Electricity
Te Komihana Hiko
Commission

Annual Security Assessment 2008

Consultation Paper – updated to address questions raised during consultation

November 2008

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1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 Around this time each year, the Electricity Commission ("Commission") undertakes a review of the security of supply outlook including possible reserve energy needs.

1.1.2 This year's assessment is based on the winter energy margin and capacity margin concepts recently adopted by the Commission for monitoring generation investment adequacy and the potential need for reserve energy or capacity needs. In this regard, the relevant assessment horizon is one to three years but, for information purposes, margins out to 2018 have also been estimated for *existing*, *committed or highly likely*, and *medium probability* generation.

1.1.3 This report sets out the Commission's margins and reserve energy/ capacity assessments.

1.2 Purpose of this paper

1.2.1 The purpose of this paper is to consult with participants and persons that the Commission thinks are representative of the interests of persons likely to be substantially affected by the Commission's assessment of reserve energy and capacity procurement requirements.

1.2.2 The Commission invites submissions on the assumptions and assessments in this paper.

No submissions sought – following section included for completeness

~~1.3 Submissions~~

~~The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to info@electricitycommission.govt.nz with Consultation Paper—Annual Security Assessment 2008.~~

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

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~~1.3.1 Submissions should be received by 5pm on 31 October 2008. Please note that late submissions are unlikely to be considered.~~

~~1.3.2 The Commission will acknowledge receipt of all submissions electronically. Please contact Maree McGregor if you do not receive electronic acknowledgement of your submission within two business days.~~

~~1.3.3 If possible, submissions should be provided in the format shown in Appendix 5. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.~~

2. Structure Of This Report

2.1.1 To simplify presentation, overall assessments of capacity and energy margins and reserve capacity and reserve energy needs are summarised in the body of this report. Detailed assumptions and analysis are set out in appendices or in other published documents referenced in this report.

2.1.2 The remainder of this report is structured as follows:

(a) Section 3 discusses key changes from previous annual security assessments and provides a high level overview of the assessment methodologies;

(b) Section 4 and section 5 summarise respective capacity margin and energy margin assessments from 2009 to 2018;

(c) Section 6 discusses reserve energy / reserve capacity needs in light of the above assessments; and

(d) Section 7 presents overall conclusions.

2.1.3 The following appendices are attached:

(a) Appendix 1 - detailed supply assumptions;

(b) Appendix 2 - detailed demand forecast assumptions;

(c) Appendix 3 - energy margin calculations;

(d) Appendix 4 - capacity margin calculations; and

(e) Appendix 5 - format for submissions.

3. Background

3.1 Approach and Responsibilities

3.1.1 As input to previous annual security reviews, the Commission has in previous years requested Concept Consulting Group (Concept) to undertake an independent assessment of the security of supply outlook and potential need for reserve energy. Given recent changes to the Commission's security of supply policy, in particular the adoption of winter energy and capacity margin concepts and associated more transparent assessment methodologies, an independent assessment is not now considered necessary.

3.1.2 The Commission has therefore assumed overall responsibility for this analysis, with assistance from Concept, and has determined supply and demand assumptions, including liaising with generators regarding fuel supply and plant availability information. Energy Link has assisted with detailed modelling to confirm some aspects of the analysis.

3.2 Basis for Assessment

3.2.1 Until 2007, annual security of supply assessments focused on dry year energy (GWh) requirements only. In 2007, an assessment of peak supply adequacy (MW) was introduced. The energy security assessment extended over the period to 2016 but the peak supply adequacy analysis focussed only on 2008. This report again covers energy security and capacity adequacy but using different methodologies as summarised in Table 1. In each case, the assessment horizon extends to 2018.

Table 1: Changes in Approach to Assessment

Issue	Basis for 2009 Assessment	Basis for 2008 Assessment
Capacity adequacy	'Capacity margin' concept. Expected winter capacity capability relative to a measure of high winter demand periods.	'Peak adequacy' concept. Ability to meet single peak half-hour demand.
Energy security	'Winter energy margin' concept. Expected winter energy supply capability relative to winter energy demand.	Hydro storage minzone concept. Storage level at which the market has the technical capacity to meet demand during a hydro drought.

Issue	Basis for 2009 Assessment	Basis for 2008 Assessment
Trigger for reserve energy procurement decision	Forecast winter energy margins below specified levels over three year horizon.	Minzone expected to reach around 70% over next two years (exact level determined by spill/ reserve energy cost trade-off).
Trigger for reserve capacity procurement decision	Forecast winter capacity margins below specified levels over two year horizon.	Not discussed.

3.2.2 To provide context for the assessments in this report, high level summaries of winter energy margins and capacity adequacy margins are set out below.

3.3 Winter Energy Margins

3.3.1 Since last year's security assessment, the 'winter energy margin' concept has replaced the 1 in 60 dry year security of supply standard i.e. security of energy supply expectations have been re-expressed as mean winter energy margins of 17% and 30% for New Zealand and the South Island respectively. Monitoring forward winter energy margins relative to these requirements provides an indication of generation investment adequacy and acts as a trigger for reserve energy procurement.

3.3.2 The 1 in 60 dry year security standard was based on the minzone concept – an expression of the technical capability of the market to meet expected demand in a 1 in 60 year hydro drought. The Commission considers that the 1 in 60 dry year and specified winter energy margins represent similar levels of security of energy supply [3].

3.3.3 Optimal New Zealand and South Island winter energy margins were derived from detailed market simulations through to 2012 and economic analysis trading off reserve energy costs, spill savings and the cost of demand restraint/ un-served energy. Although that analysis was complex, the concept of a winter energy margin is straightforward to understand and much simpler to model than the minzone. For example, calculating the New Zealand winter energy margin involves:

(a) Forecasting national energy supply capability for the 6 month period from April to September, assuming mean hydro inflows and a start storage of 2,750 GWh;

(b) Forecasting national energy demand (without allowing for any savings campaigns or forced rationing) over the same timeframe; and

(c) Dividing national winter energy supply capability by winter energy demand.

3.3.4 Calculation of the South Island winter energy margin involves the same calculations for the South Island but with 2,400 GWh start storage and taking into account expected HVDC GWh southwards transfer capability. This and other supply and demand assumptions are explained in more detail in section 5 of this report.

3.4 Capacity Adequacy Margin

3.4.1 Since last year's security assessment, the Commission has developed a methodology for assessing capacity adequacy – the ability of the system to meet instantaneous demand.

3.4.2 Through this work, the Commission has concluded that 780 MW represents an optimal North Island capacity margin. Monitoring forward winter capacity margins relative to this requirement provides an indication of generation investment adequacy and acts as a trigger for reserve capacity procurement.

3.4.3 The 780 MW capacity margin was derived from detailed simulations through to 2012 of the optimal level of supply capacity relative to MW demands and the economic implications of having more/less capacity on the system. The analysis accounted for demand and generation capacity uncertainties, including contributions from the South Island via the HVDC, and involved trading-off the respective costs of capacity shortfall/ demand restraint and reserve capacity. Last year's annual security assessment included a purely technical assessment, developed by Concept, of the system's peak winter capacity without consideration of the optimal level of supply capacity.

3.4.4 Like the winter energy margin, the capacity margin concept is straightforward to understand and, because of the complex modelling underpinning the optimal margin, is relatively simple to estimate. Estimating the North Island capacity margin involves:

- Calculating expected North Island supply capacity, including contributions from South Island capacity via the HVDC, less expected winter demand response/ interruptible load.
- Calculating generation required to meet the average of the highest 200 half hourly demands during the winter.
- Subtracting generation required from the expected available capacity.

3.4.5 The calculation of expected North Island supply capacity, which takes planned and forced outages and uncertainty associated with wind and uncontrolled hydro schemes into account, is explained more fully in section 4 of this report.

3.5 Detailed Reference Material on Energy and Capacity Margins

3.5.1 For detailed explanations of the derivation of optimal winter energy and capacity adequacy margins, and their assessment and use operationally, readers are referred to the following documents:

(a) The Commission’s September 2007 consultation paper on the reserve energy policy review [1];

(b) The revised security of supply policy published by the Commission in October 2008 [2];

(c) The updated Government Policy Statement issued in May 2008 [3]; and

(d) The Commission’s October 2008 explanatory paper on development of a capacity adequacy standard [5].

4. Capacity Margin Assessment

4.1 Methodology

4.1.1 Calculating capacity margins involves subtracting expected MW supply availability from expected MW demand, each determined in accordance with the security of supply policy [2] as summarised Table 2. A detailed explanation of the basis for these calculations can be found in [5].

Table 2: Calculating the North Island Winter Capacity Margin

		Component	Description
Expected NI Supply Capacity (MW)	=	*NI Thermal MW*	Installed capacity of North Island thermal generation sources allowing for forced and scheduled outages
	+	*NI Wind MW*	20% of North Island wind capacity
	+	*NI Base-load MW*	Expected winter daytime (1 April – 31 October between 7am and 10pm) generation available from North Island geothermal plant, the aggregate of all North Island cogeneration plants, and the aggregate of all North Island uncontrolled hydro schemes
	+	*NI Demand Response and Interruptible Load MW*	Expected demand response and interruptible load over the highest 200 half hours of winter demand (1 April – 31 October between 7am and 10pm)
	+	*NI Hydro MW*	Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and derated to account for energy and other constraints which affect output during peak times
	+	*South Island MW*	The effective contribution of South Island capacity to North Island demand accounting for factors such as transmission limits and South Island demand (1 April – 31 October between 7am and 10pm).
Less Expected NI Demand (MW)			Average of 200 highest forecast winter daytime half hour grid generation demands plus losses.
= NI Capacity Margin (MW)			

4.2 Summary of Capacity Margin Assessments

4.2.1 This section summarises assessments of expected North Island supply capacity, demand estimates and capacity margin assessments. Detailed assumptions behind these estimates are included in Appendix 1 (supply) and Appendix 2 (demand). Energy and capacity margin calculations are presented in more detail in Appendix 3.

4.2.2 Estimates of the components of North Island existing supply capacity (excluding the effective contribution from South Island supply) are set out in Table 3. The effective contribution from existing South Island supply changes over time, depending on demand assumptions, and is presented later.

Table 3: Estimated Components of Existing NI Supply Capacity)

Component	**Expected Capacity (MW)**
Thermal	2,422[1]
Wind	50
Base-load (geothermal)	455
Base-load (cogen)	90
Demand Response	176
Controllable Hydro	1,426
Uncontrolled Hydro	100
Total	4,721

4.2.3 Table 4 and Table 5 list North Island and South Island new generation project assumptions, including assumed contributions to capacity adequacy ('expected' capacity).

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[1] Note that this excludes any contribution from the 100 MW New Plymouth unit that operated over winter 2008.

Table 4: New NI Supply Assumptions for Capacity Margin Assessments

Project	**Date**	**Type**	**Status**	**MW Capacity**	
				Installed	**Expected**
Mangaio	Jul-08	Hydro	High	2	1
West Wind	Jul-09	Wind	Committed	143	29
Waipa	Jul-09	Hydro	High	9	5
Stratford-1	Dec-09	Thermal	Committed	200	194
Tauhara Binary	Dec-09	Geothermal	Committed	19	17
Central NI-2	Jun-10	Thermal	Medium	75	73
Long Gully	Jun-10	Wind	High	8	2
Nga Awa Purua	Jun-10	Geothermal	High	132	115
Hydro 1	Jun-10	Hydro	Medium	8	4
Wind 2	Dec-10	Wind	Medium	82	16
Titiokura/Te Waka Wind farm	Mar-11	Wind	High	147	29
Wind 3	Jul-11	Wind	Medium	97	19
Te Mihi	Jul-11	Geothermal	Committed	62	54
Geothermal 1	Jun-12	Geothermal	High	80	69
Geothermal 3	Jun-12	Geothermal	Medium	80	69
Hauauru ma Raki	Jul-12	Wind	High	540	108
Tauhara	Jul-12	Geothermal	Committed	225	195
Wind 1	May-13	Wind	Medium	120	24
Waitahora	Jul-13	Wind	Medium	177	35
Geothermal 2	Jul-13	Geothermal	High	80	69
Geothermal 4	Jul-13	Geothermal	Medium	80	69
Hellensville-3	Dec-13	Thermal	Medium	240	233
Turitea	Jan-14	Wind	Medium	240	48
Auckland-4	Dec-15	Thermal	Medium	240	233

Table 5: New SI Supply Assumptions for Capacity Margin Assessments

Project	Date	Type	Status	MW Capacity	
				Installed	Expected
Kaiwera Wind	Jul-09	Wind	Low	160	32
Waipori Wind Stage 1	Sep-09	Wind	Low	200	40
Hayes Stage I	Jul-10	Wind	Medium	150	30
Hydro 2	Oct-10	Hydro	Medium	110	55
Ben Refurbishment	Jul-11	Hydro	Committed	10	10
Wairau	Mar-12	Hydro	Low	72	36
Dobson (Arnold)	Mar-12	Hydro	Low	40	20
Hawea Gates	Jul-12	Hydro	High	17	17
Hydro 3	Jul-13	Hydro	Low	70	35
Hydro 4	Jul-15	Hydro	Low	280	140

4.2.4 Table 6 shows North Island generation demand and growth rates assumed in the capacity margin assessment.

Table 6: Estimated NI Generation Demand and Growth

Year	Expected MW	vs Year Before
2009	4,446	102.4%
2010	4,557	102.5%
2011	4,642	101.9%
2012	4,737	102.1%
2013	4,823	101.8%
2014	4,910	101.8%
2015	4,999	101.8%
2016	5,090	101.8%
2017	5,182	101.8%
2018	5,276	101.8%

4.2.5 Table 7 summarises overall estimates of North Island supply capacity over the period to 2018 (excluding SI contributions).

