Wholesale Advisory Group

National Instantaneous Reserves Market recommendations paper

Report by the Wholesale Advisory Group

30 July 2013

Note: This paper has been prepared for the purposes of the Wholesale Advisory Group. Content should not be interpreted as representing the views or policy of the Electricity Authority.

This is the final version of this report, to be submitted to the Authority Board.

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The Wholesale Advisory Group (WAG)

The members of the WAG, as at the date of the publication of this paper, are:
John Hancock (Chair)
Neal Barclay
John Carnegie
Graeme Everett
Stephen Peterson
Bruce Rogers
Richard Spearman
John Woods
Alan Eyes
Chris Jewell

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 instantaneous reserve (IR).

1 Introduction

1.1.1 In July 2012 the Electricity Authority (Authority) asked the Wholesale Advisory Group (WAG) to "determine the potential for developing a national market for instantaneous reserve (IR) and, if feasible, to develop arrangements to give effect to it".

1.1.2 The Authority noted that "a national IR market could contribute to the Authority's statutory objective by increasing the competition to supply IR and improving operational efficiency by reducing overall IR requirements".

1.1.3 This paper presents the results of WAG's investigation.

1.1.4 See Appendix A for an explanation of what a "national instantaneous reserves market" (NIRM) would mean.

2 Conclusion and recommendations

2.1.1 The WAG concludes that implementing a NIRM would result in a substantial net economic benefit (Section 3.6) and that doing so would be consistent with the Authority's statutory objective and Code amendment principles (Section 3.2).

2.1.2 This project is also relatively unique in that the expected impact on participant systems and resulting disruption to the industry is likely to be minor (Section 3.2.11) which simplifies implementation and is part of the reason that the WAG has chosen to move directly to its recommendations.

2.1.3 The WAG therefore recommends that the Authority should prioritise the NIRM project and progress it as swiftly as possible. The WAG considers that if necessary it would be appropriate to complete work on the NIRM ahead of some of the other wholesale market projects presently in train that involve changes to market systems.

2.1.4 There are several possible paths towards implementation of a NIRM (Section 3.2). Some of these paths might take multiple years to complete, but it may be possible to capture some early benefits by proceeding in a staged manner.

2.1.5 The WAG recommends that the Authority should engage with Transpower (as the system operator and the transmission asset owner) to identify in more detail the best options for implementing a NIRM. The WAG feels that the Authority and Transpower are best placed to complete this activity as it is primarily technical in nature.

2.1.6 Key design questions are likely to include:

a) whether planned changes to HVDC control systems will be sufficient to enable a NIRM (Section 3.2);

b) how the Reserve Management Tool (RMT) and Scheduling, Pricing and Dispatch (SPD) model will need to be modified (Section 3.2);

c) whether roundpower on the HVDC should be enabled as part of a move to introduce a NIRM, or whether that can be progressed as a separate issue (Section 3.3);

d) how the NIRM should interact with a national frequency keeping market (NFKM), which would also require the transfer of frequency control over the HVDC link (Section 3.4); and

e) whether any changes to IR availability charges and/or event charges will be needed (Section 3.5).

2.1.7 Second-tier issues that the Authority should keep in mind are that:

a) there are linkages between the NIRM initiative and the current review of under-frequency management (UFM) arrangements, which should be borne in mind in the course of both projects;

b) there might be implications for AUFLS settings; and

c) there might be implications for generator UFM asset owner performance obligations (AOPOs).

3 Approach to the project

3.1 Process

3.1.1 The WAG met three times between March 2013 and July 2013 to discuss the NIRM.

3.1.2 The WAG considered publishing a discussion paper to seek feedback from the wider industry. However, having reached the conclusion that the Authority should progress the project without further delay on the basis that the project appears to have clear benefits and be largely uncontentious the WAG decided that it was preferable to proceed directly to provide the Authority with this recommendations paper.

3.1.3 The WAG is of the view that implementing a NIRM is feasible and recommends that a strawman proposal including costs and timelines should be developed as swiftly as possible.

3.1.4 The next stage of the project will be technical, and, in WAG's view, can best be progressed by the Authority working directly with Transpower.

3.1.5 However, the WAG is keen to have further input at a later stage of the process, once more detailed information is available. An assessment regarding the optimal location for responsibility of the project can be made at that point.

3.2 Implementing a NIRM

<u>New HVDC hardware and control systems are expected to allow sufficient reserve sharing</u>

3.2.1 The WAG understands that once the HVDC becomes available in full bipole control mode (expected to be April 2014) it will enable implementation of a NIRM (subject to the changes to market systems and rules discussed in the rest of this section).[1] In other words, although some changes to control system settings would be required, it is not expected that any new system features would need to be developed as part of the process of implementing the NIRM.

3.2.2 This is consistent with the system operator's comments in the course of the UFM review.[2]

3.2.3 Accordingly, the WAG understands that no incremental costs would be incurred by Transpower, in its capacity as transmission asset owner, in the process of implementing a NIRM.[3]

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[1] It might be possible to implement a limited NIRM on one HVDC pole only before April 2014, but this would fail to capture a significant fraction of the benefits.

[2] See section 3.2.1 of http://www.systemoperator.co.nz/f4579,72340245/WS-4_UFM_collective_review.pdf.

3.2.4 However the WAG recommends that the Authority liaise with Transpower to confirm at a technical level that the planned changes to HVDC control systems will be sufficient to enable a NIRM.

System operator systems

3.2.5 There are two key areas in which changes to system operator systems could be required:

a) altering SPD so that it "knows" how the amount and type of IR procured in one island affects the amount required in the other island; and

b) updating RMT to reflect how changes to HVDC operation would affect system response to a frequency disturbance.

3.2.6 The changes to SPD appear reasonably straightforward. A possible specification for a NIRM formulation was published by Transpower in 2006, and demonstration versions of SPD incorporating a NIRM have been available for some years. For these reasons, the WAG expects that costs incurred to identify and implement the required changes to SPD will be manageable. However, it would be prudent to confirm this position with the system operator.

3.2.7 The changes to RMT are less clearly understood. The system operator has indicated that it considers that the current version of RMT could not model a NIRM. It has indicated a strong preference in favour of a complete rebuild of RMT, which could take several years.

