligned}&\mathrm{SCHEMEGENERATION}_s - \mathrm{REGULATION}_s\\&\geq \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{BLOCKSELECTED}_{s,k} \times \mathrm{RegulationCtrlMin}_s\\&\forall s \in \mathrm{Scheme}\end{aligned}$$

4.8 Regulation Control Max Definition

$$\begin{aligned}&\mathrm{SCHEMEGENERATION}_s + \mathrm{REGULATION}_s \leq \sum_g \mathrm{Capacity}_g\\&+ \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{BLOCKSELECTED}_{s,k} \times \left(\mathrm{RegulationCtrlMax}_s - \sum_g \mathrm{Capacity}_g\right)\\&\forall g \in \text{generators in Scheme s}\end{aligned}$$

4.9 Max regulation imported through HVDC

$$\begin{aligned}&\mathrm{REGULATIONHVDC}_i \leq \mathrm{RegulationSharedMax}_i\\&\forall i \in \mathrm{island}\end{aligned}$$

4.10 Available regulation to be shared through HVDC

$$\begin{aligned}&\mathrm{REGULATIONHVDC}_i \leq \sum_{s \in \text{Schemes in island} \neq i} \mathrm{REGULATION}_s\\&\forall i \in \text{island} \quad s \in \text{Schemes in the other island}\end{aligned}$$

4.11 Regulation supply balance definition

$$\begin{aligned}&\mathrm{REGULATIONHVDC}_i + \sum_s \mathrm{REGULATION}_s \geq \mathrm{RegulationRequired}_i\\&\forall s \in \text{Scheme in island i}\end{aligned}$$

5 Uniform frequency keeping offer LP model

5.1 Revised objective function

$$\mathrm{NETBENEFIT} = \sum_{p \in \mathrm{BIDS}} \sum_{k=1}^{\mathrm{DemandBidBlocks}_p} \mathrm{DEMANDBLOCK}_{p,k} \times \mathrm{DemandBidPrice}_{p,k} - \sum_{g \in \mathrm{OFFERS}} \sum_{k=1}^{\mathrm{GenerationOfferBlocks}_g} \mathrm{GENERATIONBLOCK}_{g,k} \times \mathrm{GenerationOfferPrice}_{g,k} - \sum_{r \in \mathrm{RESERVEOFFERS}} \sum_{k=1}^{\mathrm{ReserveOfferBlocks}_r} \mathrm{RESERVEBLOCK}_{r,k} \times \mathrm{ReserveOfferPrice}_{r,k} - \sum_{s \in \mathrm{REGULATIONOFFERS}} \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{REGULATIONBLOCK}_{s,k} \times \mathrm{RegulationPrice}_{r,k}$$

5.2 Scheme generation calculation

$$\mathrm{SCHEMEGENERATION}_s = \sum_g \mathrm{GENERATION}_g$$

$$\forall g \in \text{Energy Offer in Schemes}$$

5.3 Scheme reserve calculation

$$\mathrm{SCHEMERESERVE}_{s,c} = \sum_r \mathrm{PLORESERVE}_{r,c} + \mathrm{TWORESERVE}_{r,c}$$

$$\forall r \in \text{Reserve Offer in Schemes} \quad \forall c \in \text{Reserve Class}$$

5.4 Regulation offer block definition

$$\mathrm{REGULATIONBLOCK}_{s,k} \le \mathrm{RegulationMW}_{s,k}$$

$$\forall s \in \text{Scheme} \quad \forall k \in \text{Regulation Offer Block s}$$

5.5 Regulation offer definition

$$\mathrm{REGULATION}_s = \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{REGULATIONBLOCK}_{s,k}$$

$$\forall s \in \text{Scheme}$$

5.6 Regulation Energy and Reserve Maximum

For each reserve class, the sum of regulation, energy and reserve cleared is less than or equal to capacity rating.

$$\mathrm{REGULATION}_s + \mathrm{SCHEMEGENERATION}_s + \mathrm{SCHEMERESERVE}_{s,c} \le \sum_g \mathrm{Capacity}_g$$

$$\forall g \in \text{generators in Scheme s}$$

5.7 Regulation Control Min Definition

$$\text{REGULATION}_s \leq$$
$$\text{RegulationCtrlMinSlope}_s \times \text{SCHEMEGENERATION}_s$$
$$\forall s \in \text{Scheme}$$

5.8 Regulation Control Max Definition

$$\text{REGULATION}_s \leq$$
$$\text{RegulationCtrlMaxSlope}_s \times \left(\text{Capacity}_s - \text{SCHEMEGENERATION}_s\right)$$
$$\forall s \in \text{Scheme}$$

5.9 Max regulation imported through HVDC

$$\text{REGULATIONHVDC}_i \leq \text{RegulationSharedMax}_i$$
$$\forall i \in \text{island}$$

5.10 Available regulation to be shared through HVDC

$$\text{REGULATIONHVDC}_i \leq \sum_{s \in \text{Schemes in island} \neq i} \text{REGULATION}_s$$
$$\forall i \in \text{island} \quad s \in \text{Schemes in the other island}$$

