Electricity Commission
Long term projection of the Constraints Surplus

March 2009

Prepared by Energy Link

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Quality Assurance Information

Name	EL PS Report Final .docx
File reference	E-Elink-EC - Constraints
Document Number	1
Issue Status	Final
Issue Date	11 March 2009
Client	Energy Link Ltd
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Definitions

The following abbreviations and acronyms may appear in this report.

EC	Electricity Commission
ECE	Extended Contingent Event (Defined in the EGRs)
EGR	Electricity Governance Rules
FIR	Fast Instantaneous Reserves, or ‘six second’ reserves
GXP	Grid Exit Point
NI	North Island
NSP	Network Supply Point. Any point of connection between: (a) a local network and the grid; (b) two local networks; (c) a local network and an embedded network; (d) two embedded networks; or (e) a generator and the grid
SI	South Island
SIR	Sustained Instantaneous Reserves, or ‘sixty second’ reserves

Disclaimer

In preparing this report, Energy Link has made predictions of the outcome of future events including, but not limited to, spot electricity prices, electricity forward and futures market prices, local and national demand for electricity, hydrological inflows to river systems, temperature and weather conditions, and the bidding and purchasing behaviour of participants in electricity and other markets. Energy Link has made such predictions in good faith and Energy Link will not be held liable for the actual outcomes of the specified events, for the accuracy of its predictions or for any special or consequential damages or losses resulting in any way whatsoever from the purchase, consideration or use of Energy Link's forecasts.

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1 Introduction

The Electricity Commission (EC) is considering whether to introduce transmission hedges for wholesale market participants who purchase electricity in regions exposed to high volatility in price differences across the grid.

The EC Board has requested that a cost-benefit analysis of a transmission hedge option, locational rental allocations (LRAs), be presented to the Board.

To contribute to this cost-benefit analysis, the Commission wishes to assess the likely impact of planned transmission investment on future constraints. This will allow the Commission to determine the extent to which spot price volatility will be an issue in the future.

1.1 Energy Link's role

The primary question that Energy Link has been asked to address is:

What impact is planned transmission investment likely to have on the frequency, duration and location of constraints, and on constraint rentals?

This is discussed in the context of the factors giving rise to constraints (such as unexpected events, prolonged events such as wet/dry hydrological sequences, ongoing reliance on local generation, regular uncertainties such as intermittent generation, etc) and how likely these reasons are to give rise to constraints in the future.

In terms of time scale the Commission is interested in advice on constraints over the period to 2020. For comparison with historical constraints the Commission suggested the relevant period should be 2002 – 2008.

Other considerations the Commission has sought advice on includes:

- What is the likely impact of factors other than transmission investment (such as generation investment and demand) on future constraints; and
- Whether the mix of generation, in particular a potential increase in wind generation, is likely to have any impact on future constraints.

It was requested that the final report provide a combination of qualitative explanation and quantitative analysis to support the explanation. The Commission requested that any underlying assumptions in the modelling are described.

1.2 The constraints surplus

We define here the constraints surplus[1] as:

That part of the funds arising as a result of the difference between payments made for purchases of electricity from the grid and payments made for injections into the grid that can be attributed to constraints occurring in the grid.

[1] Surpluses in the spot market are often referred to as 'rentals', a term which relates to the concept of an economic rent.

The constraints surplus in any period is the sum of the constraints surplus on all lines (including transformers) in the grid. When constraints occur, in almost all cases there will be only one or a few parts of the grid constraining. In this report we refer to the HVDC constraint surplus and the AC constraints surplus (the sum of the surpluses on all AC lines in the grid), the sum of the two being the total constraints surplus.