3.2.8 If the RMT rebuild approach is taken, this may defer the benefits from a NIRM. Authority staff have suggested that it might be possible to modify the current version of RMT, rather than producing an entirely new piece of software. Under this approach it may be possible to implement a NIRM in stages, in order to capture benefits earlier if implementation would otherwise span multiple years. This work may be outside of current system operator resourcing capabilities, and consideration is required as to how it could be carried out.

3.2.9 There may be several possible paths for staged implementation of a NIRM. For instance, one transitional option could be to increase the Net Free Reserve parameters (NFR, see Appendix A) that are provided to SPD.[4] This would have the effect of reducing IR requirements in each island, on the basis that part of the IR requirement would be supplied from the other island over the HVDC link.

3.2.10 The WAG is not in a position to set out the potentially feasible paths or assess their expected costs and benefits at this time because that would require access to detailed information and analysis. Rather, WAG recommends that the Authority should work with the system operator to:

a) undertake the necessary detailed analysis;

b) determine feasible options for changing market systems to implement a NIRM; and

c) assess the net economic benefit of these options to identify a preferred option.

Participant and Clearing Manager systems

3.2.11 It is not anticipated that any changes to participant systems would be required. IR prices would continue to be determined and published for each island – the only change in a NIRM would be

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[3] As distinct from costs incurred in the course of *operating* the NIRM – for instance, it has been suggested that (under the current Code) Transpower would be liable for the cost of increased system losses due to operating the HVDC in roundpower mode.

[4] Before making such changes, it would be important to carry out offline studies to confirm the validity of the new NFR figures.

that these prices would be closer together at times. Participants would enter offers in the same format as at present, and settlement would work the same way as it currently does. Participants may choose to modify strategic or risk management systems as a result of altered market dynamics, however this should not be seen as a cost arising directly from the project.

3.2.12 Depending on the timing of go-live, there may be a range of other wholesale market changes occurring at a similar time, which may need to be considered in order to minimise impacts on participants.

3.2.13 It is not anticipated that any changes to Clearing Manager systems would be required – except, perhaps, as a result of changes to IR cost recovery, if any (Section 3.5).

3.3 Implications for roundpower on the HVDC

3.3.1 Roundpower refers to the situation where power simultaneously flows from north to south on one HVDC pole, and from south to north on the other pole. The upcoming upgrade to HVDC control systems will enable roundpower.

3.3.2 The availability of roundpower would not be a necessary condition for a NIRM, but it could enhance the effectiveness of a NIRM. As set out in Appendix A, the presence of a "HVDC dead band" could prevent or limit IR transfer in some situations. Using roundpower would remove this dead band.

3.3.3 Preliminary analysis undertaken for WAG suggests that the deadband would not materially affect the size of benefits from a NIRM (see Appendix B). However, this view should not be taken as definitive and should be reassessed once more detailed information is available on implementation options (discussed in Section 3.2).

3.3.4 With or without a NIRM, roundpower could also produce a more efficient dispatch by allowing HVDC transfer to enter the "dead band" if it was most economic to do so. On the other hand, using roundpower would increase transmission loss costs. Consideration would need to be given to how these costs should be treated (for example, as a reduction in the loss and constraint excess, or an explicit cost to be recovered in a defined manner).

3.3.5 Transpower has indicated to the WAG that it would prefer to make roundpower available as soon as possible – preferably in advance of implementing a NIRM. Amendments to the Code would be required in order to provide for roundpower to be co-optimised in the market, as there would be changes to the dispatch objective. The Code amendments would be straightforward, but a reasonably substantial amount of work would need to be done to implement them in SPD. It has previously been estimated that the cost of upgrading SPD to provide for roundpower would be approximately $5M.

3.3.6 Based on currently available information, the WAG does not see a compelling reason to predicate the introduction of a NIRM upon HVDC roundpower. However, the WAG acknowledges that each will enhance the benefits of the other, and suggests that the Authority consider this issue further as it works through feasible implementation options with Transpower.

3.4 Interaction with a NFKM

3.4.1 On 1 July 2013, the first stage of the Multiple Frequency Keeping (MFK) market went live, enabling FK services to be provided by more than one provider in an island at one time. At this stage the MFK market is active only in the North Island, but it is expected to be extended to the

South Island in the near future. When both islands are cut-over to MFK (likely to be in 2014), it will be technically possible to have a national frequency keeping market (NFKM).

3.4.2 The potential introduction of national markets for both IR and FK would mean that the control modulation function of the HVDC would need to be shared between these two ancillary services.

3.4.3 In trading periods where there was insufficient flexibility to transfer both ancillary services across the HVDC, priority would need to be given to one service or the other. Criteria for deciding which service had higher priority would need to be established. The ideal approach would be to co-optimise the two services within SPD.

3.4.4 At this point, WAG recommends that the NFKM and NIRM be advanced in parallel, and that the Authority continue to monitor progress to identify any issues where close coordination will be required.

3.5 Implications for IR cost recovery

3.5.1 The costs of IR are recovered:

a) from generators with units over 60 MW and from Transpower (as owner of the HVDC link), through the IR availability charge. Under the current regulatory framework, South Island generators pay the IR availability charges incurred by Transpower; and

b) from the causer of an under-frequency event (either a generator, or Transpower as owner of the HVDC link) through the IR event charge of $1,250 per MW of lost injection. Event charges are rebated to IR availability charge payers.

3.5.2 The establishment of a NIRM may potentially affect both the total amount and the distribution of IR charges. Depending on the extent of any change, it might therefore become appropriate to reconsider how these charges are allocated. It is too early to make any judgement on this issue, hence the WAG recommends that the Authority defer consideration of this issue until more information is available on the preferred option for implementing a NIRM.

3.5.3 Cost recovery is a contentious issue and any change will produce winners and losers. Any review of IR cost recovery should be separated from market design and implementation activities (in order to avoid unnecessary delay).

3.6 Cost-benefit analysis

<u>Benefits</u>

3.6.1 The WAG estimates that a NIRM would conservatively deliver economic benefits of approximately $1.5M per year, or $15M PV over 20 years (using a real discount rate of 8%) with substantial upside in the event of changes in demand or reserve supply, through:

a) reduced IR provision costs;[5]

b) reduced generation costs (as a result of the co-optimisation of IR and energy).

