The system impacts and costs of integrating wind power in New Zealand

Report

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EXECUTIVE SUMMARY

The New Zealand government has set a target for 90 percent of electricity to be generated from renewable sources by 2025[1]. With considerable wind generation resource available in the country, the widespread expectation is that wind power will become an increasingly significant proportion of the future generation mix to accomplish this target.

A key feature of wind generation is the variability of wind power output. This is often referred to as intermittency and it creates a number of challenges for system operators, regulators, transmission planners and industry participants.

When assessing system adequacy or security, power system planners must take the variability of wind power into account and in particular recognise that it has a lower likelihood of being available at times of peak demand when compared to "conventional" thermal plant. This raises concerns about the additional system costs to maintain system reliability at desired levels.

In the operational time scale, variability and limited predictability of wind power also creates more potential for forecasting errors in the scheduling and dispatch process. This in turn increases the levels of operating reserves that are required to be available to system operators in order to ensure that demand and generation of electricity are continually balanced. Maintaining an additional amount of operating reserve due to wind also leads to an increase in production costs, which can be attributed to wind.

With the expected large development of wind generation in New Zealand it is imperative that the technical and economic impacts of various levels of wind integration into the system are comprehensively understood. Therefore, a two phase Wind Integration Study was commissioned by Meridian Limited (MEL) to quantify the *additional system requirements* and *associated costs* under various future wind development scenarios in New Zealand. The aim of the first phase of analysis was to identify the key drivers and provide order of magnitude estimates of the additional system costs due to integration of different levels of wind power in the New Zealand electricity system over the next 10 years. A report outlining these initial findings was published in December 2006.

This updated report documents the inputs, methodology and results of further in-depth investigations into the key areas and various sensitivity factors that influence the additional system costs of wind power. In order to gain an understanding about system cost trends, a number of scenarios with different penetration levels of wind power in New Zealand were developed and then analysed.

As this analysis is concerned with the additional *system costs* that are likely to be incurred by wind generation, it does not include any savings in the fuel costs arising from the displacement of fossil fuels from thermal generation or the cost of investment incurred by wind generation developers.

The calculation of the system costs is complex and projecting these costs for next two decades is subject to a significant degree of uncertainty. Therefore, values presented in this report should be taken as indicative of the likely costs ranges.

Furthermore, the focus is on an assessment of costs rather than on possible market values of system impacts caused by wind energy. The costs evaluated in this report

[1] Government Policy Statement on Electricity Governance, Minister of Energy, New Zealand, May 2008

therefore represent an estimate of a long term equilibrium position, as in the long term, market driven operation should deliver similar values (based on the assumption that the market will be cost reflective in the long term). The differences in the market value and associated (calculated) cost of changes driven by wind power could be material in the short term[2].

Sources of Additional System Costs

The first phase of this study identified two main sources of additional system costs associated with wind integration in New Zealand, consistent with studies in overseas markets. These are the additional costs to provide adequate generating capacity to deliver long term security of supply and the additional operating reserves required to manage wind intermittency in real time.

Transmission is a third area of system cost. However significant work is underway by Transpower and the Electricity Commission in New Zealand on this issue. Our focus is therefore directed at analysing the impacts and costs of additional generation capacity and operating reserves.

The study has used scenario based analysis to investigate the plausible range of additional system costs. Scenarios for this work are designed by Meridian Limited with a view to focus on a broad but credible range of the potential energy contribution from wind generation to meet demand for electricity over several future time frames; 5% wind penetration in the year 2010, 12% in 2020 and about 20% in 2030. For each future year two different geographical distributions of wind capacity (Reference and Southland scenarios) are considered reflecting almost the same wind penetration levels.

This report presents the results along with a description of the inputs and the methodologies used in this wind integration study. On the basis of the analysis of a number of future scenarios, our key findings are summarised in Table 1 below:

Table 1 Summary of key results

	Reference scenario			**Southland scenario**		
	2010	**2020**	**2030**	**2010**	**2020**	**2030**
Interconnector (MW)	1,000	1,500	1,500	1,000	1,500	1,500
Installed wind power capacity (MW)	634	2,066	3,412	888	2,040	3,400
Wind power (GWh)	2,285	6,724	10,797	3,020	6,240	11,030
Wind penetration (%)	5	12	20	7	12	20
Required capacity margin (%)	29.7	33.4	39.7	31.8	34.3	39.6
Capacity credit of wind (%)	32	29	23	34	25	22
Additional Instantaneous Reserve (MW)	31	157	378	60	168	301
Additional Freq. Keeping Reserve (MW)	203	404	730	248	509	793
Additional Standing Reserve (MW)	46	377	566	166	394	574
Capacity cost ($/MWh of wind)	**2.4 - 3.6**	**3.6 - 5.5**	**6.2 - 9.3**	**1.7 - 2.5**	**3.0 - 4.5**	**6.3 - 9.5**
Reserve cost ($/MWh of wind)	**0.19**	**0.76**	**2.42**	**0.31**	**0.87**	**1.70**
Total cost attributed to wind ($/MWh of wind)	**1.89 - 2.69**	**2.06 - 2.76**	**8.62 - 11.72**	**2.01 - 2.81**	**3.87 - 5.37**	**8.0 - 11.20**

[2] The market itself is of course continuously evolving and improving with the objective to achieve cost reflectivity.

Adequacy of Generation Capacity and Additional Capacity Costs

1. The New Zealand system can accommodate a significant amount of wind generation. Our results indicate that there should be no major problems up to about 20% wind penetration (by energy). Furthermore this 20% figure should not be considered a maximum. It simply represents the highest penetration scenario that was considered reasonable to investigate over the 22 year time frame of the study.
2. Wind generation requires higher capacity margins to maintain system reliability which rise significantly with the increase in wind penetration. For an existing level of interconnector (DC link) between the two Islands (i.e. 520 MW) the capacity margins required to maintain system reliability (LOLE $\leq$8 hours/year) range from 37% in 2010 to about 50% in 2030.
3. The growth in power transfer capability of the interconnector enhances the system reliability through increased sharing of capacity reserve between the two Islands. Therefore, significant generation capacity savings in both islands are observed due to possible expansion of the interconnector. These savings are found in both hydro-thermal and wind-hydro-thermal systems during increased demand years of 2020 and 2030. However, beyond 1000 MW interconnector the marginal gain tends to saturate.
4. The capacity credit of wind in the hydro dominated electricity system of New Zealand is found to range from 32% for a low penetration of 5% wind by energy down to 19% for a high wind penetration of 18% by energy. These figures are typical of the reduction in capacity factors of wind observed in overseas studies as wind penetration increases. However these results are considerably higher than those experienced in thermal based systems mainly due to:
    - The presence of a significant quantity of hydro generation which can provide a considerable contribution to additional capacity requirements due to its relatively low load factor; and
    - The high load factors of wind generation in New Zealand.
5. Large wind output variations in relatively small period of time require increased amounts of operating reserves which also limits the capacity credit of wind in the New Zealand system.
6. Additional capacity costs attributed to wind generation to mitigate wind variability range from 2.4 $/MWh – 9.3 $/MWh of wind energy produced for wind penetration between 5% and 20%. Due to the high capacity credit of wind generation in New Zealand the additional capacity costs attributed to wind are substantially lower than in thermal based systems.
7. For the Southland scenario having high concentration of wind capacity in Otago region, higher capacity margins (about 1% - 2%) are found compared to the Reference scenarios. However, the role of the interconnector is found to remain the same as for the reference scenario with the predominant impact in the form of overall generation capacity savings at high wind penetration level.
8. In the Southland scenario with a low wind penetration of 7% in 2010, the capacity credit of wind is higher than the corresponding 2010 reference scenario, while at high penetration the capacity credits are relatively low.

Therefore, capacity costs attributed to wind in the southland scenario are lower in the low penetration case (1.7 – 2.5 $/MWh) while the costs at 12% (3.0 – 4.5 $/MWh) and 18% (6.3 – 9.5 $/MWh) are nearly the same as in the reference scenario.

Additional Operating Reserve and Associated Costs

1. Additional operating reserves will be needed to manage the uncertainty in wind generation output. The quantity of additional reserves needed for each scenario is summarised in Table 1 which depends on the wind characteristics such as; the level of penetration, geographical diversity, load factor and the wind output profile.
2. Various studies for the analysed scenarios indicate that for low wind penetration (2010), hydro remains the primary source of operating reserves. The role of other plant and interruptible load becomes more significant with the increased level of wind penetration (2020 and 2030 scenarios) due to the limited expansion of New Zealand's hydro capacity expected in the future.
3. The cost of additional reserve to deal with forecasting error of wind is found to increase from 0.19 $/MWh to 2.42 $/MWh of wind energy corresponding to a wind penetration of 5% in 2010 and 18% in 2030 respectively. Smaller transfer capability of interconnector leads to an additional 0.7- 1.3 $/MWh cost of wind reserve component.
4. Dry conditions lead to significant increase of the cost, in the order of 1.08 – 4.42 $/MWh. This is driven by the increased use of thermal plants to provide energy and reserves.
5. Wet conditions also lead to an additional wind reserve component cost, between 0.36 – 1.01 $/MWh, in comparison with the cost in an average hydro condition scenario. Since hydro capacity is primarily used to produce electricity during wet conditions, less hydro capacity is available for reserve. Additional reserve requirement has to be supplied from thermal generators. This increases the cost of wind reserve component.
6. The cost of wind related reserve is 44% less for 2030 in the Southland scenario (higher concentration of wind capacity in the Otago region of South Island) compared to the Reference scenario (high wind and more diverse in North Island). Since reserves in North and South Island are managed separately, low wind penetration in the North will demand less use of thermal plant in the North while allocating more wind in the South is found to be beneficial given the presence of large hydro plants in South Island.
7. Different wind profiles, mainly differing in load factors, are also found to affect the cost of additional reserve attributed to wind. Two wind profiles based on the 2005 and 2006 historical wind data are studied. The results can be summarised as follows:
    - For low (2010) and medium (2020) penetration of wind power, the effect of different wind profiles on the cost of wind reserve component is insignificant.

- For high wind penetration (2030), the additional reserve cost per MWh of wind energy is higher during less windy period (e.g. 2005)

8. The results clearly indicate that the optimal allocation of reserve at increasing penetration of wind in New Zealand will have a profound impact on the additional reserve costs attributed to wind power. For medium and high wind penetrations in 2020 and 2030 respectively, the costs of additional reserve are found to be lowest under a reserve allocation strategy that applies a balanced allocation of spinning reserve and standing reserve.

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1. INTRODUCTION

1.1. The objective of the work presented in this report is to quantify the additional ***system costs*** of integrating various levels of wind power in New Zealand compared to a future based on thermal generation technologies. The analysis is based upon three plausible future wind power development scenarios proposed by Meridian New Zealand.

1.2. This analysis builds on the scoping study (Wind Integration Costs in New Zealand: Phase I) carried out in 2006, with the final report published in December 2006. The aim of the phase I investigation was to identify the key drivers and provide order of magnitude estimates of the additional system costs incurred due to integration of different levels of wind power in the New Zealand electricity system. This report builds on this early work and provides an in-depth investigation of the key areas and factors that influence the value of wind power in the New Zealand electricity system.

1.3. This work evaluates the long-term system reliability and the short-term system operation implications for various levels of wind penetration. A range of sensitivity studies are also carried out to assess the impacts of some of the key drivers identified in phase I. The sensitivity drivers include hydrology conditions (dry/average/wet), intra-year wind variations, wind diversity as well as different operating reserve management schemes.

1.4. As with all studies of this nature it is critical to understand the underlying assumptions. The key assumptions that inform the results are:

- the assumed reliability standard for the overall power system;
- wind generation profiles, in this case based on two years of 10 minute wind data;
- the impact of hydrology, which has been tested across representative wet, average and dry years;
- input cost parameters for generation plant and thermal fuels;
- demand growth;
- system operation scheduling strategies; and
- the level and reliability of the interconnector between the North and South Islands.

1.5. Caution is advised when directly comparing the results of this study with other systems where a number of underlying assumptions may differ.

Background

1.6. The integration of large scale wind generation into power systems is a challenge being accepted by the power industry, regulators, system operators and grid owners worldwide. Wind power, like other forms of variable generation, has

different characteristics to the "conventional" forms of generation which power systems and electricity markets have been traditionally designed around.

1.7. Major challenges of integrating wind generation into an existing system include:

- **Generation capacity adequacy**

  How "reliable" is wind generation as a source? How much conventional generation capacity can it displace? What are the system integration capacity costs and benefits?

- **Real time system balancing**

  How much does wind need to be "balanced" in real time? Is there a need for additional flexibility and reserve? What are the costs? What is the role of hydro, demand side participation and interconnectors?

- **Transmission network requirements**

  How much new transmission capacity is required to efficiently transport wind power?

- **System stability**

  What is the stability performance of the system with new forms of generation? Can this technology contribute to improving stability?

- **Role of enabling technologies**

  Do hydro storage and responsive demand have a role in facilitating the integration of wind generation? Are these solutions competitive? What are the drivers of value? What new tools are required to support system management with wind generation?

- **Technical, commercial and regulatory framework**

  Are the technical, commercial and regulatory arrangements appropriate for a system with a significant contribution of wind generation? Are the Grid Code, Standards and arrangements for access to transmission networks appropriate? Does the market adequately reward flexibility?

1.8. In addition to these common issues, the integration of large scale wind generation into the New Zealand power system differs from other systems in several ways. These include:

- New Zealand has a hydro dominated power system. Hydro plant can provide substantial operating flexibility to assist in managing wind variability. However, hydro does have storage and energy limitations.
- The New Zealand power system has no interconnections to other power systems and cannot draw upon other power systems' resources.
- New Zealand's power system is long and stringy in nature as the generation and load are connected through relatively long transmission lines. This is an important point when considering transmission issues associated with connecting new wind farms.
- The nature of the wind resource in New Zealand is gusty and large wind output variations are observed in relatively small period of time. If wind

generation is concentrated it can result in increased operating reserve requirements and possibly drive transmission congestion.

- The average wind speeds in New Zealand are far in excess of those experienced in other regimes such as continental Europe. The higher average wind speeds improve the capacity value[3] of wind and deliver lower levelized electricity costs of wind integration compared to other jurisdictions that experience lower wind speeds.

1.9. In order to comprehensively understand the system costs associated with the integration of large scale wind power in New Zealand, Meridian commissioned a two phase investigation. Phase I focussed on:

- Identifying and quantifying the key technical impacts of wind generation integration into the New Zealand power system;
- Evaluating the cost impact of additional measures to securely absorb large scale wind power in the system;
- Identifying potential mitigation options and reinforcement plans required for large scale wind integration in New Zealand.

1.10. It was found that increasing wind generation (up to 20% wind penetration) can be accommodated by New Zealand's existing transmission system. However, the transmission studies showed an increased level of constraint activity. Analysing the impact of wind power on transmission will require more detailed work before any firm conclusions can be drawn. It was cautioned that any transmission impacts are highly sensitive to the location assumptions for new generation. Also the impact of increased reserve constraint requirements on additional transmission investment, were not included.

1.11. Reactive power reserves, voltage control and stability performance were not included in the analysis. The cost of reactive power mitigation options are an order of magnitude lower than for real power. Also exploring the appropriate development of technical, commercial and regulatory frameworks was also out of the scope of this work.

1.12. Having identified the pertinent drivers of costs attributed to wind integration in New Zealand in the phase I investigation, this second phase has investigated in detail the following two major areas:

- Generation capacity adequacy and additional generation capacity costs.

  Wind generation is primarily an energy source with limited ability to provide reliable output at times of peak demand. This results in the need to maintain higher levels of generation capacity in the system, with additional capacity costs, in order to maintain system reliability at a desired level.

- Additional system operation (reserve) requirements and associated costs.

  Due to variability of wind power output, additional instantaneous reserves, frequency keeping reserves and scheduling reserve will be required. This requires additional generation flexibility and incurs extra production costs.

[3] Capacity value is the contribution that wind generation will make to reliably supply peak demand.

1.13. Finally, it is important to note that no generation technology is perfect and all generation technologies have system costs and impacts. This report seeks to compare wind with a "conventional" thermal "counterfactual" analysis. We compare a system with wind to a system with thermal and examine what system cost differentials and issues may arise.

Scope of this Report

1.14. This report presents the methodology used and the results found from a detailed investigation on the integration of wind power generation into the New Zealand electricity system. The main objective of this analysis is to quantify the magnitude and cost of the additional requirements for generation capacity and operating reserve arising from the growth in wind generation in New Zealand over different future time horizons.

1.15. The work presented in this report is based upon three future generation development scenarios that provide snapshots of the system in the years 2010, 2020 and 2030. The analysis is conducted by considering various hydro conditions (wet, average and dry) and examining the interaction between hydrological conditions and wind generation. Additionally, the impact of different regional growth patterns of wind generation is also analysed for three future time horizons. The analysis shows the variations of wind diversity under these different regional growth scenarios.

1.16. The methodologies and results have been presented and discussed with key stakeholders in New Zealand, including the Electricity Commission, Transpower, Government officials and industry participants.

1.17. A comparison of the extent of the wind integration impacts identified and quantified in this work is made with studies/results obtained in other jurisdictions. Areas where the New Zealand system integration costs are found to be materially different to overseas systems have been highlighted.

Structure of Analysis

1.18. This study commenced with the development of a demand forecast for three future time horizons i.e., the years 2010, 2020, and 2030. Corresponding plausible generation development scenarios were designed which represent different levels of wind penetration. This was followed by gathering key input data, including wind speed measurements, generator characteristics with their operating constraints and the transmission network.

1.19. Methodologies were developed to assess long-term system reliability and to simulate the operation of the power system including wind generation. Once full system models were developed and tested, these were applied through a number of studies to quantify the impact of wind power integration on the New Zealand power system both in terms of additional technical measures and associated costs for the following two categories:

- Generation capacity adequacy and additional system capacity costs.
- Additional operating reserve requirements and associated costs

1.20. The results of the various studies that include a range of sensitivities around key system parameters were synthesised. The findings from this detailed analysis were discussed with stakeholders and disseminated. The details of the results along with description of applied methodologies were documented in this report.

2. SCENARIOS FOR WIND GENERATION DEVELOPMENTS

2.1. This section outlines the different generation and demand scenarios that are investigated in this work. These scenarios were developed by Meridian. The detailed description of these scenarios is presented in Appendix A.

2.2. The fundamental intent in selecting these scenarios is to focus on a broad but credible range of potential energy futures for New Zealand where wind generation helps to meet demand for electricity over several time frames. The years selected are 2010, 2020, and 2030 (over a July-June time period). These scenarios do not set out Meridian's view of the future. They are used to create snapshots of the system to investigate the impact of wind generation. In this context the years should be viewed as place holders for a possible time, rather than absolutes. Consistent with the aims of the study – to establish the additional system costs of wind – the motivation is to develop an understanding of how these system costs are affected by the overall quantum (and associated regional diversity) of future wind generation.

New Zealand Generation Supply for 2007

2.3. A common starting point for all of the generation scenarios is the current levels of supply and demand for 2007. Key characteristics of the New Zealand electricity system are:

- For the 2007 year 43,700 GWh of total demand for generation is assumed. This demand includes all losses, industrial co-generation and regional embedded generation.
- Total installed generation capacity for the 2007 year is 9,080 MW, which exceeds peak system demand of 6,820 MW for the 2007 year by more than a 30% margin.
- Hydro generation contributes 55% of the total, with gas contributing 20%, coal 10%, and geothermal 7%. Currently wind only contributes 2.5% of the total generation energy picture (or 3.5% of installed system capacity).
- In New Zealand the primary focus has been on expected generation energy yield rather than on the more conventional international focus on installed generation capacity.
    - This is a direct reflection of the historical dominance in New Zealand of hydro generation which provides a relative 'abundance' of installed capacity but carries with it significant uncertainty in the delivery of energy over all time frames, from days to years (up to +/-20% of expected annual energy yield).
    - This uncertainty has traditionally been resolved through the use of 'hydro firming' plant running on either oil, gas, or coal.
    - In the last decade this hydro dominance has been supplemented by the development of new CCGT gas-fired generation.

2.4. This current mix of installed generation is summarised briefly by fuel type below in Table 2. Note that in this summary the average energy amounts listed

are for average hydrological conditions. In dry or wet years hydro energy will fall or rise substantially by as much as 3,000 GWh to 5,000 GWh and thermal energy output will increase or decrease correspondingly.

Table 2. New Zealand generation mix assumed for 2007.

Generation Category	Commission Date	Installed Power	Average Energy	Load Factor
	[Jul yr]	[MW]	[GWh]	[%]
Thermal	2007	2,528	13,845	62.5%
Auxiliary	2007	948	6,357	76.5%
Wind	2007	321	1,240	44.0%
Hydro	2007	5,282	24,637	53.2%
Committed	by 2010	523	1,762	38.5%
		9,603	47,841	56.9%

New Zealand Demand for Generation

2.5. Demand data for the analysis is based on metered, grid exit point (GXP), non-embedded demand data for the 2006 calendar year. This does not represent all New Zealand demand and in order to be consistent with the definition used for generation supply we need to account for additional non-metered co-generation and locally embedded generation. Together these contribute approximately 2,500 GWh of additional demand. Also, since high voltage transmission losses are not explicitly modelled in this study demand is scaled by approximately 4.5% to give an appropriate picture of demand at the level of the power station 'gate'.

2.6. Raw metered demand data is aggregated by island, and scaled to represent growth through to 2030 with non-metered generation added (this is assumed to grow at the same rate as underlying energy). Assumed growth rates are Meridian's own views but at the national level these are consistent with the energy growth assumed by the New Zealand Electricity Commission's 2007 Statement of Opportunities[4]. The growth in both energy and peak power is approximately linear at 725 GWh and 120 MW per annum respectively. The resulting summary demand picture is given in Table 3.

[4] The Statement of Opportunities is a grid planning document and analysis framework published by the New Zealand Electricity Commission (http://www.electricitycommission.govt.nz/opdev/transmis/soo)

Table 3. Demand for 2006[5] and growth through to 2030.

Transmission losses	4.5%									
Embedded generation	2,500 MW									
		Load (MW)						Demand (GWh)		
		NI		SI		NZ		NI	SI	NZ
	Calendar Year	Min	Max	Min	Max	Min	Max			
Actual	2006	1,440	4,320	1,116	2,121	2,556	6,434	23,894	13,969	37,863
Forecast	2010	1,932	4,842	1,434	2,455	3,367	7,290	29,046	17,093	46,139
	2020	2,254	5,598	1,671	2,845	3,926	8,435	33,753	19,873	53,626
	2030	2,529	6,273	1,881	3,197	4,412	9,461	38,030	22,419	60,449

The Wind Resource

2.7. Fifteen regionally diverse wind farm locations have been selected as being representative of the general wind resource potential in New Zealand. At four of these sites wind farms either already exist or are being commissioned. At the remaining eleven sites, wind farms are being investigated by a range of developers and therefore represent the most credible portfolio of wind development options available. The theoretical performance of the wind farms and their locations are consistent with Meridian's views on wind behaviour and on where the better wind resources in New Zealand are located. These can be grouped into three broad regions:

- Northland/Auckland;
- HawkesBay/Manawatu/Wellington; and
- Southland/Otago.

2.8. While there are potential wind sites outside of these areas the analysis is restricted to using real wind data from actual sites with long and overlapping wind records.

New Zealand Future Generation Supply – The Wind Scenarios

2.9. Having described the basis for the supply and demand data in the preceding sections this section outlines the data used and the basis for the selection of the wind scenarios.

2.10. Six potential generation scenarios have been developed for the second phase of the NZ Wind Integration Study. The fundamental intent in selecting the scenarios presented is to focus on a broad but credible range of the potential energy contribution from wind generation to meet demand for electricity over several time frames. In order to avoid explicitly displacing economic existing generation, the wind generation assumed in the wind scenarios is a partial allocation of the need for new generation incremental demand growth over the next 3-23 years. This ranges between 2,500 GWh in 2010 to 17,000 GWh by 2030.

[5] Source: Energy Market Services, Total GXP load 01Jan2006 to 31Dec2006

2.11. There are two main bases for classifications of these scenarios. The first deals with the geographical distribution of wind across New Zealand which is followed by different penetration levels of wind in three future time frames (2010, 2020, and 2030). The geographical distribution based classification is termed as 'Reference' and 'Southland' scenarios while their sub classification is named according to the respective year in the future.

2.12. The three ***Reference*** scenarios are:

1. **2010**: In addition to existing and already committed wind projects one other South Island based wind farm is commissioned between now and 2010 – with installed wind totalling 634 MW. Other technologies 'make up the slack' to satisfy the incremental 2,500 GWh of new demand growth. All projects between now and 2010 are already committed, and no existing generation is displaced.
2. **2020**: In addition to existing and already committed wind projects, a relatively high range of regional wind farms are assumed to be commissioned between now and 2020 – with installed wind totalling 2,066 MW. Other technologies 'make up the slack' to satisfy the incremental 10,500 GWh of new demand growth – with new wind contributing some 6,200 GWh. Other generation is assumed here to consist of a range of generation projects: principally geothermal (2,000 GWh), gas (300 GWh), and hydro (200 GWh).
3. **2030**: In addition to existing and already committed wind projects this scenario assumes a high number of regional wind farms are commissioned between now and 2030 – with installed wind totalling 3,412MW. Other technologies 'make up the slack' to satisfy the incremental 17,000 GWh of new demand growth – with new wind contributing some 11,000GWh. Other generation is assumed here to consist of a range of generation projects: principally gas (2,000 GWh), geothermal s (2,000 GWh), and hydro (200 GWh).