In the EGRs; "**constraint**" means:

a limitation in the capacity of the ***grid*** *to convey electricity caused by limitations in capability of available* ***assets*** *forming the* ***grid****; or limitations in the performance of the integrated power system.*

The occurrence of grid constraints impacting on electricity prices is determined by more factors than just the total physical capacity of the grid. In order to form a view of the constraints surplus in the future, we outline below the potential causes of constraints over the short and long term:

i. **Limits to the capacity of lines and transformers** to carry electricity. These are defined by the Grid Owner (Transpower) with regard to factors such as supplier's specifications and warranties, ground clearances, expected ambient temperatures, equipment life, and safety and security allowances.

ii. **Limits on groups of lines and transformers, defined by security issues** such as:

   a. Power flows through the network as determined by Resistance and Impedance values.

   b. Voltage stability in parts of the network, particularly areas where there is minimal generation, e.g. lower North Island,

   c. Security levels, i.e. the potential impact on a component of the network if there is equipment failure in another parts of the network.

iii. **Generation capability** in terms of:

   a. Provision of voltage support or reactive power within a region,

   b. Ability to provide reserves (FIR and SIR), e.g. this summer we are seeing limitations on the northwards transfers across the HVDC due to the availability of Reserves to cover the risk in the North Island of an HVDC outage.

iv. Availability and reliability of **ancillary equipment** in the network to:

   a. Measure power flows (meters),

   b. Open and close circuits to manage power flows (switches),

   c. Provide protection to parts of the network in the event of CEs or ECEs (relays)

   d. Provide voltage support and manage Power Factors (capacitors, static var compensators, synchronous condensors)

   e. Measure temperatures, both ambient and equipment temperature.

v. Lines and equipment **maintenance activities**, i.e. the real time availability of the various components of the grid. This includes both maintenance work and lines outages and equipment failures. The incidence of constraints is dependent on both the timing of the event, and the time involved in completing any rectifying work necessary.

vi. The **performance of the System Operator** in anticipating short term constraints and acting to avoid them within the resources available to them, e.g. bypassing circuits that may become constrained under certain load conditions. There are a number of circuits that are left disconnected under normal conditions because otherwise they are prone to constraining. Examples include the lines between MHO_PRM on the Kapiti Coast and FHL_WPW in Hawkes Bay.

vii. The **systems, policies and procedures** used by the System Operator when setting parameters within SPD. These are set out under the EGRs, but still require the System Operator to exercise judgement in the real time management of the system.

viii. The **behaviour of market participants**, particularly generators, when constraints may potentially occur. Generators can both avoid constraints, or aggravate constraints depending on how they choose to offer their generation capacity. Their choice essentially depends on whether the constraint is to their advantage or disadvantage given the amount and location of their retail load and generation. Some major consumers can also manage their load or offer reserves to offset potential constraints.

ix. The **performance of the Grid Owner** in anticipating potential constraints in the long term and designing the grid to avoid those constraints.

x. The **ability to change the grid** in response to anticipated constraints, i.e. the lead times involved in upgrading or changing the grid in response to changing load patterns and generation availability, e.g.:

   a. planning and approval timeframes

   b. securing Resource Consents,

   c. purchasing specialist equipment from overseas suppliers, or

   d. supply of skilled labour and key resources.

Because of the very large range of factors that can potentially lead to grid constraints, or conversely, potential constraints being circumvented, we cannot rely on conventional scenario modelling using the expected grid and a range of demand and generation scenarios to determine the likely future incidence of grid constraints.

1.3 Our approach

We have endeavoured to use relevant historical trends and quantitative analysis to provide some clues as to expected future constraints and constraints surplus.

Our projections are necessarily subjective: the existing capability of the grid and the expected growth in the electricity market is important, but so are the capability and approach of the grid owner and systems operator and effectiveness in grid planning and investment by both Transpower and the EC.

2 Conclusions

The size of the surplus created when there is a constraint on the grid is the product of the price difference and the power flow across the constraint.

The timing of the largest annual constraints surpluses on the grid has lead us to the conclusion that the largest surpluses are arising when the South - North and North – South power flows are at their maximum, i.e. when there are constraints occurring on the central core of the transmission grid.

The AC and HVDC constraints surplus, while being significant in 2008, have otherwise not been the major contributors to the overall pool surplus in recent years.

The capacity of the core grid and expected power flows therefore has an important influence on the incidence of constraints. Increased investment on the HVDC and core grid is therefore expected to reduce the average size of the constraint surplus over time.