3.6.2 See Appendix B for more detail on how this estimate was derived. The figure is also broadly consistent with earlier estimates published by Transpower in 2004[6] ($0.68 M over 4 months studied) and by the Electricity Commission in 2006[7] ($2M p.a.).

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[5] This refers to a reduction in the *economic costs* of IR provision, as opposed to a reduction in the IR charges paid by participants – which would be a wealth transfer as opposed to a true economic cost.

3.6.3 It has been suggested that a NIRM might also deliver additional economic benefits of at least $7M per year from 2018 onwards,[8] or $50M over 20 years (using a real discount rate of 8%), by deferring the need for investment in peaking capacity. See Appendix C for more detail on how this estimate was derived.

3.6.4 There may also be dynamic efficiency benefits as a result of new IR providers entering the market in the South Island (which would be uneconomic in the absence of a NIRM because average IR prices in the South Island are lower than in the North Island).

3.6.5 Table 1 contains known information about benefits stated in annual and 20 year PV terms using an 8% discount rate.

Item	Annual Value	Present Value
Economic benefits of reduced IR provision costs	$1.5 M	$15 M
Economic Benefits of avoided investment in peaking capacity	$7.0 M (from 2018 onwards)	$50 M
Dynamic efficiency benefits from additional SI providers	Not calculated	Not calculated.
Total	$1.5 M (2015 to 2017) $8.5 M (from 2018)	$65 M

Costs

3.6.6 The WAG anticipates that the main costs incurred in the course of implementing a NIRM would be service provider costs (see Section 3.2) since:

a) existing information indicates little or no incremental costs associated with changes to HVDC control systems (although this should be confirmed with the Grid Owner); and

b) there should be no need for changes to existing participant systems.

3.6.7 The WAG has not investigated the service provider costs that would be associated with implementing a NIRM, but anticipates that they would be much lower than the estimated benefit of $65M PV.

3.6.8 Operating a NIRM could potentially also create on-going economic costs through:

6 http://www.systemoperator.co.nz/f4579,62752192/UFM-WS3-Appendix-_3-NRM-2004.pdf

7 "Common Quality Development Plan, Evaluation of Options" (http://www.ea.govt.nz/dmsdocument/3574).

8 The system operator's Annual Security Assessment shows that for the next few years there will be no need for additional peaking investment. However, from roughly 2018 onwards, more peaking capacity will be required to balance peak demand growth and/or retirement of ageing generation.

a) additional "wear and tear" on HVDC assets;

b) changes to frequency quality through increased linkage of frequency response across both islands

c) additional losses if HVDC roundpower is used.

3.6.9 However, the WAG has insufficient information to assess the likely scale of these costs.

4 Explanation of how the WAG's recommendations are consistent with the Authority's statutory objective and the Code amendment principles

4.1.1 The WAG considers that its recommendations are consistent with the Authority's statutory objective, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

4.1.2 The WAG agrees with the Authority's original assessment that "a NIRM could contribute to the Authority's statutory objective by increasing the competition to supply IR, and [by] improving operational efficiency by reducing overall IR requirements". Both IR and energy costs would be expected to reduce.

4.1.3 The WAG is not recommending specific Code amendments to the Authority at this point but expects that some will be required. The WAG considers that its recommendations are consistent with the Authority's Code amendment principles.

4.1.4 In particular, the recommendations (if followed) should lead to outcomes that are *lawful* (Principle 1) and would *improve the efficiency of the electricity industry for the long-term benefit of consumers* (Principle 2). Economic benefits have been *quantified* (Principle 3) and are set out in Section 3.6 and Appendix B – though estimates of economic costs are not yet available.

5 Next steps

5.1.1 If the Authority agrees with the WAG's recommendations, then it should progress the NIRM project as soon as possible. This is expected to primarily involve bilateral work with Transpower regarding system design and development, leading to detailed market design, Code development, and consultation with stakeholders.

5.1.2 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 NIRM.

5.1.3 The WAG requests the Authority to keep it updated with progress on this project. In particular if the Authority expects that it will be unable to progress the project in line with WAG's two key recommendations (proceeding without delay and considering staged implementation) the WAG requests a detailed explanation of the relevant issues and measures taken to resolve them.

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John Hancock
Chair, Wholesale Advisory Group

Appendix A What a NIRM would mean

Currently there are separate IR markets for the two islands

A.1.1 Instantaneous reserve (IR) is an ancillary service, procured to assist in management of under-frequency events. IR providers include:

a) generators, which can increase output in response to a drop in frequency; and

b) parties offering interruptible load, which can reduce consumption in response to a drop in frequency.

A.1.2 Both fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) are procured.

A.1.3 These products are procured separately in the North and South Islands. So, for each trading period, there are four IR prices – i.e. for:

a) North Island FIR;

b) North Island SIR;

c) South Island FIR; and

d) South Island SIR.

Each island can assist the other

A.1.4 The quantities of IR procured in each trading period are determined by the SPD model, and are co-optimised with energy dispatch.

A.1.5 The Reserve Management Tool (RMT) is used to calculate the net free reserve (NFR) parameters that are input to SPD. These NFRs are used by SPD to calculate how much IR is needed in order to manage contingent events, which are caused by the sudden and unexpected tripping of generation or transmission.

A.1.6 When there is an under-frequency event in island A, then (providing the HVDC link is still operational) the inertia of the load and generation in island B will help to stabilise frequency in island A. This process can be thought of as 'inertia being shared over the HVDC link'. RMT takes account of this phenomenon when calculating NFRs. The result is that the amount of IR needed in island A is less than it otherwise would have been – *unless* the need for IR in island A is driven by the possibility of the HVDC itself tripping, in which case sharing across the link does not help.

A.1.7 Currently, the FIR assumed to be shared over the HVDC link is in the range of 25-50 MW (providing the under-frequency event is a generating unit tripping, rather than the HVDC itself tripping). No SIR is assumed to be shared over the HVDC link.

A national IR market (NIRM) would extend this sharing

A.1.8 At present RMT does not explicitly allow for an under-frequency event in island A to result in load tripping or generation ramping up in island B (although NFRs do implicitly include some response from island B generators).