2.13. Assumed new generation built between 2007 and 2030 is grouped by scenario and technology types and is summarised in Table 4.

Table 4. Wind scenarios. New generation assumed between 2007 and 2030 – by year and technology. – Reference Scenario

Year	2010			2020			2030		
	Capacity	Energy	Load Factor	Capacity	Energy	Load Factor	Capacity	Energy	Load Factor
	MW	GWh/yr	(%)	MW	GWh/yr	(%)	MW	GWh/yr	(%)
Wind	313	1,169	43	1,745	6,241	41	3,090	10,865	40
Hydro	148	213	16	148	213	16	148	213	16
Geothermal	106	779	84	255	1,962	88	294	2,286	89
Gas	-	-	0	70	307	50	310	2,094	77
Total conventional	254	991	45	473	2,481	60	752	4,592	70
Total new generation	567	2,161	44	2,217	8,722	45	3,842	15,458	46

2.14. The new thermal capacity additions as shown in table 4 are based on a simplistic expansion rule to balance overall energy demand. These were used as an initial estimate of the system capacity requirements. Any capacity deficit was then determined in the explicit capacity analysis as elaborated in section 3.

2.15. Conventionally, the level of wind in a system is expressed in terms of energy penetration. This is the electricity produced by the wind generation, normalised by the gross electricity consumption in the system, usually on an annual basis. Throughout this report wind penetration will be referred to as wind energy penetration. The corresponding statistics for all the developed scenarios are given in Table 5.

Table 5. Wind (energy) penetration and energy balanced capacity margin - Reference Scenario

Year >>	2010		2020		2030	
	Capacity	Energy	Capacity	Energy	Capacity	Energy
	MW	GWh/yr	MW	GWh/yr	MW	GWh/yr
Wind	634	2,409	2,066	7,481	3,412	12,105
Hydro	5,430	24,850	5,430	24,850	5,430	24,850
Geothermal + Others	1,056	7,136	1,203	8,319	1,242	8,643
Gas/Coal	2,528	13,845	2,598	14,152	2,838	15,939
Total NZ demand	7,290	46,139	8,435	53,626	9,461	60,449
Capacity Margin (%)	32.3%		33.9%		36.6%	
Wind Penetration (%)		5.2%		13.9%		20.0%

2.16. The varying magnitude of regionally allocated wind data is achieved by scaling the raw wind data sets. This is a conservative assumption, in that future regional wind contributions are unlikely to come from a single wind farm. Also, 'within region' (and within wind farm) diversity effects are likely to make the variation in total wind less volatile than assumed in these scenarios. The assumed regional dispersal of wind and the variation by scenario and year is shown in Table 6.

Table 6. Allocated regional wind capacity – Reference scenario

Region	2010		2020		2030	
	MW	GWh	MW	GWh	MW	GWh
Auckland (NI)					225	788
Canterbury (SI)	-	-	-	-	215	660
Central (NI)	-	-	100	350	100	350
Hawke's Bay (NI)	-	-	198	663	309	1,052
Manawatu (NI)	280	1,089	430	1,654	580	2,180
Northland (NI)	-	-	171	600	422	1,479
Otago (SI)	144	492	405	1,384	755	2,632
Southland (SI)	58	220	226	809	226	809
Taranaki (NI)	-	-	99	361	99	361
Waikato (NI)	-	-	-	-	44	135
Wairarapa (NI)	9	33	99	356	99	356
Wellington (NI)	143	574	337	1,303	337	1,303
North Island	**432**	**1,696**	**1,434**	**5,287**	**2,215**	**8,004**
South Island	**202**	**713**	**632**	**2,194**	**1,197**	**4,100**
New Zealand	**634**	**2,409**	**2,066**	**7,481**	**3,412**	**12,104**

2.17. In the ***Southland*** scenario the location of various wind farms considered in the reference scenario is reallocated to be in the South Island (largely in the Otago region) and rest is mainly unaltered. The three wind scenarios are:

1. **2010**: In addition to existing and already committed wind projects, one other SI based wind farm is commissioned between now and 2010 – with installed wind totalling 888 MW. This is an addition of 250 MW of wind capacity in the Otago region compared to the reference 2010 scenario.
2. **2020**: In addition to existing and already committed wind projects a relatively high range of regional wind farms are assumed to be commissioned between now and 2020 – with installed wind totalling 2,040 MW. The total installed wind considered in this scenario is the same as the corresponding reference scenario. However, the allocation of new wind capacity between the islands is skewed i.e. 610 MW in the North Island and 1100 MW in the South Island, with about 940 MW in Otago.
3. **2030:** In addition to existing and already committed wind projects a high number of regional wind farms are assumed to be commissioned between now and 2030 – with installed wind totalling 3,402MW. Again the total installed wind considered in this scenario is the same as corresponding reference scenario. However, the allocation of new wind capacity between the islands is relatively balanced i.e. 1430 MW in the North Island and 1650 MW in the South Island, with about 940 MW in Otago.

2.18. The regional allocation of the wind capacity considered in the Southland scenario is shown in Table 7. Where the indicated expected energy yield is based on 2005 wind data.

Table 7. Allocated regional wind capacity - Southland scenario

Region	2010		2020		2030	
	MW	GWh	MW	GWh	MW	GWh
Auckland (NI)	0	0	0	0	225	788
Central (NI)	0	0	100	350	100	350
Hawke's Bay (NI)	0	0	0	0	111	358
Manawatu (NI)	273	1,112	430	1,750	430	1,750
Northland (NI)	0	0	0	0	251	878
Otago (SI)	405	1,384	939	3,208	1,480	5,055
Southland (SI)	58	0	226	792	226	792
Taranaki (NI)	0	0	99	361	99	361
Waikato (NI)	0	0	0	0	44	161
Wairarapa (NI)	9	0	9	0	99	354
Wellington (NI)	143	550	237	913	337	1,299
North Island	**425**	**1,661**	**875**	**3,375**	**1,696**	**6,301**
South Island	**463**	**1,384**	**1,165**	**4,000**	**1,706**	**5,847**
New Zealand	**888**	**3,045**	**2,040**	**7,375**	**3,401**	**12,148**

2.19. All of the wind scenarios assume that all currently committed new generation as described earlier will proceed to full commissioning. Aside from those mentioned above, no other new generation option is considered 'firm' and is therefore available to be 'displaced' by assumed new wind generation. Finally, no existing generation plant is assumed to be decommissioned over this period.

3. CAPACITY ADEQUACY ASSESSMENT AND ADDITIONAL CAPACITY COSTS

3.1. This section is principally concerned with evaluating the ability of the electricity system in New Zealand to meet demand with desired levels of reliability under various wind development scenarios. This encompasses a comprehensive range of the factors that influence the system's reliability. These include an impact assessment of different penetration levels of wind, different power transfer capabilities of the North-South interconnector as well as the three (dry/average/wet) hydro conditions.

3.2. Based on maintaining the system reliability at a desired level, adequate generation capacity requirements are determined to meet both energy security and peak demand security. The capacity value of wind and additional capacity costs attributed to wind generation are then appraised.

Background

3.3. The reliability of the system involves maintaining appropriate levels of generation capacity in order to keep the system operating under a range of conditions. Such conditions essentially include credible plant outages, intra-year variation of available hydro energy, effects of limited predictability and variation of wind generation as well as uncertainty in demand.

3.4. Wind generation is generally considered an energy source with limited capability to reliably contribute to peak demand. Systems with high wind penetration generally need some form of capacity, either conventional plant or an alternative backup option such as energy storage or responsive demand, to ensure that the security of supply is maintained at peak demand times. The primary reason that wind creates additional generation capacity costs is therefore because it provides more energy into the system than reliable capacity.

3.5. In New Zealand a significant portion of generation comes from hydro, geothermal, cogeneration and landfill. The utilisation of these plants will not be affected as the system will continue to maximise the use of these zero/very-low marginal cost sources. However, the utilisation of thermal plant (coal, gas and oil) will be effected by wind. These plants will be required to maintain system reliability at different levels of wind generation as well as providing energy.

Methodology

Generation Capacity Adequacy

3.6. The amount of generation capacity in a power system is considered to be adequate if it meets electricity demand with a desired level of system reliability. The reliability criterion applied in this analysis is the loss of load expectation (LOLE) which is defined as the number of hours per year when load is expected to exceed the available generation. The developed capacity adequacy model is also capable of evaluating Expected Energy Not Served (EENS) as a reliability

index. However, the more widely applied LOLE criterion is applied in this work.

3.7. The current electricity system in New Zealand does not operate to a statutory or formal generation reliability standard. Such a standard would require a given capacity margin[6] for any particular mix of plant to be available to maintain adequate security of supply. From an analytical perspective, the overall system must be ascribed a target reliability standard. This enables scenarios with and without wind to be developed and solved to achieve an equivalent level of reliability. The difference in generation capacity in with and without wind scenarios is the additional generation capacity required to firm wind. We have applied a reliability standard of LOLE $\leq$ 8 hours/year to determine adequate capacity level in the system. Similar standards are exercised in other power systems such as France[7] (LOLE: 3 hours/year) and the Republic of Ireland[8] (LOLE: 8 hours/year).

3.8. The methodology to assess the adequacy of generation capacity is developed in two distinct phases. Initially the methodology is developed for an entirely thermal based generation system. Wind and hydro generation is then introduced to the thermal system to achieve a combined wind-hydro-thermal system. In this way we can identify the differences between a wind scenario and a conventional thermal generation counterfactual scenario.

Capacity Adequacy of Thermal systems

3.9. Each generating plant in the system is characterised by its maximum rated capacity and its operating capacity states with associated probabilities. The possible unit states assumed are; full capacity, derated capacity (consistent with a minimum stable generation output) and out of service. Each of these states is allocated an associated probability based on the average behaviour of generators.

3.10. The capacity model of the entire thermal generation is prepared by applying Markov model to compute the probability or long-term availability of various capacity states of the thermal capacity. This results in an array of possible capacity levels of the system with their associated probabilities called capacity outage probability table (COPT). The relevant mathematical formulation is provided in Appendix A.

3.11. The load model is based on a time series of half-hourly peak loads over a one year time horizon.

3.12. For each half hour time period the probability of all those capacity states that lead to insufficient available generation (i.e., a loss of load situation) is added to determine the loss of load probability (LOLP) in that period. The annual loss of load expectation (LOLE in hours/year) is then determined by summing the LOLP values in each half hour period of the entire year.

[6] Capacity margin (also called plant margin) is the amount of capacity installed in excess of peak demand, expressed as percentage of the total installed capacity in the system.

[7] Generation Adequacy Report - on the electricity supply-demand balance in France, RTE 2005

[8] Generation Adequacy Report, EirGrid, Republic of Ireland 2007

3.13. The adequacy of the generation capacity is then assessed by comparing the calculated LOLE with the reliability standard (LOLE ≤ 8 hours/year). The amount of capacity considered in the system is adequate if the reliability standard is satisfied, otherwise capacity is iteratively added (or removed) and LOLE is computed again until the required reliability standard is achieved.

Capacity Adequacy of Wind-Hydro-Thermal Systems

3.14. The methodology described earlier for evaluating the capacity adequacy of a thermal system alone, is extended for a system having wind, hydro and thermal generation.

3.15. A linear programming based optimisation model for generation dispatch is developed. It optimally dispatches wind, hydro and thermal generation during each half hour time slot such that the requirements of thermal capacity in the system are minimised. The optimisation includes several constraints including the production of wind, hydro and thermal power plants. The formulation is in Appendix A.

3.16. Half-hourly wind power output profiles for various sites corresponding to the wind capacity considered in each scenario, are aggregated at an Island level. Wind power output is assumed to have zero marginal cost. The model will attempt to use all available wind output in each half-hour unless it is restricted by load conditions or other constraints.

3.17. Daily run-of-river (ROR) hydro energy inflows are adopted from historical data for all three (dry/average/wet) hydro conditions. The daily available energy is equally divided in each half-hourly time slot of the day. Like wind energy all available ROR energy during each time period is modelled to be fully used unless constrained by load or constrained by other generator's operations. The weekly available reservoir energy (inflows) have been obtained from the SPECTRA model for all scenarios and different hydro conditions. This weekly available hydro reservoir energy is dispatched optimally in combination with the available ROR and wind output during each half-hour in order to achieve minimisation of the overall thermal capacity requirements.

3.18. The generation dispatch optimisation model provides the optimal half-hourly thermal generation dispatch. The available reserve hydro capacity for each half hour, which is the difference between the total hydro capacity and dispatched hydro power, is also calculated in the optimization process.

3.19. The COPT of the total thermal capacity considered in the system is determined in the same way as explained earlier for thermal systems alone. The optimal half-hourly thermal generation dispatch and reserve hydro capacity obtained from the dispatch model is then combined with the COPT of the total thermal capacity to evaluate the system's reliability (LOLE) as described earlier for the thermal system.

3.20. The adequacy of the overall system capacity is finally assessed by comparing computed LOLE with the LOLE standard. The thermal capacity is iteratively added (or removed) followed by the recalculation of the LOLE until the required reliability level is attained.

3.21. A schematic representation of the capacity adequacy assessment model is described in Figure 1.

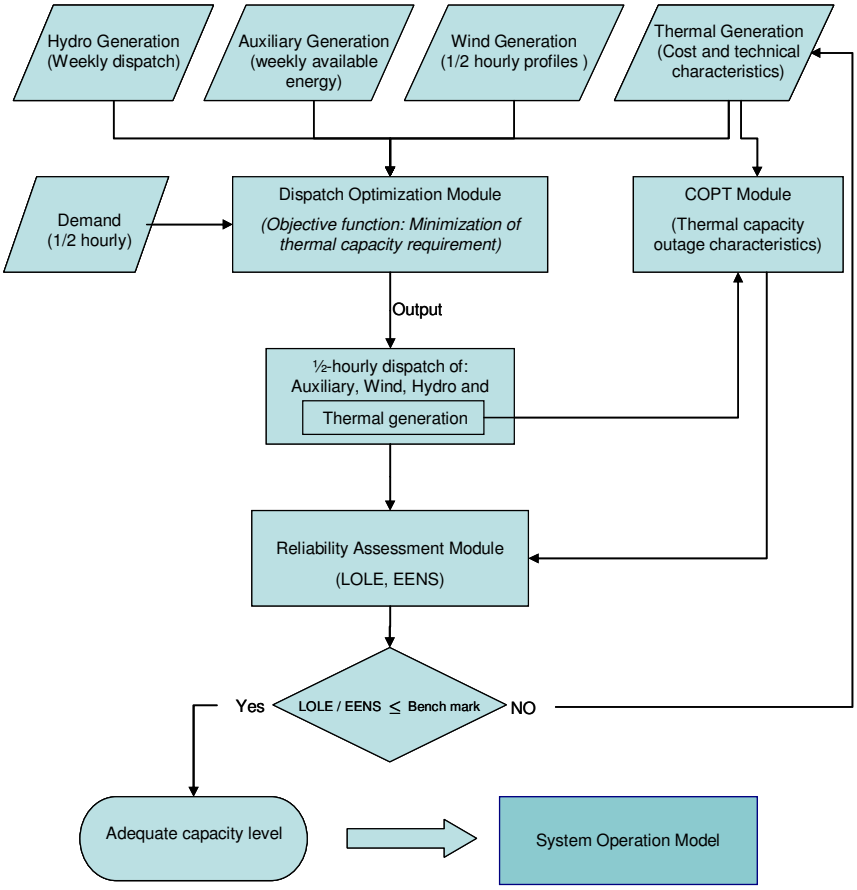

Figure 1. A simplified representation of the capacity adequacy assessment model

Capacity Credit of Wind Generation

3.22. The capacity credit of wind generation is defined as "The reduction in the capacity of thermal plant needed to provide a reliable supply of electricity, due to the introduction of wind generation". It is determined by applying the earlier mentioned capacity adequacy evaluation (optimisation) model with a few additional steps.

Wind Capacity Credit in Wind-Thermal Systems

3.23. The starting point is to compute the adequate amount of thermal capacity necessary to supply a demand profile to a required LOLE standard.

3.24. Wind generation is then added to the system and the generation adequacy evaluation model is re-run. The LOLE of the system will reduce as the system becomes more secure, with the addition of wind generation into an already

adequate system. An iterative process is then applied to gradually reduce thermal capacity until the required LOLE is achieved.

3.25. The amount of thermal capacity reduction provides the capacity credit of wind generation in the wind-thermal system. This capacity credit is expressed as a percentage of the wind capacity considered introduced into the system.

Wind Capacity Credit in Wind-Hydro-Thermal Systems

3.26. First the adequate level of thermal capacity necessary to supply a given demand profile with desired level of LOLE in the hydro-thermal system is assessed. Wind power is subsequently added to this system which results in decreasing the LOLE of the system. As above, thermal generation capacity is reduced until the calculated LOLE equals the LOLE standard.

3.27. Finally, the difference in the thermal capacity between with wind (i.e. wind-hydro-thermal) and without wind (i.e. hydro-thermal) systems, both meeting the same LOLE, provides the capacity credit of wind generation in the wind-hydro-thermal system.

Additional Capacity Credit of Wind due to Hydro Generation:

3.28. The flexibility and energy storage capability of hydro generation means that it is ideally placed to manage variability in wind generation output. During periods of high wind power output, hydro power output can be reduced and hydro energy stored for later use during periods of low wind output or high demand. Therefore the presence of hydro generation enhances the capacity value of wind generation i.e. it reduces the amount of thermal capacity that would be required to maintain system security.

3.29. In order to quantify the benefit of co-ordinating wind and hydro power, the capacity credit of wind generation can be determined in a wind-thermal and wind-hydro-thermal system. The difference in the wind capacity credit between the two systems indicates the capacity credit benefit (added value) due to hydro generation.

Additional Capacity Cost Evaluation

3.30. A new methodology is developed to quantify additional system capacity costs attributed to wind power. The difference between the capacity and energy that is displaced by wind power is the cause of these additional capacity costs. These costs which are attributed to wind power are dependent on the characteristics of the incumbent system.

3.31. Having assessed the capacity credit of wind power at various levels of wind penetration, the additional capacity costs attributed to wind power are determined using the formulation given in Appendix A.

3.32. In order to provide a like-for-like comparison, these additional capacity costs due to wind are compared with the corresponding costs of a thermal substitute.

The additional capacity costs for wind generation are then expressed as the difference between the wind and thermal augmented systems.

Key Assumptions

3.33. The assumptions related to the evaluation of generation capacity adequacy and capacity credit of wind power are:

- Generating units are assumed to operate independently. For example, we assume that an outage of one generator will not directly affect the operation of the other units in the system.
- The generating units are assumed to be either fully available or out of service in accordance with their long-term plant availability statistics.
- Hydro generators are considered to be fully reliable i.e. these are modelled as units which are available all the time and constrained only by their rated capacities and available hydro energy.
- Reservoir inflows in each week are assumed to arrive equally at the start of each half hour in the week.
- The reliability of wind generators is assumed to be 94% (considering a forced outage rate of 6%).
- The interconnector between the two Islands is assumed to be 99% reliable and operating in two states only i.e.,
    - available with full transfer capability with a probability of 0.99
    - unavailable with no flow possible with a probability of 0.01
- The capacity benefit due to the hydro-wind coordination in the system has been attributed to wind generation. This assumes that the hydro generation displaces the same amount of thermal capacity in hydro-thermal and wind-hydro-thermal systems.
- In the additional capacity cost assessment, the thermal plant used for cost comparisons are assumed to operate as base load plant with a load factor of 85% and a 100% capacity credit.

Case Studies and Results

3.34. The three main wind scenarios, or reference scenarios, are first analysed to determine if there is adequate generation capacity in the system.

The capacity value and associated capacity costs attributed to wind generation are then evaluated in each of these scenarios. These generation scenarios correspond to the projected demand of the year 2010, 2020 and 2030 as summarized in

3.35. Table 7. The amount of available wind energy shown is based on the historical wind data for the year 2005.

Table 7: Summary of generation development scenarios – Reference scenario

Scenario/ Year	Scenario variant	North Island		South Island		New Zealand	
		MW	TWh	MW	TWh	MW	TWh
2010	Demand	4,842	29.0	2,455	17.1	7,290	46.1
	Wind	432	1.7	202	0.6	634	2.1
	Wind load factor (%)		43.8%		35.9%		41.3%
	Wind (energy) penetration (%)		5.9%		3.5%		4.5%
	Hydro (Average conditions)	1,873	6.9	3,557	17.9	5,430	24.8
	Thermal + auxiliary generation (Initial estimate)	3,650		37		3,687	
2020	Demand	5,600	33.7	2,850	19.9	8,450	53.6
	Wind	1,434	4.9	631	1.8	2,065	6.7
	Wind load factor (%)		39.2%		33.1%		37.3%
	Wind (energy) penetration (%)		15.5%		9.0%		12.5%
	Hydro (Average conditions)	1,873	6.9	3,557	17.9	5,430	24.8
	Thermal + auxiliary generation (Initial estimate)	3,850		37		3,887	
2030	Demand	6,273	38.0	3,197	22.4	9,461	60.5
	Wind	2,225	7.4	1,196	3.3	3,411	10.7
	Wind load factor (%)		38.5%		32.2%		36.3%
	Wind (energy) penetration (%)		19.5%		14.7%		17.7%
	Hydro (Average conditions)	1,873	6.9	3,557	17.9	5,430	24.8
	Thermal + auxiliary generation (Initial estimate)	4,150		37		4,187	

Capacity Adequacy

3.36. The capacity adequacy assessment model seeks to firstly maximise the use of zero marginal hydro and wind energy, and secondly minimise the thermal capacity requirement, while meeting demand with the required reliability level. For illustration a one week dispatch for both islands, resulting from a one year capacity optimisation process is depicted in Figure 2. This shows that the hydro generation tends to flatten the output of thermal generation, therefore minimising the thermal capacity requirements of the system.

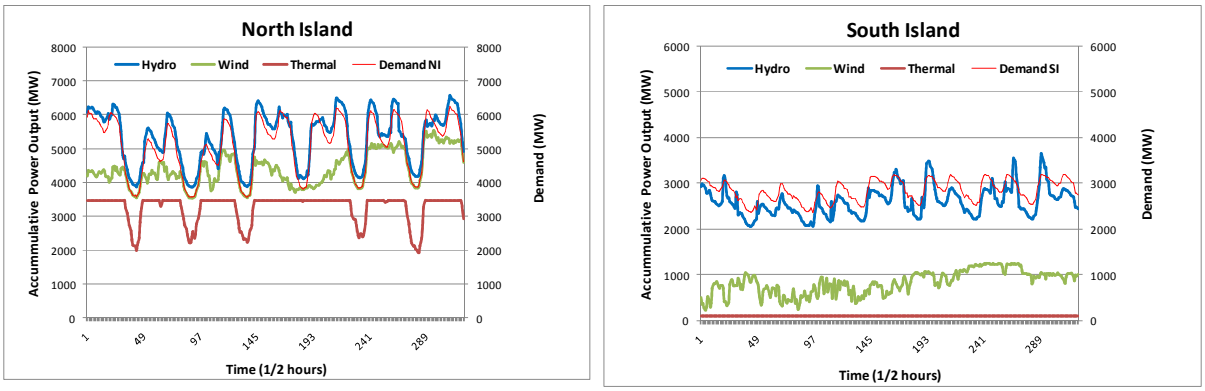

Figure 2: Illustrative one week dispatch – year 2030 scenario

3.37. Having determined the half-hourly optimal dispatch of each type of generation plant in the system, we then compute the risk of losing load during each half hour expressed in LOLP[9]. This is dependent on the average behaviour of both the generators and the interconnector in the system. An example of the 2020 distribution of LOLP in New Zealand is shown in Figure 3. This is based on the actual demand for the year 2006-2007 extrapolated for the year 2030. It is seen that the LOLP is higher during the New Zealand winter which is the peak demand period.

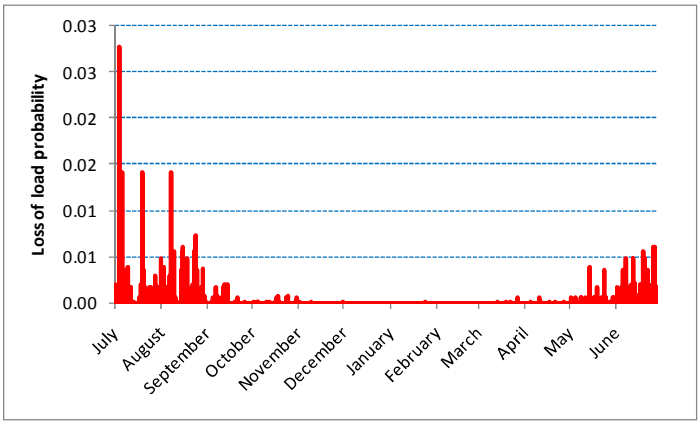

Figure 3: Yearly distribution of loss of load probability

3.38. The above LOLP values for each half hour of the year are added to determine the annual LOLE (hours/year). For each scenario, thermal capacity is added or removed to the initial capacity estimates given in table 1 such that a LOLE of 8 hours/year is obtained. Thus the final capacity levels corresponding to the LOLE standard provide the adequate capacity requirement in each scenario. This means that generation capacity in each scenario is despatched to meet the target LOLE of 8 hours.