We note particularly that:

i. The HVDC upgrade will have a large impact on the expected constraints surplus, both for the HVDC link and AC network. We expect the HVDC upgrade to improve the voltage stability issues in the Wellington region, which will therefore enable greater power flows southwards across the AC network into the Wellington region from BPE when the SI hydro lakes are low;
ii. Many of the lower cost upgrades made to date have had a significant effect, and most new investments will have a relatively lesser impact for the money spent;
iii. The actual operation of the grid and its application by the System Operator to the pricing runs in SPD also has a significant impact on the occurrence of constraints.

Despite the considerable uncertainties involved in any estimates, we have endeavoured to quantify the potential size of the constraints surplus in future years:

i. We expect the AC Constraints surplus to average less than $5 million p.a. in future.

ii. There is still a significant chance that the AC Constraints surplus will exceed $20 million in any one year.

iii. Our modelling results suggest that the HVDC Constraints surplus may average at around $20 million p.a. once Pole 1 is upgraded, but double that until that time. Current evidence is that the SI hydro generators will avoid constraining the South – North and North - South transfers if they can through their generation strategies. This is because the constraints can cost them significant sums on the balance between their generation revenues and retail purchases.

iv. The HVDC Constraints surplus may exceed $60 million in any one year prior to the pole 1 upgrade.

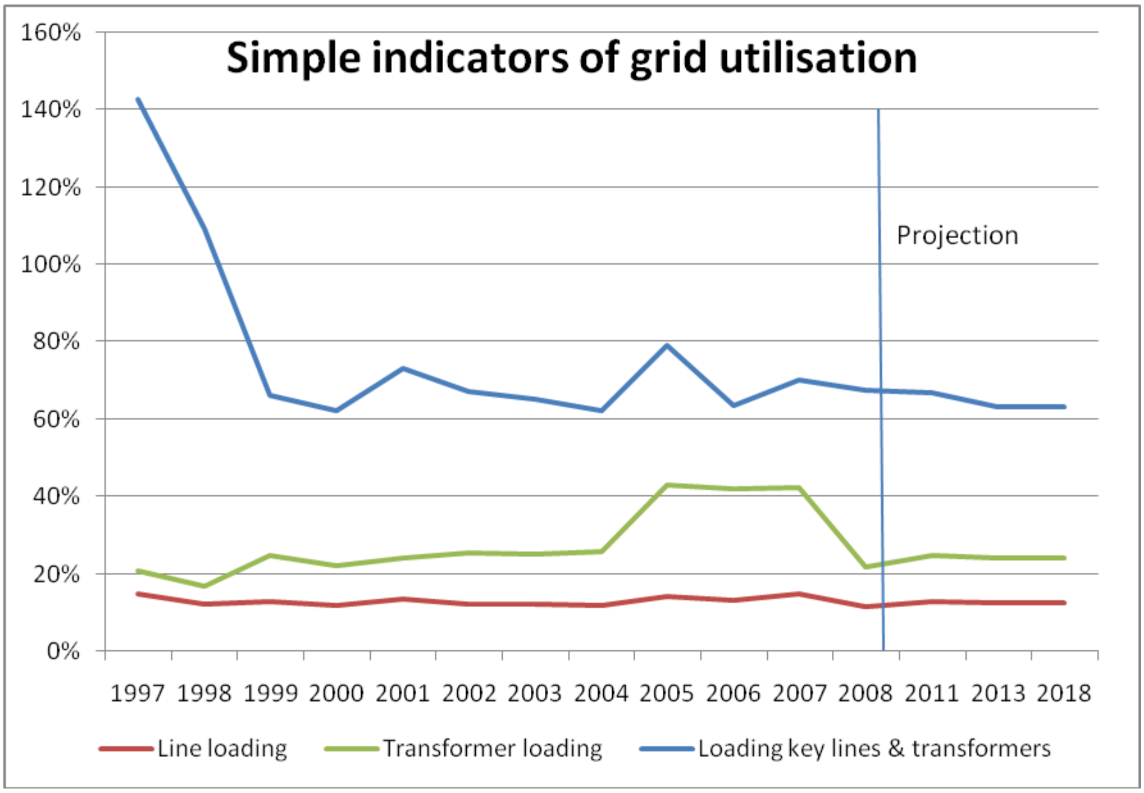
3 Historical trends

3.1 Grid capacity and load

Much has been said recently about the increasing investment in the grid[2]. As a simple measure of how that investment might be reflected in reducing constraints on the grid we looked at comparing the historical capacity of the grid against load.