A.1.9 With the commissioning of Pole 3 (and subject to confirmation by the Grid Owner) it appears that the frequency in the two islands can be more closely linked, which will allow IR to be shared more effectively between islands. In other words, IR procured in island B could help to satisfy the requirement for IR in island A.

A.1.10 As well as changes to the HVDC control settings, there would be a need for:

a) changes to RMT, to model the response of the HVDC link and relevant connected AC systems; and/or

b) changes to SPD, to reflect the contribution of IR in each island to meeting IR requirements in the other island.

A.1.11 The result would be that most of the time:

a) less IR will be required overall; and

b) if IR is available at a cheaper price in island A than in island B, it will be possible to procure more IR from island A and less from island B.

<u>There would be limitations on the NIRM</u>

A.1.12 For various reasons, there would be limits on the amount of IR that could be shared between the islands. These limits would include that:

a) the IR transfer from island A to island B could not exceed the IR procured in island A;

b) the total transfer from island A to island B (post contingency) could not exceed the overload capacity of the HVDC link (minus a frequency keeping band, if a NFKM was in place);

c) a contingency (combined with frequency response) could not result in transfer moving into the HVDC 'dead band' (unless roundpower was enabled);

d) IR sharing across the HVDC link could not be used to manage the consequences of a HVDC link failure (since there would be reduced flow over the link post contingency[9]);

e) an upper limit on the amount of IR that could be shared across the link at any point in time (related to technical capabilities of the link or stability requirements in each island); and

f) a 'derating' on shared IR – i.e. 1 MW of IR in island A might only be worth 0.9 MW when it came to meeting the need for IR in island B. This arises due to potential losses or distance/time effects.

9 Following a single pole failure, the HVDC would still be able to transfer energy on the secondary pole.

Appendix B Economic benefits of implementing a NIRM – reduced IR provision and energy costs

B.1.1 This Appendix explains the basis for estimating the conservative economic benefit of a NIRM (through reducing IR provision and energy costs) at $15M PV.

B.1.2 A NIRM would be expected to substantially reduce the amount of IR availability charges payable by IR purchasers. These have been in the order of $40M per year in recent years, with considerable variation from year to year, but are expected to be lower now that HVDC Pole 3 is available. However, the reduction in costs to purchasers (or procurement cost) potentially represents a wealth transfer and therefore is not the same as the reduction in economic costs.

Economic benefits

B.1.3 The economic costs of IR include the direct costs (e.g. through tripping IL) and opportunity costs (e.g. because a MW of generation capacity being 'reserved' to provide IR in a given trading period cannot also be providing active energy in that trading period).

B.1.4 A NIRM has the potential to reduce these costs, by:

a) reducing the total amount of IR dispatched; and

b) allowing IR in one island to substitute for (more expensive) IR in the other island.

B.1.5 Two approaches (described below) have been used to estimate the reduction in economic costs as a result of implementing a NIRM:

a) an IR stack model (for 2007-2012); and

b) a more complex co-optimized model for recent years using a range of different input parameters.

B.1.6 Both approaches indicate a conservative economic benefit of approximately $1.5M per year. An economic benefit of $1.5M per year equates to a PV of $15M over 20 years (using an 8% real discount rate).

IR stack model

B.1.7 This is a simple model, which does not incorporate the co-optimisation of IR and energy. The model is based on actual IR offer data for the period from 2007 to 2012 inclusive. For each trading period, it determines the IR offers that would have been cleared if a NIRM had been in place and compares these with the IR offers cleared with no NIRM.

B.1.8 The model makes some assumptions about the capacity of the HVDC to transfer reserves. The HVDC cannot transfer reserves if it is itself the largest risk. This can be calculated directly using vSPD, but doing so for historical periods is not very useful as the HVDC was operating with only a single pole for much of the time, while the NIRM will be operating in a two pole network. As such, the capacity of the HVDC to transfer energy plus reserve was assumed to be the higher of 700MW northwards/500MW southwards or the actual flow.

B.1.9 These numbers are much lower than the rated maximum bipole flow of 1,000MW; however they incorporate a number of additional restrictions. Reserve cannot be transferred across the HVDC if the HVDC itself is the largest risk. To help with this, the HVDC is able to "self cover" a single contingency event up to 550MW and there was assumed to always be 250MW of reserve in the North Island to cover generator risk. So the HVDC's self cover plus reserve to meet the largest generator risk totals 800MW. An allowance of 100MW was subtracted from this value to account for changes in real time HVDC flow, and a "margin of error" was included so as to produce a somewhat conservative figure for possible benefits.

B.1.10 For the southward HVDC flow, the key constraint is the ability to transfer power between Bunnythorpe and Wellington. During the 2008 dry year, this was often the 'bottleneck' that restricted flow southwards, rather than the HVDC. The amount of power that the South Island received from the North Island only exceeded 500MW on rare occasions, and was never more than 550MW. Acknowledging that the impact of AC transmission constraints may vary in future, the maximum South Island received value was set to 500 MW for the purpose of this analysis.

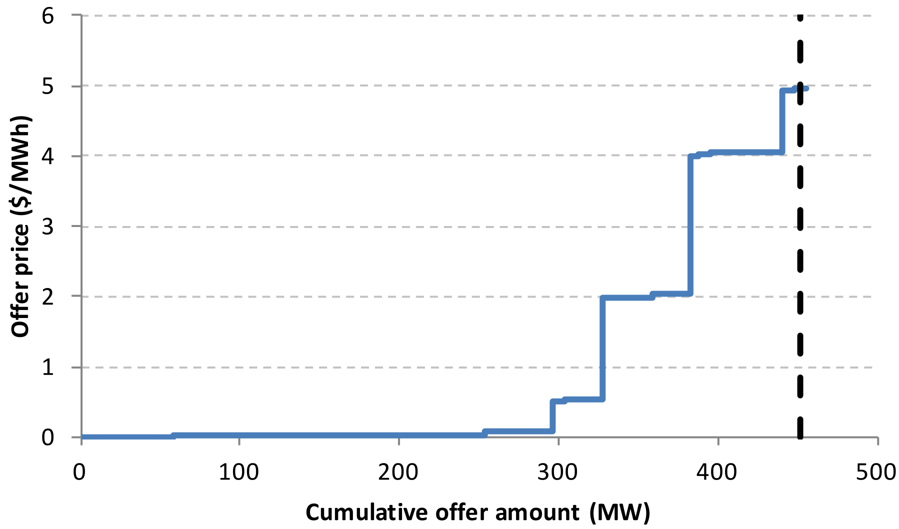
B.1.11 Otherwise the modelling is carried out on an "all else being equal" basis – in particular it is assumed that IR offer prices and quantities would not have changed.