3.39. The capacity adequacy requirement for each wind scenario is shown in Figure 4. These are based on an existing interconnector level of 520 MW between the

[9] LOLP represents the probability that load will exceed available generation in the system resulting in a loss of load situation.

North and the South Islands and dry hydro conditions. The sensitivity of generation adequacy to power transfer capability of the interconnector and other hydro conditions is elaborated in later subsections. It can be observed that with the increase in wind penetration (4.5% in 2010 to 18% in 2030) the magnitude of capacity that is required above the peak demand increases significantly. This is due to the relatively limited contribution of wind generation to system reliability.

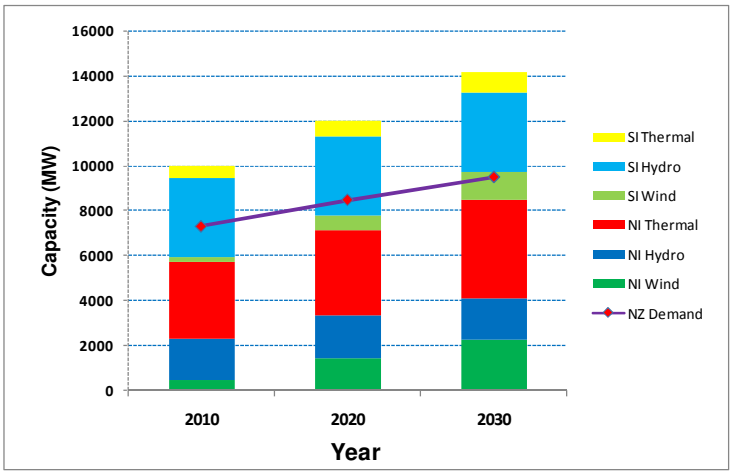

Figure 4: Adequate capacity requirements (Interconnector 520 MW)

Capacity Value of Wind

3.40. In order to determine the capacity value of wind in New Zealand's hydro dominated electricity system, the overall generation capacity for the future demand projections in each scenario are first determined. These generation capacity requirements are determined for two cases i.e., with wind (wind-hydro-thermal) and without wind (hydro-thermal) in each scenario. The difference in the thermal capacity between the two cases, expressed as a percentage of the wind capacity, provides the capacity credit of wind as given in Figure 5 as 'capacity credit with hydro'.

3.41. In order to see the role that hydro power has in firming up wind output, the capacity credit of wind is also assessed without the presence of hydro in the system. For each scenario again two cases i.e., with wind (wind-thermal) and without wind (only thermal) are analysed. The adequate overall capacities in both cases are computed. Their difference provides the capacity credit of wind as shown in figure 5 as 'capacity credit without hydro'.

3.42. The difference in the capacity credit of wind between with- and without hydro systems provides the additional contribution of hydro to increase the capacity value of wind in wind-hydro-thermal systems.

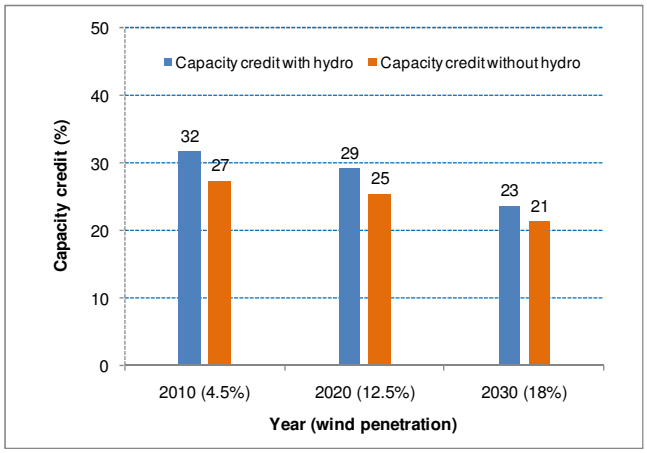

Figure 5: Capacity credit of wind generation

3.43. The results demonstrate that hydro generation in the New Zealand system considerably enhances the capacity value of wind. However, the marginal contribution of hydro generation to the capacity credit of wind declines with the increasing penetration of wind in the system. This is because, for a given level of hydro plant in the system, this plant will be able to mitigate the wind variability up to a certain extent. If wind variability exceeds the mitigation limits of the hydro reserve available in the system then thermal plant will be required to provide capacity reserve to maintain system reliability. Also, during rainy seasons, the hydro capacity reserve may also be limited due to the presence of a large run-of-river component of hydro plant in the system.

3.44. Another benefit of hydro is also found in avoiding wind curtailment during periods of high wind output coinciding with low demand and high run-of-river hydro yield. During such conditions dispatch from hydro reservoirs can be reduced and hydro energy stored in the hydro storage reservoirs (significant in size) present in both islands. In thermal based systems with limited flexibility such conditions lead to considerable curtailment of wind energy, in particular at higher penetration levels[10].

3.45. A snapshot of an optimal wind-hydro-thermal dispatch for a week is shown in Figure 6. It can be observed that during periods of relatively high wind power output (day 3 and 5), hydro output is reduced to conserve hydro energy for use during periods of low wind output which coincide with high demand periods (day 2 and 7). It can also be observed that during periods when high wind power output coincides with low demand conditions (start of the day 3 and 5), the power output from thermal generators is also reduced.

[10] ILEX Energy and Strbac, G., Quantifying the system costs of additional renewables 2020, 2002

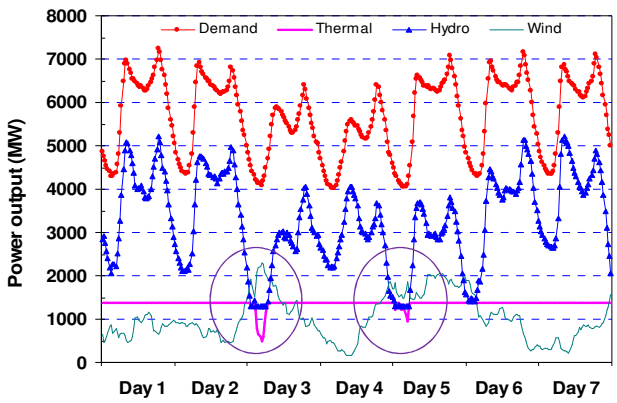

Figure 6: Optimal output of wind, hydro and thermal generation (one week period)

3.46. Capacity adequacy evaluation methodologies conventionally tend to ignore wind forecasting errors in wind output. However, in the New Zealand context, it is considered necessary to take into account the impact of wind forecasting errors on the capacity value of wind. This is due to New Zealand's power system's energy limitations being dominated by hydro generation production.

3.47. Capacity credit, including the effect of wind forecasting errors, is based on a conservative approach. Capacity reserve in the system is maintained at levels that would accommodate 99% of the wind forecasting errors across a four hour time horizon. During each time-slot (1/2-hour) of simulation, ten discrete levels of wind forecasting errors are considered around the concurrent wind output level (available from data). These error levels range between plus (rise) and minus (drop) three standard deviations of wind forecasting errors in 4 hours time. The corresponding probability of each level of error is determined from the statistical behaviour of wind output. The results are shown in Figure 7.

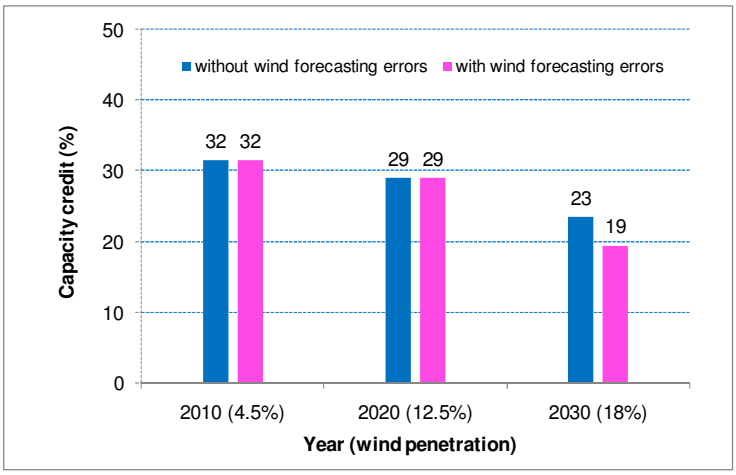

Figure 7: Capacity credit of wind - with and without wind forecasting errors

3.48. It can be observed that at up to medium levels of wind penetration (i.e., 12% by 2020) the impact of a wind forecasting errors on its capacity value is negligible. However, at a high penetration (i.e., 18% by 2030) the capacity credit of wind drops by 4 percentage points due to the large forecasting errors involved.

3.49. The decrease in the capacity credit of wind due to wind forecasting errors discussed above is attributed to the additional capacity reserve requirement. This will be required during windy days due to the large expected variations in wind output. This is contrary to thermal based systems where wind drives higher capacity margins (resulting in low capacity credit) mainly to manage the no/low wind days during peak demand periods.

Additional Capacity Costs Attributed to Wind Power

3.50. The system capacity costs attributed to wind generation are computed for each wind development scenario as given in Figure 8. These costs are expressed in comparison to a thermal plant that will substitute the same amount of energy as wind while operating as a base load plant. For each penetration level of wind the additional costs are expressed as a range. The lower limit of the range corresponds to an investment cost of 100 $/kW/yr, while the upper value corresponds to a higher investment cost of 150 $/kW/yr for base load thermal plant.

3.51. It is noted that at wind penetrations of 4.5% to 12.5% the additional capacity costs attributed to wind are considerably lower. These increase sharply with a further increase in wind penetration to 18%. This is mainly due to a significant drop in the capacity credit of wind at higher penetrations.

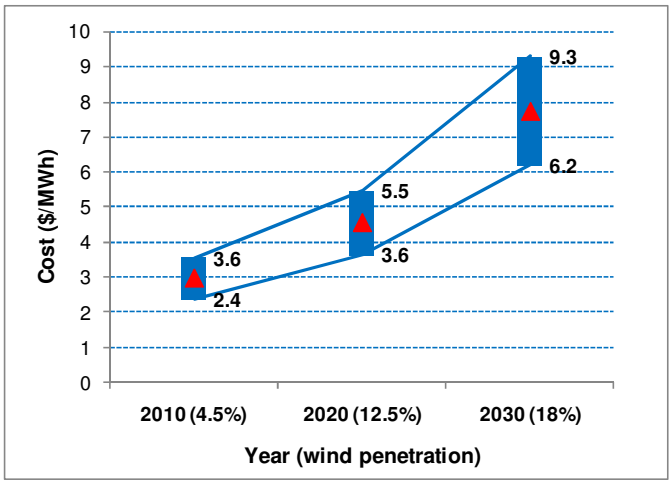

Figure 8 Ranges of additional capacity cost of wind generation

3.52. Similar cost estimates for other countries reveal significantly higher levels. For example, in Great Britain the relevant cost estimates[11] range between 7.5 $/MWh (3 £/MWh) to 12.5 $/MWh (5 £/MWh) corresponding to 5% and 20% wind penetration respectively.

[11] The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network, UK Energy Research Centre (UKERC), 2006

Impact of Key Factors

Impact of Power Transfer Capability of the NI-SI Interconnector

3.53. The North to-South Island interconnector is an integral part of the electricity system in New Zealand. Therefore, it is considered necessary to analyse the impact of the power transfer capability of this interconnector on maintaining adequate generation capacity requirements. First the impact of interconnector level on the risk of supply is evaluated both in terms of LOLE and EENS in the system. An example of 2030 scenario is depicted in Figure 9 below.

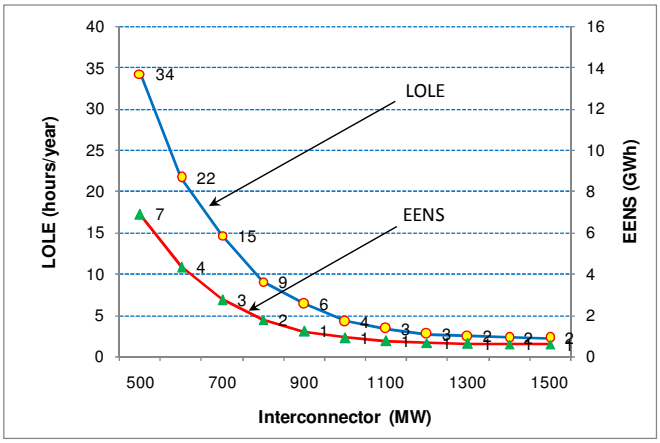

Figure 9. Impact of interconnector on system reliability

3.54. The increase in the power transfer capability of the interconnector clearly reduces the system risk. This is mainly due to enhanced sharing of the capacity reserve between the two islands through the interconnector. The marginal reduction in the risk gradually decreases till it saturates at a certain threshold (about 1100MW in this case, Figure 9). This is because for a fixed generation capacity in the system, both Islands can only share the reserve capacity equal to their individually available reserve. Therefore, when both exhaust their individually available reserve no further gain of interconnector growth can be seen.

3.55. Each future wind development scenario is analysed for three different power transfer capability levels of the interconnector i.e., 520 MW, 1000 MW and 1500 MW. The North-South flow in each case is limited to a maximum of 2/3rd of the total power transfer capability of the interconnector, while for South-North flow no flow constraints are applied. The adequate capacity requirements in each Island corresponding to the three analysed levels of the interconnector are presented in Figure 10, where all the cases meet the reliability standard of LOLE $\leq$8 hours/year.

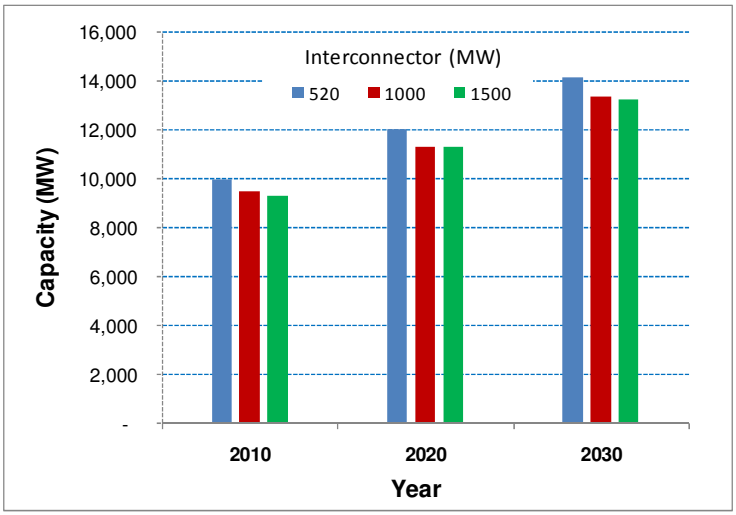

Figure 10: Impact of interconnector on generation capacity requirements in each scenario

3.56. As mentioned previously, the increase in the power transfer capability of the interconnector clearly reduced the overall system risk. This is directly related to the ability of the interconnector to enable each Island to access generation capacity in the other Island in order to maintain security of supply. Therefore, at increased interconnector levels, overall generation capacity can be reduced to bring the LOLE to desired levels.

3.57. Table 8 provides the regional allocation of the different capacity types in the two islands for all the analysed interconnector levels. It shows that both islands benefit from thermal generation capacity savings with the increase in the power transfer capability of the interconnector. The incremental capacity savings tend to reduce with the increase in the interconnector level.

Table 8. Impact of interconnector on adequate capacity requirements (MW)

Scenario/Year		2010			2020			2030		
Interconnector (MW)		520	1000	1500	520	1000	1500	520	1000	1500
North Island	Wind	432			1,434			2,215		
	Hydro	1873			1,873			1,873		
	Thermal	3,400	3,200	3,200	3,800	3,400	3,400	4,400	3,800	4,000
	Total Capacity	5,705	5,505	5,505	7,107	6,707	6,707	8,488	7,888	8,088
South Island	Wind	202			631			1196		
	Hydro	3,557			3,557			3557		
	Thermal	500	200	0	700	400	400	900	700	400
	Total Capacity	4,259	3,959	3,759	4,888	4,588	4,588	5,653	5,453	5,153
New Zealand	Wind	634			2,065			3,411		
	Hydro	5,430			5,430			5,430		
	Thermal	3,900	3,400	3,200	4,500	3,800	3,800	5,300	4,500	4,400
	Total Capacity	9,964	9,464	9,264	11,995	11,295	11,295	14,141	13,341	13,241
Capacity Margin (%)		36.6	29.7	27.0	41.7	33.4	33.4	49.2	40.8	39.7

3.58. A consistent trend of overall capacity savings exists with growth in the power transfer capability of the interconnector between the two Islands. However, it is found that a major impact is observed in the high wind scenario (18% wind in 2030). In this scenario the overall system benefits by 800 MW (equivalent to 8% capacity margin gain) by a simple increase of 500 MW in the interconnector level. This is strongly linked to the enhanced sharing of capacity reserve. In particular hydro in the south complements wind in the North Island.

3.59. System reliability and the resultant capacity adequacy assessments are conventionally carried out to cover conceivable extremities in operating conditions. Due to the dominance of hydro power in New Zealand, the capacity adequacy evaluations presented in figure 5 and table 2 are carried out while applying dry hydro conditions. This is considered necessary for long-term reliability assessments including intra year availability of hydro energy in the system. However, sensitivity studies for other hydro conditions are also performed and explained in the next section.

Impact of Different (Dry, Average, Wet) Hydro Conditions

3.60. The variation of hydro conditions can have a profound effect on the availability of annual hydro energy in the system. The historical data indicates that different hydro conditions can lead to about +/- 25% variation in available annual hydro energy. Therefore, several sensitivity studies are conducted in order to quantify the effect of dry, average and wet hydro conditions on generation capacity adequacy. Additionally these sensitivity studies have been conducted for different power transfer capability of the NI-SI interconnector in each scenario. The required capacity margins necessary to maintain system reliability are shown in Table 9.

Table 9: Required capacity margins under different hydro conditions and interconnector levels

	Interconnector (MW)								
	520			**1000**			**1500**		
Hydro condition	**Dry**	**Avg.**	**Wet**	**Dry**	**Avg.**	**Wet**	**Dry**	**Avg.**	**Wet**
Scenario/Year	Capacity margin (%)								
2010	36.6	31.1	29.7	29.7	27.0	24.2	27.0	27.0	24.2
2020	41.7	39.3	37.0	33.4	33.4	28.7	33.4	33.4	26.3
2030	49.2	47.1	45.0	40.8	40.8	37.6	39.7	39.7	37.6

3.61. For any given level of power transfer capability on the interconnector it is found that the required capacity margins, necessary to maintain system reliability, decrease with the increase in availability of hydro energy. On the other hand, for each hydro condition the increase in the interconnector level saves the capacity margin.

3.62. The benefit of the increase in the available hydro energy gradually reduces with the rise in wind penetration in the system. For example, in the 2010 scenario (4.5% wind) and 1000 MW interconnector case, the capacity margin reduction due to wet hydro conditions compared to dry conditions is: 29.7% – 24.2% = 5.5%. However, the results for the 2030 scenario with 18% wind penetration are: 40.8% – 37.6% = 3.2% percentage points. As the installed hydro capacity in these scenarios is almost the same, the ability to mitigate the larger variability of wind at higher wind penetrations will be limited.

Impact of Spatial Distribution of Wind Resource

3.63. Another scenario has been created to study the effect of different regional distributions of wind generation in New Zealand on capacity adequacy and the capacity credit of wind generation. This has been named the '*Southland scenario'*. A key feature of this scenario is a relatively more balanced distribution of wind capacity between the two Islands. However, in this scenario wind capacity is more concentrated in the southland region of the South Island. Details of this scenario are provided in the scenario section of this report and a brief summary is given in Table 10.

Table 10: Summary of 'Southland' wind scenario

Scenario/ Year	Scenario Variants	North Island		South Island		New Zealand	
		MW	TWh	MW	TWh	MW	TWh
2010	Wind generation	425	1.7	463	1.4	888	3.1
	Wind (energy) penetration (%)		5.9		8.2		6.7
2020	Wind generation	875	3.1	1,165	3.1	2,040	6.2
	Wind (energy) penetration (%)		9.2		15.6		11.6
2030	Wind generation	1,695	5.9	1,706	5.2	3,401	11.1
	Wind (energy) penetration (%)		15.5		23.2		18.4

3.64. All variants except wind generation in the Southland scenario are assumed to be the same as given in the earlier scenario, referred to here as the *'Reference scenario'* (summarised earlier in table 2).

Applying the system adequacy assessment model with the same reliability targets of LOLE $\leq$ 8 hours/year, the required generation capacity to satisfy demand corresponding to the three time horizons is evaluated as given in

3.65. Table 11. It should be noted that this capacity adequacy assessment is also based on dry hydro conditions.

Table 11: Capacity (MW) requirements in 'Southland' wind scenario

Scenario/Year		2010			2020			2030		
Interconnector (MW)		520	1000	1500	520	1000	1500	520	1000	1500
North Island	Demand	4,840			5,600			6,275		
	Wind	425			875			1,695		
	Hydro	1,873			1,873			1,873		
	Thermal	3,200	3,200	3,200	4,000	3,600	3,800	4,600	4,000	4,200
	Total	5,498	5,498	5,498	6,748	6,348	6,548	8,168	7,568	7,768
South Island	Demand	2,455			2,865			3,200		
	Wind	463			1,165			1,706		
	Hydro	3,557			3,557			3,557		
	Thermal	400	100	0	600	400	100	800	500	200
	Total	4,420	4,120	4,020	5,322	5,122	4,822	6,063	5,763	5,463
New Zealand	Demand	7,295			8,465			9,475		
	Wind	888			2,040			3,401		
	Hydro	5,430			5,430			5,430		
	Thermal	3,600	3,300	3,200	4,600	4,000	3,900	5,400	4,500	4,400
	Total	9,918	9,618	9,518	12,070	11,470	11,370	14,231	13,331	13,231
Capacity Margin (%)		36.0	31.8	30.5	42.6	35.5	34.3	50.2	40.7	39.6

3.66. The results indicate that the overall capacity requirements in the Southland scenario are slightly higher compared to the reference scenario. This is primarily due to the low average load factor of the wind farms compared to the reference scenario.

3.67. It is interesting to note that the role of interconnector remains the same as for the reference scenario with the predominant impact in the high wind penetration (2030) scenario. Interconnector growth to 1000 MW above the existing level of 520 MW in 2030 scenario saves about 9% capacity margin.

3.68. The requirement of adequate generation capacity under the three hydro conditions is also investigated for the Southland scenario. The required capacity margins relevant to each are given in Table 12.

Table 12: Impact of hydro conditions on adequate capacity requirement – Southland scenario

	520			1000			1500		
Hydro Condition	Dry	Avg.	Wet	Dry	Avg.	Wet	Dry	Avg.	Wet
Year (wind penetration)									
2010 (7%)	36.0	31.8	30.5	31.8	30.5	30.5	30.5	30.5	30.5
2020 (12%)	42.6	40.2	37.9	35.5	34.3	33.1	34.3	35.5	33.1
2030 (18%)	50.2	48.1	46.0	40.7	39.6	38.6	39.6	39.6	39.6

3.69. At all wind penetrations, the higher availability of water in average and wet conditions compared to a dry hydrology scenario reduces the amount of adequate generation capacity while providing the same reliability of LOLE $\leq$8 hours/year.

3.70. The potential benefit of interconnector growth varies slightly for the three hydro conditions. The capacity margin benefits are higher under dry conditions, primarily due to larger sharing of thermal capacity reserve of the North to help the hydro power dominated South Island. However, the marginal contribution to capacity savings diminishes with the enhancement in the power transfer capability of the interconnector beyond 1000MW.

3.71. The capacity credit of wind determined for the Southland Scenario at various penetration levels of wind is presented in Figure 11. The capacity credit of wind for the 2010 case is higher than the corresponding year in the reference scenario. This is because more wind is placed in the hydro dominated South Island, where hydro can easily absorb the variability of the relatively small wind penetration in this year.

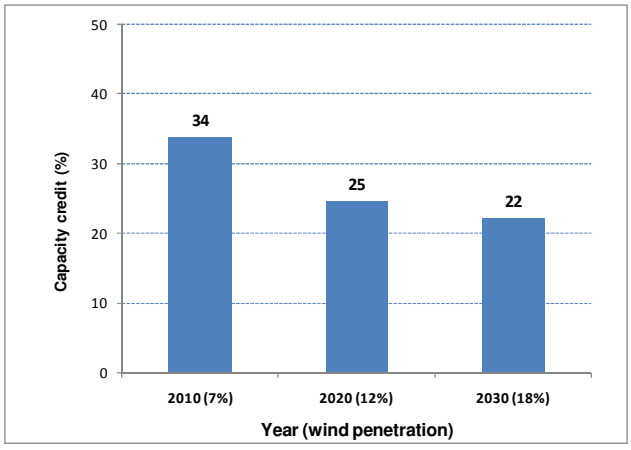

Figure 11. Capacity credit of wind in the Southland scenario

3.72. Also the concentration of wind farms in the South Island leads to a loss of diversity of wind resource. This has attributed to a loss of some capacity value of wind in this scenario at higher penetrations. The capacity credit of wind in 2020 is lower by about four percentage points compared to the reference scenario. One of the factors here is the relatively low average load factor (about 3% low) of wind farms that are included in South Island scenario.