Table 7: Estimated NI Supply Capacity to 2018 (Excl HVDC)

Year	**Existing Supply (MW)**	**+ Committed/ Highly Likely (MW)**	**+ Medium Probability (MW)**
2009	4,721	4,738	4,738
2010	4,730	5,052	5,103
2011	4,730	5,147	5,250
2013	4,730	5,582	5,836
2014	4,730	5,617	6,208
2015	4,730	5,617	6,208
2016	4,730	5,617	6,441
2017	4,730	5,617	6,441
2018	4,730	5,617	6,441

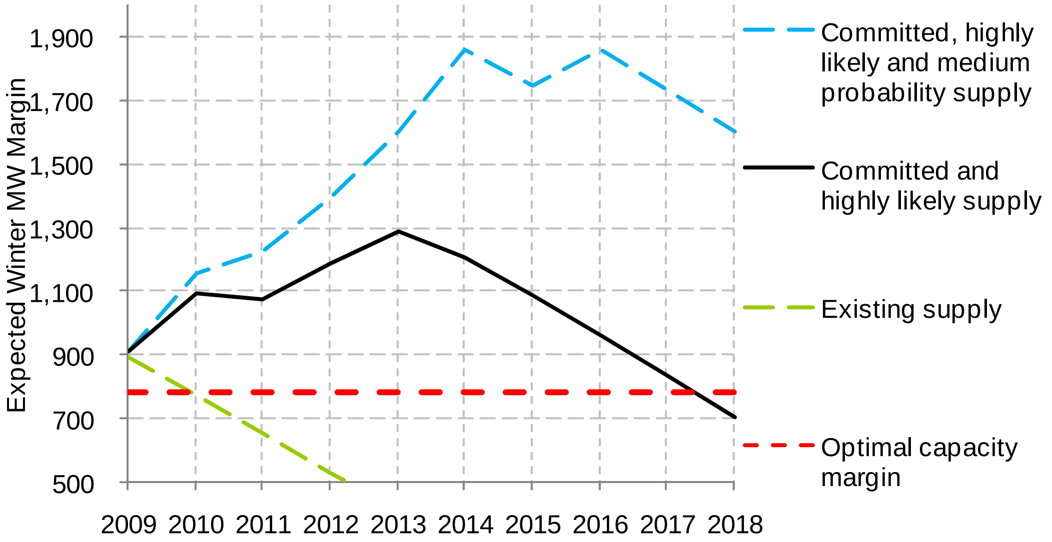
4.2.6 Table 8 summarises North Island capacity margin estimates to 2018, taking South Island contributions and expected North Island demand into account. Recall that expected demand is the average of the forecast highest 200 half hourly demands on the year. Effective South Island contributions are a function of expected South Island supply capacity, demand, HVDC capacity/ losses, and an offset to account for reserves and correlation with North Island demand.

Table 8: Estimates of NI Capacity Margins to 2018 (MW)

Scenario	Year	NI Capacity (MW)	+ SI (MW)	- NI Demand (MW)	Margin (MW)
Existing Supply	2009	4,721	620	4,446	**894**
	2010	4,730	600	4,557	**773**
	2011	4,730	567	4,642	**656**
	2012	4,730	539	4,737	**532**
	2013	4,730	512	4,823	**419**
	2014	4,730	482	4,910	**301**
	2015	4,730	447	4,999	**177**
	2016	4,730	411	5,090	**51**
	2017	4,730	375	5,182	**-77**
	2018	4,730	336	5,276	**-210**
+ Committed/ Highly Likely Projects	2009	4,735	620	4,446	**912**
	2010	4,969	600	4,557	**1,095**
	2011	4,996	571	4,642	**1,076**
	2012	5,121	546	4,737	**1,187**
	2013	5,218	519	4,823	**1,290**
	2014	5,218	489	4,910	**1,209**
	2015	5,218	456	4,999	**1,088**
	2016	5,218	420	5,090	**961**
	2017	5,218	385	5,182	**834**
	2018	5,218	345	5,276	**702**
+ Medium Probability Projects	2009	4,738	620	4,446	**912**
	2010	5,052	600	4,557	**1,155**
	2011	5,147	571	4,642	**1,227**
	2012	5,372	552	4,737	**1,398**
	2013	5,582	531	4,823	**1,601**
	2014	5,617	502	4,910	**1,861**
	2015	5,617	471	4,999	**1,745**
	2016	5,617	434	5,090	**1,858**
	2017	5,617	399	5,182	**1,734**
	2018	5,617	361	5,276	**1,603**

4.2.7 Figure 1 shows North Island capacity assessments to 2018 relative to the optimal margin of 780 MW. Recall that the optimal margin of 780 MW is based on simulations to 2012 and is therefore less meaningful as a benchmark beyond 2012.

Figure 1: North Island Capacity Margin Assessments to 2018



4.2.8 Sensitivity analysis is discussed in section 6 with a focus on the impact of changes to expected assumptions over the next 2-3 years, including the incremental effects on alternate assumptions about pole 1, losses, demand growth, and new supply. Regarding pole 1, the margin calculations assume that pole 1 is available for assisting with south-north transfers under the same arrangements as made for the winter of 2008. No adjustment has been made for the upgrade of the HVDC, expected in 2012, which will likely increase south-north capability[2]. If pole 1 was unavailable and HVDC transfers were only available on pole 2, then approximately 200 MW would need to be subtracted from the margins shown above. For example, without pole 1, the projected 2009 capacity margin is 690 MW (90 MW deficit), though from 2010 onwards the standard would be exceeded.

4.2.9 Key conclusions from this analysis of North Island capacity margins are that:

(a) New generation is needed to ensure that the 780 MW capacity adequacy standard can be maintained from 2010;

(b) Availability of ½ pole 1 in 2009 is needed to meet capacity adequacy standards;

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[2] While the maximum transfer capability will be increased, the effective contributions from the South Island used for calculating the capacity margins are likely to be similar (though no lower) to those presented here given the assumptions about new supply and demand growth.

(c) The capacity margin including committed and highly likely generation projects is significantly above this figure through to 2018; and

(d) The level of confidence around the assumptions about new capacity will be an important consideration.

4.2.10 The implications of this analysis on the need for reserve capacity are discussed in section 6 following discussion, in the next section, of winter energy margin analysis.

4.2.11 More details assumptions and calculations can be found in Appendix 1 (supply assumptions), Appendix 2 (demand) and Appendix 3 (margin calculations).

5. Winter Energy Margin Assessments

5.1 Methodology

5.1.1 Calculating winter energy margins involves dividing expected energy supply capability by expected energy demand, each determined for the period 1 April to September 30 in accordance with the security of supply policy [2]. This is summarised for the New Zealand margin in Table 9 and for the South Island margin in Table 10.

Table 9: Calculating the NZ Winter Energy Margin

		Component	Description
Expected Supply Capability (GWh)	**=**	*Thermal GWh*	Maximum expected thermal generation available to meet winter (1 April to 30 September) energy demand allowing for forced and scheduled outages, available fuel supply and transmission constraints
	+	*Wind GWh*	Expected winter (1 April to 30 September) wind generation based on long-run average supply
	+	*Base-load GWh*	Expected winter (1 April to 30 September) base-load generation available from geothermal and cogeneration plants based on long-run average supply
	+	*Mean Hydro GWh*	Expected winter (1 April to 30 September) hydro generation based on mean inflows and including expected 1 April start storage of 2,750 GWh.
Less Expected Demand (GWh)			Expected grid generation demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing)
x 100 = Energy Supply Margin (%)			

Table 10: Calculating the South Island Winter Energy Margin

		Component	Description
Expected Supply Capability (GWh)	=	*HVDC GWh*	Maximum expected thermal generation available to meet winter energy demand allowing for forced and scheduled outages, available fuel supply and transmission constraints
	+	*Wind GWh*	Expected winter (1 April to 30 September) wind generation based on long-run average supply
	+	*Mean Hydro GWh*	Expected winter (1 April to 30 September) hydro generation based on mean inflows and including expected 1 April start storage of 2,400 GWh.
Less Expected Demand (GWh)			Expected grid generation demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing)
x 100 = Energy Supply Margin (%)			

5.1.2 A detailed explanation of the basis for winter energy margin calculations can be found in [1].

5.2 Summary of Winter Energy Margin Assessments

5.2.1 This section summarises assessments of expected New Zealand and South Island winter supply capability, winter energy demand estimates and corresponding energy margin assessments. Detailed assumptions behind these estimates are included in Appendix 1 (supply) and Appendix 2 (demand), with the calculations discussed and illustrated in Appendix 3.

New Zealand Winter Energy Margin

5.2.2 Assumed components of the New Zealand existing winter supply capability are set out in Table 11.

Table 11: Components of Existing NZ Winter Supply Capability

Component	Expected Capacity (GWh)
Start storage	2,750
Thermal	10,199
Cogen	423
Geothermal	1,818
Hydro (excl. storage)	10,803
Wind	592
Total	**26,584**

5.2.3 Table 12 and Table 13 list North Island and South Island new generation project assumptions, including contributions to New Zealand winter energy supply capability.

Table 12: New NI Supply Assumptions for Energy Margin Assessments

Project	Date	Type	Status	Winter Supply (GWh)
Mangaio	Jul-08	Hydro	High	6
West Wind	Jul-09	Wind	Committed	286
Waipa	Jul-09	Hydro	High	16
Stratford-1	Dec-09	Thermal	Committed	849
Tauhara Binary	Dec-09	Geothermal	Committed	79
Central NI-2	Jun-10	Thermal	Medium	318
Long Gully	Jun-10	Wind	High	16
Nga Awa Purua	Jun-10	Geothermal	High	549
Hydro 1	Jun-10	Hydro	Medium	19
Wind 2	Dec-10	Wind	Medium	169
Titiokura/Te Waka Wind farm	Mar-11	Wind	High	212
Wind 3	Jul-11	Wind	Medium	191
Te Mihi	Jul-11	Geothermal	Committed	225
Geothermal 1	Jun-12	Geothermal	High	333
Geothermal 3	Jun-12	Geothermal	Medium	315
Hauauru ma Raki	Jul-12	Wind	High	961
Tauhara	Jul-12	Geothermal	Committed	617
Wind 1	May-13	Wind	Medium	236
Waitahora	Jul-13	Wind	Medium	293
Geothermal 2	Jul-13	Geothermal	High	333
Geothermal 4	Jul-13	Geothermal	Medium	333
Hellensville-3	Dec-13	Thermal	Medium	1,019

Table 12: New NI Supply Assumptions for Energy Margin Assessments

Project	Date	Type	Status	Winter Supply (GWh)
Turitea	Jan-14	Wind	Medium	473
Auckland-4	Dec-15	Thermal	Medium	1,019

Table 13: New SI Supply Assumptions for Energy Margin Assessments

Project	Date	Type	Status	Winter Supply (GWh)
Kaiwera Wind	Jul-09	Wind	Low	325
Waipori Wind Stage 1	Sep-09	Wind	Low	385
Hayes Stage I	Jul-10	Wind	Medium	290
Hydro 2	Oct-10	Hydro	Medium	45
Ben Refurbishment	Jul-11	Hydro	Committed	25
Wairau	Mar-12	Hydro	Low	189
Dobson (Arnold)	Mar-12	Hydro	Low	103
Hawea Gates	Jul-12	Hydro	High	33
Hydro 3	Jul-13	Hydro	Low	165
Hydro 4	Jul-15	Hydro	Low	740

5.2.4 Note that in the following energy margin analysis, “committed” and “highly likely” projects have been combined into a single “committed/highly likely” category.

5.2.5 Table 14 shows estimated New Zealand winter supply capability over the period to 2018.

Table 14: Estimates of NZ Winter Supply Capability to 2018

Year	Existing Supply (GWh)	+ Committed/ Highly Likely (GWh)	+ Medium Probability (GWh)
2009	26,584	26,742	26,742
2010	26,632	28,247	28,618
2011	26,632	28,773	29,711
2013	26,632	31,009	32,868
2014	26,632	31,176	34,879
2015	26,632	31,176	34,879
2016	26,632	31,176	35,899
2017	26,632	31,176	35,899
2018	26,632	31,176	35,899

5.2.6 Table 15 shows assumed New Zealand winter generation demand and growth rates over the period to 2018.

Table 15: Forecast NZ Winter Generation Demand and Growth

Year	Winter Generation Demand (GWh)	vs Year Before
2009	21,389	102.9%
2010	21,870	102.2%
2011	22,363	102.3%
2012	22,805	102.0%
2013	23,246	101.9%
2014	23,697	101.9%
2015	24,156	101.9%
2016	24,624	101.9%
2017	25,101	101.9%
2018	25,587	101.9%

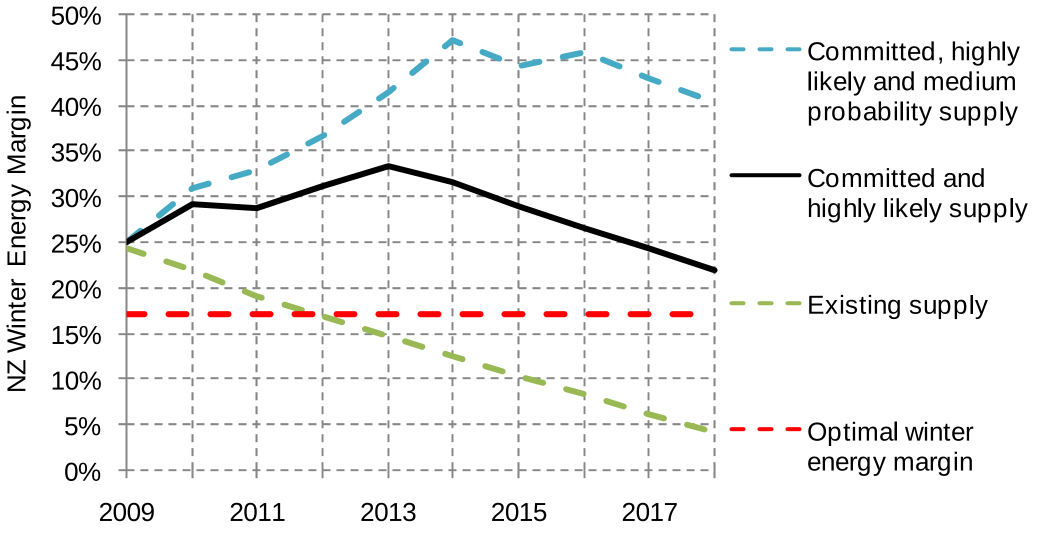
5.2.7 Table 16 summarises New Zealand winter energy margin estimates to 2018.