5.11 Regulation supply balance definition

$$\text{REGULATIONHVDC}_i + \sum_s \text{REGULATION}_s \geq \text{RegulationRequired}_i$$
$$\forall s \in \text{Scheme in island i}$$

6 Uniform frequency keeping offer MIP model

6.1 Revised objective function

$$\mathrm{NETBENEFIT} = \sum_{p\in \mathrm{BIDS}} \sum_{k=1}^{\mathrm{DemandBidBlocks}_p} \mathrm{DEMANDBLOCK}_{p,k} \times \mathrm{DemandBidPrice}_{p,k} - \sum_{g\in \mathrm{OFFERS}} \sum_{k=1}^{\mathrm{GenerationOfferBlocks}_g} \mathrm{GENERATIONBLOCK}_{g,k} \times \mathrm{GenerationOfferPrice}_{g,k} - \sum_{r\in \mathrm{RESERVEOFFERS}} \sum_{k=1}^{\mathrm{ReserveOfferBlocks}_r} \mathrm{RESERVEBLOCK}_{r,k} \times \mathrm{ReserveOfferPrice}_{r,k} - \sum_{s\in \mathrm{REGULATIONOFFERS}} \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} 2 \times \mathrm{REGULATIONBLOCK}_{s,k} \times \mathrm{RegulationPrice}_{r,k}$$

6.2 Scheme generation calculation

$$\mathrm{SCHEMEGENERATION}_s = \sum_g \mathrm{GENERATION}_g$$

$$\forall g \in \text{Energy Offer in Schemes}$$

6.3 Scheme reserve calculation

$$\mathrm{SCHEMERESERVE}_{s,c} = \sum_r \mathrm{PLORESERVE}_{r,c} + \mathrm{TWORESERVE}_{r,c}$$

$$\forall r \in \text{Reserve Offer in Schemes} \quad \forall c \in \text{Reserve Class}$$

6.4 Regulation offer block definition

$$\mathrm{REGULATIONBLOCK}_{s,k} \le \mathrm{SCHEMESELECTED}_s \times \mathrm{RegulationMW}_{s,k}$$

$$\forall s \in \text{Scheme} \quad \forall k \in \text{Regulation Offer Blocks}$$

6.5 Regulation offer definition

$$\mathrm{REGULATION}_s = \sum_{k=1}^{\mathrm{RegulationOfferBlocks}_s} \mathrm{REGULATIONBLOCK}_{s,k}$$

$$\forall s \in \text{Scheme}$$

6.6 Regulation Energy and Reserve Maximum

For each reserve class, the sum of regulation, energy and reserve cleared is less than or equal to capacity rating.

$$\mathrm{REGULATION}_s + \mathrm{SCHEMEGENERATION}_s + \mathrm{SCHEMERESERVE}_{s,c} \le \sum_g \mathrm{Capacity}_g$$

$$\forall g \in \text{generators in Scheme s}$$

6.7 Regulation Control Min Definition

$$\mathrm{SCHEMEGENERATION_s - REGULATION_s}$$
$$\geq \mathrm{RegulationCtrlMin_s \times SCHEMESELECTED_s}$$
$$\forall \mathrm{s} \in \mathrm{Scheme}$$

6.8 Regulation Control Max Definition

$$\mathrm{SCHEMEGENERATION_s + REGULATION_s}$$
$$\leq \sum\nolimits_g \mathrm{Capacity_g} + \mathrm{SCHEMESELECTED_s} \times \left(\mathrm{RegulationCtrlMax_s} - \sum\nolimits_g \mathrm{Capacity_g}\right)$$
$$\forall \mathrm{g} \in \text{generators in Scheme s}$$

6.9 Max regulation imported through HVDC

$$\mathrm{REGULATIONHVDC_i} \leq \mathrm{RegulationSharedMax_i}$$
$$\forall \mathrm{i} \in \mathrm{island}$$

6.10 Available regulation to be shared through HVDC

$$\mathrm{REGULATIONHVDC_i} \leq \sum\nolimits_{\mathrm{s \in Schemes\ in\ island} \neq \mathrm{i}} \mathrm{REGULATION_s}$$
$$\forall \mathrm{i} \in \mathrm{island} \quad \mathrm{s} \in \text{Schemes in the other island}$$

6.11 Regulation supply balance definition

$$\mathrm{REGULATIONHVDC_i} + \sum\nolimits_s \mathrm{REGULATION_s} \geq \mathrm{RegulationRequired_i}$$
$$\forall \mathrm{s} \in \text{Scheme in island i}$$

Appendix A Converting block offer to uniform offer

A.1 Appendix heading 2 is the style to use for the main text in an appendix.

(a) Appendix paragraph (a)

(b) Appendix paragraph (a)

(i) Appendix paragraph (i)

(ii) Appendix paragraph (i)

A.2 Appendix heading 2

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Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code 2010
Regulations	Electricity Industry (Enforcement) Regulations 2010