3.73. The additional system capacity costs, as shown in Figure 12, for the Southland scenario are lower for the years 2010 and 2020 in comparison to the reference scenario. The lower capacity costs in 2010 are attributed to the high capacity credit of wind in this scenario. Also, in the 2020 scenario the costs are lower although the capacity credit in this case is low in the southland scenario. This is due to the low load factor of wind which results in a smaller disproportion between the displaced capacity and displaced energy by wind. No significant difference between the Southland and Reference scenario is found for the year 2030.

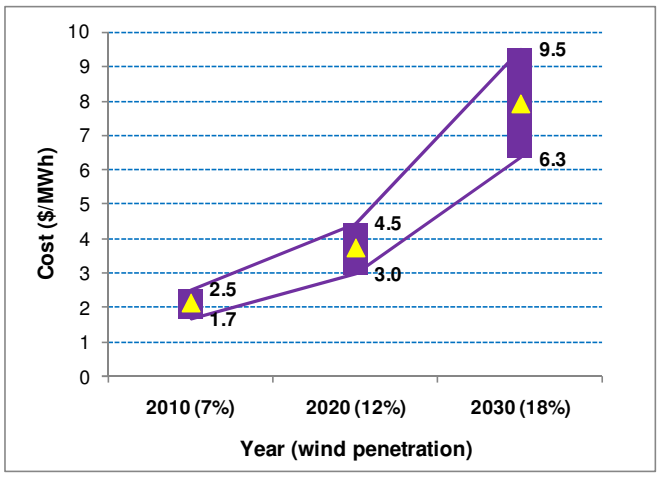

Figure 12. Additional capacity cost due to wind - Southland scenario

Conclusions

3.74. A new model for analysing the capacity adequacy in wind-hydro-thermal systems is applied. The model evaluates the level of adequate generation capacity in the system based on a reliability criterion of LOLE ≤8 hours/year.

3.75. Three main wind development scenarios termed here as 'Reference scenarios' that correspond to 2010, 2020, and 2030 demand projections are investigated. Greater levels of wind penetration result in higher capacity margins to maintain system reliability, rising with each increase in wind penetration. For an existing level of interconnector (DC link) between the two Islands (i.e. 520 MW) the required capacity margins range from 37% in 2010 to about 49% in 2030, corresponding to 5% and 18% wind penetrations respectively.

3.76. The power transfer capability of the interconnector directly influences system reliability. Therefore, significant overall generation capacity savings in both islands are observed due to the possible expansion of the interconnector. In general, the generation capacity benefits due to interconnector growth are higher at a high wind penetration. For example, the high wind scenario (18% wind penetration in 2030). In this scenario the system benefits by an 800 MW thermal capacity saving (equivalent to a 8% capacity margin gain) by the increase in the interconnector level from 500 MW to 1000 MW. This is strongly linked to the enhanced sharing of capacity reserve, mainly hydro in the south complementing large wind in the North Island.

3.77. Sensitivity studies over a range of hydro conditions (dry/average/wet) that influence the availability of annual hydro energy have been conducted. For any given level of the interconnector it is found that the required capacity margins, necessary to maintain system reliability, decrease with the increase in the availability of hydro energy. The benefit of the increase in the available hydro energy gradually reduces with the rise in wind penetration in the system. For example, in the 2010 (4.5% wind) scenario and 1000 MW interconnector case, the capacity margin reduction due to wet hydro conditions compared to dry

conditions is: 29.7% – 24.2% = 5.5%. However, the same for the 2030 (18% wind) scenario is: 40.8% – 37.6% = 3.2%.

3.78. The capacity credit of wind in the hydro dominated electricity system of New Zealand is found to range between 32% and 19% for wind penetration of 5% and 18% respectively. The results demonstrate that hydro generation in the New Zealand system will considerably enhance the capacity value of wind. The additional gain in capacity credit of wind due to hydro can be up to 5 percentage points. However, the marginal contribution of hydro generation to the capacity credit of wind declines with increasing penetration of wind in the system. These capacity credits of wind are higher compared to thermal generation based systems.

3.79. The high load factor of New Zealand wind also contributes to higher capacity and energy contributions for any given level of wind penetration. Also, the capacity value of wind is affected by its large variations in relatively small time periods that need increased amounts of capacity reserves. This reduces its capacity credit at higher penetration levels. On the other hand the presence of large hydro storage capacity in New Zealand helps to avoid wind curtailment during periods of high wind output coinciding with low demand and/or high run-of-river hydro yield periods.

3.80. Due to the relatively high capacity credit of wind generation in New Zealand the disproportion between the amount of capacity and energy displaced by wind power is relatively small. Therefore, the additional capacity costs attributed to wind generation in New Zealand are lower than in thermal based systems. Additional capacity costs attributed to wind generation for the analysed scenarios: range between 2.4 $/MWh and 9.3 $/MWh of wind energy produced. The higher costs in the 2030 scenario are primarily driven by larger capacity reserve requirements to accommodate larger wind forecasting errors.

3.81. A different set of wind development scenarios in terms of spatial distribution of wind capacity in New Zealand have also been analysed. In theses scenarios capacity margin requirements are higher compared to the Reference scenarios by a small margin. Of note, the role of interconnector remains the same in the Southland scenario as for the reference scenario, with a predominant impact at high wind penetration. Interconnector growth to 1000 MW above the existing level of 520 MW in 2030, saves about 9% capacity margin.

3.82. In the Southland scenario at a low wind penetration of 7% in 2010, the capacity credit of wind is higher than the corresponding reference scenario, while at high penetration the capacity credits are relatively low. Therefore, capacity costs attributed to wind in the southland scenario are lower in the low penetration case while at other penetrations (12% and 18%) the costs are nearly the same as in the reference scenario.

4. MAGNITUDE AND COST OF ADDITIONAL OPERATING RESERVE REQUIREMENTS

BACKGROUND

4.1. One important aspect of system security is its ability to balance demand and supply over different time horizons. Operating reserves are provided by flexible generation in the system so that supply and demand can be continuously balanced. The need for operating reserves is driven by a number of factors, including:

- unplanned outages of generating plant or major elements of transmission or distribution networks;
- forecasting error in wind power output;
- unpredicted changes in consumer demand levels due to changes in weather conditions and other events; and
- imperfections in the dispatch process that result in an imbalance between supply and demand.

4.2. As the installed capacity of wind power generation on the New Zealand electricity network increases, the uncertainties in wind power output start to have considerable effect on the amount of reserves needed. One of the key challenges associated with wind integration is to quantify the amount of additional operating reserves needed and their cost effective provision in order to capture most of the variation in wind power output to maintain system frequency and system security.

4.3. Additional reserves will be provided by an increased number of part loaded thermal generators and more interruptible loads as well as hydro plant. Thermal units operate less efficiently when part-loaded, with an efficiency loss between 10% and 20%. Losses in efficiency could be higher, particularly for new gas plant. Since some of generating units will be part-loaded to provide the balancing service, other units will need to be brought in to supply energy that was originally allocated to flexible plant. This usually means that plant with higher marginal cost will need to run. This leads to higher system operating costs. However, the magnitude of increased system operating costs caused by increased operating reserves driven by wind power in the New Zealand system needs to be comprehended.

4.4. In addition to the capacity issues discussed in section 3, the New Zealand system should have adequate flexible generators which can provide various types of operating reserves. Hydro plant is considered as the most flexible plant and currently is the primary source of operating reserves. Considering small expansion of hydro plant in New Zealand over the next couple of decades, there is a question whether the system would have adequate flexibility in the future to accommodate significant volume of wind generation.

Objectives

4.5. In order to address the issues described in 4.1 - 4.4, the work presented in this section focuses on the following key objectives:

- determine the magnitude of additional operating reserves needed to deal with wind power variability and unpredictability;
- quantify the increase of system operating costs due to increased reserve requirement;
- analyse the impact of hydrology conditions, wind penetration level, and the power transfer capability of the North and South Islands interconnector on the increased system operating costs; and
- assess the adequacy of New Zealand's future generation to provide the required system reserve and flexibility.

Scope

4.6. Studies have been carried out on the three future generation scenarios described in section 2. Sensitivity analysis has been carried out for three hydrology conditions (wet, average and dry), various power transfer capabilities of the interconnector and two different wind profiles (based on years 2005 and 2006 using wind speeds at various sites across New Zealand).

4.7. The impact of increased wind penetration levels on operating reserves is investigated for three types of reserves. These are: instantaneous reserve, frequency keeping reserve and standing reserve.

Instantaneous Reserve

4.8. Instantaneous reserve in New Zealand is provided to manage the risk of the loss of infeed from the largest single plant (a contingent event). Two categories of instantaneous reserve are procured by the system operator. These are fast instantaneous reserve (FIR), this is available within 6 sec and sustained for a minute, and sustained instantaneous reserve (SIR), available within 60 sec and sustained for 15 minutes. The objective of FIR is to arrest the system frequency decline after a contingent event. The objective of SIR is to then restore the frequency to within the normal band of 50 (+/- 0.2) Hz.

4.9. Presently in the North Island the largest generator outage is typically around 380 MW (one CCGT unit) and is met from a combination of Huntly generation, hydro generation (mainly the Waikato chain) and demand-side interruptible load.

4.10. In the South Island the risk is typically between 60-120MW (one Manapouri unit) and is met from hydro generation.

4.11. An outage at the HVDC link will become the largest loss of infeed if the instantaneous flow is greater than the largest generation unit in the importing

area. However, considering the high reliability of the HVDC link, the risk becomes relatively small and was excluded from the reserve studies.

Frequency Keeping Reserve

4.12. The system operator has a principal performance objective to manage the frequency in the North and South Islands within the normal band of 50 +/- 0.2 Hz. In order to meet this objective, the system operator procures frequency keeping quantities of +/- 50 MW (i.e. a 100 MW range) from nominated frequency keeping stations in each island. The Huntly coal station or Waikato hydro stations typically provide this service in the North Island and hydro stations provide this service in the South Island.

Standing Reserve

4.13. In addition to spinning reserve, which is provided by part-loaded synchronised plant, the balancing task can be supported by so called standing reserve, which is supplied by higher fuel cost plant, such as OCGTs or energy storage facilities.

4.14. The application of standing reserve can improve system performance through the reduction of the fuel cost associated with system balancing. This reduction in the amount of committed synchronised reserve leads to (i) an increase in the efficiency of system operation and (ii) an increase in the ability of the system to absorb wind power, and hence reduce the amount of fuel used.

4.15. The allocation of reserve between synchronised and standing plant is a trade-off between the cost of efficiency losses of part-loaded synchronised plant (plant with relatively low marginal cost) and the cost of running standing plant with relatively high marginal cost. The balance between synchronised and standing reserve can be optimised to achieve a minimum overall reserve cost of system management.

4.16. To balance load and generation synchronised and standing reserve serve the following roles:

- Synchronised reserve is used to accommodate relatively frequent but comparatively small imbalances between generation and demand.
- Standing reserve is used for absorbing less frequent but relatively large imbalances.

MODELLING

Wind Modelling

4.17. The wind farm outputs used in this analysis are based on normalised half-hourly annual profiles. The output profiles are based on single point wind speed data which is then converted into expected generation profiles from proposed wind

farms. The conversion process is completed using the 'Windfarmer' modelling package.

4.18. The outputs of wind farms at various locations in the respective islands have been aggregated in order to obtain half-hourly annual wind output profiles for the North and South Islands.

4.19. Wind generation is dispatched as base load plant as it has a zero marginal cost of production. All wind power is assumed to be fully utilised unless plant or system constraints lead to the curtailment of some wind energy. As an example, wind curtailment may happen during periods where there is a combination of low demand, high wind power output, wet hydro conditions and must-run thermal plant e.g. CCGT.

Modelling of Geothermal, Landfill, Co-Generation and Thermal Plants

4.20. All geothermal, landfill, and co-generation power stations are assumed to follow fixed seasonal base load profiles over the course of the year and typically run as base load plant. The marginal cost of production for geothermal, landfill and co-generation power stations is assumed to be zero. Their aggregated maximum weekly electricity production profiles for the years 2010, 2020 and 2030 are based upon historical patterns as shown in Figure 13.

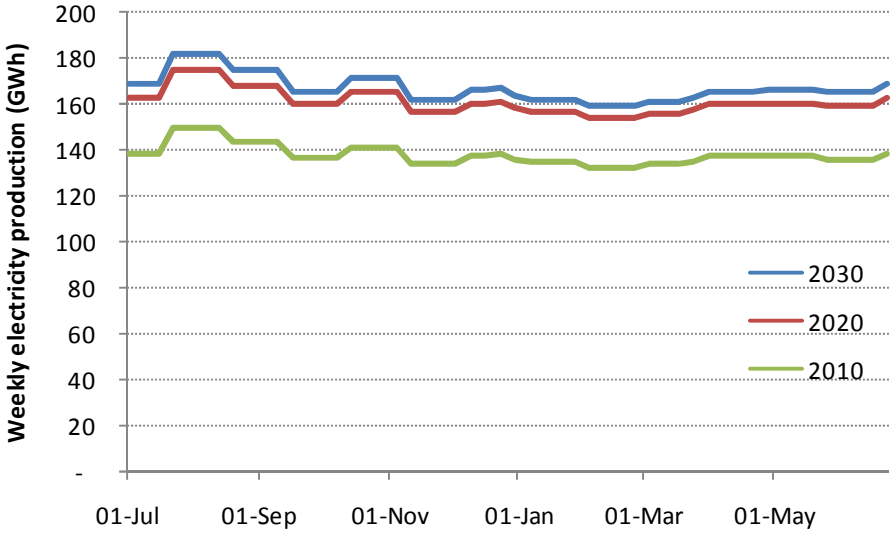

Figure 13. Aggregated geothermal, landfill, and cogeneration maximum weekly output profile for the 2010, 2020 and 2030 scenarios.

4.21. CCGT gas-fired stations are typically dispatched ahead of the Huntly coal power station, largely due to inflexibility in gas deliverability and gas contracts. Distillate and oil fired plants have high marginal costs and are mainly operated as reserve plant. Therefore they operate under extreme hydrological conditions or extreme peak load circumstances. These operational strategies are applied for all scenarios.

4.22. We assume that all generating units are available for scheduling by the system operator to balance supply and demand, to provide reserves and to control network flows.

4.23. Generators are modelled to operate within their specified operating constraints. These include maximum output (rating), minimum stable operating levels, ramp up and ramp down rates, minimum up and down time, and the maximum capability to provide instantaneous reserve.

4.24. All conventional thermal generation is assumed to be dispatched efficiently according to the specified operating constraints, marginal costs and system demands for energy and reserve.

Modelling Dispatch of Run-of-River and Storage Type Hydro

4.25. In total there are over 50 major hydro stations across New Zealand. For simplicity, key hydrological characteristics (as of 2006/2007), including expected energy yields for wet, average and dry hydrological conditions, are restricted to major hydro catchment totals as described earlier in section 3.

4.26. The modelling and analysis of hydro generation in New Zealand is challenging due to the combination of storage reservoirs, small catchment areas, highly unpredictable rainfall, short historical records (1931-2006) and complex river operating constraints.

4.27. For each solution 'step' (one week for the operating reserve study) modelling of hydro generation, storage and associated flexibility can be summarised as follows:

Run-of-river: This is assumed to be must-run base load hydro generation constrained in size by daily available energy. No ability to re-dispatch run-of-river generation to meet a demand or reserve profile is included, although the model can constrain off (i.e. 'spill') the run-of-river generation if necessary. Note that over short time frames covering several hours the base load generation assumption is conservative in that most hydro plant in New Zealand, even run-of-river plant, will have some ability to control their level of output.

Reservoir-Release: This is assumed to be fully flexible hydro generation constrained only by the available energy for the week. Hydro inflows can be stored in the reservoir or used to produce electricity. Maximum hydro energy that can be stored in the reservoir is limited according to the reservoir capacity. Within a week, hydro generation in this category can be scheduled to minimise system costs. Typically, generation in this hydro category will be used to 'peak-fill', i.e. to meet peak load requirements first, with residual hydro energy for the week then used to offset other mid-merit thermal generation. As with run-of-river generation, the model could constrain off (i.e. 'spill') reservoir-release generation if necessary.

4.28. Considering New Zealand's hydrological conditions, three states are used to examine the sensitivity of the availability of hydro-generation on the additional reserve costs due to wind integration. The three hydrological scenarios considered for this study are:

1. **Average**: Represents the average of all historically observed hydrological conditions and can be thought of as 'typical' hydro conditions.
2. **Dry**: Represents extremely dry (annual) hydro conditions. This is derived from the historical data, which shows the available hydro energy to be about 13% less than the average year.
3. **Wet**: Represents extremely wet (annual) hydro conditions. This was also based upon historical inflows, and indicates about 14% more available hydro energy than the average year.

Modelling of Demand and Interruptible Load

4.29. Half-hourly annual profiles for demand at both Islands were modelled for each scenario under study. The future demand projections corresponding to the year 2010, 2020 and 2030 are extrapolated as given in the scenario section.

4.30. The interruptible load is modelled to be flexible. It is modelled as a reduction in demand in cases where the reserve provided from other generation sources is exhausted or inefficient (i.e. less economic).

System Reserve Assumptions

4.31. Conservative input assumptions are used in this study to identify the potential upper limits of additional operating reserve quantities and their associated costs. These assumptions include:

- Reserve requirements are computed for each half hour time slot of the overall system simulation.
- The additional reserve requirement to deal with wind variability never exceeds expected wind power output.
- The inter-half hour variations of reserve requirements are assumed to be primarily driven by wind variations across the portfolio of wind generation modelled.
- For daily load cycles, the impact of different loading conditions during day and night periods on the operating reserve requirements is also modelled. This reflects the expected; day (peak) and night (off-peak) loading conditions in each Island.
- All operating spinning reserve quantities for instantaneous reserve and frequency keeping are assumed to be unable to contribute to meeting demand requirements.
- In determining the required level of additional operating reserve we analysed each island (separately), i.e. the reserve requirement in one island does not effect the requirement in the other island. Also no provision of reserve is allowed through the HVDC link.
- The target levels of reserve required is assumed to cover four standard deviations of system variability, i.e. reserve provision covers 99.5% of

all operating conditions. This is consistent with the level of reserve cover planned for in the UK. It is worth noting that existing levels of operating reserve in New Zealand appear to cover approximately 2.5 standard deviations of operating conditions.

- Reserve requirements are assessed at both 30 minutes and 1 hour. This provides an indication of how sensitive the reserve requirements are to the dispatch process minimising the difference between supply and demand balances. Standing reserve is allocated for dealing with the forecasting errors up to 4 hours ahead.
- Operating reserve is assumed to be mainly provided by part loaded plant along with a contribution from demand side (interruptible load) during critical periods, consistent with existing practices.
- Standing reserve is assumed to be provided by off-line thermal plants which can synchronise and produce electricity quickly to maintain balance between supply and demand, for example OCGT plant.
- CCGTs were assumed to operate with minimum load factor of 75% irrespective of hydro and wind conditions.
- Total hydro power output for each hydro catchment, i.e. ROR + reservoir output cannot exceed the aggregated power rating of hydro plants.
- The magnitude of power transfers across HVDC link is constrained by power transfer capability constraint. The maximum of NI to SI is set to 60% of SI to NI power transfer.

METHODOLOGY

Assessment of Magnitude of Operating Reserve Requirements

4.32. This study has applied a technique that statistically assesses the variable behaviour of wind output. The technique uses the frequency distribution of wind variations obtained from the annual profiles over different time resolutions, for each of the scenarios. The impacts on instantaneous reserves and frequency keeping under various levels of wind penetration have been evaluated.

4.33. To determine the magnitude of operating reserve requirements two distinct time horizons were used. A sub-minute to a few minute time horizon was used for Instantaneous Reserves. A several minutes to a few hours time horizon was used for Frequency Keeping. The forecast errors in demand and conventional generation were determined separately from historical data while the wind power variations over corresponding time scales were based upon the standard deviations of wind power variations of annual (prepared) wind generation profiles. Figure 14 represents the range of wind output variations in the two islands for the 2010, 2020 and 2030 scenarios under study.

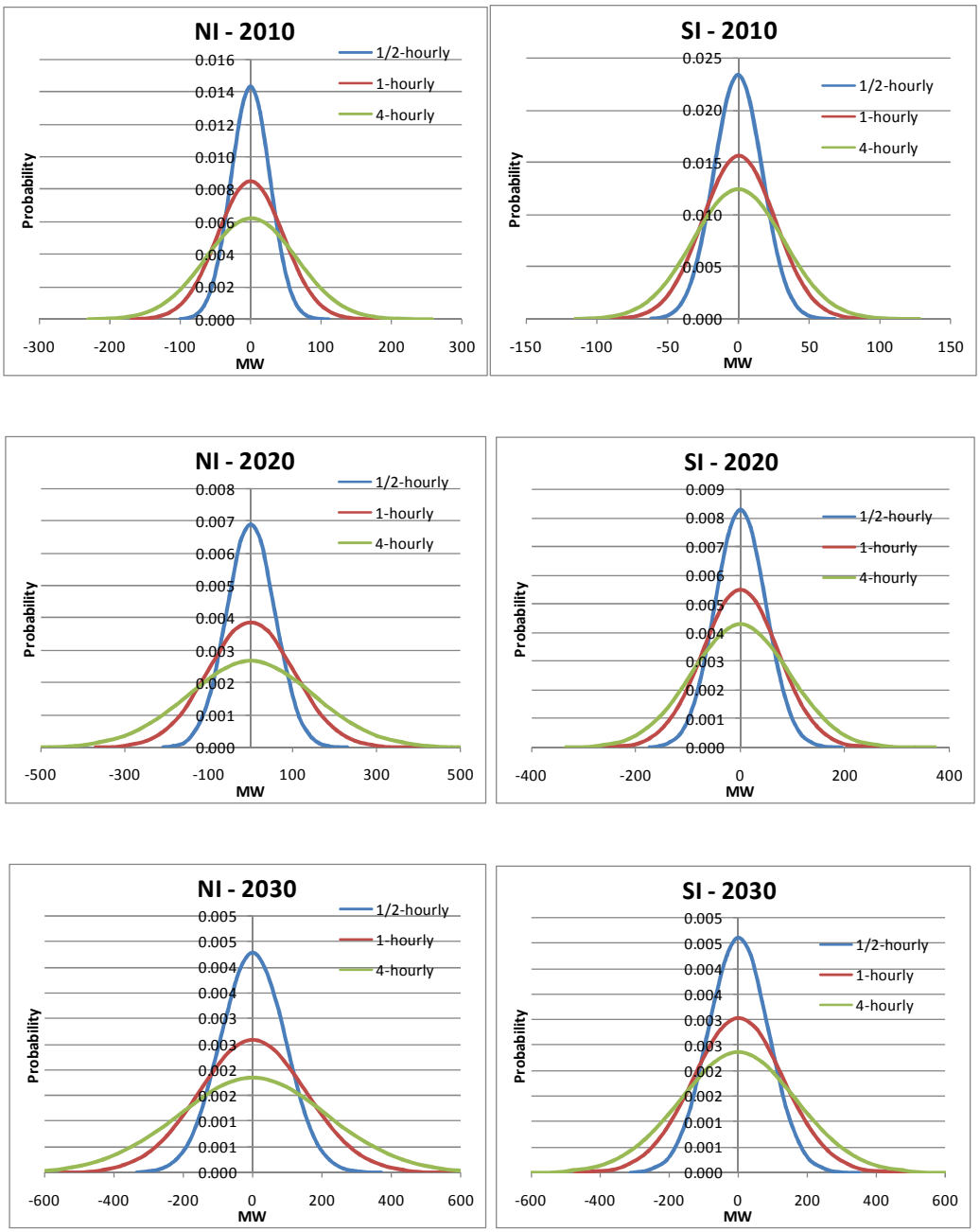

Figure 14. Frequency Distribution of fluctuations in wind power output in all scenarios at North (NI) and South Islands (SI)

4.34. Based upon the wind output variations, the standard deviations of changes in wind power output were computed for the projected wind capacities in all generation scenarios on both Islands as shown in Table 13.

Table 13 Standard deviations of wind variations (MW) – Reference scenario

Year	Variation Period	NI	SI
2010	1/2-hr	28	17
	1-hr	35	21
	4hr	64	32
2020	1/2-hr	58	48
	1-hr	103	72
	4hr	150	93
2030	1/2-hr	93	87
	1-hr	154	131
	4hr	216	169

4.35. The computed standard deviations of changes in wind output for the two characteristic time horizons (in both islands for each scenario), were combined with the standard deviations of the demand forecast errors and changes in conventional-generation to determine the level of the overall uncertainty to be managed. This was calculated following the standard statistical approach of combining the independent (uncorrelated) errors (the mean square error root of the combination of the mean square errors).

4.36. For a distribution that follows a normal trend about 99% of the data will be covered by 3 x standard deviations. However, wind power variations do not exhibit a classical normal distribution. Therefore, a more conservative approach using 4 standard deviations was used which covered more than 99% of the wind forecast errors. Having determined the overall standard deviation (σ_{Total}) of all forecast errors for both reserve categories the level of reserve requirements were calculated using (3x σ_{Total}).