Table 16: Estimates of NZ Winter Energy Margins to 2018

Scenario	Year	NZ Supply (GWh)	NZ Demand (GWh)	Margin %
Existing Supply	2009	26,584	21,389	**24.3%**
	2010	26,632	21,870	**21.8%**
	2011	26,632	22,363	**19.1%**
	2012	26,632	22,805	**16.8%**
	2013	26,632	23,246	**14.6%**
	2014	26,632	23,697	**12.4%**
	2015	26,632	24,156	**10.3%**
	2016	26,632	24,624	**8.2%**
	2017	26,632	25,101	**6.1%**
	2018	26,632	25,587	**4.1%**
+ Committed/ Highly Likely Projects	2009	26,742	21,389	**25.0%**
	2010	28,247	21,870	**29.2%**
	2011	28,773	22,363	**28.7%**
	2012	29,926	22,805	**31.2%**
	2013	31,009	23,246	**33.4%**
	2014	31,176	23,697	**31.6%**
	2015	31,176	24,156	**29.1%**
	2016	31,176	24,624	**26.6%**
	2017	31,176	25,101	**24.2%**
	2018	31,176	25,587	**21.8%**
+ Medium Probability Projects	2009	26,742	21,389	**25.0%**
	2010	28,618	21,870	**30.9%**
	2011	29,711	22,363	**32.9%**
	2012	31,169	22,805	**36.7%**
	2013	32,868	23,246	**41.4%**
	2014	34,879	23,697	**47.2%**
	2015	34,879	24,156	**44.4%**
	2016	35,899	24,624	**45.8%**
	2017	35,899	25,101	**43.0%**
	2018	35,899	25,587	**40.3%**

5.2.8 Figure 2 illustrates New Zealand winter energy margin assessments to 2018 relative to the optimal margin of 17%. Recall that the optimal margin is based on simulations to 2012 and is therefore less meaningful as a benchmark beyond 2012.

Figure 2: Projected NZ Winter Energy Margins To 2018



5.2.9 Key conclusions from analysis of the New Zealand winter energy margin are that:

(a) New generation is needed to ensure that the 17% standard can be maintained after 2011;

(b) Taking committed and highly likely generation projects into account, the estimated winter energy margin is significantly above the 17% standard through to 2018; and

(c) The level of confidence in new supply assumptions will therefore be an important consideration.

5.2.10 The implications of this analysis are discussed in section 6. Given the extent of these margins, the sensitivity of the New Zealand margin to supply and demand assumptions about has not been explored in detail at this stage.

5.2.11 More details assumptions and calculations can be found in Appendix 1 (supply assumptions), Appendix 2 (demand) and Appendix 3 (margin calculations).

South Island Winter Energy Margin

5.2.12 Assumed components of the South Island existing winter supply capability (excluding HVDC contributions) are set out in Table 17.

Table 17: Assumed Existing SI Winter Supply Capability Components (Excl HVDC)

Component	**Expected Capability (GWh)**
Start storage	2,400
Thermal	0
Cogeneration	0
Geothermal	0
Hydro (excl. storage)	7,125
Wind	110
Total	**9,635**

5.2.13 Table 18 summarises overall estimates of South Island winter supply capability over the period to 2018 (excluding HVDC contributions).

Table 18: Estimates of SI Winter Supply Capability to 2018 (Excl HVDC)

Year	**Existing Supply (GWh)**	**+ Committed/ Highly Likely (GWh)**	**+ Medium Probability (GWh)**
2009	9,635	9,635	9,635
2010	9,635	9,635	9,780
2011	9,635	9,648	9,983
2013	9,635	9,693	10,028
2014	9,635	9,693	10,028
2015	9,635	9,693	10,028
2016	9,635	9,693	10,028
2017	9,635	9,693	10,028
2018	9,635	9,693	10,028

5.2.14 Table 19 shows assumed South Island winter generation demand and growth rates over the period to 2018.

Table 19: Forecast SI Winter Generation Demand and Growth

Year	Winter Generation Demand (GWh)	vs Year Before
2009	7,954	103.7%
2010	8,108	101.9%
2011	8,360	103.1%
2012	8,518	101.9%
2013	8,671	101.8%
2014	8,827	101.8%
2015	8,986	101.8%
2016	9,148	101.8%
2017	9,313	101.8%
2018	9,480	101.8%

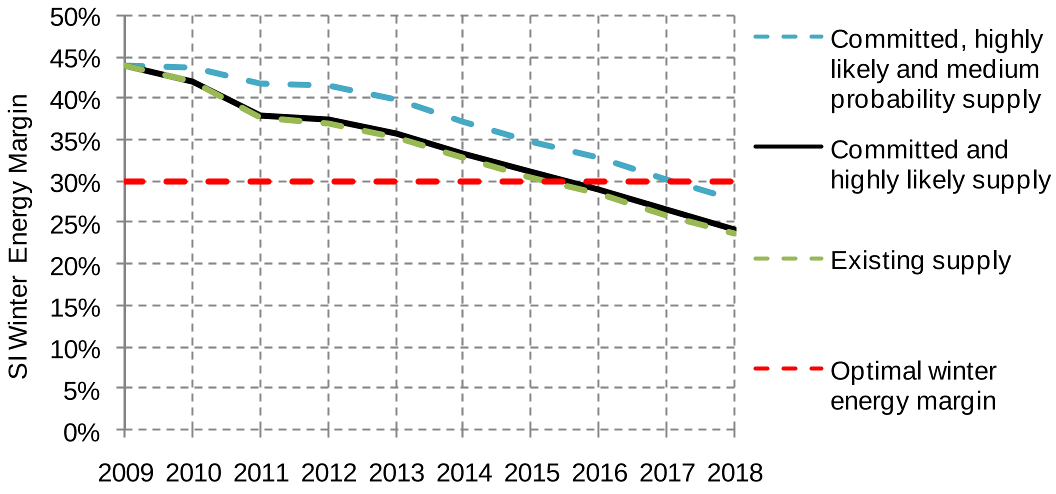
5.2.15 Table 20 summarises South Island winter energy margin estimates to 2018, taking expected HVDC contributions and North Island demand into account. Expected HVDC capability is based on expected South Island supply capability, demand and HVDC capacity/ losses).

Table 20: Estimates of SI Winter Energy Margins to 2018

Scenario	Year	SI Supply (GWh)	+ HVDC (GWh)	Tot Supply (GWh)	SI Demand (GWh)	Margin %
Existing Supply	2009	9,635	1,809	11,444	7,954	**43.9%**
	2010	9,635	1,873	11,508	8,108	**41.9%**
	2011	9,635	1,871	11,506	8,360	**37.6%**
	2012	9,635	2,033	11,668	8,518	**37.0%**
	2013	9,635	2,086	11,721	8,671	**35.2%**
	2014	9,635	2,076	11,712	8,827	**32.7%**
	2015	9,635	2,087	11,722	8,986	**30.4%**
	2016	9,635	2,116	11,752	9,148	**28.5%**
	2017	9,635	2,089	11,724	9,313	**25.9%**
	2018	9,635	2,085	11,720	9,480	**23.6%**
+ Committed/ Highly Likely Projects	2009	9,635	1,809	11,444	7,954	**43.9%**
	2010	9,635	1,873	11,508	8,108	**41.9%**
	2011	9,648	1,871	11,519	8,360	**37.8%**
	2012	9,677	2,033	11,709	8,518	**37.5%**
	2013	9,693	2,086	11,779	8,671	**35.8%**
	2014	9,693	2,076	11,770	8,827	**33.3%**
	2015	9,693	2,087	11,780	8,986	**31.1%**
	2016	9,693	2,116	11,810	9,148	**29.1%**
	2017	9,693	2,089	11,782	9,313	**26.5%**
	2018	9,693	2,085	11,778	9,480	**24.2%**
+ Medium Probability Projects	2009	9,635	1,809	11,444	7,954	**43.9%**
	2010	9,780	1,873	11,653	8,108	**41.9%**
	2011	9,983	1,871	11,854	8,360	**37.8%**
	2012	10,012	2,033	12,044	8,518	**37.5%**
	2013	10,028	2,086	12,114	8,671	**35.8%**
	2014	10,028	2,076	12,105	8,827	**33.3%**
	2015	10,028	2,087	12,115	8,986	**31.1%**
	2016	10,028	2,116	12,145	9,148	**29.1%**
	2017	10,028	2,089	12,117	9,313	**26.5%**
	2018	10,028	2,085	12,113	9,480	**24.2%**

5.2.16 Figure 3 illustrates South Island winter energy margin assessments to 2018 relative to the optimal margin of 30%. Recall that the optimal margin is based on analysis to 2012 and is therefore less meaningful as a benchmark beyond 2012.

Figure 3: Projected SI Winter Energy Margins To 2018



5.2.17 Sensitivity analysis is discussed in section 6 with a focus on the impact of changes to expected assumptions over the next 2-3 years, including the incremental effects on alternate assumptions about southward HVDC transfers, losses, and demand growth/response.

5.2.18 A key input to these margin calculations is the maximum energy able to be received in the South Island from HVDC transfers. An average of around 1,750 GWh has been assumed, which is based on market simulations across many hydrological sequences (see section 1.8 in Appendix 1). The HVDC transfer capabilities required to maintain 30% South Island margins are 700 GWh for winter 2009 (161MW average) and 900 GWh for winter 2010 (205 MW average) respectively. By way of comparison, average southward transfers over the winter months of 2008 averaged well over 200 MW[3].

5.2.19 Key conclusions from the analysis of South Island winter energy margins are that:

(a) Existing supply is sufficient to meet the 30% standard beyond 2015;

(b) Committed and highly likely generation projects make little impact on the winter energy margin; and

(c) The level of confidence in existing supply assumptions will be an important consideration.

5.2.20 The implications of this analysis are discussed in the next section.

5.2.21 More detailed assumptions and calculations can be found in Appendix 1 (supply assumptions), Appendix 2 (demand) and Appendix 3 (margin calculations).

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[3] Average received flows over winter 2008 at Benmore were 231MW (June), 350MW (July), and 258MW August).

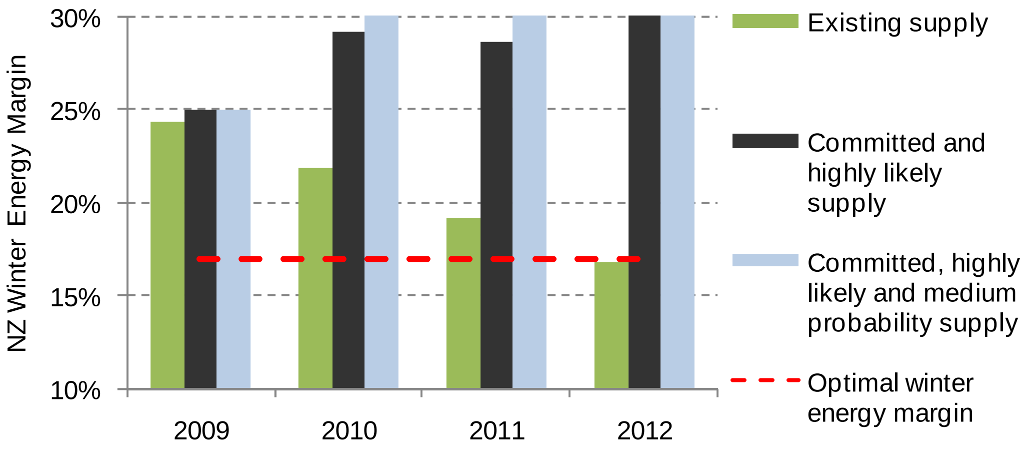
6. Reserve Energy / Capacity Assessments

6.1 Need for reserve energy

6.1.1 The Commission’s security of supply policy [2] specifies that if winter energy margins are expected to fall below 17% (New Zealand) or 30% (South Island) within the next three years this will trigger a reserve energy procurement decision i.e. if the Commission considers that the market is unlikely to invest in sufficient supply capability to meet the optimal winter energy margins.

6.1.2 Figure 4 shows estimated New Zealand winter energy margins to 2012.

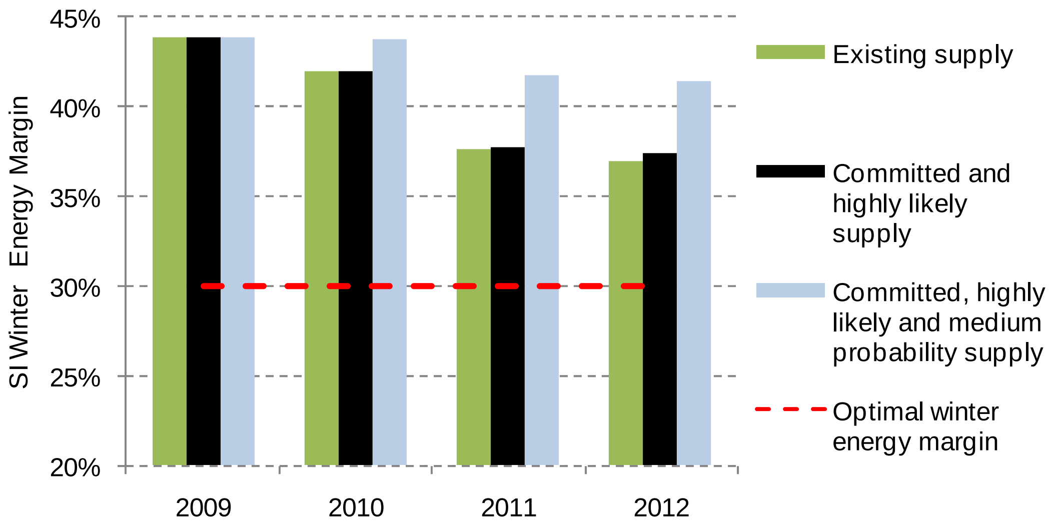
Figure 4: Estimated NZ Winter Energy Margins to 2012



6.1.3 From a reserve energy perspective, the chart indicates that with no new generation investment, New Zealand winter energy margins are not projected to fall below the optimal level over the next three years. Committed and highly likely generation projects significantly increase headroom. Unless there are concerns about the level of new generation investments assumed, New Zealand winter energy margins over the next three years indicate no need for additional reserve energy procurement.

6.1.4 Figure 5 shows estimated South Island winter energy margins to 2012.

Figure 5: Estimated SI Winter Energy Margins to 2012



6.1.5 This indicates that existing supply is capable of exceeding the 30% South Island winter energy margin over the next 4 years. However, unlike the North Island, only a small amount of new investment is projected. This being the case, the Commission notes that reliance on its assumptions regarding the market's existing supply capability is necessary for adequate South Island energy margins can be maintained.