B.1.12 For each trading period, the model assumes that the quantity of IR offers cleared (in each island, of each reserve class) would have been equal to the *actual* quantity of IR offers cleared, minus the additional[10] amount of IR that could have been shared from the other island if the NIRM was in place.

B.1.13 This is illustrated with the following example (note Figure 1 is expressed in $/MWh, and that Figure 2 and Figure 3 are expressed in c/MWh, to reflect lower assumed reserve costs in the South Island).

B.1.14 With the current split-island arrangements, a North Island SIR risk of 451MW can only be met with North Island SIR offers. The resulting cleared price is $6/MWh.

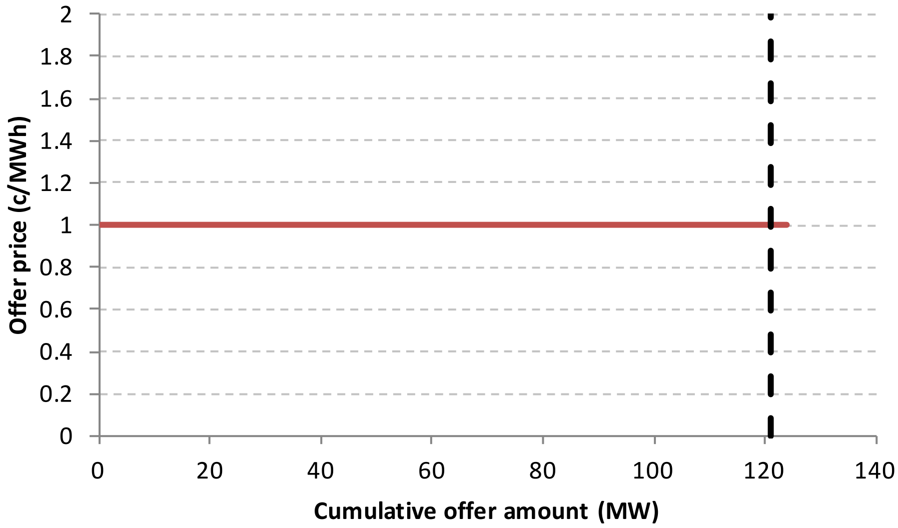
Figure 1: Illustrative IR offer stack for North Island



B.1.15 The South Island SIR risk of 121 MW can only be met with South Island offers. The cleared price is 0.01 $/MWh (1 c/MWh).

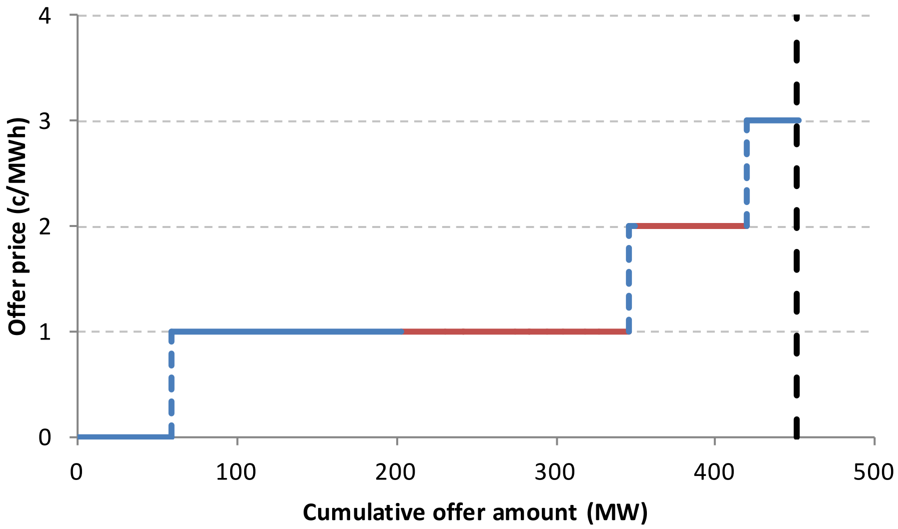
[10] *Additional*, because even without the NIRM there is some sharing (through NFRs).

Figure 2: Illustrative IR offer stack for South Island



B.1.16 With a NIRM, the total amount of reserve required is 451MW, as only the North Island risk needs to be covered. Reserve from both islands can be procured to meet this risk and the resulting cleared price is 3 c/MWh. HVDC flow during this period is 444MW northwards, so there is enough spare capacity (assuming a bipole) to transfer reserve from the South Island to the North Island.

Figure 3: Illustrative national IR offer stack



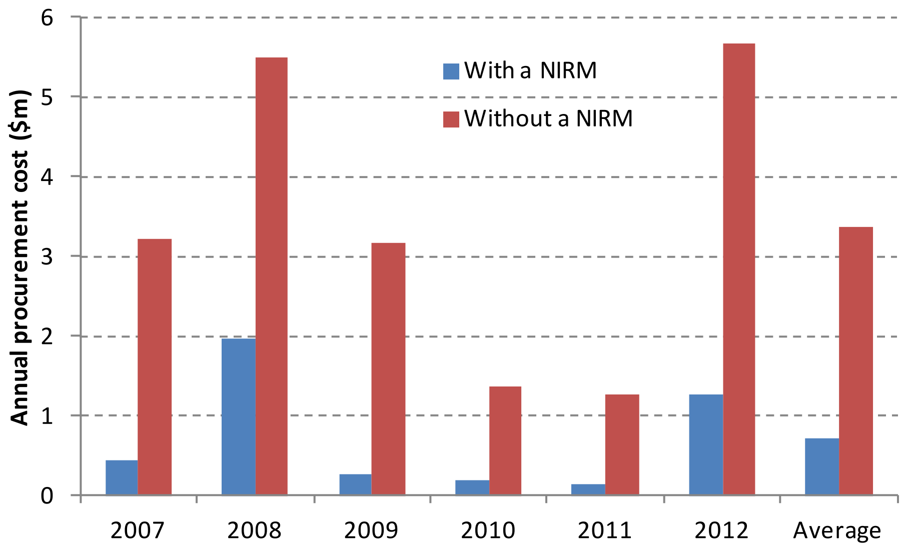
B.1.17 The model then estimates the economic benefit of the NIRM as the difference between:

a) *simulated IR provision cost without a NIRM,* calculated as the sum (over cleared IR offers) of the *actual* cleared quantity multiplied by the actual offer price;[11] and

b) *simulated IR provision cost under a NIRM*, calculated as the sum (over IR offers cleared in the simulation) of the *simulated* cleared quantity multiplied by the actual offer price.