4.37. In the daily load cycles, the impact of different loading conditions during day and night periods on the operating reserve requirements was also considered. For each Island, a further segregation of the non-wind reserve components of both operating reserve types was applied, which reflects Day (peak) and Night (off-peak) loading conditions.

Optimisation of Generation Dispatch

4.38. The optimisation of scheduling generation to meet demand including operating reserve requirements is formulated as a mixed integer linear program. The objective function is to minimise the overall annual generation costs for providing energy and reserve.

4.39. The cost of reserve obtained from generators is not modelled explicitly in the objective function. However, the provision of reserve will increase generation costs since some generators will need to be part loaded and will run at sub-optimal levels leading to lower operating efficiencies. The optimisation recognises the cost of part loading generation through considering the no-load

cost of generation, start-up costs and possible commitment of more expensive generators.

4.40. The cost of reserve purchased from interruptible loads is modelled explicitly in the optimisation problem.

4.41. An increase in wind generation increases the magnitude of operating reserve required, which in turn creates additional system costs. These additional costs of operating reserve provision due to wind in each scenario are assessed by computing the overall production costs with and without the impact of wind generation. The difference of these two is the additional operating reserve required due to wind generation.

4.42. The additional reserve cost evaluation is performed as a cost-based rather then market-based approach (we appreciate that the current market co-optimises energy and reserve). Clearly, cost of reserve will be included in the overall generation costs.

CASE STUDIES AND RESULTS

4.43. Studies are carried out for the developed scenarios to determine the magnitude of additional reserve requirement driven by wind power and to quantify the associated costs. In order to get the typical value of the cost, the average hydro condition is considered. South to North Island interconnector capacity is set to 1 GW for the 2010 scenario and 1.5 GW for the 2020 and 2030 scenarios. The key results are presented in Table 14.

Table 14 Average additional reserves for wind and the associated costs

	2010	*2020*	*2030*
Installed wind power capacity (MW)	634	2,066	3,412
Wind power (GWh)	2,285	6,724	10,797
Additional Instantaneous Reserve (MW)			
- Average	22	73	184
- Maximum	31	157	378
Additional Frequency Keeping (MW)			
- Average	126	296	543
- Maximum	203	404	730
Additional Standing Reserve (MW)			
- Average	17	158	278
- Maximum	46	377	566
Reserve cost ($/MWh of wind)	0.19	0.76	2.42

4.44. The average additional requirement for instantaneous and standing reserves for the low wind penetration (2010 scenario) is relatively small. However, the frequency keeping reserve is significant i.e., 126 MW additional FK reserve are needed.

4.45. During windy days, the additional operating reserves, expressed here as maximum requirements, are much higher. For example, the additional FK reserve can be up to 203 MW. More capacity is needed to provide this reserve. However, an increase in wind power output will enable other generators to be

part loaded and therefore it does not necessarily increase demand for generating capacity.

4.46. The additional reserve costs attributed to wind are found to be relatively modest. However, these costs increase sharply with the growth of wind power. An increase in wind penetration from 4.5% (2010) to 12.5% (2020) results in four fold increase in cost, while moving to 18% (2030) wind penetration the costs increase by about 12 times relative to 2010 costs. The source of these costs will be explained in detail later.

4.47. Figure 15 shows profiles of weekly electricity production from different generation technologies in North and South Island for the 2010 scenario. Week 1 corresponds to the beginning of July and week 52 corresponds to the end of June next year. Demand is at peak during winter and at minimum during summer.

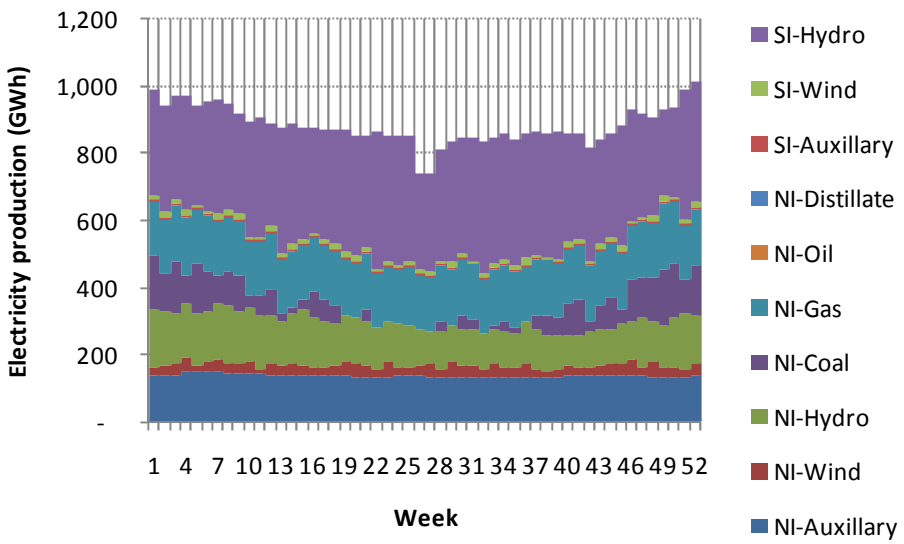

Figure 15. Weekly electricity production (2010 scenario)

4.48. During off peak demand periods, electricity is produced mainly by auxiliary, wind, hydro and gas plant. Contribution from coal and peaking plant during these periods is relatively small and therefore, engaging such generators to provide reserve in these periods will be expensive. However, the cost of reserve from coal and peaking plant will drop during peak demand periods when such plant is also needed to supply energy.

4.49. Results from the scheduling program show that the frequency keeping reserves for the 2010 scenario are mainly provided by Hydro generators. Contribution from gas and coal power plants is relatively small.

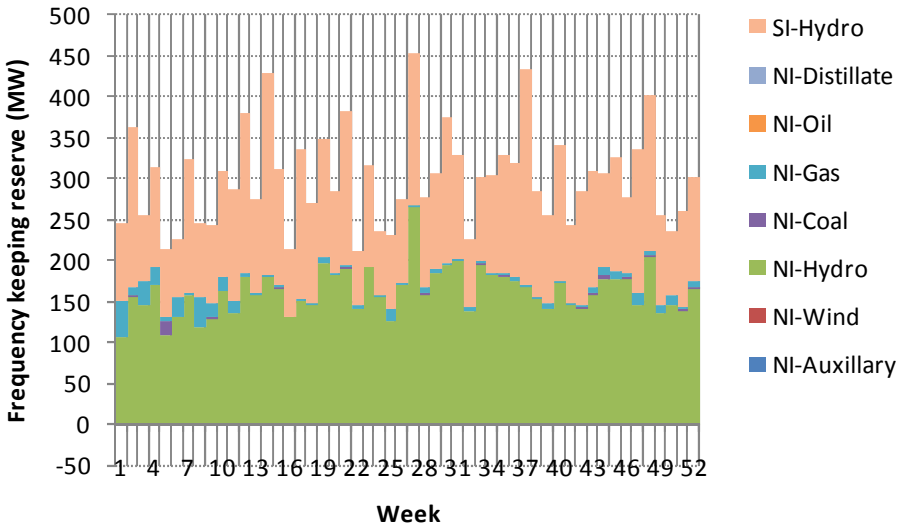

Figure 16. Weekly average provision of frequency keeping reserve services (2010 scenario)

4.50. For instantaneous reserve, the main provider is still hydro followed by gas and coal plants and interruptible load (Figure 17). Contribution from gas, coal and interruptible load is fairly small (less than 10%). Reserve from gas plant comes primarily from CCGT plants. As 75% of their capacity is dispatched as base load plant, they run part loaded most of the times and therefore can provide reserves.

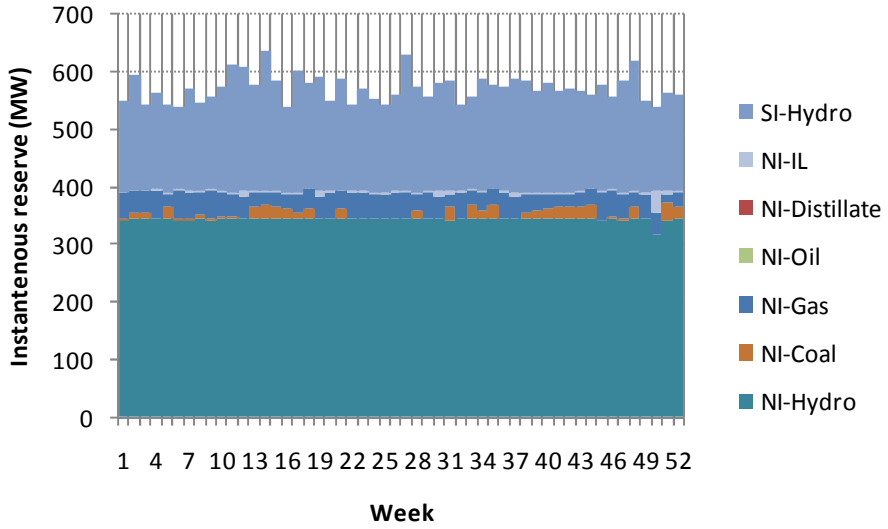

Figure 17. Weekly average provision of instantaneous reserve services (2010 scenario)

4.51. Since the additional reserve requirement for the low wind penetration (2010) scenario is primarily provided by hydro plant, there is no significant increase in operating costs. Thus, the cost of additional operating reserves is modest (0.19 $/MWh of wind energy).

4.52. The amount of reserve dispatched (available) by the generation scheduling program may exceed the amount of reserve required. However, this will not

incur additional cost. This is caused by the lumpiness of generation scheduling problem.

4.53. The magnitude and the cost of additional operating reserve requirement increase inline with the increase in wind penetration level (Table 14). Installed capacity of wind power in the 2020 scenario is 2.1 GW with annual production of 6.7 TWh. This is about three times the installed capacity in the 2010 scenario. Total additional operating reserves are also in the same proportion i.e., about three times in 2020 compared to 2010 reserve requirements. However, the relevant cost increase is four times.

4.54. Significant cost-increase is found in the 2030 scenario where the annual contribution from wind power is about 18% to the total annual electricity consumption. Figure 18 shows weekly electricity produced by different generation technologies including wind power in the North and South Islands for the 2030 scenario. Total installed wind power capacity in both islands is 3.4 GW i.e., 1.7 times the wind capacity considered in the 2020 scenario. However, the cost increases about 3.2 times - from 0.76 (2020 scenario) to 2.42 $/MWh (2030 scenario).

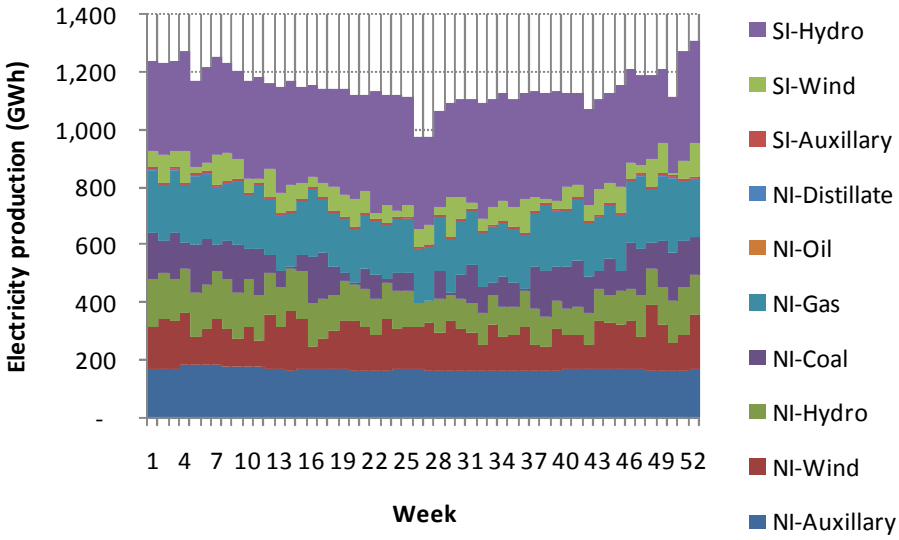

Figure 18. Annual electricity production of each generation technology (2030 scenario)

4.55. In the 2030 scenario, the role of thermal plants (gas, coal, distillate) in providing frequency keeping and instantaneous reserves in North Island increases considerably (Figure 19 and Figure 20). About 60% of frequency keeping reserve is provided by thermal plants during peak demand periods (Figure 19). While in off peak demand periods (week 26 and week 27), hydro remains the main provider for frequency keeping reserve.

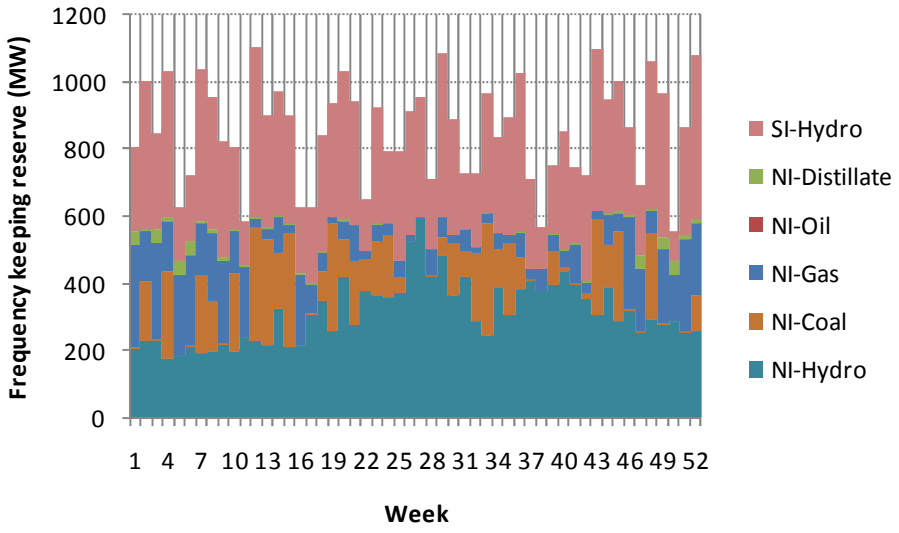

Figure 19. Weekly average provision of frequency keeping reserve services (2030 scenario)

4.56. In contrast, variation in demand has less impact on the contribution from hydro plants in the North Island to instantaneous reserve. The contribution remains similar across the year. This is driven by the technical characteristics of hydro plants which can provide significantly larger amount of fast reserve in comparison with thermal plants. However, the role of thermal plants and interruptible load becomes more significant.

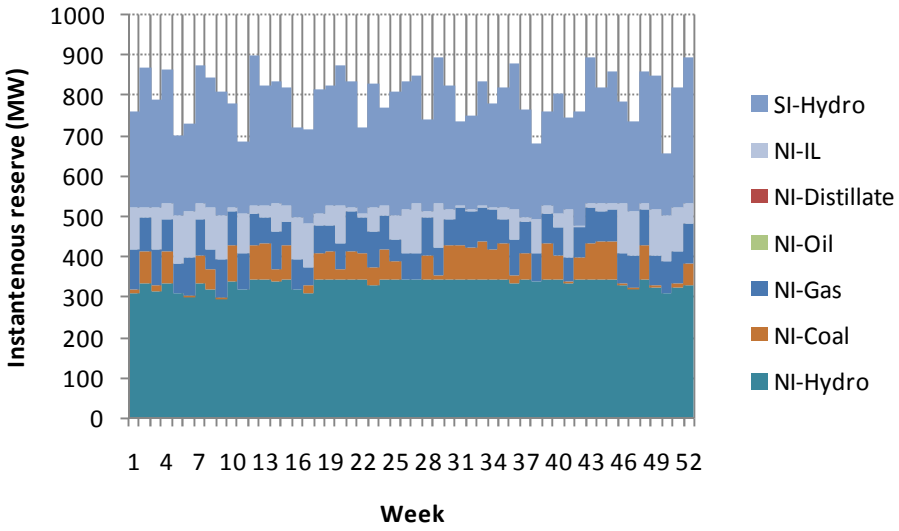

Figure 20. Weekly average provision of instantaneous reserve services (2030 scenario)

4.57. Increase in the use of thermal plant and interruptible loads, drives the increase in the cost of additional reserve. Thus, the cost of additional operating reserves in the 2030 scenario is higher, 2.42 $/MWh.

IMPACT OF KEY FACTORS

Hydrological Conditions

4.58. Hydro plant plays an important role in providing reserves. However, the amounts of electricity and reserves that can be provided are primarily driven by the availability of hydro energy. A range of studies have been carried out to investigate the impact of wet and dry hydrology conditions on the cost of additional reserve contributed by wind power. Results of these studies are presented in Figure 21.

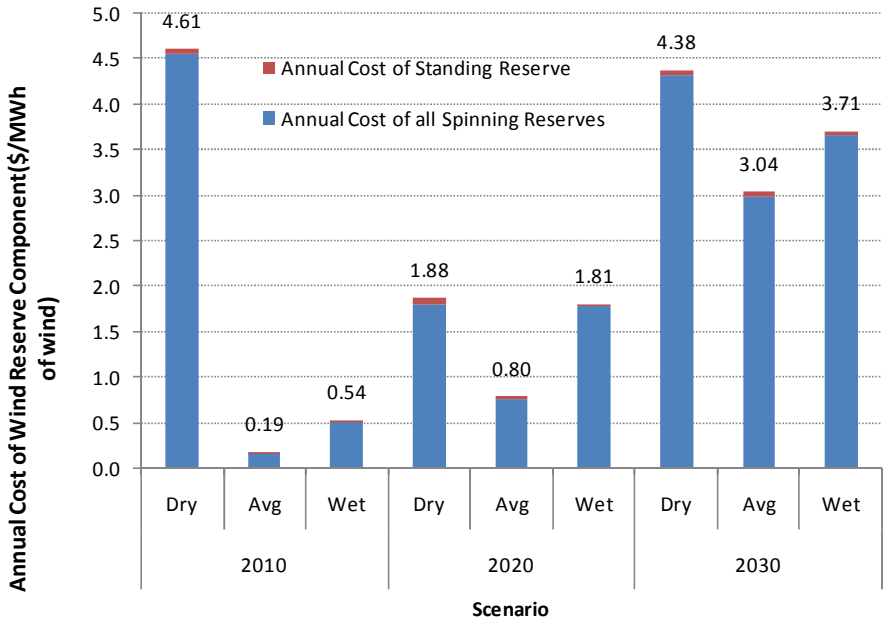

Figure 21. Impact of hydro conditions on the cost of wind reserve component

4.59. The results show that during dry and wet hydrology conditions, cost of additional reserves attributed to wind power can be significantly higher[12] than the corresponding costs under average hydrology conditions.

4.60. In dry conditions, the amount of reserve available from hydro is less and thermal generators have to contribute more for reserve provision. Thus additional reserve requirement driven by wind power in the system leads to higher utilisation of thermal generation to provide reserves. This leads to higher costs.

4.61. In wet conditions, hydro energy is used more to produce electricity rather than to provide reserves. Thus, additional increase in reserve requirement leads to an

[12] In the 2010 scenario and the dry hydrology condition, significant increase of the cost of additional reserve is driven by the increase in operating cost divided by a relatively low wind energy production resulting relatively high cost per MWh of wind energy.

increased use of thermal generation to provide reserves. This also leads to higher costs.

Interconnector

4.62. Hydro plant plays an important role for system balancing in New Zealand. Large hydro plant in the South Island can contribute to system balancing to harness the intermittency and variability effect of wind power in the North Island and vice versa. However, the power transfer capability of the HVDC interconnector does limit access between the two islands.

4.63. Sensitivity studies are carried out to investigate the effect of the power transfer capability between the North and South islands on the cost of wind reserve components. Two different power transfer capabilities are investigated for each scenario (Table 15). The transfer capability from the North to South Island is set to 60% of the transfer capability in the opposite direction. Average hydro conditions are used in these studies. The results are presented in Figure 22.

Table 15 Power transfer capability from South Island to North Island (MW)

Scenario	Case I	Case II
2010	520	1000
2020	1000	1500
2030	1000	1500

4.64. A significant reduction in the cost of the wind reserve component can be achieved if the power transfer capability between two islands is sufficiently large. Smaller power transfer capability leads to higher costs. For example, for a low wind penetration level (2010 scenario), the cost of wind reserve component is 0.19 $/MWh if the capability is 1000 MW. The cost increases about 5 times when the capability is reduced to 520 MW.

4.65. For a high wind penetration (scenario 2030), the cost of wind reserve component can be reduced from 4.36 $/MWh to 3.04 $/MWh if the power transfer capability at the interconnector is upgraded from 1000 MW to 1500 MW.

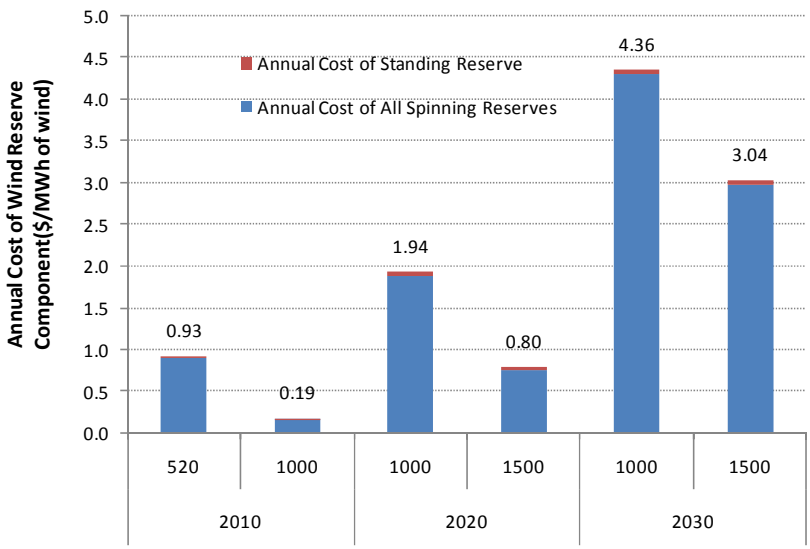

Figure 22. Impact of interconnector capacity on the cost of wind reserve component

Wind Profiles

4.66. Sensitivity studies are also carried out to evaluate the impact of different wind profiles on the costs of wind reserve component. The profiles of wind power output based on 2005 and 2006 wind speeds at different sites across New Zealand were used in these studies. Installed capacity and wind power energy for both wind profiles for each scenario are summarised in Table 16 and Table 17. For each scenario, the installed wind capacity is set to be the same for both wind profiles. The wind power load factor from the 2006 wind profile is about 10% higher than the one from the 2005 profile.

Table 16 Installed wind power capacity and annual wind power energy based on 2005 wind profiles

Reference Scenario (2005)		*2010*	*2020*	*2030*
NI	Wind Power (MW)	432	1,434	2,215
	Wind Energy (GWh)	1,653	4,906	7,442
SI	Wind Power (MW)	203	632	1,197
	Wind Energy (GWh)	631	1,819	3,354
NZ	Wind Power (MW)	634	2,066	3,412
	Wind Energy (GWh)	2,285	6,724	10,797

Table 17 Installed wind power capacity and annual wind power energy based on 2006 wind profiles

Based on 2006 Wind data		*2010*	*2020*	*2030*
NI	Wind Power (MW)	432	1,434	2,215
	Wind Energy (GWh)	1,803	5,429	8,152
SI	Wind Power (MW)	203	632	1,197
	Wind Energy (GWh)	707	2,171	4,011
NZ	Wind Power (MW)	634	2,066	3,412
	Wind Energy (GWh)	2,510	7,599	12,162

4.67. Results from the studies are presented in Figure 23. The results show that wind profiles (i.e., different wind load factors) have a considerable impact on the cost of additional operating reserves. Two of the three scenarios (2020 and 2030 scenarios) show that the additional operating reserve costs are lower in the case with high wind load factor profiles (2006). A significant reduction was observed in the 2030 scenario. The only slight increase was observed for the low wind penetration 2010 scenario.

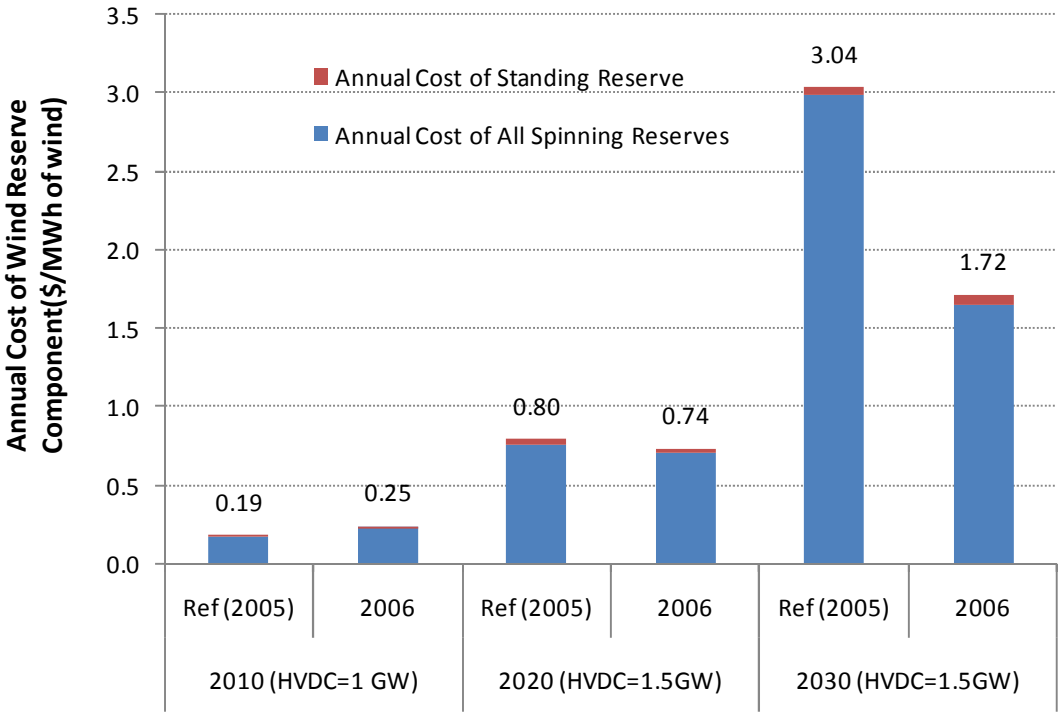

Figure 23. Impact of wind profiles on the cost of wind reserve component

4.68. Since operating reserves are functions of the expected wind power output, the average of additional operating reserves in the cases where the 2006 wind profile was used is higher. This does not imply that the cost will increase since the higher output of wind power will enable other plant to be part loaded. This in turn reduces the need to use out of merit generation and thus decreases the

cost as observed in the 2030 scenario. However, the impact is complex and non linear.