6.1.6 Unless reasons are identified why these assumptions cannot be relied on, the Commission finds it difficult to make an argument that additional reserve energy needs to be procured.

6.1.7 While the Commission is comfortable with the base set of assumptions presented for this assessment, it is prudent, and informative, to consider the sensitivity of the results to variations in key assumptions. Based on the current assumptions, the South Island margin is forecast to be breached in 2016. Sensitivities have been assessed on the effect that they have on that breach date e.g., a systemic increase in forecast demand would bring this date forward and vice versa.

6.1.8 The sensitivities considered are summarised below, with each having an upper and lower variation around the base assumption used in the analysis:

(a) *South Island demand growth*. Expected demand growth is around 2% on average (or around 300 GWh per annum, see Table 29). Sensitivities illustrate +/-50% of the forecast annual growth. For example, in 2013 annual South island demand is 16.4 TWh (base case), 17.4 TWh (150% sensitivity) and 15.5 TWh (50% sensitivity);

(b) *Average inflows*. Expected South Island inflows are 7.1 TWh (see Table 38). Sensitivities illustrate +/-250 GWh variations;

(c) *HVDC flows.* Expected maximum supply from the North Island via the HVDC is 1800 GWh in 2009 (see Table 26), and increases over time[4]. Sensitivities illustrate -100/+50 MW variations;

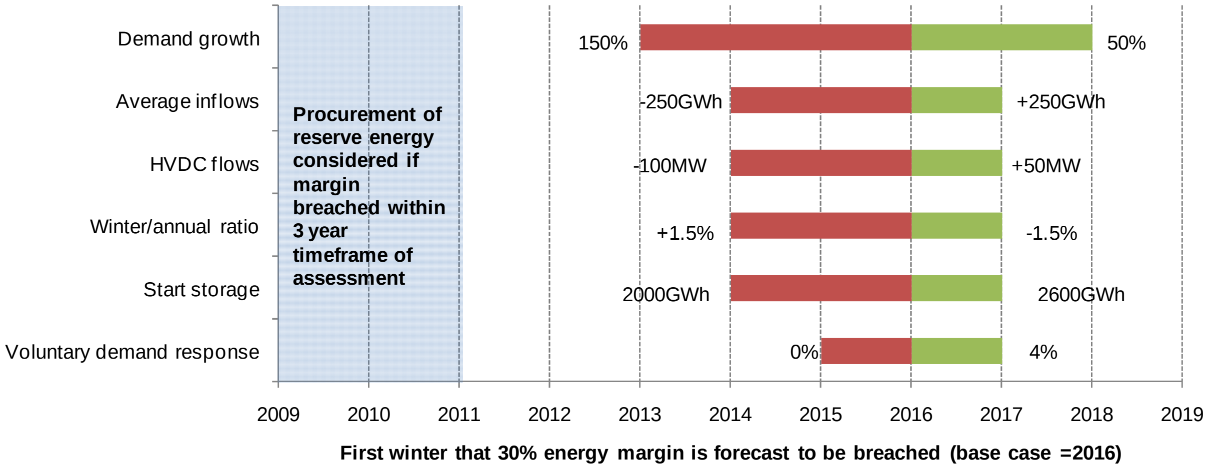
(d) *Winter/annual ratio.* Winter demand is assumed to be 51.5% of forecast annual demand (see Figure 11). Sensitivities illustrate +/- 1.5% variations;

(e) *Start storage.* An expected start storage of 2400GWh has been assumed in the base case (see Figure 10). Sensitivities illustrate low (2,000 GWh) and high (2,600 GWh) variations; and

(f) *Voluntary demand response.* Voluntary demand response to price has been assumed at 2% (see Section 2.3 in Appendix 2). Sensitivities illustrate the impact of no demand response (0%) and higher demand response (4%).

6.1.9 Figure 5 illustrates the effect of these sensitivities on the "margin breach date" (relative to the base case result of 2016), providing an indication of the relative significance of varying the relevant assumptions. Note that the variation considered is not year-on-year variation as this is captured in the analysis underlying the definition of the margin itself. The variation reflects a systemic change to the expected value of the underlying distributions.[5]

Figure 6: Sensitivity analysis for SI Winter Energy Margins



6.1.10 The red bars in Figure 5 reflect the impact of changing assumptions that increase demand or reduce supply, while the green bars reflect the opposite. For example, consider the effect of varying the assumption about HVDC transfer capability. If the base assumption is reduced by 100 MW (440 GWh), the effect is to bring forward the breach year from 2016 to 2014. Or with respect to demand growth, if forecast

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[4] This is due to additional North Island generation and increased transmission capacity.

[5] For example, with respect to inflows, the impact of assuming inflows are 250GWh lower than the base assumption does not reflect the impact of inflows over any particular winter being 250GWh lower than average. It reflects an assessment that average future inflows will be 250GWh lower than expected on a continuing basis.

growth is reduced to 50% of the current forecast, the breach year is pushed back from 2016 to 2018.

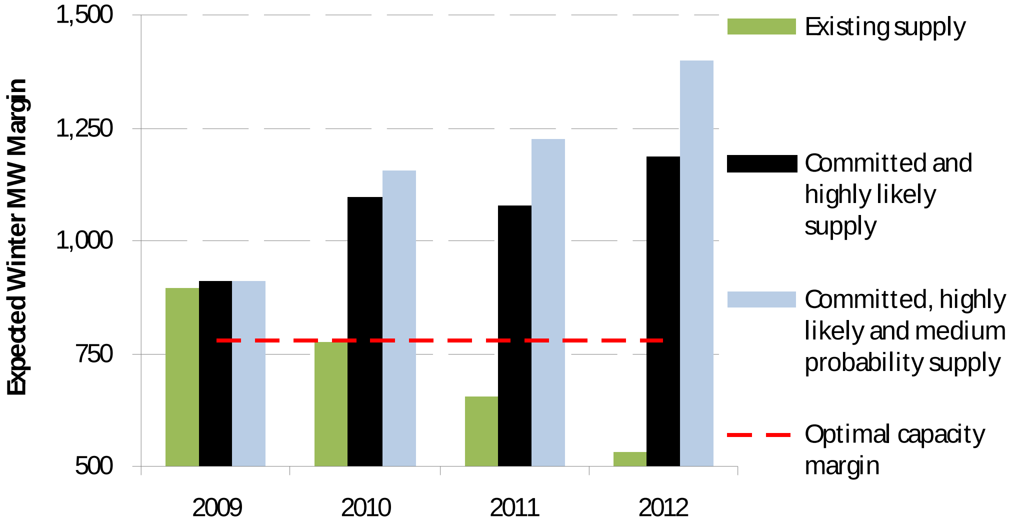
6.1.11 These sensitivities indicate a degree of robustness around the core assumption set, with the South Island margin equally, but not overly, sensitive to variations of all the core assumptions. In terms of the need for reserve energy, the same conclusion discussed above holds.

6.2 Need for reserve capacity

6.2.1 The Commission's security of supply policy [2] specifies that if the North Island capacity margin is expected to fall below 780 MW within two years this will trigger a reserve capacity procurement decision i.e. if the Commission considers that market is unlikely to invest in sufficient supply-side or demand-side options to meet the optimal capacity margins.

6.2.2 Figure 7 shows North Island capacity margin assessments to 2012.

Figure 7: Estimated Capacity Margins to 2012



6.2.3 Without new investment, the North Island capacity margin is projected to roughly equal the adequacy standard in 2010. However, the level of committed/ highly likely generation investment pushes the capacity margin 200 MW to 300 MW above the adequacy standard over the period to 2012[6]. On that basis, additional reserve capacity is not needed.

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[6] The net increase in 'Expected supply margin' in 2010 rises by approximately 240 MW given assumed committed plant i.e. West Wind (29 MW contribution to expected supply capacity), Stratford peaker (194 MW), Nga Awa Purua (132 MW) and Tauhara binary (17 MW).

6.2.4 While the Commission is comfortable with the base set of assumptions presented for this assessment, it is prudent, and informative, to consider the sensitivity of the projected margins. The capacity margin is not forecast to be breached until 2018, but as noted, this result is dependent, particularly over the next few years, on expected new capacity and continued south-north HVDC transfer capability The capacity margin sensitivities are summarised below, including a number of "downside" scenarios:

(a) *Demand growth*. Expected H200 demand growth is around 2% on average (or around 90MW per annum, see Table 30). The sensitivities illustrate +/- 50% the forecast annual growth. For example, in 2013 North Island H200 demand is 4,688 MW (base case), 4,922 MW (150% sensitivity) and 14,454 MW (50% sensitivity);

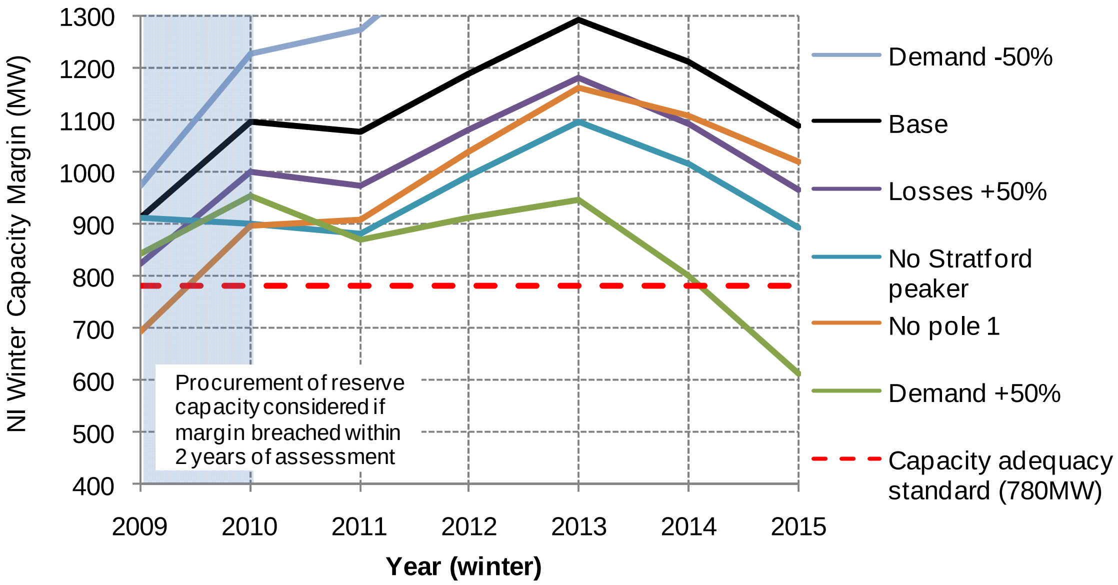
(b) *Higher losses*. Expected losses are 2.88% and 4.88% for the North and South Islands respectively (see Appendix 2). This sensitivity illustrates the effect of losses being 50% higher than the base case assumptions for both islands.;

(c) *No Stratford peaker.* A 200 MW gas-fired peaking unit is treated as being available for winter 2010. This sensitivity illustrates a scenario where the unit it is not commissioned at all (or equivalently, the loss of 200 MW of any other firm capacity); and

(d) *No pole 1.* The sensitivity illustrates the effect of reduced contributions from the South Island due to pole 1 not being operational.

6.2.5 Figure 8 illustrates the effect of these sensitivities on the projected capacity margins out to 2015.

Figure 8: Sensitivity analysis for NI Winter Capacity Margins



6.2.6 The chart reflects a reasonably tight situation over 2009 and a reliance on pole 1 for maintaining capacity adequacy. From 2010 onwards, additional new generation means that, margins are exceeded by even if pole 1 or the Stratford peaking plant is not available (they are expected to be). Sustained higher demand growth would erode the impact of additional new supply such that margins would be at similar levels to 2013. In terms of the need for reserve capacity in 2009/10, the same conclusion discussed above holds.

7. Overall Conclusions

7.1.1 Overall, the longer term security of supply outlook (beyond 2012) looks positive given the level of committed/ highly likely generation investments and their impact on winter energy and capacity margins.

7.1.2 As the assumed committed/ highly likely generation investments are mostly North Island projects, maintenance of South Island winter energy margins through to 2015 depends on existing supply capabilities. Over the next few years, investment in generation in the South Island would be helpful. During the preparation of this report, the Commission issued a final decision to approve Transpower's proposal to upgrade the HVDC link. While the impacts of this decision fall outside the immediate timeframe for considering reserve energy requirements, the impact of this and other transmission investments will assist in maintaining or improving South Island margins.

7.1.3 It is difficult to mount an argument for procuring additional reserve energy. North Island winter energy margins are projected to increase over the next few years and South Island estimated winter energy margins under existing supply assumptions exceed the standard over the next few years. Conversely, for the Commission to contemplate reserve energy procurement, there would need to be concerns about assumed North Island committed/ highly likely projects affecting New Zealand supply adequacy or existing South Island generation and/or North Island contributions to South Island winter energy margins.

7.1.4 In respect of reserve capacity, the North Island capacity margin can be maintained at or above the adequacy standard of 780 MW until 2010 under existing supply assumptions. New generation investments are projected to push the capacity margin significantly above the adequacy standard in 2010.

References

1 "Review of Reserve Energy Policy"; Electricity Commission Consultation Paper, September 2007. **http://www.electricitycommission.govt.nz/consultation/reserveenergypolicy07**

2 "Security of Supply Policy"; Electricity Commission, October 2008. **http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/sos-policyOct08.pdf**

3 "May 2008 Government Policy Statement On Electricity Governance." **http://www.med.govt.nz/templates/MultipageDocumentTOC____35669.aspx**

4 "Demand forecast for Reserve Energy Needs Assessment", Electricity Commission report, http://www.electricitycommission.govt.nz/opdev/modelling/demand/security/index.html

5 "Development of a Capacity Adequacy Standard", Electricity Commission explanatory paper, October 2008. **http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/capacity-adequacy-standard.pdf**

6 "National Winter Group 2008 Update Report", February 15, 2008. **http://www.systemoperator.co.nz/?id=6107**

7 "Issues Paper – Survey of Market Performance", May 2007. http://www.electricitycommission.govt.nz/consultation/mktdesignreview

Appendices

Appendix 1 Supply Assumptions

1.1 Introduction

1.1.1 This Appendix sets out key supply assumptions. It includes some assumptions that are common to the energy and capacity margin assessments. The focus of this analysis is on supply connected to the grid (or net injection where supply has an embedded load). Some embedded supply has been included in demand forecasts and this is discussed in Appendix 2.