B.1.18 The model indicates that the NIRM would have reduced IR provision costs by about 80%, representing between $1.1M and $4.4M per year, or $2.5M per year on average. (The reduction in IR availability charges would be much higher, but much of this change would represent transfers among parties rather than an economic benefit.)

Figure 4: Estimated change in economic cost of IR (stack model)



<u>Co-optimised energy and IR model</u>

B.1.19 This approach uses the vSPD (vectorised scheduling, pricing and dispatch) model. This could reasonably be expected to be more accurate than the simple stack model described above – because (for instance) it takes into account the co-optimisation between IR and energy.

B.1.20 Two modified versions of vSPD were developed and applied to each trading period:

a) a *bipole base case*, identical to the real final pricing case except that the bipole HVDC is always available. The HVDC is updated to include two poles with 700MW capacity. Reserve requirements and self-cover capability is also updated; and

b) a *NIRM case, allow*ing sharing of IR between islands, but otherwise the same as the bipole base case.

B.1.21 In the NIRM case, each MW of IR shared from island A contributes 0.9 MW towards satisfying the IR requirement (of the same reserve class) in island B. The total amount of IR shared (in each reserve class) cannot be more than 200MW. The GAMS code used to implement these two cases

11 Note that this is not the same as the actual IR provision cost. The simple offer curve model does not take into account co-optimization, whereby offers can be removed from the IR market to service the energy market. The simulated IR provision cost without a NIRM will often be less than the actual IR provision cost.

in vSPD has been provided to the Authority. The code changes doubtless understate the true complexity of implementing a NIRM in a production SPD environment, but appear to be fit for the purposes of an indicative benefit estimate (e.g. factors outside the model are likely to have larger degrees of uncertainty).

B.1.22 The model then estimates the economic benefit of the NIRM as the sum of the differences between:

a) simulated system costs in the bipole base case; and

b) simulated system costs in the NIRM case, where system costs are approximated by the vSPD objective function, excluding penalty terms.

B.1.23 Additionally, some scenarios were tested with small changes to inputs to test the sensitivity of the results to possible changes in system conditions:

a) Scenario A (base case): All inputs are unchanged[12]

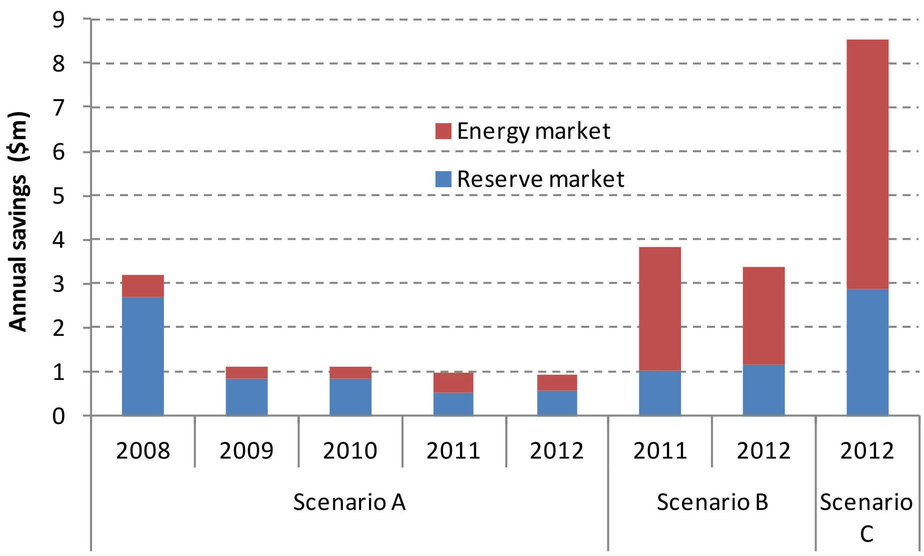
b) Scenario B: Demand was increased by 5%

c) Scenario C: Demand was increased by 5% and the IR offers at the KAW bus were removed.

B.1.24 The base case was applied to the five most recent calendar years (2008-2012). However, because vSPD is more computationally intensive than the stack model, the additional scenarios were only applied to a selection of previous years.

B.1.25 The model indicates that the NIRM would have reduced overall system costs by an average of approximately $1.5M per year for the years studied. However, the scenario analysis indicates that benefits are likely to increase significantly with modest demand increases, and are highly sensitive to changes in the IR supply situation.

Figure 5: Estimated change in economic cost of IR (vSPD model)



Sensitivity test on effect of HVDC deadband and roundpower

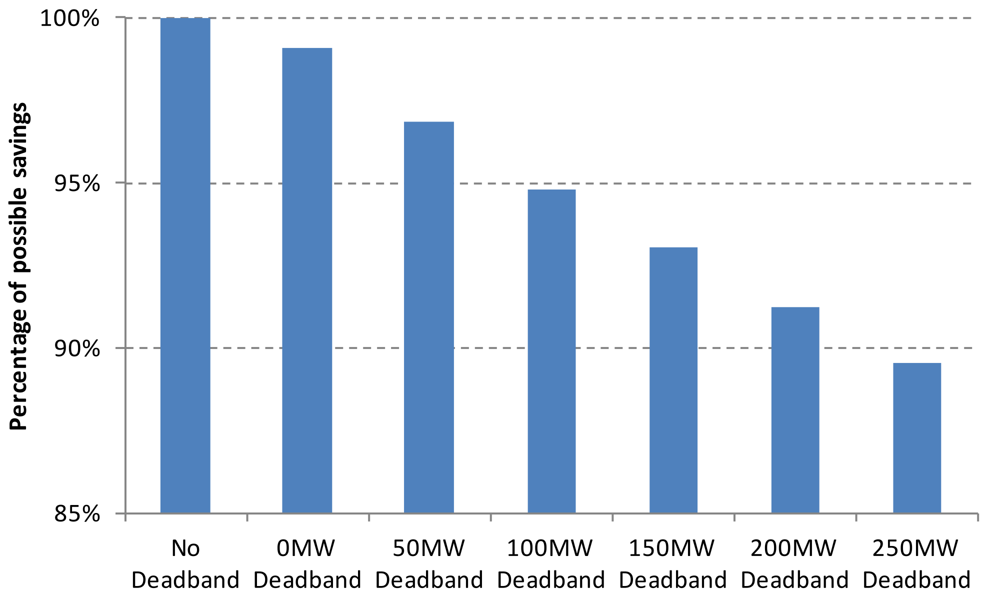
[12] Some inputs relating to the HVDC were changed as described above