Spatial Distribution of Wind generation

4.69. Sensitivity studies have been carried out to evaluate the impact of different spatial distribution of wind farms across the New Zealand system. Results from the earlier mentioned studies are used as references (Ref.) and compared with the results obtained from the studies which used different wind farms scenarios (Southland scenarios) described in the scenario section 2. The results are presented in Figure 24.

4.70. For the 2010 and 2020 scenarios, the costs obtained from these two different wind distributions are similar in magnitude with the Southland scenario slightly on the higher side.

4.71. However, the 2030 scenario results indicate that the Southland scenario incurs considerably lower reserve costs compared to the Ref. scenario. This is mainly due to the introduction of more wind in the South Island in the Southland Scenario compared to the reference scenario. Although the total wind capacity (and wind penetration) in both cases remains the same the presence of large hydro plant in the South Island can better support the higher wind levels in the same island.

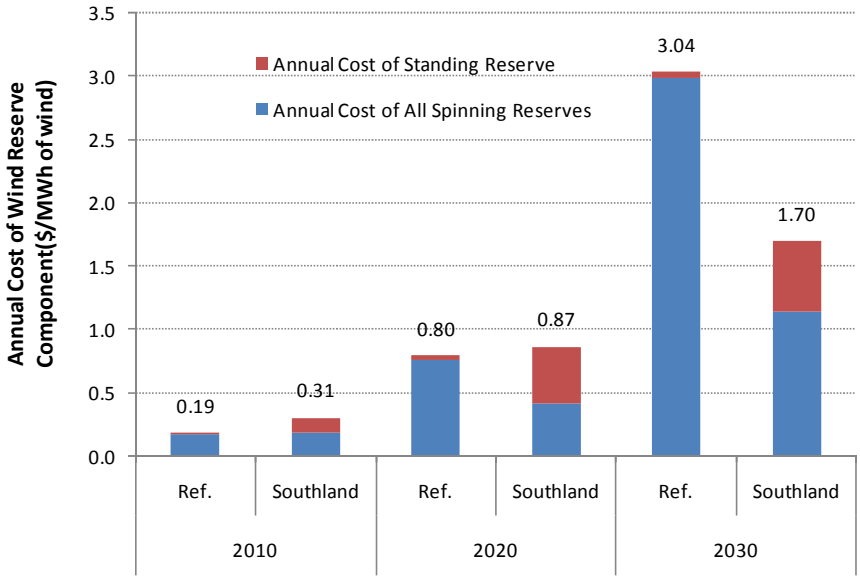

Figure 24. Impact of wind diversity on the cost of wind reserve component

4.72. It can be concluded that the distribution of wind farms across New Zealand will have a considerable impact on the cost of additional reserves.

4.73. The aim of these studies is also to demonstrate the effect of different allocation of reserves (spinning and standing) on the overall cost of additional reserve due to wind generation. An allocation will be considered optimal if it provides minimum possible overall reserve costs. The trade-off lies mainly between the efficiency lost costs of low marginal cost synchronised plant and the high marginal cost standing plant.

4.74. The costs associated with additional spinning and standing reserve requirements contributed by wind power have been computed for different reserve allocation strategies. Three different reserve allocation cases are explored. Case 1 presents a standing reserve dominated allocation. At the other extreme case 3 uses a spinning reserve dominated allocation. Case 2 uses a balanced mixture of reserve allocation, and is intermediate between case 1 and 3. The allocation of reserves for each case can be found in Table 18.

Table 18 Allocation of operating reserves

		2010			***2020***			***2030***		
		IR	**FK**	**Standing**	**IR**	**FK**	**Standing**	**IR**	**FK**	**Standing**
Case 1	NI	398	107	124	446	215	312	533	315	503
	SI	167	73	65	245	157	174	379	271	326
	NZ	565	180	189	691	372	486	912	586	829
Case 2	NI	398	150	81	446	314	272	533	466	352
	SI	167	93	31	245	226	105	379	400	214
	NZ	565	243	112	691	540	377	912	866	566
Case 3	NI	398	194	37	446	416	170	533	618	200
	SI	167	115	9	245	296	35	379	530	67
	NZ	565	309	46	691	712	205	912	1148	267

4.75. Results of the studies are presented in Figure 25. In case 3 at a low wind penetration level (2010), the cost of additional reserve is minimal (0.19 $/MWh). This indicates that a strategy to meet the reserve requirement using mainly spinning reserve is best in this scenario.

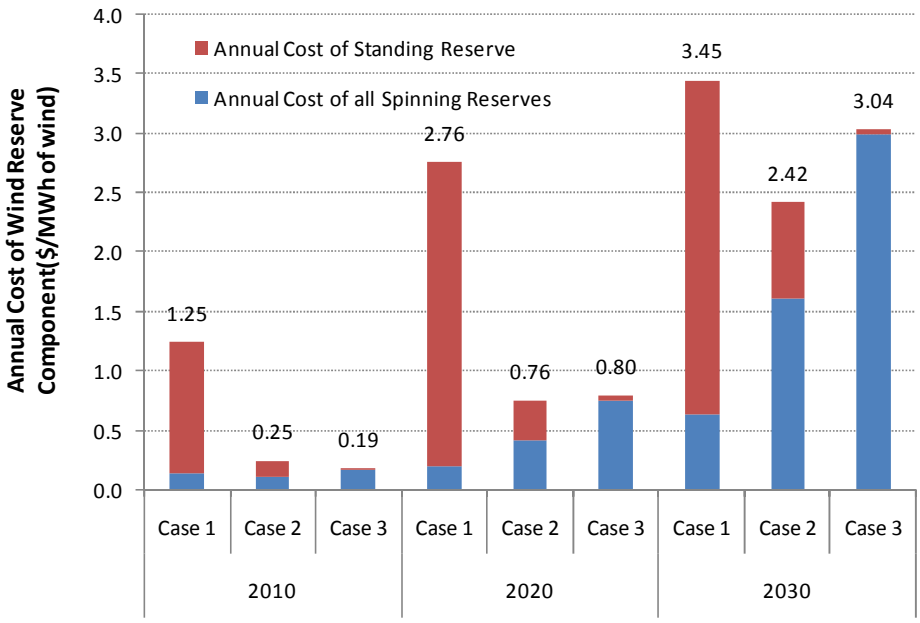

Figure 25. Cost of additional reserve requirement contributed by wind power

4.76. For medium and high wind penetrations in 2020 and 2030 respectively, the costs of additional reserve increase considerably. However, for both of these scenarios minimum overall costs are obtained in Case 2. This means the optimum strategy should to balance the use of spinning reserve and standing reserve in these scenarios.

4.77. These results clearly indicate that the optimal allocation of reserves at increasing levels of wind penetration in New Zealand will have a profound impact on the additional reserve costs attributed to wind power.

CONCLUSIONS

4.78. Additional operating reserves are needed to manage the uncertainty in wind generation output. The quantity of additional reserves needed depends on the wind characteristics (level of penetration, diversity, load factor, profile). These additional reserve requirements due to wind are quantified from the statistical behaviour of wind output. This technique uses the frequency distribution of wind variations obtained from the annual profiles over different time resolutions that is 30 minutes for Instantaneous Reserve, 1 hour for Frequency Keeping Reserve and 4 hour for Standing Reserve.

4.79. A new model of system operation simulation is developed to analyse the cost efficient provision of reserve for different penetration levels of wind in a future New Zealand electricity system. The model provides additional reserve costs attributed to wind power in order to mitigate the variability of wind power output over different time horizons. Various studies implementing the developed model indicate that for a low wind penetration (2010), hydro will be the primary source of operating reserves. The role of other plant and

interruptible load becomes more significant with the increased level of wind penetration (2020 and 2030 scenarios).

4.80. The cost of additional reserve to deal with forecasting error of wind for several scenarios has been quantified. For low wind penetration (4.9% in 2010), it is around 0.19 $/MWh of wind energy. It is found to increase to 2.42 $/MWh of wind energy with high wind penetration i.e. 18% in 2030.

4.81. The impact of hydro conditions has been studied. Dry conditions lead to a significant increase of the cost, driven by the increased use of thermal plants to provide energy and reserves. Wet conditions also lead to a higher wind reserve cost component. Since part of the hydro capacity is needed to provide reserves, less capacity can be used to utilise hydro energy and produce electricity

4.82. We also investigated the effect of the power transfer capability constraint between the North and South Islands. The studies show that a smaller transfer capability of interconnector leads to a 0.7- 1.3 $/MWh higher cost of wind reserve component. More thermal plants in the North will be used to provide energy and reserves

4.83. The impact of different distributions of wind farms across New Zealand on additional operating costs has also been studied. The cost of wind related reserve is 44% less for 2030 in the Southland scenario (equal distribution of wind in both islands) compared to the Reference scenario (wind is more concentrated in the North Island). Reserves in the North Island and South Island are managed separately, so a low wind penetration in the North will demand less use of thermal plant in the North while allocating more wind in the South is found to be beneficial given the presence of large hydro plants in South Island.

4.84. Different wind profiles, mainly differing in load factors, may also affect the cost of additional reserve attributed to wind. Two wind profiles based on the 2005 and 2006 historical data are studied. The results can be summarised as follows:

- For low (2010) and medium (2020) penetrations of wind power, the effect of different wind profiles on the cost of wind reserve component is insignificant.
- For a high wind penetration (2030), the cost per MWh of wind power energy is higher during less windy period (e.g. 2005)

4.85. The results clearly indicate that the optimal allocation of reserve at increasing penetrations of wind in New Zealand will have a profound impact on the additional reserve costs attributed to wind power. In the medium and high wind penetration scenarios for 2020 and 2030 respectively, the costs of additional reserve are found to be minimum under a reserve allocation strategy that applies a balanced allocation of spinning reserve and standing reserve.

5. APPENDICES

Appendix A - SCENARIOS FOR WIND GENERATION DEVELOPMENTS

5.1. This section provides details of the various generation and demand scenarios that are investigated in this work. These scenarios are primarily based on internal Meridian Energy data and analysis.

5.2. The fundamental intent in selecting the scenarios presented later is to focus on a broad but credible range of the potential energy contribution arising from wind generation in helping to meet demand for electricity over several time frames: namely the 2010, 2020, and 2030 Jul-Jun years. Consistent with the aims of the study – to establish the additional system costs of wind – the motivation is to develop an understanding of how these system costs are affected by the overall quantum (and associated regional diversity) of future wind generation.

5.3. In view of the objectives and scope of this work, the wind generation scenarios selected for the New Zealand Wind Integration Study are not intended to be a forecast of the future per se. Rather they do not include investment market efficiency and focus instead on answering the two related questions:

1. If in several years time New Zealand has a given quantum of installed wind generation, how will the operation of the system be affected?

and …

2. How does the system impact vary as both the level of installed wind generation and overall system demand change?

5.4. A more comprehensive examination of Meridian Energy's views on investment efficiency and the likely range of costs of new generation technologies in the New Zealand context is best summarised in the recently released 'Choices' document[13].

New Zealand Generation Supply for 2007

5.5. A common starting point for all of the generation scenarios is current levels of supply and demand for 2007. Demand assumptions are described afterwards in detail. A current description of the total New Zealand generation position – including an assessment of locally embedded generation and industrial co-generation is presented.

5.6. Key characteristics of the New Zealand electricity system are:

For the 2007 year some 43,700 GWh of total demand for generation are assumed which includes all losses, industrial co-generation, and regional embedded generation.

- Total installed generation capacity for the 2007 year is some 9,080 MW.

[13] "Options, Choices, Decisions – Understanding The Options for Making Decisions about New Zealand's Electricity Future", Nov-2006 (http://www.meridianenergy.co.nz/aboutus/news/meridian+launches+discussion+document+on+energy+future+.htm).

This exceeds peak system load (6,820 MW for the 2007 year) by more than a 30% margin.

- Generation ownership is divided between six major companies and a number of smaller ones.
- The bulk of the existing hydro resource in New Zealand is in the South Island while the majority of the demand is in the North Island.
- Hydro generation contributes some 55% of the total, with gas contributing 20%, coal 10%, and geothermal 7%. Currently wind only contributes a small 2.5% of the total generation energy picture (or 3.5% of installed system capacity).
- In New Zealand the primary focus has been on expected generation energy yield rather than on the more conventional international focus on installed generation capacity.
  - This is a direct reflection of the historical dominance in New Zealand of hydro generation which has gifted the country with an 'abundance' of installed capacity but carries with it significant uncertainty in the delivery of energy over all time frames, from days to years (up to +/-20% of expected annual energy yield).
  - This uncertainty has traditionally been resolved through the use of open-cycle 'hydro firming' plant running on either oil, gas, or more recently on coal.
  - In the last decade this hydro dominance has been supplemented by the development of new CCGT gas-fired generation.
  - Currently, a nascent wind generation industry together with renewed interest in geothermal generation is likely to alter this mix once again.

5.7. This current mix of installed generation is summarised briefly by fuel type below in Table 19. Note that in this summary the average energy amounts listed are for typical hydrological conditions. In dry or wet years hydro energy will fall or rise substantially by as much as 3,000 GWh to 5,000 GWh and the thermal energy will increase or decrease in direct proportion.

Table 19. New Zealand generation mix assumed for 2007.

NZ Generation Summary				
Generation Category	Commission Date *[Jul yr]*	Installed Power *[MW]*	Average Energy *[GWh]*	Load Factor *[%]*
Thermal	2007	2,528	13,845	62.5%
Auxiliary	2007	948	6,357	76.5%
Wind	2007	321	1,240	44.0%
Hydro	2007	5,282	24,637	53.2%
Committed	by 2010	523	1,762	38.5%
		9,603	47,841	56.9%

Key thermal, geothermal, and co-generation station characteristics (as at 2007) including expected energy yields for average hydrological conditions are described in Table 20 and

5.8. Table 21. In a typical year these plant can collectively be expected to deliver some 20,000 GWh in total. Geothermal, co-generation, and landfill generation typically run in a baseload fashion while CCGT gas-fired plant are typically dispatched ahead of the Huntly coal power station – largely due to inflexibility in physical gas deliverability and gas contracts. Distillate and oil fired plant are chiefly 'reserve' plant that run either when extreme hydrological conditions or extreme peak load circumstances are experienced.

Table 20. 2007 thermal generation plant and characteristics.

2007 Existing NZ THERMAL Power Stations

Station Name	Owner	Region	Island	Fuel	Grid Type	Grid Connection	Tx Node	Heat Rate [HHV GJ/MWh] Min	Heat Rate [HHV GJ/MWh] Avg	Fuel Cost [$/GJ]	Size [MW]	Energy Avg [GWh]
Huntly Unit 1	Genesis	Waikato	NI	Coal	Grid	HLY2201	HLY	11.03	10.50	$ 4.00	243	1,064
Huntly Unit 2	Genesis	Waikato	NI	Coal	Grid	HLY2201	HLY	11.03	10.50	$ 4.00	243	1,064
Huntly Unit 3	Genesis	Waikato	NI	Coal	Grid	HLY2201	HLY	11.03	10.50	$ 4.00	243	1,064
Huntly Unit 4	Genesis	Waikato	NI	Coal	Grid	HLY2201	HLY	11.03	10.50	$ 4.00	243	1,064
Huntly-GT	Genesis	Waikato	NI	Gas	Grid	HLY2201	HLY	9.98	9.50	$ 7.00	48	210
Huntly-CCGT	Genesis	Waikato	NI	Gas	Grid	HLY2201	HLY	7.54	7.18	$ 7.00	385	2,698
Otahuhu B	Contact	Auckland	NI	Gas	Grid	OTA2202	OTA	7.67	7.30	$ 7.50	395	2,768
Southdown CCGT+GT	MightyRiver	Auckland	NI	Gas	Grid	SWN2201	OTA	8.66	8.25	$ 7.50	178	1,247
TCC	Contact	Taranaki	NI	Gas	Grid	SFD2201	SFD	7.82	7.45	$ 6.50	367	2,572
Te Awamutu Cogen	Genesis	Waikato	NI	Gas	Co-Gen	TMU1101	HAM	14.49	13.80	$ 7.00	27	24
Whirinaki	EC	HawkesBay	NI	Distillate	Grid	WHI2201	WHI	11.55	11.00	$ 25.00	156	68
											2,528	13,845

Table 21. 2007 geothermal and co-generation plant and characteristics.

2007 Existing NZ GEOTHERMAL, Co-GEN & Other Auxiliary Power Stations

Station Name	Owner	Region	Island	Fuel	Grid Type	Grid Connection	Tx Node	Heat Rate [GJ/MWh HHV] Min	Heat Rate [GJ/MWh HHV] Avg	Fuel Cost [$/GJ]	Size [MW]	Energy Avg [GWh]
Kawerau Geothermal	Todd	Bay of Plenty	NI	Geothermal	Embedded	#N/A	TRK	#N/A	#N/A	$ -	6.4	43
Mokai Geothermal	MightyRiver	Waikato	NI	Geothermal	Grid	WKM2201	WKM	#N/A	#N/A	$ -	100	832
Ngawha Geothermal	TopEnergy	Northland	NI	Geothermal	Embedded	KOE0331	MDN	#N/A	#N/A	$ -	9.5	75
Ohaaki Geothermal	Contact	Bay of Plenty	NI	Geothermal	Grid	OKI2201	WRK	#N/A	#N/A	$ -	46	363
Poihipi Road Geothermal	Contact	Bay of Plenty	NI	Geothermal	Grid	PPI2201	WRK	#N/A	#N/A	$ -	53	418
Rotokawa Geothermal	MightyRiver	Waikato	NI	Geothermal	Embedded	WRK0331	WRK	#N/A	#N/A	$ -	35	276
Tasman Geothermal	EnergyCo	Bay of Plenty	NI	Geothermal	Embedded	#N/A	TRK	#N/A	#N/A	$ -	26.2	192
Wairakei Geothermal	Contact	Bay of Plenty	NI	Geothermal	Grid	WRK2201	WRK	#N/A	#N/A	$ -	181.0	1,468
Greenmount & Rosedale	MightyRiver	Auckland	NI	Bigas	Embedded	#N/A	HEN	12.60	12.00	$ -	11.7	83
NI Landfill & Sewage	Various	Various	NI	Bigas	Embedded	#N/A	OTA	12.60	12.00	$ -	16.4	130
SI Landfill & Sewage	Various	Various	SI	Bigas	Embedded	#N/A	ISL	12.60	12.00	$ -	4.2	32
NI Fertiliser	Various	Various	NI	Bigas	Embedded	#N/A	TRK	12.60	12.00	$ -	20.8	84
SI Fertiliser	Various	Various	SI	Bigas	Embedded	#N/A	HWB	12.60	12.00	$ -	5.9	18
NI Woody Biomass	Various	Various	NI	Bigas	Embedded	#N/A	TRK	12.60	12.00	$ -	43.1	160
SI Woody Biomass	Various	Various	SI	Bigas	Embedded	#N/A	HWB	12.60	12.00	$ -	10.6	40
Other NI	Various	Various	NI	Various	Embedded	#N/A	TRK			$ -	35.1	143
Other SI	Various	Various	SI	Various	Embedded	#N/A	HWB			$ -	16.5	27
Edgecumbe Cogen	Todd	Bay of Plenty	NI	Gas	Co-Gen	KAW0111	TRK	13.13	12.50	$ 7.00	10.0	61
Glenbrook Cogen	Alinta	Auckland	NI	Gas	Co-Gen	GLN0332	OTA	12.60	12.00	$ 3.50	107.0	609
Kapuni Cogen	Todd	Taranaki	NI	Gas	Co-Gen	KPA1101	SFD	9.77	9.30	$ 7.00	25.3	175
Kiwi Cogen	Todd	Taranaki	NI	Gas	Co-Gen	HWA1101	SFD	9.77	9.30	$ 7.00	69.6	380
Te Awamutu Cogen Base	Genesis	Waikato	NI	Gas	Co-Gen	TMU1101	HAM	14.49	13.80	$ 7.00	27	191
Te Rapa Cogen	Contact	Waikato	NI	Gas	Co-Gen	TRC0331	HAM	13.23	12.60	$ 7.00	48	298
Kinleith Cogen	Genesis	Bay of Plenty	NI	Wood	Co-Gen	KIN0112	TRK	11.55	11.00	$ -	40	261
											948	6,357

5.9. All conventional thermal generation is assumed to be dispatched efficiently according to the specified station heat rates, minimum stable generation levels, fuel costs and system demands for energy and reserve.

5.10. All geothermal, landfill, and co-generation power stations – in total contributing some 6,500 GWh per annum – are assumed to follow fixed seasonal baseload profiles over the course of the year and are not available for dispatch in a conventional sense for the purposes of this study. These profiles have been derived where possible from observable market behaviour. The aggregate weekly energy profiles assumed are summarised in Figure 26.

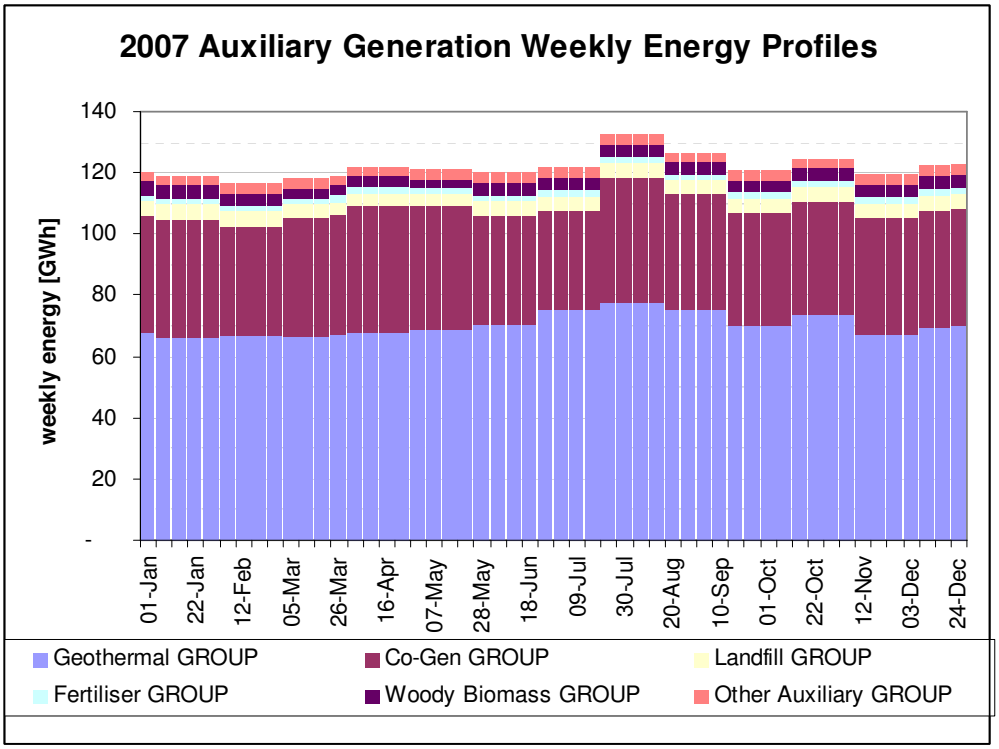

Figure 26. Geothermal, landfill, and cogeneration seasonal output profile.

Hydro and Wind 2007 Generation Assumptions

5.11. All hydro stations are modelled individually. However all hydrological information and key constraints are principally modelled at the catchment level. Key hydrological characteristics (as at 2007) including expected energy yields for average hydrological conditions for major hydro catchments (or groups) are described in Table 22. Aggregate wind farm details for existing wind generation including expected energy yield in an average year are described in Table 23.

Table 22. 2007 hydro group characteristics.