1.1.2 For winter energy and capacity margin assessment purposes, supply has been grouped into existing, committed and highly likely, and medium probability.

1.2 Existing Supply

1.2.1 Table 21 and Table 22 summarise assumed existing supply.

Table 21: Existing North Island Supply

Scheme	Type	MW	Scheme	Type	MW
Otahuhu B	Thermal	390	Mokai	Geothermal	110
TCC	Thermal	380	Ohaaki	Geothermal	65
Huntly	Thermal	972	Poihipi	Geothermal	53
Whirinaki	Thermal	155	Wairakei	Geothermal	163
NPL	Thermal	100	Wairakei binary	Geothermal	14
Huntly U5 (e3p)	Thermal	385	Kawerau	Geothermal	90
Huntly U6 (P40)	Thermal	50	Ngawha II	Geothermal	15
Southdown	Thermal	175			
			Patea	Hydro	31.5
Kaponga	Cogen	20	Wheao	Hydro	27
Kinleith	Cogen	41	Waikaremoana	Hydro	141
Whareroa	Cogen	54	Mangahao	Hydro	42
Te Awamutu	Cogen	0	Matahina	Hydro	80
Te Rapa	Cogen	49	Tokaanu/Rangipo	Hydro	360
			Waikato	Hydro	1063
Tararua 1-3	Wind	161			
Te Apiti	Wind	91			

Table 22: Existing South Island Supply

Scheme	**Type**	**MW**
Argyle	Hydro	11
Kumara	Hydro	10.5
Opuha	Hydro	7.5
Teviot	Hydro	14.8
Clutha	Hydro	720
Cobb	Hydro	32
Coleridge	Hydro	40
Waitaki	Hydro	1723
Manapouri	Hydro	728
White Hill	Wind	58

1.2.2 Since last year's assessment, there have been minor increases in the capacity of thermal plant and the Kawerau and Ngawha II schemes have been added.

1.2.3 The contributions of existing plant to energy and capacity margin calculations are discussed later.

1.3 New Supply

1.3.1 Following discussions with generators, the Commission has developed assumptions for new supply projects, categorised as:

(a) *Committed and highly likely*– a project is under construction or firm commercial commitments have been made to proceed, or a firm commercial commitment has yet to be made but a project is highly likely to proceed;

(b) *Medium Probability* – a project is under serious consideration but is only considered moderately likely to proceed at this time; and

(c) *Low Probability* – a project is considered to have a low likelihood of proceeding at this time.

1.3.2 New North Island and South Island supply assumptions are shown in Table 23 and Table 24 respectively.

1.3.3 Note that low probability projects are listed for completeness but, as noted previously, have not been specifically included in our energy and capacity margin assessments.

Table 23: New North Island plant

Scheme	Fuel type	Island	Status	Planned commissioning date	MW	Expected annual output (GWh)
West Wind	Wind	N	Committed	01-July-2009	143	573
Stratford Peaker	Gas	N	Committed	01-Dec-2009	200	
Te Mihi	Geothermal	N	Committed	01-Jul-2011	225	450[7]
Tauhara	Geothermal	N	Committed	01-Jul-2012	225	1235
Mangaio	Hydro	N	High	01-Jul-2008	2	13
Waipa	Hydro	N	High	01-Jul-2009	9	33
Nga Awa Purua	Geothermal	N	High	01-Jun-2010	132	1099
Long Gully	Wind	N	High	01-Jun-2010	8	32
Titiokura/Te Waka Wind farm	Wind	N	High	01-Mar-2011	147	1099
Geothermal 1	Geothermal	N	High	01-Jun-2012	80	666
Hauauru ma Raki	Wind	N	High	01-Jul-2012	540	1922
Geothermal 2	Geothermal	N	High	01-Jul-2013	80	666
Thermal 1	Gas	N	Medium	01-Jun-2010	75	
Hydro 1	Hydro	N	Medium	01-Jun-2010	8	39
Wind 2	Wind	N	Medium	01-Dec-2010	82	338
Wind 3	Wind	N	Medium	01-Jul-2011	97	382
Geothermal 3	Geothermal	N	Medium	01-Jun-2012	80	631
Rodney	Gas	N	Medium	01-Dec-2013	240	
Wind 1	Wind	N	Medium	01-May-2013	120	473
Waitahora	Wind	N	Medium	01-Jul-2013	177	586
Geothermal 4	Geothermal	N	Medium	01-Jul-2013	80	666
Turitea	Wind	N	Medium	01-Jan-2014	240	946
Thermal 2	Gas	N	Medium	01-Dec-2015	240	

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[7] This reflects the incremental energy from Wairakei rather than the total output of the scheme.

Table 24: New South Island supply assumptions

Scheme	Fuel type	Island	Status	Planned commissioning date	MW	Expected annual output (GWh)
Ben Refurbishment	Hydro	S	Committed	01-Jul-2011	10	50
Hawea Gates	Hydro	S	High	01-Jul-2012	17	66
Hayes Stg I	Wind	S	Medium	01-Jul-2010	150	580
Hydro 2	Hydro	S	Medium	01-Oct-2010	110	90
Kaiwera Wind	Wind	S	Low	01-Jul-2009	160	650
Waipori Wind Stage 1	Wind	S	Low	01-Sep-2009	200	771
Wairau	Hydro	S	Low	01-Mar-2012	72	378
Dobson (Arnold)	Hydro	S	Low	01-Mar-2012	40	206
Hydro 3	Hydro	S	Low	01-Jul-2013	70	330
Hydro 4	Hydro	S	Low	01-Jul-2015	280	1481

1.4 Planned Outages

1.4.1 The energy margin calculations focus on winter (April – Sept) availability. The only planned outage of note is that of Huntly unit 2 in 2009, which has a 75 MW derating over April, then 50 MW over May. Other thermal planned outages are expected to be scheduled over the summer period, outside the window consider in the margin calculations.

1.5 Forced Outages

1.5.1 For energy margin calculations, thermal units have been de-rated to allow for forced outages (Table 25). These estimates were developed from statistical analysis of similar power stations in North America. A review of more recent data (see discussion in [5]) and Commission discussions with asset owners indicate that the assumptions used in evaluating system security in previous needs assessments are reasonable.

Table 25: Forced outage assumptions

Plant type	Forced Outage Rate
Thermal	3%
Controlled hydro plant	2%

1.5.2 In previous years, a 2% forced outage rate has been used for combined and open cycle plant, and this has been increased to 3%. Also note that the hydro forced outage rate is only used in the capacity margin calculations where a derating factor is required for flexible hydro plant. Additional derating assumptions used in the assessment of capacity adequacy are set out in Appendix 3.

1.6 Other Deratings

1.6.1 The energy margin calculations use a simple calculation of winter availability. Previous needs assessments have made deratings to Huntly units 1-4 to reflect Huntly maintenance outages and system ancillary service requirements.

(a) *Maintenance outages*[8]: one of the Huntly units is assumed to be out of service for maintenance three weekends in four. This equates to 190 GWh (or a constant 43 MW over a 6 month period); and

(b) *Ancillary services requirements*: Huntly has been de-rated by 130 MW overnight to reflect spinning reserve (80 MW) and frequency keeping (50 MW) requirements. These de-ratings have been applied to Huntly based as in previous security assessments. This equates to 303 GWh (or a constant 69 MW over a 6 month period).

1.6.2 For the purposes of calculating maximum expected thermal output, Huntly capacity has therefore been derated by 42+69 = 112 MW.

1.6.3 Derating of Whirinaki was contemplated, but analysis of simulation runs indicated Whirinaki could be dispatched at almost full utilisation over winter periods where demand is extremely high (or supply low).

1.7 Thermal Generator Fuel

1.7.1 At the time of preparing this report, thermal fuel supply arrangements over 2009 and 2010 are not expected to constrain thermal generation capability.

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[8] These are outages that can be scheduled at short notice to carry out necessary maintenance, typically on weekends.

1.8 Transmission

1.8.1 Transmission assumptions are required for the assessments of energy and capacity margins. The calculation of the South Island energy margin needs to account for the extent to which North Island supply can meet south Island demand. The calculation of North Island capacity margin needs to account for the ability of South Island capacity to be utilised to meet North Island demand given South Island demand and the capability of the HVDC link.

1.8.2 For calculating the South Island energy margin, an estimate of the maximum expected winter GWh delivered to the South Island is required. Analysis of recent market simulations indicated maximum expected winter energy of exceeding 1,750 GWh. For the purposes of deriving a “maximum expected value”, the average of the highest 10 simulated winter transfers was used (see Figure 9 and Table 26). For 2009, the equated to 1,800 GWh (413 MW).

Figure 9: Simulated average HVDC (south) flow

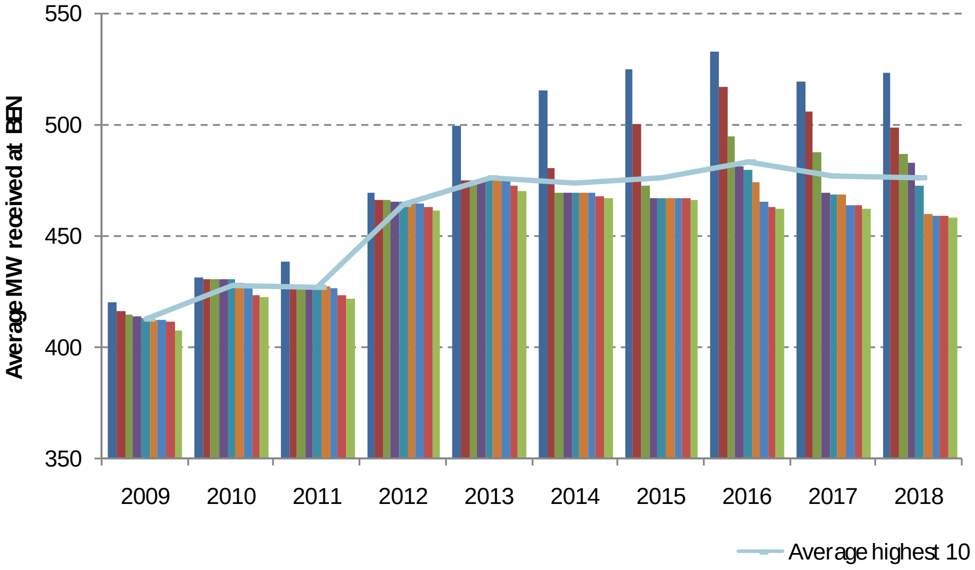


Table 26: Southward HVDC transfer assumptions for winter margin calculations

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Winter GWh	1,809	1,873	1,871	2,033	2,086	2,076	2,087	2,116	2,089	2,085
Average MW	413	428	427	464	476	474	476	483	477	476

1.8.3 With respect to capacity margin calculations, the Commission’s capacity margin analysis included a curve (or function) that defines the relationship between South Island (expected) capacity and South Island H200 demand to derive an effective contribution to North Island demand. That function encapsulates assumptions about the capacity and availability of the HVDC link, with key assumptions being that it had a forced outage rate of 0.25%, and a maximum transfer of 686 MW (with half-pole 1 available). The use of this function in the capacity margin calculations is discussed in Appendix 3. Note that it has not been updated for the upgrade to HVDC capacity.

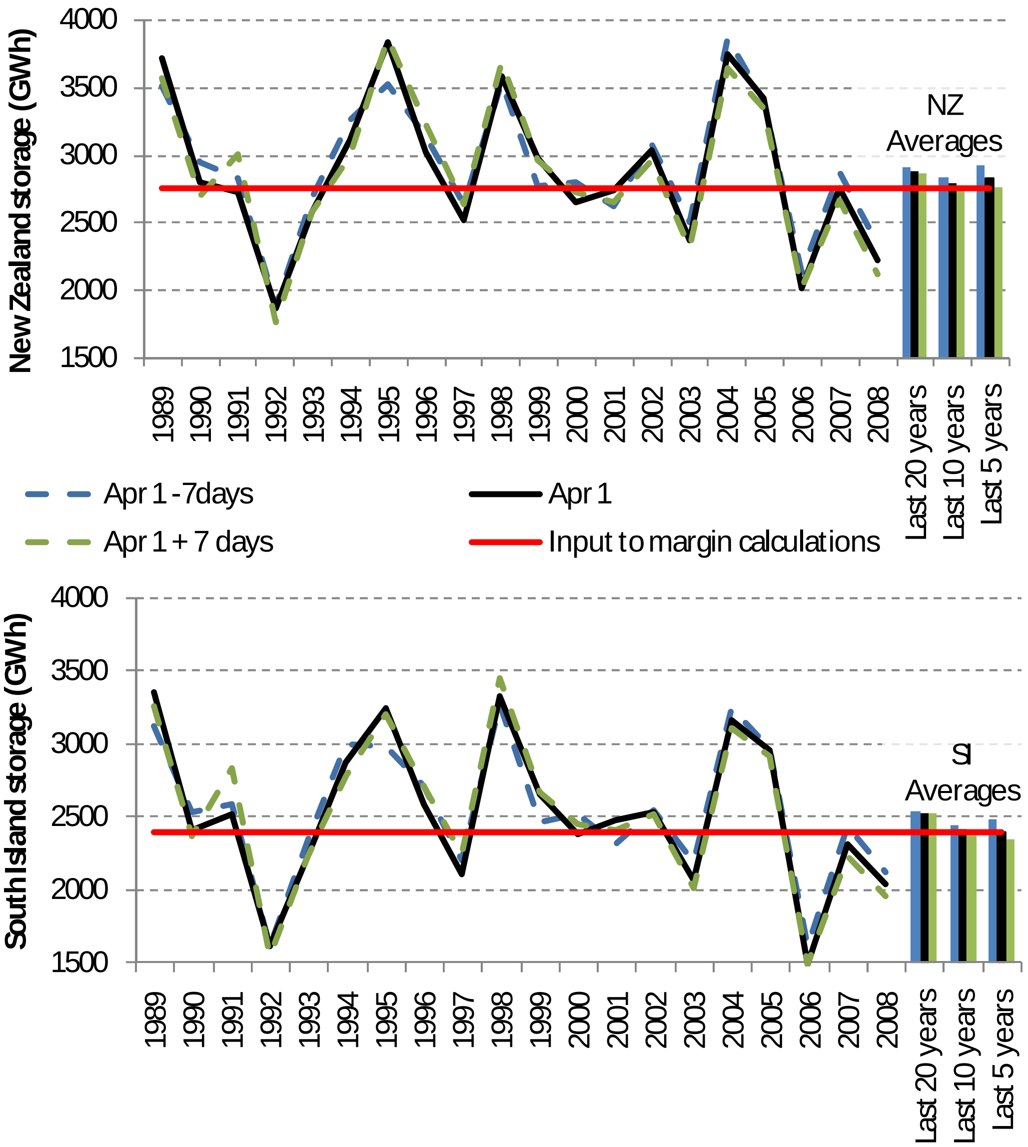
1.9 Start storage assumptions

1.9.1 The energy margin calculations require an assessment of expected winter hydro capability, which is expressed as expected storage at the beginning of winter plus expected inflows. Expected storage levels at the beginning of winter (April 1) are stated in the Commission’s Security of Supply Policy, and defined as 2,750 GWh for New Zealand margin calculations and 2,400 GWh for South Island margin calculations. These are not a forecast of what actual storage will be in any given year, but instead, reflect an estimate of the start storage across many years. Figure 10 shows:

(a) Actual storage levels at April 1 over the last 20 years, as well as profiles storage +/- 7 days from April 1; and

(b) Average storage calculated as averages over a range of timeframes.