B.1.26 To provide reserve in the island that is sending power across the HVDC, the HVDC needs to reduce its flow, and even in some cases reverse the direction of flow. This may be a problem as each single pole on the HVDC is not able to reduce flow below a minimum level. The section of flow between minimum northwards and minimum southwards is typically referred to as the "deadband". As a result, sometimes the HVDC would not be able to provide the full amount of – or any – reserve cover for the sending island.

B.1.27 The stack model was used to try to estimate the extent to which the deadband could reduce the benefits of a NIRM. The analysis used the procedure described above, with the deadband initially set at nil (i.e. no deadband) and then progressively increased.

B.1.28 This analysis suggests that the presence of a deadband may not have a large effect on NIRM benefits (at least within the limitations of the analysis undertaken to date). As shown in Figure 6, even with a 250MW deadband, almost 90% of estimated benefits would be available.

Figure 6: Estimated effect of deadband on NIRM benefits



B.1.29 While this may initially be surprising, consider a hypothetical situation where the HVDC could never reduce flow – this would have no effect on the ability of the HVDC to increase flow.

B.1.30 Therefore, it could be expected that 50% of benefits would remain (i.e. the instances where reserve transfer require higher flow would still be possible). In reality, the proportion is expected to be larger than 50%, as the price of reserve is typically higher in the island receiving energy, so being able to increase flow is the more valuable practice.

B.1.31 Put simply, the presence of a deadband would limit IR transfer in some situations, but these are expected to be the less common and less valuable opportunities for gaining benefits from a NIRM.

<u>Caveats with analysis based on historic offer prices and quantities</u>

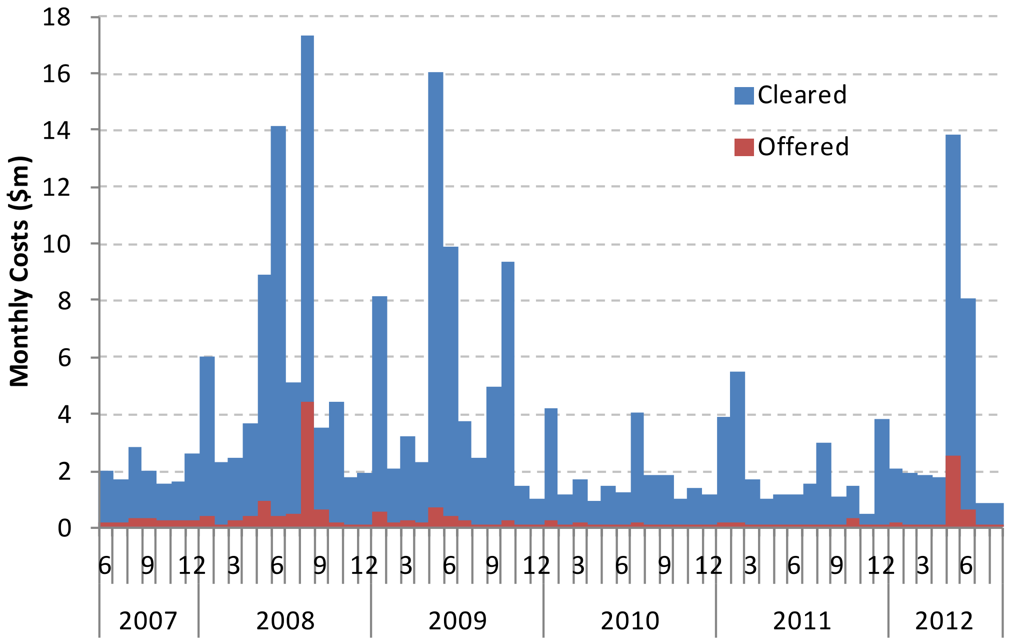
B.1.32 The analysis set out above seeks to simulate the presence of a NIRM, using historic offer prices and quantities. Clearly this is an important simplification as the presence of a NIRM could well have altered market offers. More generally, it could be argued that historic data may not be a good guide to the future for other reasons (e.g. a rising proportion of intermittent and must-run generation coming onto the system). While these factors are relevant, historic offer information at least reflects real rather than conjectured behaviour. For this reason, the use of historic data appears reasonable as an approximation.

B.1.33 A second important caveat is that this analysis treats offer prices as a good indicator of the marginal economic cost of IR. This assumption should be reasonable when focusing on marginal suppliers, because those parties will presumably not offer their resources if the revenue does not cover costs. Furthermore, if the offer price is persistently above the full cost of supply, this is likely to attract alternative providers (absent barriers to competition).

B.1.34 However, this logic does not necessarily hold for offers by non-marginal suppliers. Providers with resources that have a high commitment cost or lead time may prefer to offer their resource at below full production cost to ensure commitment, and rely on an expectation that the clearing price will be acceptable. If they experienced insufficient revenue over time, they would presumably not offer that capacity in future periods. This means that offer prices for non-marginal IR may not be a good indicator of economic cost.