2007 Existing NZ HYDRO Power Groups

Station Group Name	Owner	Region	Island	Fuel	Grid Type	Grid Connection	Tx Node	Station # Units	Size [MW]	Energy Avg [GWh]
Clutha GROUP	Contact	Otago	SI	Hydro	Grid	CYD2201	HWB	12	700.0	3,666.2
Manapouri GROUP	Meridian	Southland	SI	Hydro	Grid	MAN2201	HWB	7	710.0	4,921.1
Other_NI GROUP	Genesis	Wairarapa	NI	Hydro	Embedded	MST0331	HAY	2	11.8	49.9
Other_SI GROUP	Alpine	Canterbury	SI	Hydro	Embedded	ABY0111	ISL	2	39.8	192.1
Todd GROUP	Todd	Bay of Plenty	NI	Hydro	Grid	MAT1101	TRK	5	69.0	286.5
Tongariro GROUP	Genesis	Taupo	NI	Hydro	Grid	RPO2201	TKU	6	360.0	1,245.8
TrustPower_NI GROUP	Trustpower	Bay of Plenty	NI	Hydro	Embedded		TRK	8	196.1	744.7
TrustPower_SI GROUP	Trustpower	Marlborough	SI	Hydro	Grid	COB0661	KIK	16	161.0	614.1
TrustPower_SI OTHER GRO	Trustpower	WestCoast	SI	Hydro	Embedded	DOB0331	GYM	9	75.8	320.7
Waikaremoana GROUP	Genesis	Hawkes Bay	NI	Hydro	Grid	TUI1101	WHI	7	140.0	486.9
Waikato GROUP	MightyRiver	Waikato	NI	Hydro	Grid	ARA2201	WRK	39	1,095.7	4,102.4
Waitaki GROUP	Meridian	Waitaki	SI	Hydro	Grid	TKA0111	BEN	32	1,723.0	8,006.9
									5,282	**24,637**

Table 23. 2007 wind farm characteristics.

2007 Existing NZ WIND Power Stations

Station Name	Owner	Region	Island	Fuel	Grid Type	Grid Connection	Tx Node	Station # Units	Size [MW]	Energy Avg [GWh]
Haunui	Genesis	Wairarapa	NI	Wind	Embedded	GYT0331	HAY	15	8.7	32.6
Tararua Wind Farm	Trustpower	Manawatu	NI	Wind	Embedded	LTN0331	BPE	134	160.7	616.9
Te Apiti	Meridian	Manawatu	NI	Wind	Grid	WDV1101	BPE	55	90.8	357.7
Te Rere Hau	NZ Windfarm	Manawatu	NI	Wind	Grid	WDV1101	BPE	5	2.5	9.9
WhiteHill	Meridian	Southland	SI	Wind	Grid	NMA0331	HWB	29	58.0	220.0
Other Wind	Various	Various		Wind				2	0.7	2.4
									321	**1,240**

5.12. In a typical year the 5,300 MW of total installed hydro generation is expected to deliver around 25,000 GWh at an average load (utilisation) factor of approximately 55%. Wind is currently only a small contributor to the energy picture delivering some 1,250 GWh in an average year – but with a high load (utilisation) factor of 44%.

5.13. The modelling and analysis of hydro generation in New Zealand is typically made difficult by relatively limited storage (some 10% of total hydro generation), small catchment areas, highly unpredictable regional and temporal precipitation patterns, short historical records (1931-2007), and complex river linkage and water consenting issues. The hydro problem in New Zealand is often resolved through the application of stochastic optimisation techniques such as; one encapsulated by proprietary mathematical software packages like SDDP[14] or Spectra.

5.14. For this analysis hydro storage has not been explicitly modelled. Instead all hydro generation has been portioned into 11 separate groups or catchment areas. Output from each of these 11 groups has been further partitioned into 'run-of-river'[15] generation and controllable 'reservoir-release'[16] generation. Output from a separate hydro-thermal electricity dispatch model Spectra (similar in nature to SDDP) is used to produce weekly profiles of available hydro generation for each catchment and for the subsequent separation into run-of-river and reservoir-releases generation. This means that medium-to long-run hydro storage co-ordination and dispatch beyond a week is exogenous to this analysis.

5.15. Within the modelled timeframe of each 'step' used in the analysis (one week for the capacity and reserve studies) hydro generation, storage, and associated flexibility can thus be summarised as follows:

[14] SDDP is a hydro-thermal dispatch model with representation of the transmission network used for short, medium and long term operation studies. The model calculates the least-cost stochastic operating policy of a hydrothermal system, taking into account multiple aspects of real electrical systems (http://www.psr-inc.com.br/sddp.asp).

[15] Run-of-river generation is broadly associated with hydro generation that has no meaningful hydro storage and is to all intents and purposes run as baseload generation.

[16] Reservoir-release generation is broadly associated with controllable releases from major hydro reservoirs and can be dispatched in a very flexible fashion. However depending on the timeframe reservoir-release generation is still constrained by available inflows (and their inherent associated uncertainty), reservoir storage limits, and water consents limitations (eg minimum/maximum river flows).

- **Run-of-river**: This is must-run baseload hydro generation constrained in size by the available energy for the *day*. No ability to re-dispatch run-of-river generation to meet a demand or reserve profile is allowed, although the model can constrain off (i.e. 'spill') the run-of-river generation if necessary. Note that over short time frames covering several hours the baseload generation assumption is conservative in that most hydro plant, even run-of-river plant, have some ability to control their level of output.
- **Reservoir-Release**: This is fully flexible hydro generation constrained only by the available energy for the *week*. Within a week hydro generation in this category can be re-dispatched in almost any fashion to minimise system costs. Typically generation in this hydro category will be used to 'peak-fill', i.e. to meet peak load requirements first, with residual hydro energy for the week then used to offset other mid-merit thermal generation. As with run-of-river generation, the model can constrain off (i.e. 'spill') the reservoir-release generation if necessary.

5.16. Acknowledging New Zealand's unique hydrological conditions, three hydrological states are used here to examine the sensitivity of the system impacts of wind to the availability of hydro-generation. This is a proxy for a more complete hydrological examination. Three hydrological scenarios are used:

1. **Average**: Represents the average of all historically observed hydrological conditions and can be thought of as 'typical' hydro conditions.
2. **Dry**: Represents extremely dry (annual) hydro conditions. This is associated with the historical inflows as occurred over the 1977 year.
3. **Wet**: Represents extremely wet (annual) hydro conditions. This is associated with the historical inflows as occurred over the 1995 year.

5.17. The separation of annual energy yield by hydro catchment, run-of-river generation, reservoir-release generation, and typical versus extreme hydrological conditions are summarised in Table 24. Note that the reservoir generation displays less variation from dry to wet than does the run-of-river generation. This is due to the mitigating influence of the exogenously modelled reservoir operation. Note that in an average year this data suggests that approximately 50% of total hydro generation is entirely inflexible and 50% is fully flexible to serve the needs of system operation – although clearly there is large variation between individual catchments as to the extent of flexibility assumed.

Table 24. Hydro catchment annual energy summary.

Hydro Annual Energy Summary for 2007	Average Year			Dry (1977) Year			Wet (1995) Year			Installed	
Catchment	Total	Reservoir	Run-Of-River	Total	Reservoir	Run-Of-River	Total	Reservoir	Run-Of-River	Capacity	Load Factor
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	%
Clutha	3,666	479	3,187	2,983	346	2,637	4,536	504	4,032	700	59.8%
Manapouri	4,921	2,461	2,461	4,242	2,121	2,121	5,231	2,615	2,615	710	79.1%
Other NI	50	-	50	-	-	-	-	-	-	12	48.3%
Other SI	192	-	192	173	-	173	185	-	189	40	55.1%
Taupo	4,102	3,170	933	3,705	2,950	754	5,075	3,903	1,171	1,096	42.7%
Todd	287	29	258	236	24	212	343	34	309	69	47.4%
Tongariro	1,246	-	1,246	999	-	999	1,698	-	1,698	360	39.5%
Trust NI	745	74	670	631	63	567	862	86	775	196	43.4%
Trust SI	935	467	467	815	407	204	900	450	225	237	45.1%
Waikaremoana	487	487	-	461	461	-	608	608	-	140	39.7%
Waitaki	8,007	5,582	2,425	7,206	5,205	2,000	8,709	5,337	3,372	1,723	53.0%
TOTAL	**24,637**	**12,749**	**11,888**	**21,449**	**11,578**	**9,667**	**28,146**	**13,538**	**14,387**	**5,282**	**53.2%**
Difference from Mean				- 3,189	- 1,171	- 2,221	6,697	1,961	4,720		
				-13%	-9%	-19%	27%	15%	40%		

5.18. The average weekly energy profiles assumed in the analysis are shown in Figure 27 by catchment total which also indicates how dry and wet hydro conditions affect the total island energy profiles.

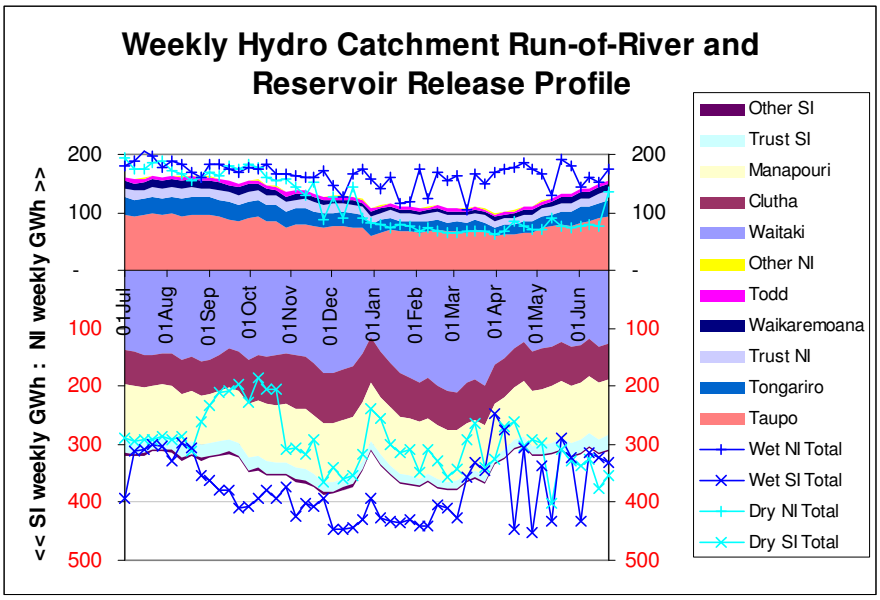

Figure 27. Average weekly hydro energy profiles by catchment. South Island hydro generation profiles are 'stacked' below the axis while North Island hydro generation profiles are 'stacked' above the axis.

5.19. Energy from run-of-river catchment flows is constrained at the daily level rather than at the weekly level that is assumed for reservoir release hydro generation.

This is assumed in order to introduce additional volatility and realism into the hydro modelling used for the study. While total weekly run-of-river energy amounts are consistent with the picture shown in Figure 27 , on a day-to-day basis the run-of-river flows display significantly greater volatility than this implies. This is accounted for by selecting daily run-of-river flows from the historical record and using these to calibrate the run-of-river flows assumed in the study. The daily run-of-river flows assumed for average (1953), dry (1977), and wet (1995) conditions can be seen in Figure 28 for the New Zealand total. While there is significant variation between catchments, for the sake of brevity only the total New Zealand run-of-river daily flows are shown here. Note that regardless of the hydro flow conditions that dominate for the year the run-of-river flows and associated generation are characterised by rainfall events that spike high above the average before reverting more slowly back to more typical levels.

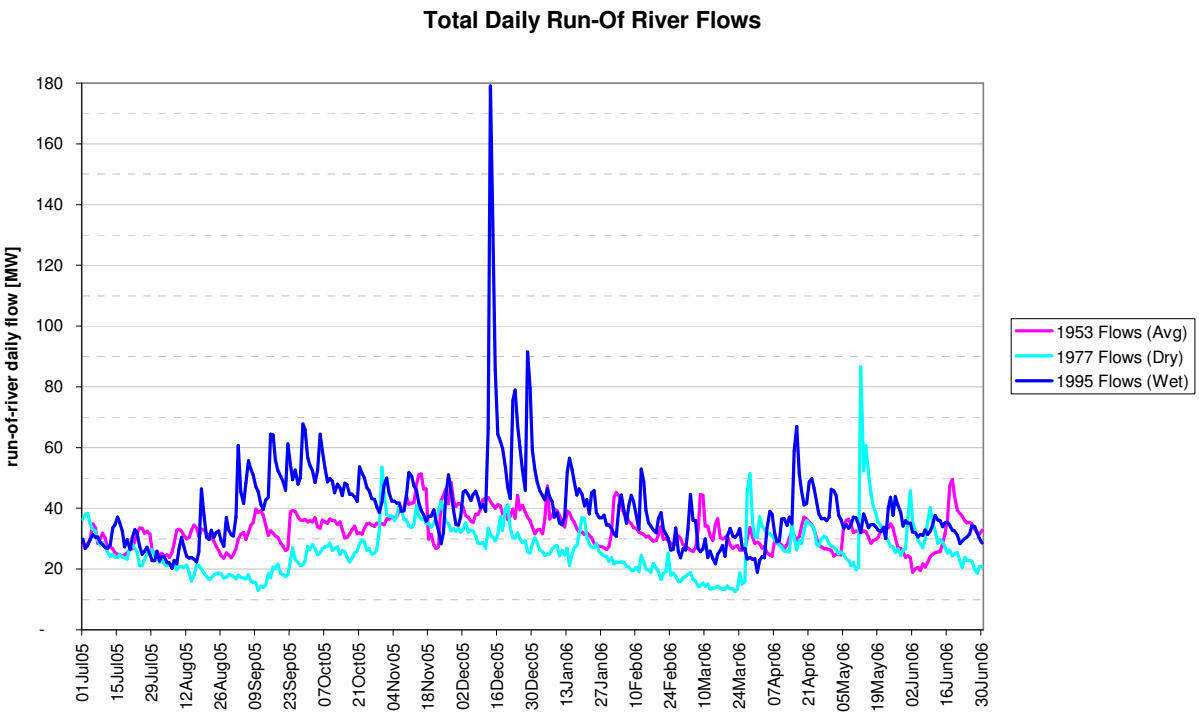

Figure 28. Daily total NZ run-of-river generation flows.

Committed Generation to 2007-2010

5.20. In addition to the 2007 generation system snapshot a number of new generation plants are committed (assessed as at mid-2007) for commissioning before 2010. To ensure the realism of the scenarios these committed (but not yet commissioned) generation plant are included in all scenarios from 2010 onwards. These projects are listed in Table 25.

Table 25. 2007-210 committed new generation characteristics.

2007-2010 Committed New Generation

Station Name	Owner	Region	Island	Fuel	Grid Type	Grid Connection	Tx Node	Heat Rate Min	Heat Rate Avg	Fuel Cost [$/GJ]	Size [MW]	Energy Avg [GWh]
Stratford GT	Contact	Taranaki	NI	Gas	Grid	SFD2201	SFD	9.45	9.00	$ 7.50	100	88
Ngawha	TopEnergy	Northland	NI	Geotherm	Embedded	HLY2201	MDN			$ -	16	126
Te Rere Hau Stage II	NZ Windfarm	Manawatu	NI	Wind	Embedded	LTN0331	BPE			$ -	27	104
West Wind	Meridian	Wellington	NI	Wind	Grid	WIL1101	HAY			$ -	143	573
Kawerau II	MightyRiver	BOP	NI	Geotherm	Grid	KAW0111	TRK			$ -	90	653
Benmore Refurbishment	Meridian	Waitaki	SI	Hydro	Grid	BEN0161	BEN			$ -	11	52
Manapouri Discharge	Meridian	Otago	SI	Hydro	Grid	MAN2201	HWB			$ -	120	100
Hawea Turbines	Contact	Otago	SI	Hydro	Grid	CYD2201	HWB			$ -	17	66
											523	1,762

New Zealand Demand for Generation

5.21. Demand data for the analysis is based on metered, grid exit point (GXP), non-embedded demand data for the 2006 calendar year. This does not represent all New Zealand demand and in order to be consistent with the definition used for generation supply we need to account for additional non-metered co-generation and locally embedded generation. Together these contribute approximately 2,500 GWh of additional demand. Also, since high voltage transmission losses are not explicitly modelled in this study demand is scaled by approximately 4.5% to give an appropriate picture of demand at the level of the 'station gate'.

5.22. Raw metered demand data is aggregated by island, and scaled to represent growth through to 2030 with non-metered generation added (this is assumed to grow at the same rate as underlying energy). Assumed growth rates are Meridian's own views but at the national level these are consistent with the energy growth assumed by the New Zealand Electricity Commission's 2007 Statement of Opportunities[17]. The growth in both energy and peak power is approximately linear at 725GWh and 120MW per annum respectively. The resulting summary demand picture is given in Table 26 with further summary distributional statistics given in Figure 29 and Figure 30.

[17] The Statement of Opportunities is a grid planning document and analysis framework published by the New Zealand Electricity Commission (http://www.electricitycommission.govt.nz/opdev/transmis/soo)

Table 26. Demand for 2006 and growth through to 2030.

Wind Integration Demand Growth 2010-2030

source: energy market services total GXP load 1-Jan-2006 to 31-Dec-2006

Tx Losses >>	4.5%				
Embedded >>	2,500				
	Cal Year		**GWh**	**Min**	**Max**
Actuals	2006	GXP NI	23,894	1,440	4,320
		GXP SI	13,969	1,116	2,121
		GXP TOTAL	37,863	2,556	6,434
		Implied Total	42,066	2,957	7,009
Forecast	**2007**	NI	27,473	1,728	4,588
		SI	16,236	1,325	2,332
		Total	**43,709**	**3,055**	**6,914**
	2010	NI	29,046	1,932	4,842
		SI	17,093	1,434	2,455
		Total	**46,139**	**3,367**	**7,290**
	2020	NI	33,753	2,254	5,598
		SI	19,873	1,671	2,845
		Total	53,626	3,926	8,435
	2030	NI	38,030	2,529	6,273
		SI	22,419	1,881	3,197
		Total	**60,449**	**4,412**	**9,461**

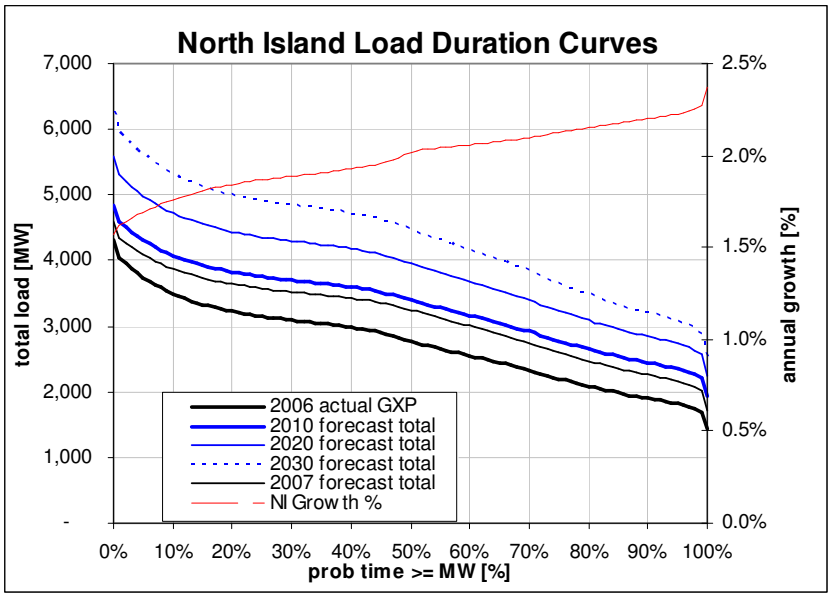

Figure 29. 2006 half-hourly NI load distribution curve and growth to 2030.

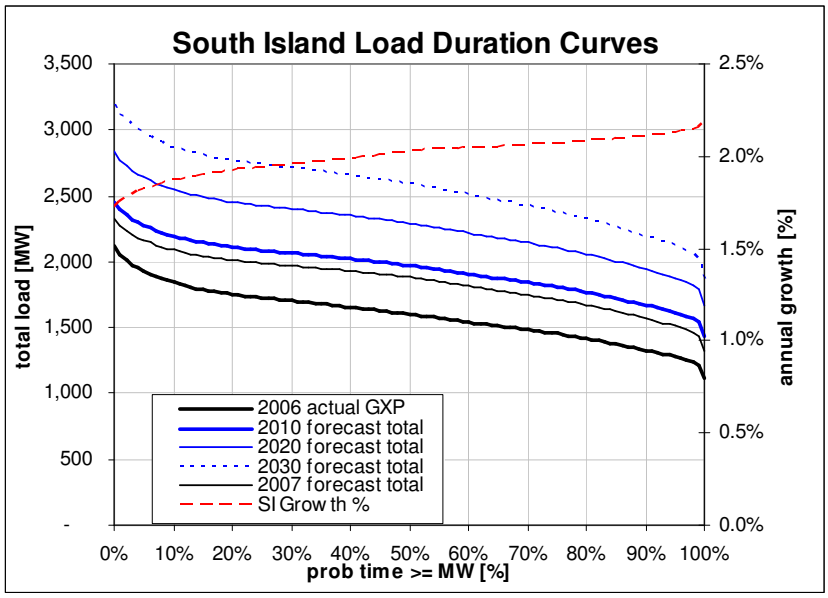

Figure 30. 2006 half-hourly SI load distribution curve and growth to 2030.

The Wind Resource

5.23. Fifteen regionally diverse wind farm locations have been selected as being representative of the general wind resource potential in New Zealand. At four of these sites wind farms either already exist or are being commissioned while at the remaining eleven sites, wind farms are being investigated (by Meridian and others) as credible development options. The theoretical performance of the wind farms and their locations are consistent with Meridian's views on wind behaviour and on where the better wind resources in New Zealand are located. These can be grouped into three broad regions:

- Northland/Auckland;
- HawkesBay/Manawatu/Wellington; and
- Southland/Otago.

5.24. While there are potential wind sites outside of these areas the analysis is restricted here to use real wind data from actual sites with long and overlapping wind records.

5.25. The raw data was gathered over a 24 month period covering the 2005 – 2006 calendar years from wind monitoring sites typically at a 40m height or higher, and at a 10 minute recording resolution. Representative wind turbines have been selected for each site and the resulting energy output at the 10 minute level (as produced by the WindFarmer software package[18]) has been derived over the same two year period. Note that the generation profiles assumed are measured at the "station gate" and are thus nett of topological and array effects, turbine outages, hysteresis, and local losses. The annual summary of the raw wind data for the fifteen sites is shown in Table 27.

[18] GH WindFarmer is a proprietary integrated wind farm design and optimisation software tool from GarradHassan (http://www.garradhassan.com/products/ghwindfarmer/index.php).

Table 27. Raw wind data and energy production

Phase II Wind Dataset Summary

Net of Topological & Array Effects, Outages, Hysteresis, and Losses

		Year 1 - 2005			Year 2 - 2006			Long-Run
	Installed	MW	GWh	LF	MW	GWh	LF	Average
01 Northland	69	67	205	34%	67	220	36%	40%
02 North Auckland 1	103	100	328	36%	100	332	37%	40%
03 North Auckland 2	251	246	867	39%	246	912	41%	40%
04 Hawkes Bay	150	147	417	32%	147	481	37%	37%
05 Central North Island	100	100	286	33%	100	325	37%	40%
06 Taranaki	99	97	296	34%	97	360	42%	42%
07 Te Apiti (Manawatu)	**91**	**89**	**319**	**40%**	**89**	**348**	**44%**	**46%**
08 Wellington1	**161**	**158**	**690**	**49%**	**158**	**750**	**53%**	**46%**
09 Wellington2	90	88	364	46%	88	403	51%	44%
10 Wairarapa	90	88	289	37%	88	316	40%	41%
11 NorthCanterbury	215	211	559	30%	211	664	35%	35%
12 Central Otago	405	397	1,140	32%	397	1,361	38%	39%
13 Whitehill (Southland)	**58**	**57**	**230**	**45%**	**57**	**223**	**44%**	**43%**
14 Southland	168	164	462	31%	164	587	40%	40%
15 Tararuas (Manawatu)	**161**	**158**	**594**	**42%**	**158**	**647**	**46%**	**45%**
	2,211	**2,167**	**7,046**	**36%**	**2,167**	**7,928**	**41%**	**41%**

Existing WindFarms
Commissioning WindFarm
Potential WindFarms

5.26. This raw wind data forms the basis for all wind scenario data assumed in the rest of the analysis with simple scaling of the basic fifteen wind data sets used to produce different levels of wind penetration. This is a conservative assumption in the sense that, for example, all Southland wind generation will not come from a single source and is likely to be more diverse than this methodology implies. However also note that this is only two years worth of wind data. Significant variation in wind behaviour from year to year at any given site is observable, weather measuring extremes or annual energy yields can be clearly seen here when comparing the reduced wind energy production (by some 11%) in 2005 to the 2006 wind year.

5.27. The raw 10 minute wind data has a combined portfolio power output over this two year period as shown in Figure 31. We can clearly see as with Figure 31that 2005 is a significantly less windy year than 2006. For an equivalent 'installed' portfolio capacity of approximately 2,200 MW, note that the maximum theoretical output is seldom reached – never in fact for this data set – with the data only exceeding 1,900 MW between 0.1% to 0.5% of the time. Conversely, for this data set the wind portfolio never registers a zero combined output, although again the data does get close, dropping to under 50MW approximately 0.1% of the time. Similarly, the variation in the wind portfolio output can be seen to be relatively stable at the 10 minute level being confined to:

- Between +/-90-105MW (4-5% of installed capacity) for 90% of the time
- Between +/-180-200MW (8-9% of installed capacity) for 99% of the time.
- Between +/-230-260MW (11-12% of installed capacity) for 99.9% of the time.