Figure 10: Historic and average storage (April 1)



1.9.2 For these calculations, average storage at controlled reservoirs has been included. South Island includes Tekapo, Pukaki, Hawea, Manapouri, Te Anau, Cobb, Coleridge, and Mahinerangi. New Zealand storage also includes Tekapo, Waikaremoana, and Moawhango.

1.9.3 These figures indicate that the initial storage assumptions of 2,750 GWh and 2,400 GWh are consistent with average storage calculated over a range of timeframes.

Appendix 2 Demand Forecasting

2.1 Introduction

2.1.1 This appendix sets out demand assumptions used from which expected energy and MW demand inputs to energy and capacity margin have been derived.

2.2 Treatment of generation

2.2.1 As for previous assessments, demand forecasts are nominally at the GXP level but with certain generation included. The Commission's demand forecasting methodology for security assessments has a number of conventions for handling new, embedded, and cogeneration plant and explains why some plant are, or are not, included in the supply assumptions. These are summarised in Table 27.

Table 27: Summary of generation inclusions/exclusions in demand forecast

Generator	Netted off	Not netted off
Glenbrook – cogeneration at NZ Steel mill	*All* cogeneration is netted off forecasts (including grid-injected generation at GLN0332)	
Highbank – 'partly embedded' hydro generation Aniwhenua – 'partly embedded' hydro generation	*All* generation is netted off forecasts (whether embedded or grid-injected)	
Waipori – 'partly embedded' hydro generation	*All* generation, *including* Deep Stream, is netted off forecasts (whether embedded or grid-injected)	
Kawerau (Norske Skog), Karioi (Winstone Pulp and Paper), and Whirinaki (Pan Pac) – wood processing cogeneration	Cogeneration is netted off forecasts	
Rotokawa – geothermal generation	Generation is netted off forecasts	
Whareroa, Te Awamutu – dairy factory cogeneration		Generation is not netted off forecasts. *Net* injection should be modelled on the supply side
Te Rapa – dairy factory cogeneration		Generation is not netted off forecasts, *even though it is embedded*. *Net* injection should be modelled on the supply side

Generator	**Netted off**	**Not netted off**
Kapuni – CHP cogeneration Kinleith - cogeneration Southdown - cogeneration		Generation is not netted off forecasts and should be modelled on the supply side
Tararua Wind Farm – existing stages 1 & 2 and future stage 3		Generation is not netted off forecasts, even though stages 1 and 2 are embedded, and should be modelled on the supply side
Te Apiti		Generation is not netted off forecasts and should be modelled on the supply side
White Hill		Generation is not netted off forecasts, even though embedded, and should be modelled on the supply side
Other new wind farms	Generation from new wind farms with capacity *under 30 MW* is assumed to be netted off forecasts	
New geothermal development at Ngawha, and any new grid-connected geothermal development		Generation is not netted off forecasts and should be modelled on the supply side
Other embedded generators not listed above, whether existing or new	Generation is assumed to be netted off forecasts	
Other grid-connected generators not listed above, whether existing or new		Generation is not netted off forecasts and should be modelled on the supply side

2.3 Demand Forecasts

Approach

2.3.1 The Commission has updated its demand forecasts for security of supply assessment purposes. These forecasts consist of:

(a) Annual energy demand (GWh) forecasts for each island; and

(b) Probability distributions of “peak” MW demand levels in each island and nationally.

2.3.2 The energy demand assumptions are used for assessing reserve energy whereas the “peak” MW forecasts are an input in to measuring capacity adequacy. Table 28 summarises the basis for the demand assumptions used in this report, relative to the approach used in the assessment conducted last year.

Table 28: Basis for demand assumptions

Parameter	Comments
Annual energy demand to 2018	2009-2013: Commission's P50 forecasts for the North Island and South Island. 2014-18: P50 forecast extrapolated at 2013 growth rate.
Proportion of annual demand over winter (Apr Sept)	Based on average of observed proportions from 2005-2007.
'Energy' demand response to price	Nominal demand response to price is assumed to be 2% in each island.
Average of highest 200 half-hour winter demands for 2009-18	2009-2013: P50 forecast from the Commission's demand forecast. 2014-18: P50 forecast extrapolated at 2013 growth rate.

Demand assumptions for energy margin assessments

2.3.3 Annual demand figures (calendar years) for the current assessment (P50 forecasts) are summarised in Table 29, along with assumptions used in the assessment conducted last year.

Table 29: Forecast nominal grid exit point demand assumptions

	New Zealand (GWh)		**North Island (GWh)**		**South Island (GWh)**		**NI as a % of NZ**	
	Current	**Previous**	**Current**	**Previous**	**Current**	**Previous**	**Current**	**Previous**
2009	40,552	40,745	25,471	25,650	15,082	15,095	62.8%	63.0%
2010	41,464	41,693	26,090	26,250	15,374	15,443	62.9%	63.0%
2011	42,400	42,479	26,548	26,745	15,852	15,734	62.6%	63.0%
2012	43,237	43,367	27,086	27,347	16,151	16,020	62.6%	63.1%
2013	44,075	44,274	27,633	27,963	16,441	16,311	62.7%	63.2%
2014	44,928	45,200	28,191	28,592	16,737	16,608	62.7%	63.3%
2015	45,799	46,145	28,760	29,236	17,039	16,910	62.8%	63.4%
2016	46,686	47,111	29,341	29,894	17,345	17,217	62.8%	63.5%
2017	47,590		29,933		17,657		62.9%	
2018	48,513		30,537		17,975		62.9%	

2.3.4 Over the next 2-3 years, which is the period most relevant to assessing the need for reserve energy, the demand forecasts are of a similar, if slightly lower, magnitude than last year's forecasts.

2.3.5 The demand used in the margin calculations is adjusted in three ways

(a) Winter demand is derived from annual forecasts

(b) Voluntary demand reductions are subtracted

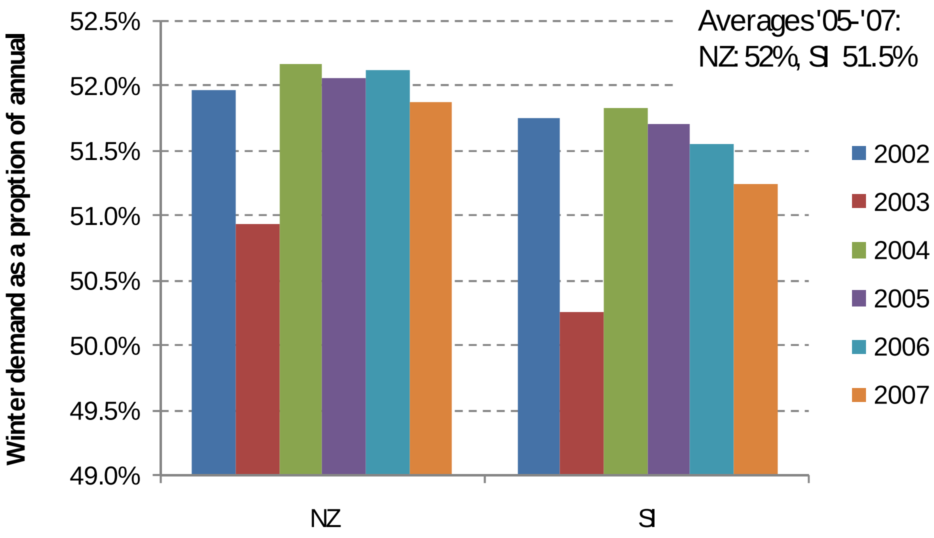
(c) Losses are added.

2.3.6 These assumptions are discussed in the following sections.

Estimating winter demand

2.3.7 The winter energy margin calculations are based on the 6 month winter demands from April through September, so an assumption is required about the proportion of annual demand that is expected to occur over winter. These proportions can then be applied to the annual New Zealand and South Island GWh demand forecasts in Table 29. Figure 11 illustrates these proportions for historic New Zealand and South Island demand (calculated on the same basis as the forecast).

Figure 11: Winter Energy Demand as a Proportion of Annual Demand



2.3.8 Other than the effect of the demand savings campaign on demand over winter 2003, the proportions are of a similar magnitude. In nominal terms (i.e., excluding corrections for temperature or other drivers), there has been a slight downward trend in the South Island proportion, while the New Zealand demand proportion is flat. The extent to which these patterns are systemic may be an aspect for further consideration at some point.

2.3.9 For the purposes of estimating expected winter demand, the average of the last 3 years has been used (2005 – 2007), yielding 52% for New Zealand and 51.5% for the South Island. To the extent there is a downward trend, these figures will produce a higher (conservative) estimate of the winter demands. It is important to consider the scale of this variation. A 0.5% change in the assumed SI proportion corresponds to approximately 80 GWh (1%) of winter South Island demand. This is ½ of the year-on year South Island winter demand growth so would have a secondary effect on the projected margins relative to the demand growth assumptions.

Demand response

2.3.10 Demand is adjusted for expected voluntary demand response resulting from high spot prices or retailer pricing initiatives (and excluding reductions in demand as a result of savings campaigns or calls for conservation). Annual security assessments over recent years have reduced demand by a notional 2% to reflect this behaviour. This has been considered a pragmatic approach for a number of reasons:

(a) An assumption of no demand response to price (i.e., 0%) would be inconsistent with historic evidence of at least some price response (see pages 4-8 and 4-9 in [7]).

(b) Estimating actual historic response is complex and would involve reconciling historic price-related demand reductions with other drivers of demand (e.g., temperature, seasonal factors such as irrigation). Savings campaigns also complicate this analysis.

(c) Estimating future demand response is also complex, in principle involving estimates of the drivers of demand response (expected level of high prices, spot price exposure) and fundamental factors affecting prices during dry periods (e.g., fuel contracts).

2.3.11 Given these factors, an assumption of 2% demand response has again been applied to demand forecasts.

Losses

2.3.12 Figure 12 illustrates average quarterly losses for the period 2005-2007, with average winter (Q2 and Q3) losses over this period for New Zealand and the South Island being 3.3% and 4.25%, respectively[9].

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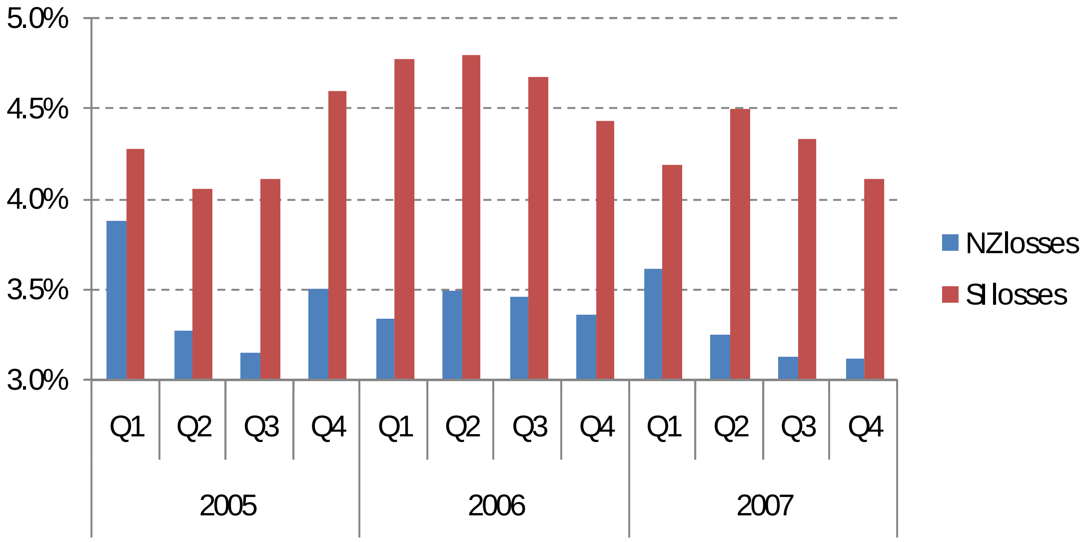
[9] Losses on HVDC transfers are included for New Zealand figures and excluded for the South Island figures.

Figure 12: Historic average quarterly losses (2005-2007)



2.3.13 Market simulations indicated New Zealand winter losses ranging from 3%-4% for New Zealand and 4%-5% for the South Island. For this analysis, losses of 3.5% have been assumed for New Zealand demand as a whole, and 4.5% on South Island demand. Losses on HVDC transfers are accounted for in the assumptions about southward HVDC transfers, which reflect energy received in the South Island after losses.

Demand assumptions for capacity margin assessments

2.3.14 An input to the assessment of capacity adequacy is a forecast of the average of the highest 200 half-hours of North Island and South Island winter demands (referred to as “H200 demand” and generically as “peak” demand). The Commission has developed distributions of H200 demand (excluding losses) as part of the updated demand forecasts security of supply assessments [4]. Forecasts from 2014 onwards have been derived by extrapolation (and note that the critical period for assessing reserve capacity requirements is 2009/2010).