B.1.35 Analysis of historic data suggests this may well be the case. Figure 7 shows the cleared cost of IR (payments to providers) and the 'offered' cost (the area under the supply curve for IR offers that were dispatched). There is a large difference between these figures, indicating that the IR supply curve was very steep at times. It is not possible to identify whether the steepness reflects differences in production costs among suppliers, or the effect of commitment costs or lead times, or other factors.[13]

Figure 7: Cleared and offered IR costs



B.1.36 If the steepness of the supply curve reflects commitment costs, it would suggest that non-marginal offers are not necessarily a good indicator of the economic cost of IR. This in turn means

[13] IR costs may be quite low for generators if they are available to generate but have some spare capacity. For example, it may simply reflect a slight efficiency loss. However, opportunity costs may be quite high if a unit has to be backed off or constrained on to make IR available.

that the benefit estimates derived in this way may not be accurate, although the data suggests that the outcomes are likely to be on the conservative side.

B.1.37 Given these caveats, the estimates have also been compared to earlier analyses that use different methods for calculating potential benefits.

Comparison with earlier estimates of NIRM benefits

B.1.38 In 2004, Transpower published an indicative estimate that national IR market would yield benefits of around $0.68 million based on analysis over 4 months in 2004. [14] This equates to around $2 million in annualised terms.

B.1.39 The Electricity Commission published a high level analysis of the benefits of introducing a national IR market in 2006. That estimate assumed that 200 MW of South Island IR (similar to the average level of free IR) could replace North Island IR for 60% of the time, and that the South Island IR would be up to $2 per MWh cheaper than displaced North Island IR.[15] That approach suggested that IR cost savings of around $2 million per year would be generated.

[14] http://www.systemoperator.co.nz/f4579,62752192/UFM-WS3-Appendix- 3-NRM-2004.pdf

[15] "Common Quality Development Plan, Evaluation of Options" (http://www.ea.govt.nz/dmsdocument/3574).

Appendix C Economic benefits of implementing a NIRM – deferral of capacity investment

C.1.1 Previous analysis of the economic benefits of implementing a NIRM has largely focused on estimating a *small* reduction in IR provision and energy costs across a *large* number of trading periods (as discussed in Appendix B).

C.1.2 There is also the potential for a NIRM to contribute to North Island capacity requirements in a *small* number of trading periods when capacity is most valuable, and hence to reduce the need for investment in peaking capacity.

C.1.3 At times of capacity scarcity, it is unlikely that the NIRM would directly 'free up' North Island capacity by reducing the amount of IR required in the North Island. However, it could assist more indirectly.

C.1.4 Consider the situation where capacity is scarce in the North Island (due to a combination of high peak demand, low intermittent generation output and/or unavailability of major generating units) and there is high energy export from the South Island over the bipole HVDC link.

C.1.5 With no NIRM in place, roughly 120 MW of IR must be provided in the South Island, in order to manage the consequences of the largest generating unit (in practice, a Manapouri unit) tripping. Usually this IR is provided by hydro generation,[16] which reduces the amount of energy that can be generated in the South Island, and hence the amount of energy that can be exported to the North Island.

C.1.6 With the NIRM in place, it could be possible to meet South Island IR requirements using North Island IR. This would mean that, in the event of an under-frequency event in the South Island, there would be a response in the North Island (involving load tripping and/or generation ramping up), and a reduction in northward flow in the HVDC, which would act to correct South Island frequency. Less IR would be needed in the South Island – perhaps none at all – which would increase the amount of energy that could be exported to the North Island.

C.1.7 This would potentially result in a more economic dispatch, with:

a) lower system costs; and/or

b) higher system security.

C.1.8 Limitations on the ability of the NIRM to increase the amount of energy exported to the North Island at such times might include:

a) if South Island IR requirements were already met by IL, then satisfying these requirements from the North Island would not 'free up' any further hydro generation;

b) it might not be possible to increase hydro production any further, regardless of the amount of IL dispatched, due to short-term water management issues;

c) the amount of energy exported might be capped by HVDC capacity;

d) or, more likely, by the limits on the ability of the HVDC to self-cover[17]

[16] At present, the only alternative is interruptible load at the Tiwai smelter – which is not always offered into the market.

[17] The bipole HVDC can self-cover up to a north transfer of approximately 950 MW, received at Haywards. The system operator's Annual Security Assessment indicates that there will not usually be as much as 950 MW available for export from the South

C.1.9 Nonetheless, it does appear that the NIRM would sometimes assist in meeting North Island capacity requirements.

C.1.10 One way to estimate the benefit of this capacity provision would be to take a *static* approach, and consider how often there might be North Island capacity scarcity and how the NIRM would affect dispatch at some times.

C.1.11 The WAG considers that it is more appropriate to take a *dynamic* approach, and consider the market response to the NIRM. The NIRM would allow investment in peaking capacity to be deferred (or allow existing capacity to be retired earlier) – thus providing an economic benefit.

C.1.12 New Zealand is currently in a period of overcapacity. However, it is expected that new peaking capacity may be needed from around 2018 on.[18] Peaking capacity is assumed to cost approximately $145/kW per year.[19]

C.1.13 There is the potential for the NIRM to increase South Island energy production by as much as 120 MW during periods of North Island capacity scarcity. However, given the limitations set out in paragraph C.1.8, the contribution to North Island peaking capacity needs would sometimes be less than 120 MW. The WAG suggests that it would be reasonable to assume that the NIRM might allow the South Island to contribute 100 MW to North Island capacity. This would be an increase of at least 50 MW over the status quo – since, currently, frequency response over the HVDC can contribute up to about 50 MW to North Island capacity (through FIR NFRs – see paragraph A.1.8).

C.1.14 Thus, the NIRM could avoid the need for approximately 50 MW of North Island peaking capacity investment.

C.1.15 The economic benefit of the NIRM (through deferral of capacity investment) is therefore estimated as $7M per year, or $50M PV over 20 years (using an 8% real discount rate).

C.1.16 This is additional to the economic benefit estimated in Appendix B. (The methodology used in Appendix B could potentially identify a benefit from increasing South Island export when there is North Island capacity scarcity; however, because of the overcapacity experienced in recent years, and because the study assumes a bipole HVDC configuration available at all times, the results do not include periods in which there is serious North Island capacity scarcity, and so no such benefit is observed.)

Island at times of North Island peak. However, this constraint may sometimes bind (if, for instance, South Island demand is low and South Island intermittent generation is high).

[18] See figure 14 of http://www.systemoperator.co.nz/f4571,80947535/SoS_Annual_Assessment_2013_PUBLISH.pdf

[19] http://www.ea.govt.nz/dmsdocument/13400