5.28. This variation increases as the lead time increases with the above changes in output growing by approximately a factor of 2.5 at the two hour level and by a factor of 4.5 at the six hour level – as shown in Table 28.

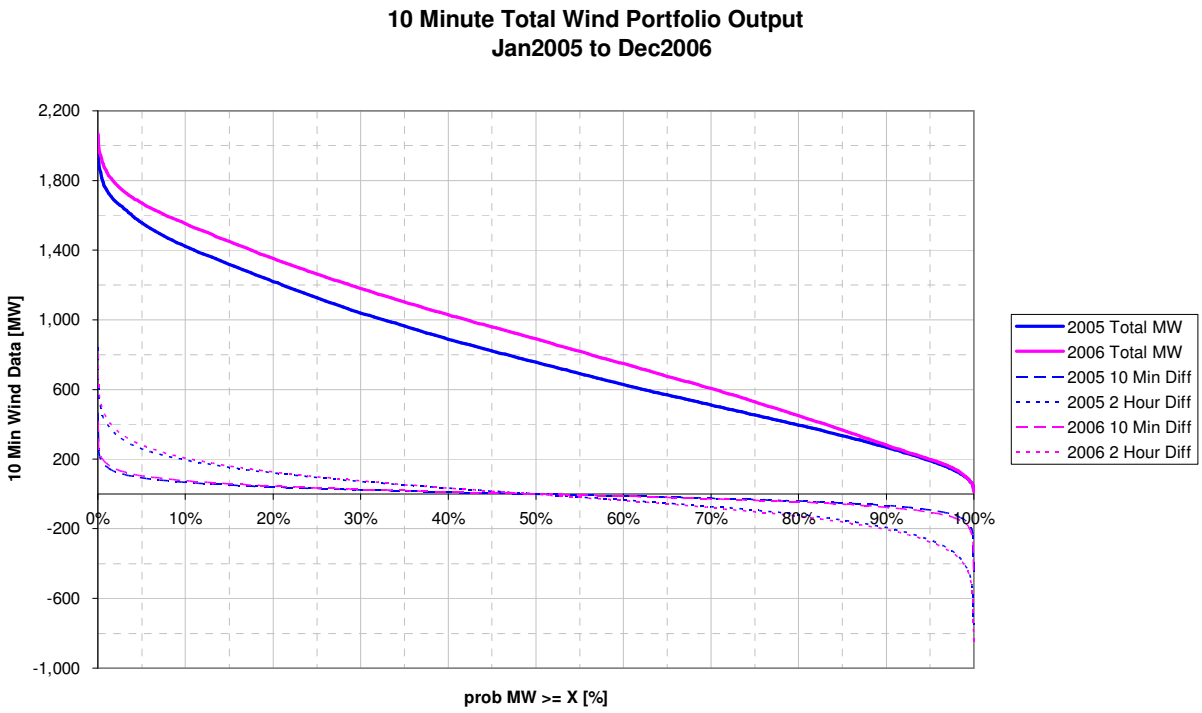

Figure 31. Total wind portfolio distribution of 10 min power output for raw wind dataset for 2005 and 2006.

Table 28. Wind portfolio variation in power output.

Wind Portfolio Output MW Variation						
	2005			2006		
% ile	10 Min	2 Hour	6 Hour	10 Min	2 Hour	6 Hour
0.1%	246	581	975	259	595	1,021
0.5%	180	451	798	199	489	820
2.5%	120	324	574	133	349	605
5.0%	93	259	457	105	281	486
95.0%	-92	-264	-450	-105	-276	-456
97.5%	-117	-328	-547	-132	-338	-545
99.5%	-175	-456	-731	-197	-468	-724
99.9%	-233	-571	-903	-260	-582	-885

New Zealand Future Generation Supply – The Wind Scenarios

5.29. Having described the basis for the supply and demand data in the preceding sections this section outlines the data used and the basis for the selection of the wind scenarios.

5.30. Six potential generation scenarios have been developed for the second phase of the New Zealand Wind Integration Study. The fundamental intent in selecting the scenarios presented is to focus on a broad but credible range of the potential energy contribution from wind generation to meet demand for electricity over several time frames: namely the 2010, 2020, and 2030 Jul-Jun years. In order to avoid explicitly displacing economic existing generation, the quanta of wind generation assumed in the wind scenarios is simply a partial allocation of the need for new generation created by incremental demand growth in electrical

energy over the next 3-23 years. This ranges between 2,500 GWh in 2010 to 17,000 GWh by 2030.

5.31. There are two main bases for classifications of these scenarios. First deals with the spatial distribution of wind across New Zealand which is followed by different penetration levels of wind in three future time frames (2010, 202, and 2030). The spatial distribution based classification is termed as 'Reference' and 'Southland' scenarios while their sub classification is named according to the respective year in the future.

5.32. The three ***Reference*** scenarios are:

1. **2010**: In addition to existing and already committed wind projects one other SI based wind farm is commissioned between now and 2010 – with installed wind totalling 634 MW. Other technologies 'make up the slack' to satisfy the incremental 2,500 GWh of new demand growth. All projects between now and 2010 are already committed, no generation projects are displaced.
2. **2020**: In addition to existing and already committed wind projects a relatively high range of regional wind farms are assumed to be commissioned between now and 2020 – with installed wind totalling 2,066 MW. Other technologies 'make up the slack' to satisfy the incremental 10,500 GWh of new demand growth – with new wind contributing some 6,200 GWh. Other generation is assumed here to consist of a range of generation projects: principally geothermal (2,000GWh), gas (300GWh), and hydro (200GWh).
3. **2030**: In addition to existing and already committed wind projects a rather extreme range of regional wind farms are assumed to be commissioned between now and 2030 – with installed wind totalling 3,412MW. Other technologies 'make up the slack' to satisfy the incremental 17,000 GWh of new demand growth – with new wind contributing some 11,000GWh. Other generation is assumed here to consist of a range of generation projects: principally gas (2,000GWh), geothermal s (2,000GWh), and hydro (200GWh).

5.33. Assumed new generation built between 2007 and 2030 is grouped by scenario and technology types and is summarised in Table 29.

Table 29. Wind scenarios. New generation assumed between 2007 and 2030 – by year and technology.

Year	2010			2020			2030		
	Capacity	Energy	Load Factor	Capacity	Energy	Load Factor	Capacity	Energy	Load Factor
	MW	GWh/yr	(%)	MW	GWh/yr	(%)	MW	GWh/yr	(%)
Wind	313	1,169	43	1,745	6,241	41	3,090	10,865	40
Hydro	148	213	16	148	213	16	148	213	16
Geothermal	106	779	84	255	1,962	88	294	2,286	89
Gas	-	-	0	70	307	50	310	2,094	77
Total conventional	254	991	45	473	2,481	60	752	4,592	70
Total new generation	567	2,161	44	2,217	8,722	45	3,842	15,458	46

5.34. Conventionally, level of wind in a system is expressed in terms of energy penetration. This is the electricity produced by the wind generation, normalised by the gross electricity consumption in the system, usually on an annual basis. Throughout this report wind penetration is referred to wind energy penetration. The corresponding statistics for all developed scenarios are given in Table 30.

Table 30. Wind penetration statistics and energy balanced system security margin by scenario

Year >>	2010		2020		2030	
	Capacity	Energy	Capacity	Energy	Capacity	Energy
	MW	GWh/yr	MW	GWh/yr	MW	GWh/yr
Wind	634	2,409	2,066	7,481	3,412	12,105
Hydro	5,430	24,850	5,430	24,850	5,430	24,850
Geothermal + Others	1,056	7,136	1,203	8,319	1,242	8,643
Gas/Coal	2,528	13,845	2,598	14,152	2,838	15,939
Total NZ demand	7,290	46,139	8,435	53,626	9,461	60,449
Capacity Margin (%)	32.3%		33.9%		36.6%	
Wind Penetration (%)		5.2%		13.9%		20.0%

5.35. The varying quanta of regional wind data are achieved through simple scaling of the raw wind data sets. As mentioned previously in terms of wind variation this is a conservative assumption in that future regional wind contributions are unlikely to come from a single wind farm and 'within region' (and within wind farm) diversity effects will likely make the variation in total wind less volatile. The assumed regional dispersal of wind and the variation by scenario and year is shown in Table 31.

Table 31. Allocated regional wind capacity – Reference scenario.

Region	2010		2020		2030	
	MW	GWh	MW	GWh	MW	GWh
Auckland (NI)					225	788
Canterbury (SI)	-	-	-	-	215	660
Central (NI)	-	-	100	350	100	350
Hawke's Bay (NI)	-	-	198	663	309	1,052
Manawatu (NI)	280	1,089	430	1,654	580	2,180
Northland (NI)	-	-	171	600	422	1,479
Otago (SI)	144	492	405	1,384	755	2,632
Southland (SI)	58	220	226	809	226	809
Taranaki (NI)	-	-	99	361	99	361
Waikato (NI)	-	-	-	-	44	135
Wairarapa (NI)	9	33	99	356	99	356
Wellington (NI)	143	574	337	1303	337	1,303
North Island	**432**	**1,696**	**1,434**	**5,287**	**2,215**	**8,004**
South Island	**202**	**713**	**632**	**2,194**	**1,197**	**4,100**
New Zealand	**634**	**2,409**	**2,066**	**7,481**	**3,412**	**12,104**

5.36. In the ***Southland*** scenario the location of various wind farms considered in the reference scenario is reallocated to be in the South Island (largely in the Otago region) and rest is mainly unaltered. The wind three scenarios are:

1. **2010**: In addition to existing and already committed wind projects one other SI based wind farm is commissioned between now and 2010 – with installed wind totalling 888 MW. This is an addition of 250 MW wind capacity in Otago compared to the reference 2010 scenario.
2. **2020**: In addition to existing and already committed wind projects a relatively high range of regional wind farms are assumed to be commissioned between now and 2020 – with installed wind totalling 2,040 MW. Although the total installed wind considered in this scenario is the same as corresponding reference scenario, however, the allocation of new wind capacity between the islands is skewed i.e. 610 MW in the North Island and 1100 MW in the South Island (about 940 MW in Otago).
3. **2030:** In addition to existing and already committed wind projects a rather extreme range of regional wind farms are assumed to be commissioned between now and 2030 – with installed wind totalling 3,402MW. Again the total installed wind considered in this scenario is the same as corresponding reference scenario. However, the allocation of new wind capacity between the islands is relatively balanced i.e. 1430 MW in the North Island and 1650 MW in the South Island (about 940 MW in Otago).

5.37. The regional allocation of the wind capacity considered in the Southland scenario is shown in Table 32.

Table 32. Allocated regional wind capacity - Southland Scenario, 2005/2006 wind

Region	2010		2020		2030	
	MW	GWh	MW	GWh	MW	GWh
Auckland (NI)	0	0	0	0	225	788
Central (NI)	0	0	100	350	100	350
Hawke's Bay (NI)	0	0	0	0	111	358
Manawatu (NI)	273	1,112	430	1,750	430	1,750
Northland (NI)	0	0	0	0	251	878
Otago (SI)	405	1,384	939	3,208	1,480	5,055
Southland (SI)	58	0	226	792	226	792
Taranaki (NI)	0	0	99	361	99	361
Waikato (NI)	0	0	0	0	44	161
Wairarapa (NI)	9	0	9	0	99	354
Wellington (NI)	143	550	237	913	337	1,299
North Island	**425**	**1,661**	**875**	**3,375**	**1,696**	**6,301**
South Island	**463**	**1,384**	**1,165**	**4,000**	**1,706**	**5,847**
New Zealand	**888**	**3,045**	**2,040**	**7,375**	**3,401**	**12,148**

5.38. All of the wind scenarios assume that all currently committed new generation as described earlier will proceed to full commissioning. Aside from those mentioned above, no other new generation option is considered 'firm' and is therefore available to be 'displaced' by assumed new wind generation. Finally, note that no existing generation plant is assumed to be decommissioned over this period.

5.39. The initial focus of the wind scenarios is to match demand growth with equal amounts of total new energy growth while simultaneously varying the quantum of new wind generation assumed. Note that at extreme levels of wind penetration the default assumption of meeting incremental demand growth with equivalent levels of new baseload generation may no longer be valid in maintaining an 'adequate' system – from either or both perspectives of 'security of supply' or 'dynamic efficiency'. However, since part of the purpose in undertaking the work in this study is to explicitly estimate if a deficit in system capacity exists. Therefore this simplistic expansion rule in representing a future energy balanced system is considered suitable for an initial estimate of the system capacity and indeed any capacity deficit will be apparent from the results of the study.

Appendix-B: MATHEMATICAL FORMULATION FOR CAPACITY ADEQUACY ASSESSMENT

List of Acronym

Notation	Definition
T	Time horizon for simulation (yearly)
t	Time index
τ	Duration of time interval in hour
I	No of thermal generators
H	No of hydro generators
i	Index for particular thermal generator
h	Index for particular hydro generator
W	No of wind generators
w	Index for particular wind generator
n	number of states of the unit
C_i	capacity outage (MW) of state *i* of the unit
p_i	probability of the unit state *i*
$\lambda_{\pm i}$	Upwards and downwards transition rates of the thermal capacity states
$P'(X-C_i)$	Cumulative probability of the system capacity outage state of 'X–C_i' MW before the unit was added
$P^{th}_{\min_i}$, $P^{th}_{\max_i}$	Minimum and maximum power output limits of the thermal generator i in MW
$W_w(t)$	Maximum wind power output of wind generator w at time t in MW (historical wind data)
$P^{hd}_{\min_h}$, $P^{hd}_{\max_h}$	Minimum and maximum power output limits of the hydro generator h
η_h	Efficiency of the water reservoir and hydro generators h
$E_h(t)$	Hydro energy inflow of the hydro generator h at time t in MWh
$E^{hd}_{\min_h}$, $E^{hd}_{\max_h}$	Minimum and maximum energy stored limits in the reservoir of the hydro generator h in MWh
ror_h	Percentage of energy of the water inflow representative of hydro run of river
res_{InSt}	Percentage of maximum energy storage level of the reservoir
$d(t)$	Load demand at time t in MW
$MaxP^{th}$	Peak of total power output of all thermal generators required to supply demand across all considered operating conditions in MW
$P^{th}_i(t)$	Power output of thermal generator i at time t in MW
$P^{hd}_h(t)$	Power output of hydro generator h at time t in MW
$P^{wd}_w(t)$	Wind power output of wind generator w at time t in MW
$E^{hd}_h(t)$	Energy stored in the reservoir of the hydro generator h at time t in MWh

ΔC_{Sec}	additional per-unit system costs of secondary technology
D_{Pr}^{C}	percentage displaced capacity of primary technology (due to penetration of secondary technology)
D_{Pr}^{E}	percentage displaced energy of primary technology (due to penetration of secondary technology)
$C_{Pr}^{I_0}$	per-unit cost of capacity of primary generation technology ($/MWh) in the original system when supplied with the primary technology only. This per-unit cost is simply equal to the annuitised investment capacity cost of the original system (£/annum) divided by the total annual energy produced (MWh/annum).

Modelling of Thermal Generation in the Capacity Adequacy Model

The thermal capacity in the system is represented by generic

1. The cumulative probability P(X) of a particular capacity outage state of the system, say 'X' MW on addition of a unit of capacity 'C' MW, is given by:

$$P(X) = \sum_{i=1}^{n} P'(X - C_i)\, p_i$$

2. Loss of load probability in each time slot (half hour) of the simulation is computed by:

$$LOLP_t = \sum_{i=1}^{n} p(C_i < L_t)$$

3. Annual loss of load expectation (LOLE)

$$LOLE = \frac{1}{2}\sum_{t=1}^{T} LOLP_t$$

4. Annual expected loss of load frequency (LOLF)

$$LOLF = \sum_{t=1}^{T} LOLF_t$$

5. Annual expected loss of load duration (LOLD)

$$LOLD = \frac{LOLE}{LOLF}$$

Capacity Adequacy - Optimization Model for Generation Dispatch

Objective function:

$$\text{Minimize} \quad MaxP^{th}$$

Constraints:

1. Balancing supply and demand:

$$\left(\sum_{i=1}^{I} P_i^{th}(t)\right) + \left(\sum_{h=1}^{H} P_h^{hd}(t)\right) + \left(\sum_{w=1}^{W} P_w^{wd}(t)\right) = d(t), \quad \forall t \in T$$

2. Sum of the maximum output of thermal generators:

$$MaxP^{th} \geq \sum_{i=1}^{I} P_i^{th}(t); \quad \forall t \in T$$

3. Power output limits of individual thermal generators:

$$P_{\min_i}^{th} \leq P_i^{th}(t) \leq P_{\max_i}^{th}; \quad \forall i \in I, \forall t \in T$$

4. Wind power output:

$$P_w^{wd}(t) \leq W_w(t); \quad \forall w \in W, \forall t \in T$$

5. Power output limits of hydro generators:

$$P_{\min_h}^{hd}(t) = \frac{ror_h \cdot E_h(t)}{\tau}; \quad \forall h \in H, \forall t \in T$$

$$P_{\min_h}^{hd} \leq P_h^{hd}(t) \leq P_{\max_h}^{hd}; \quad \forall h \in H, \forall t \in T$$

6. Hydro energy balance:

$$\sum_{t=1}^{T} \left(\eta_h \cdot P_h^{hd}(t)\right) \cdot \tau \leq \sum_{t=1}^{T} E_h(t); \quad \forall h \in H, \forall t \in T$$

7. Energy balance in the reservoir:

$$E_h^{hd}(t) = res_{InSt} \cdot E_{\max}^{hd} - \eta_h \cdot P_h^{hd}(t) \cdot \tau + E_h(t); \quad \forall h \in H, \forall t \in T$$

$$E_h^{hd}(t) = E_h^{hd}(t-1) - \eta_h \cdot P_h^{hd}(t) \cdot \tau + E_h(t); \quad \forall h \in H, \forall t \in T$$

8. Constraint on energy level of the reservoir in each half hour period:

$$E_{\min_h}^{hd} \leq E_h^{hd}(t) \leq E_{\max_h}^{hd}; \quad \forall h \in H, \forall t \in T$$

Capacity Credit of Wind Generation

$$(Cap.\,Credit\ of\ Wind)_{WHT} = \frac{(Therm.\,cap.)_{HT} - (Therm.\,cap.)_{WHT}}{(Wind\ cap.)_{WHT}}$$

The subscript *HT* and *WHT* represent the hydro-thermal and wind-hydro-thermal system respectively.

Additional Capacity Costs Attributed to Wind power

$$\Delta C_{Sec} = (1 - \frac{D_{Pr}^{C}}{D_{Pr}^{E}}) \cdot C_{Pr}^{I_0}$$

Appendix C – PROBLEM FORMULATION FOR RESERVE STUDIES

List of Acronym

Notation	Definition
ψ	Objective function ($/year)
NP	Number of demand period
NG	Number of generators
NS	Number of seasons
NW	Number of weeks
G	Set of generators
τ^t	Number of hours at demand period t (hours)
$tup_i^{\min}$	Minimum up time for generator i (hours)
$tdw_i^{\min}$	Minimum down time for generator i (hours)
c_{gi}	Fuel cost of generator i ($/MWh)
c_{IL}	Cost of interruptible loads ($/MWh)
cst_{gi}	Start up cost of generator i ($/start up)
c_{Fj}	Annuitised investment cost of branch j ($/MW/year)
nlc_{gi}	No load cost of generator i ($)
D^t	Total demand at period t (MW)
pg_i^t	MW output of generator i at period t (MW)
γ_i^t	Online status of generator i at period t.
$pg_i^{\min}, pg_i^{\max}$	Minimum and maximum limits of generator i (MW)
$pgror_i^t$	Run of river hydro output of generator i at period t (MW)
$pgrsv_i^t$	Hydro reservoir output of generator i at period t (MW)
ror_i^t	Run of river inflows at period t (MWh)
rsv_i^t	Reservoir inflows at period t (MWh)
$Ersv_i^t$	Energy in the hydro reservoir of generator i at period t (MWh)
$Ersv_i^{\max}$	Reservoir capacity of generator i (MW)
sr_i^t	Frequency keeping reserve provided by generator i at period t (MW)
il^t	Amount of interruptible loads purchased at period t
$il_{\max}^t$	Maximum amount of interruptible loads can be purchased at period t
$stup_{gi}^t$	Equal 1 if generator i is started at period t otherwise 0
$ramp_i^{up}$	Maximum ramp up rate of generator i (MW/min)

$ramp_i^{dw}$	Maximum ramp down rate of generator i (MW/min)
SR^t	Total system requirement of frequency keeping reserve at period t (MW)
fr_i^t	Instantaneous reserve provided by generator i at period t (MW)
FR^t	Total system requirement of instantaneous reserve at period t (MW)
EH_i^s	Total of energy inflows for hydro generator i at season s (MWh)
CF_i	Annual capacity factor of generator i (%)
$DClink$	Power transfer capability at the HVDC Link (MW)
NI	North island
SI	South island
σ_{Dem}	Standard deviation of errors in demand forecast
$\sigma_{Conv.Gen}$	Standard deviation of errors in conventional generation.
σ_{Wind}	Standard deviation of wind output variations.
$\gamma_{D/W}$	Correlation coefficient between demand and wind generation. (The available data does not show any correlation between demand and wind output over shorter time horizons, therefore, it was considered to be zero in this study).

Problem Formulation for Reserve Studies

1. Overall standard deviation of variations

$$\sigma_{Total} = \sqrt{\sigma_{Dem}^2 + \sigma_{Conv.Gen}^2 + \sigma_{Wind}^2}$$

2. Reserve requirements:

$$Overall\ Reserve = 3 \times \sigma_{Total}$$

Objective Function:

Minimize $$\psi = \sum_{t=1}^{NP} \sum_{i=1}^{NG} \{\tau^t \cdot [(c_{gi} \cdot pg_i^t + nlc_{gi} \cdot \gamma_i^t) + c_{IL} \cdot il^t] + cst_{gi} \cdot stup_{gi}^t\}$$

Constraints (applied to all periods $\forall t \in T$):

1. Balance of supply and demand constraints

$$\sum_{i=1}^{NG} pg_i^t = D^t$$

2. Generator limits

$$\gamma_i^t \cdot pg_i^{\min} \le pg_i^t \le \gamma_i^t \cdot pg_i^{\max}; \forall i \in G; \gamma_i^t \in \{0,1\}$$

3. Minimum up and down time

$$(\gamma_i^t - \gamma_i^{t-1}) \cdot tup_i^{\min} \le \sum_{k=t}^{k=t+tup_i^{\min}-1} \gamma_i^k; \forall i \in G$$

$$(\gamma_i^t - \gamma_i^{t-1}) \cdot tdw_i^{\min} \ge \sum_{k=t}^{k=t+tdw_i^{\min}-1} (\gamma_i^k - 1); \forall i \in G$$

4. Ramp rate

$$pg_i^t \le pg_i^t + ramp_i^{up}; \forall i \in G$$

$$pg_i^t \ge pg_i^t - ramp_i^{dw}; \forall i \in G$$

5. Start Up

$$stup_i^t \ge \gamma_i^t - \gamma_i^{t-1}; stup_i^t \in \{0,1\}$$

6. Frequency keeping reserve constraints

$$\sum_{i \in \{\text{NI gen}\}} sr_i^t \ge SR_{NI}^t$$

$$\sum_{i \in \{\text{SI gen}\}} sr_i^t \ge SR_{SI}^t$$

$$sr_i^t \le \gamma_i^t \cdot pg_i^{\max} - pg_i^t; \forall i \in G$$

7. Instantaneous reserve constraints

$$\sum_{i \in \{\text{NI gen}\}} fr_i^t + il^t \ge FR_{NI}^t$$

$$\sum_{i \in \{\text{SI gen}\}} fr_i^t \ge FR_{SI}^t$$

$$fr_i^t \le [-fr_i^{\max} \cdot (pg_i^{\max} - pg_i^{\min})^{-1}] \cdot (pg_i^t + sr_i^t - \gamma_i^t \cdot pg_i^{\min}) + \gamma_i^t \cdot fr_i^{\max}; i \forall G$$

8. Interruptible loads

$$il^t \le il_{\max}^t$$

9. Hydro generation

$$\sum_{t}^{W}(\tau^{t}\cdot pg_{i}^{t})\le EH_{i}^{w}\quad \forall w\in\{1..NW\}$$

$$\sum_{t}^{W}(ror_{i}^{t}+rsv_{i}^{t})=EH_{i}^{w}$$

$$\tau^{t}\cdot pgror_{i}^{t}\le ror_{i}^{t}$$

$$pgror_{i}^{t}+pgrsv_{i}^{t}\le pg_{i}^{t}$$

$$Ersv_{i}^{t}=Ersv_{i}^{t-1}+rsv_{i}^{t}-\tau^{t}\cdot pgrsv_{i}^{t}$$

$$Ersv_{i}^{t}\le Ersv_{i}^{\max}$$

10. Constraints for inter-connector

$$DClink_{SI->NI}\ge D_{NI}^{t}-\sum_{i\in\{\text{NI gen}\}}pg_{i}^{t}$$

$$DClink_{NI->SI}\ge D_{SI}^{t}-\sum_{i\in\{\text{SI gen}\}}pg_{i}^{t}$$