Table 30: Forecast average of highest 200 hours of winter demands (excluding losses)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
NI	4,322	4,429	4,512	4,605	4,688	4,773	4,859	4,947	5,037	5,128
SI	2,166	2,205	2,257	2,297	2,333	2,370	2,408	2,446	2,484	2,524

2.3.15 For reference purposes, the Commission’s forecast of “P50 peak” demand, or the mid-point estimate of the highest single half-hour of demand is shown in Table 31.

Table 31: Forecast P50 peak demand (excluding losses)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
NI	4,539	4,653	4,727	4,818	4,909	5,000	5,094	5,189	5,286	5,385
SI	2,233	2,270	2,315	2,353	2,388	2,423	2,458	2,494	2,530	2,567

2.3.16 The H200 demand is in the order of 150-200 MW less than the forecasts P50 peak demand.

2.3.17 Losses of 2.88% (North Island) and 4.88% (South Island) are added to H200 demand. These assumptions are the same as defined in [5] (the assumptions implied by the loss and demand figures reported in the analysis of supply adequacy in winter 2008 by the National Winter Group 2008 [6]). Losses on northward HVDC transfers are reflected in the calculation of the effective contribution of South Island supply to the capacity margin.

Appendix 3 Energy Margin Calculations

3.1 Introduction

3.1.1 This appendix describes the supply components used in the energy margin calculations described in the main body of the report, along with any related assumptions. Assumptions about supply (by fuel type) are discussed first, with the final section aggregating these calculations to produce the energy margins discussed in the main body of the report.

3.2 Energy assumptions for thermal schemes

3.2.1 Table 32 summarises the thermal GWh values used in the New Zealand energy margin calculations and forecasts of supply over 2009-11. The “Base GWh” column indicates the maximum expected GWh based on the simple calculation of capacity derated for forced outages. The forecasts shown for 2009-11 adjust the baseline figure for issues specific to the forecast year, such as planned outages, planned commissioning over a winter, or fuel constraints.

Table 32: North Island thermal energy assumptions (winter GWh)

Scheme	MW	Status	Date	Base GWh	2009	2010	2011
Otahuhu B	390	Existing		1,657	1,657	1,657	1,657
TCC	380	Existing		1,614	1,614	1,614	1,614
Huntly	972	Existing		3,725	3,678	3,725	3,725
Whirinaki	155	Existing		659	659	659	659
NPL	100	Existing		425	0	0	0
Huntly U5 (e3p)	385	Existing		1,636	1,636	1,636	1,636
Huntly U6 (P40)	50	Existing		212	212	212	212
Southdown	175	Existing		744	744	744	744
Stratford-1	200	Committed	Dec '09	850	0	850	850
Central NI-2	75	Medium	Jun '10	319	0	212	319
Hellensville-3	240	Medium	Dec '13	1,020	0	0	0
Auckland-4	240	Medium	Dec '15	1,020	0	0	0
Total (existing + committed + highly likely)					**10,199**	**11,097**	**11,097**

3.2.2 We make the following comments in relation to the calculations of the GWh figures:

(a) Capacity has been derated by a forced outage rate of 3% for all thermal plant;

(b) The "Base GWh" figures are a simple calculation of MW x (1-FO derating)*4,380 hours (6 months);

(c) Where a unit is expected to be commissioned part-way through a winter, its baseline winter output has been scaled accordingly;

(d) Huntly output has been derated by approximately 415 GWh to account for provision of ancillary services requirements and maintenance outages. The 2009 figure has been derated by a further 48 GWh to reflect planned outages over April/May; and

(e) Were thermal plant built in the South Island, it would be included in calculations of the New Zealand and South Island margins.

3.3 Energy assumptions for wind schemes

3.3.1 Table 33 and Table 34 summarise the North Island and South Island wind GWh values used in the energy margin calculations and forecasts of supply over 2009-11. Assumptions from generators are expressed here in annual GWh; for the purposes of calculating winter energy margins, these figures have been halved[10]. The forecasts shown for 2009-11 adjust the base figure for planned commissioning over a winter and implicitly ignore any contribution from the wind farms until the time that the entire farm is expected to be operational ("Date" column).

Table 33: North Island wind energy assumptions (winter GWh)

Scheme	MW	Status	Date	Base GWh	2009	2010	2011
Tararua 1-3	161	Existing		303	303	303	303
Te Apiti	91	Existing		179	179	179	179
West Wind	143	Committed	Jul '09	287	143	287	287
Long Gully	8	High	Jun '10	16	0	11	16
Titiokura/Te Waka Wind farm	147	High	Mar '11	212	0	0	212
Hauauru ma Raki	540	High	Jul '12	961	0	0	0
Wind 2	82	Medium	Dec '10	169	0	0	169
Wind 3	97	Medium	Jul '11	191	0	0	96
Wind 1	120	Medium	May '13	237	0	0	0
Waitahora	177	Medium	Jul '13	293	0	0	0
Turitea	240	Medium	Jan '14	473	0	0	0
Total (existing + committed + highly likely)					**625**	**779**	**997**

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[10] Variation in expected output reflecting summer/winter variation could be considered at some point. While some variation may exist, it should be recognized that the total output from these schemes is approximately 6% of the assumed thermal output capability plant over the same period.

Table 34: South Island wind energy assumptions (winter GWh)

Scheme	MW	Status	Date	Base GWh	2009	2010	2011
White Hill	58	Existing		110	110	110	110
Hayes Stg I	150	Medium	Jul '10	290	0	145	290
Kaiwera Wind	160	Low	Jul '09	325	163	325	325
Waipori Wind Stage 1	200	Low	Sep '09	385	64	385	385
Total (existing + committed + highly likely)					**110**	**110**	**110**

3.4 Energy assumptions for geothermal schemes

3.4.1 Table 35 summarises the North Island geothermal GWh values used in the energy margin calculations and forecasts of supply over 2009-11. For the purposes of calculating winter energy margins, annual GWh figures have been halved. The forecasts shown for 2009-11 adjust the base GWh of new projects for planned commissioning over a winter.

Table 35: North Island geothermal energy assumptions (winter GWh)

Scheme	MW	Status	Date	Base GWh	2009	2010	2011
Mokai	110	Existing		395	395	395	395
Ohaaki	65	Existing		158	158	158	158
Poihipi	53	Existing		100	100	100	100
Wairakei	163	Existing		650	650	650	650
Wairakei binary	14	Existing		59	59	59	59
Kawerau	90	Existing		394	394	394	394
Ngawha II	15	Existing		62	62	62	62
Tauhara Binary	19	Committed	Dec '09	79	0	79	79
Te Mihi	62	Committed	Jul '11	225	0	0	113
Tauhara	225	Committed	Jul '12	618	0	0	0
Nga Awa Purua	132	High	Jun '10	550	0	366	550
Geothermal 1	80	High	Jun '12	333	0	0	0
Geothermal 2	80	High	Jul '13	333	0	0	0
Geothermal 3	80	Medium	Jun '12	315	0	0	0
Geothermal 4	80	Medium	Jul '13	333	0	0	0
Total (existing + committed + highly likely)					**1,818**	**2,263**	**2,559**

3.4.2 The forecasts for Te Mihi reflect the incremental increase over Wairakei output.

3.5 Energy assumptions for cogeneration schemes

3.5.1 Table 36 summarises the existing North Island cogeneration GWh values used in the energy margin calculations and forecasts of supply over 2009-11. The Commission assumptions are expressed in annual GWh, so for the purposes of calculating winter energy margins, these figures have been halved. There are no new cogeneration schemes included in this analysis.

Table 36: North Island geothermal energy assumptions (winter GWh)

Scheme	MW	Status	Date	Base GWh	2009	2010	2011
Kaponga	20	Existing		73	73	73	73
Kinleith	41	Existing		133	133	133	133
Whareroa	54	Existing		127	127	127	127
Te Rapa	49	Existing		90	90	90	90
Total (existing + committed + highly likely)					**423**	**423**	**423**

3.6 Energy assumptions for hydro schemes

3.6.1 Table 37 and Table 38 summarise the North Island and South Island expected inflows used in the energy margin calculations and forecasts of supply over 2009-11. The forecasts shown for 2009-11 adjust the base figure of new projects for planned commissioning over a winter.

Table 37: North Island hydro energy assumptions (winter GWh)

Scheme	MW	Status	Date	Base GWh	2009	2010	2011
Waikato	1,063	Existing		2,311	2,311	2,311	2,311
Tokaanu/Rangipo	360	Existing		700	700	700	700
Waikaremoana	141	Existing		306	306	306	306
Matahina	80	Existing		160	160	160	160
Patea	32	Existing		56	56	56	56
Wheao	27	Existing		57	57	57	57
Mangahao	42	Existing		87	87	87	87
Mangaio	2	High	Jul '08	6	6	6	6
Waipa	9	High	Jul '09	17	8	17	17
Hydro 1	8	Medium	Jun '10	19	0	13	19
Total (existing + committed + highly likely)					**3,692**	**3,700**	**3,700**

Table 38: South Island hydro energy assumptions (winter GWh)

Scheme	MW	Status	Date	Base GWh	2009	2010	2011
Waitaki	1,723	Existing		2,886	2,886	2,886	2,886
Manapouri	728	Existing		2,363	2,363	2,363	2,363
Clutha	720	Existing		1,583	1,583	1,583	1,583
Cobb	32	Existing		102	102	102	102
Coleridge	40	Existing		121	121	121	121
Argyle	11	Existing		27	27	27	27
Kumara	11	Existing		23	23	23	23
Opuha	8	Existing		10	10	10	10
Teviot	15	Existing		11	11	11	11
Ben Refurbishment	10	Committed	Jul '11	25	0	0	13
Hawea Gates	17	High	Jul '12	33	0	0	0
Hydro 2	110	Medium	Oct '10	45	0	0	45
Wairau	72	Low	Mar '12	189	0	0	0
Dobson (Arnold)	40	Low	Mar '12	103	0	0	0
Hydro 3	70	Low	Jul '13	165	0	0	0
Hydro 4	280	Low	Jul '15	741	0	0	0
Total (existing + committed + highly likely)					**7,125**	**7,125**	**7,138**

3.6.2 For the major existing hydro schemes, energy figures are based on the Commission's estimates of average winter inflows over the period 1931-2007 (which are based on estimates of metered flows). For the smaller schemes (e.g., Argyle in the South Island and Wheao in the North Island) as well as new schemes, expected output is derived from halving the Commission's estimate of annual expected output.

3.6.3 Recall that in addition to expected winter inflows, expected storage at April 1 of 2,750 GWh (New Zealand) and 2,400 GWh (South Island) is included in the margin calculations, as described in the Security of Supply Policy [2].

3.7 Calculating the New Zealand Winter Energy Margin

3.7.1 Calculation of the New Zealand Winter Energy margin involves summing the GWh relevant figures from the supply sources discussed above (including expected start storage), and expressing the difference between total supply and forecast demand as a percentage of demand. These calculations are summarised in Table 39 for existing, committed, and highly likely schemes.

Table 39: New Zealand Winter Energy Margin calculations (existing + committed and highly likely schemes)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Start storage	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750	2,750
Thermal	10,199	11,097	11,097	11,097	11,097	11,097	11,097	11,097	11,097	11,097
Cogen	423	423	423	423	423	423	423	423	423	423
Geothermal	1,818	2,263	2,559	3,202	3,789	3,955	3,955	3,955	3,955	3,955
Hydro	10,817	10,826	10,838	10,867	10,884	10,884	10,884	10,884	10,884	10,884
Wind	735	889	1,107	1,587	2,068	2,068	2,068	2,068	2,068	2,068
Total	26,742	28,247	28,773	29,926	31,009	31,176	31,176	31,176	31,176	31,176
Demand	21,389	21,870	22,363	22,805	23,246	23,697	24,156	24,624	25,101	25,587
% Margin	**25.0%**	**29.2%**	**28.7%**	**31.2%**	**33.4%**	**31.6%**	**29.1%**	**26.6%**	**24.2%**	**21.8%**

3.8 Calculating the South Island Winter Energy Margin

3.8.1 Calculation of the South Island Winter Energy margin is the same as for the New Zealand winter energy margin except in one respect: an estimate of the maximum expected transfer across the HVDC link is required. The base case assumption is 1,650 GWh, and when combined with supply and start storage assumptions for existing, committed, and highly likely South Island schemes, yields the energy margin calculations in Table 40.

Table 40: South Island Winter Energy Margin calculations (existing + committed and highly likely schemes)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Start storage	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
HVDC	1,809	1,873	1,871	2,033	2,086	2,076	2,087	2,116	2,089	2,085
Thermal	0	0	0	0	0	0	0	0	0	0
Cogen	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Hydro	7,125	7,125	7,138	7,167	7,183	7,183	7,183	7,183	7,183	7,183
Wind	110	110	110	110	110	110	110	110	110	110
Total	11,444	11,508	11,519	11,709	11,779	11,770	11,780	11,810	11,782	11,778
Demand	7,954	8,108	8,360	8,518	8,671	8,827	8,986	9,148	9,313	9,480
% Margin	**43.9%**	**41.9%**	**37.8%**	**37.5%**	**35.8%**	**33.3%**	**31.1%**	**29.1%**	**26.5%**	**24.2%**

Appendix 4 Capacity Margin Calculations

4.1 Introduction

4.1.1 This section describes the supply components used in the capacity margin calculations described in the main body of the report, along with any related assumptions. Assumptions about supply (by fuel type) are discussed first, with these calculations aggregated to produce the capacity margins discussed in the main body of the report.

4.1.2 It is important to note that the capacity calculations discussed here are intended to be consistent with the approach taken to “counting” capacity in the development of the capacity adequacy standard and reflect the assumptions developed in that analysis. Plant output is aggregated in some circumstances, and several hydro schemes are derated to reflect the impact of the characteristics of the schemes on its ability to meet demand when contingencies occur. These assumptions are discussed where appropriate.

4.1.3 Note too that the term “expected capacity” is not always used in the pure mathematical sense; it is simply the contribution in MW terms of each form of supply to the capacity margin.

4.2 Capacity assumptions for thermal schemes

4.2.1 Table 41 summarises the thermal MW values used in the capacity margin calculations and forecasts of capacity over 2009-11. The “Base MW” column reflects the simple calculation of capacity derated for forced outages. The forecasts shown for 2009-11 adjust the baseline figure for issues specific to the scheme in the forecast year, such as planned outages or planned commissioning during a winter.

Table 41: North Island thermal capacity assumptions (winter MW)

Scheme	MW	Status	Date	Base MW	2009	2010	2011
Otahuhu B	390	Existing		378	378	378	378
TCC	380	Existing		369	369	369	369
Huntly	972	Existing		943	933	943	943
Whirinaki	155	Existing		150	150	150	150
NPL	100	Existing		97	0	0	0
Huntly U5 (e3p)	385	Existing		373	373	373	373
Huntly U6 (P40)	50	Existing		49	49	49	49
Southdown	175	Existing		170	170	170	170
Stratford-1	200	Committed	Dec '09	194	0	194	194
Central NI-2	75	Medium	Jun '10	73	0	49	73
Hellensville-3	240	Medium	Dec '13	233	0	0	0
Auckland-4	240	Medium	Dec '15	233	0	0	0
Total (existing + committed + highly likely)					**2,422**	**2,626**	**2,626**

4.2.2 As with the energy margin calculations, Huntly is derated for planned outages over April/May 2009. Note that there is no derating for ancillary service requirements as this is already accounted for in the capacity standard.

4.2.3 Discussion of chronological constraints in the explanatory paper on development of the capacity adequacy standard [5] suggested that the impact of unit commitment, delays and ramping did not appear to be a significant issue during peak demand periods over the next few years for the major thermal plant, so capacity is not derated for these issues.

4.3 Capacity assumptions for wind schemes

4.3.1 Wind schemes are counted at 20% of nominal capacity, as reflected in Table 42 and Table 43 for the North and South Islands.

Table 42: North Island wind capacity assumptions (winter MW)

Scheme	MW	Status	Date	Base MW	2009	2010	2011
Tararua 1-3	161	Existing		32	32	32	32
Te Apiti	91	Existing		18	18	18	18
West Wind	143	Committed	Jul '09	14	29	29	29
Long Gully	8	High	Jun '10	0	1	2	2
Titiokura/Te Waka Wind farm	147	High	Mar '11	0	0	29	29
Hauauru ma Raki	540	High	Jul '12	0	0	0	54
Wind 2	82	Medium	Dec '10	0	0	16	16

Scheme	MW	Status	Date	Base MW	2009	2010	2011
Wind 3	97	Medium	Jul '11	0	0	10	19
Wind 1	120	Medium	May '13	0	0	0	0
Waitahora	177	Medium	Jul '13	0	0	0	0
Turitea	240	Medium	Jan '14	0	0	0	0
Total (existing + committed + highly likely)					**80**	**110**	**164**

Table 43: South Island wind capacity assumptions (winter MW)

Scheme	MW	Status	Date	Base MW	2009	2010	2011
White Hill	58	Existing		12	12	12	12
Hayes Stg I	150	Medium	Jul '10	30	0	15	30
Kaiwera Wind	160	Low	Jul '09	32	16	32	32
Waipori Wind Stage 1	200	Low	Sep '09	40	7	40	40
Total (existing + committed + highly likely)					**12**	**12**	**12**

4.4 Capacity assumptions for geothermal schemes

4.4.1 Geothermal output from existing plant (Mokai, Wairakei, Poihipi and Ohaaki) was aggregated in the capacity standard analysis. In that analysis, the expected MW used for margin calculations was 87% of the maximum capacity. This factor has also been used here for scaling the capacity of new geothermal plant, as shown in Table 44. (This assumption can be revised for new plant as operational data becomes available, though is likely to be of a similar order given the base load nature of geothermal generation).

Table 44: North Island geothermal capacity assumptions (winter MW)

Scheme	MW	Status	Date	Base MW	2009	2010	2011
Mokai	110	Existing		0	103	103	103
Ohaaki	65	Existing		0	53	53	53
Poihipi	53	Existing		0	42	42	42
Wairakei	163	Existing		0	153	153	153
Wairakei binary	14	Existing		0	13	13	13
Kawerau	90	Existing		78	78	78	78
Ngawha II	15	Existing		13	13	13	13
Tauhara Binary	19	Committed	Dec '09	17	0	17	17
Te Mihi	62	Committed	Jul '11	54	0	0	27
Tauhara	225	Committed	Jul '12	195	0	0	0
Nga Awa Purua	132	High	Jun '10	115	0	76	115
Geothermal 1	80	High	Jun '12	69	0	0	0
Geothermal 2	80	High	Jul '13	69	0	0	0
Geothermal 3	80	Medium	Jun '12	69	0	0	0
Geothermal 4	80	Medium	Jul '13	69	0	0	0
Total (existing + committed + highly likely)					**455**	**548**	**613**

4.5 Capacity assumptions for cogeneration schemes

4.5.1 The capacity standard analysis used aggregate output from the four existing cogeneration schemes modelled (Kaponga, Kinleith, Te Rapa, and Whareroa). The assumption used in that analysis for the capacity margin calculations was 90 MW (approximately 55% of installed capacity). Given there has been no fundamental change to the characteristics or expectations about operation of these schemes, the 90MW assumption is also used here.

4.6 Capacity assumptions for hydro schemes

4.6.1 The analysis underlying the capacity adequacy standard considered in some detail the treatment of hydro schemes and the effect of chronological constraints on the supply capability of those schemes at times of high demand or contingencies. For measuring capacity, hydro plant are treated in two ways:

(a) The capacity of uncontrolled plant used in the margin calculations is the expected output derived from a distribution of the aggregate output (by island) over winter daytimes:

(i) Uncontrolled North Island plant are: Wheao, Mangahao, and Rangipo; and

(ii) Uncontrolled South Island plant are: Argyle, Kumara, Opuha, and Teviot;

(b) The capacity of controllable hydro schemes is derated by a 2% forced outage rate, along with any scheme-specific deratings to account for chronological constraints or other restrictions. These factors are described in the capacity margin analysis [5], and are repeated here:

(i) The Waikato scheme is treated as uncontrolled) as controlled hydro, but derated by 60 MW (~6%) to account the impact of chronological constraints;

(ii) Matahina, Patea and Tokaanu are treated as controlled with but derated by 13 MW, 5 MW and 20 MW to account for their limited short term storage;

(iii) Cobb, Coleridge, Roxburgh are treated as controlled rather than uncontrolled as they have sufficient short term storage to enable full output during contingencies; and

(iv) The Waitaki scheme is derated by 90 MW due to transmission-related restrictions on the output of a single Benmore unit at times of high South-North transfers.

4.6.2 In the absence of further information, new hydro schemes have been treated as uncontrolled, with expected capacity conservatively estimated at 50% of nominal capacity. The only exceptions are the Benmore (10 MW) and Hawea (17 MW) projects which have been treated as controllable given they are small modifications to existing controlled schemes.

4.6.3 Table 45 and Table 46 summarise the derivation of expected capacity for North and South Island hydro schemes. The “CCD” column reflects the chronological deratings discussed above for chronological effects.

Table 45: North Island hydro capacity assumptions (winter MW)

Scheme	MW	Status	Date	Base MW	Derate	2009	2010	2011
Waikato	1,063	Existing		1,063	60	983	983	983
Tokaanu	240	Existing		240	20	216	216	216
Waikaremoana	141	Existing		141	0	138	138	138
Matahina	80	Existing		80	13	66	66	66
Patea	32	Existing		32	5	26	26	26
Uncontrolled hydro[11]	188	Existing		188	0	98	98	98
Mangaio	2	High	Jul '08	2	0	1	1	1
Waipa	9	High	Jul '09	9	0	2	5	5
Hydro 1	8	Medium	Jun '10	8	0	0	3	4
Total (existing + committed + highly likely)						**1,530**	**1,532**	**1,532**

Table 46: South Island hydro capacity assumptions (winter MW)

Scheme	MW	Status	Date	Base MW	Derate	2009	2010	2011
Waitaki	1,723	Existing		1,723	90	1,600	1,600	1,600
Manapouri	728	Existing		728	0	713	713	713
Clutha	720	Existing		720	0	706	706	706
Cobb	32	Existing		32	0	31	31	31
Coleridge	40	Existing		40	0	39	39	39
Uncontrolled hydro[12]	44	Existing		44	0	23	23	23
Ben Refurbishment	10	Committed	Jul '11	10	0	0	0	5
Hawea Gates	17	High	Jul '12	17	0	0	0	0
Hydro 2	110	Medium	Oct '10	110	0	0	0	55
Wairau	72	Low	Mar '12	72	0	0	0	0
Dobson (Arnold)	40	Low	Mar '12	40	0	0	0	0
Hydro 3	70	Low	Jul '13	70	0	0	0	0
Hydro 4	280	Low	Jul '15	280	0	0	0	0
Total (existing + committed + highly likely)						**3,113**	**3,113**	**3,118**

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[11] Wheo, Mangahao, and Rangipo.

[12] Argyle, Kumara, Opuha, and Teviot.

4.7 Capacity assumptions for demand response and interruptible load

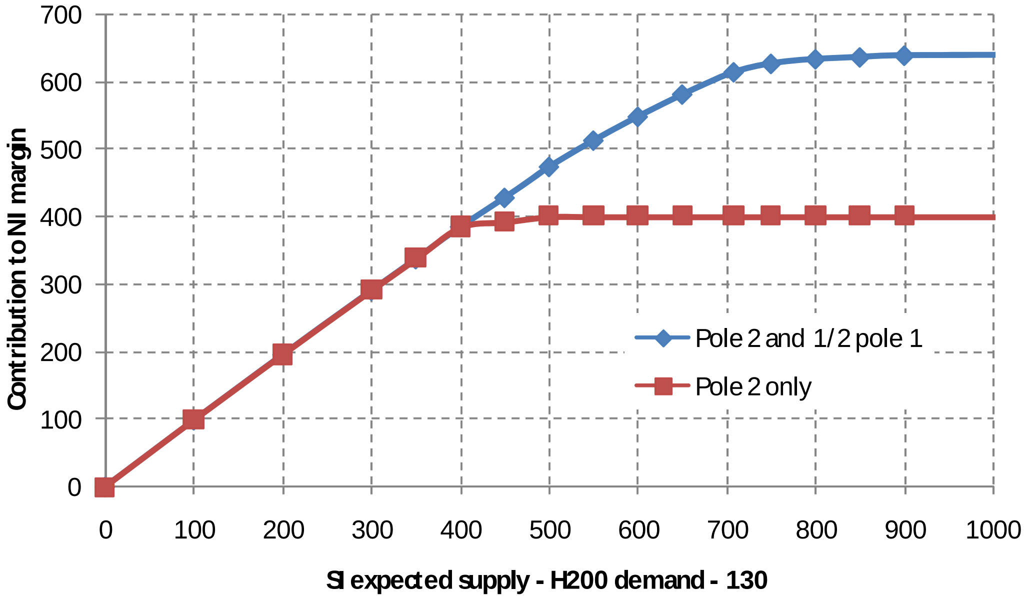
4.7.1 The base case assumption are taken from the capacity standard analysis, and comprise is a nominal 10 MW from demand response and 166 MW from interruptible load. The demand forecasts implicitly account for historic demand response, so these assumptions do not include any additional response. Any new, and non-additive, demand response contracts/availability would be treated in the same way as new supply in the margin calculations.

4.8 Calculating the North Island Winter Capacity Margin

4.8.1 The process of calculating the North Island Winter Capacity Margin (MW) involves adding expected North Island expected capacity (as defined in the previous tables) to the effective contribution from South Island supply.

4.8.2 The effective contribution from South Island supply is calculated using the curve in Figure 13, which is the same as defined in [5]. Note that the maximum contribution is 641 MW, which is less than the actual maximum transfer (including operation of ½ Pole 1). This is equivalent to a 25 MW derating (~3.5%) on maximum flow received due, primarily, to the economic effect of the 0.0025% HVDC forced outage assumption in the economic analysis detailed in [5]. Without half-pole 1, the same curve is effectively capped at 400MW, regardless of the surplus in the South Island.

Figure 13: Effective contribution to capacity margin from South Island supply



4.8.3 The calculations of the South Island contribution margin projections are summarised in Table 47 for existing, committed, and highly likely plant. For example, in 2009, the SI surplus (x-axis in Figure 13) is calculated as 3124 – 2272[13] – 130 = 723 MW. Interpolating between the relevant points in Figure 13 yields a contribution of 620 MW.

Table 47: Calculating South Island capacity contribution

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
SI supply	3,124	3,124	3,129	3,143	3,151	3,151	3,151	3,151	3,151	3,151
SI demand	2,272	2,313	2,367	2,409	2,447	2,486	2,525	2,565	2,605	2,647
SI offset	130	130	130	130	130	130	130	130	130	130
SI surplus	723	681	632	603	574	535	496	456	415	374
SI contribution	**620**	**600**	**571**	**552**	**531**	**502**	**471**	**434**	**399**	**361**

4.8.4 Calculating projections of the North Island Winter Capacity Margin involves subtracting the North Island expected capacity (earlier tables of winter MW), and South Island contribution (as above), from North Island H200 demand (including losses). These calculations are summarised in Table 48 for existing, committed, and highly likely schemes. The margin is simply the difference between the total supply and North Island H200 demand.

Table 48: Calculating projections of North Island winter capacity margins

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Thermal	2,422	2,626	2,626	2,626	2,626	2,626	2,626	2,626	2,626	2,626
Cogen	90	90	90	90	90	90	90	90	90	90
Geothermal	455	548	613	784	940	975	975	975	975	975
Hydro	1,530	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532
Wind	65	80	110	164	218	218	218	218	218	218
DR & IL	176	176	176	176	176	176	176	176	176	176
SI contribution	620	600	571	552	531	502	471	434	399	361
Total supply	5,358	5,552	5,721	5,776	6,116	6,123	6,091	6,055	6,019	5,981
NI demand	4,446	4,557	4,642	4,737	4,823	4,910	4,999	5,090	5,182	5,276
Capacity Margin	**912**	**1,095**	**1,076**	**1,187**	**1,290**	**1,209**	**1,088**	**961**	**834**	**702**

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[13] South Island demand is the H200 demand forecast + 4.88% losses = 2166*1.0488 = 2272MW.

Appendix 5 Format for submissions

Question No.	General comments in regards to the:	Response