Figure 1 provides a chart of the annual peak load[3] against the total capacity of all transformers and circuits on the grid, excluding the HVDC lines. Also shown on the chart is a measure of capacity utilisation of the 20 most heavily loaded lines and transformers for a sample TP in each year (the top line).

Figure 1 Indicative grid loading



This is obviously a relatively crude measure of grid capacity in that it gives an equal weighting to all transformers and circuits, irrespective of location or significance. The average loading of the 20 most heavily loaded lines and transformers is quite variable and is likely to depend on the specific conditions at the time. The loading on transformers appears to have been gradually increasing over time, while overall the loading on the lines has been relatively static. (The period 1997-1999 is outside the scope of this study, but we suspect that the very high apparent loadings in that period relate to how the line ratings were set in that period.)

[2] "Transpower has moved from a long period of very low investment, over the last 20 years, to a concentrated period of high reinvestment in the transmission grid. Between 1995/96 and 2004/05, capital expenditure on new build and asset renewal averaged around $100 million per year. However, over the next decade Transpower expects to spend $3 to $5 billion to meet future electricity demand." Patrick Strange, www.gridnewzealand.co.nz/asset-management-review

[3] This is the load for the peak half hour trading period rather than instantaneous peak load.

The projections in the chart are based on planned and anticipated grid upgrades between now and 2018. The chart suggests that the expected grid upgrades included in these projections do not significantly improve the overall ratio of peak load to capacity.

This of course ignores the expected quality of the grid in terms of upgrading key infrastructure, retiring equipment at the end of its useful life, and improved maintenance schedules. Our list of the potential causes of constraints tells us that constraints on the grid are a function of much more than just conductor and transformer capacity.

Table 1 below shows the loading on various components in the grid on the highest half hourly demand during 2008 (TP37, 18 August 2008). These are ranked from the highest loading and only include those components with loading of over 70%.

Table 1 Loading at peak demand in 2008

Name	From	To	Capacity	Power Flow	Loading %
HLY_OTA2.1	HLY2201	TAK2201	760	691	91%
BEN_T2.L2	BEN0162	BEN1002	232	210	90%
BEN_T2.T2	BEN2201	BEN1002	232	- 209	90%
HAY_T5.M5	HAY1101	HAY1005	200	- 178	89%
HAY_T1.M1	HAY1101	HAY1001	200	- 178	89%
HAY_T2.M2	HAY1101	HAY1002	200	- 178	89%
LIV_WTK.1	LIV2201	WTK2201	323	- 268	83%
HAY_T2.T2	HAY2201	HAY1002	216	178	82%
HAY_T5.T5	HAY2201	HAY1005	216	178	82%
HAY_T1.T1	HAY2201	HAY1001	216	178	82%
BRY_T6.M6	BRY0661	BRY1006	100	- 81	81%
BRY_T5.M5	BRY0661	BRY1005	100	- 80	80%
HLY_OTA2.2	OTA2201	TAK2201	762	- 602	79%
TMI_T1.T1	TMI1101	TMI0331	30	24	79%
OTA_T2.M2	OTA1007	OTA1002	100	- 78	78%
HAY_T11.T11	HAY1101	HAY0111	21	16	77%
PAL_T1.T1	PAL0331	PAL1101	10	- 8	76%
AVI_WTK.1	AVI2201	WTK2201	323	240	74%
BRY_T3.T3	BRY0661	BRY0111	37	27	74%
BEN_T5.L5	BEN0163	BEN1005	232	170	73%
TIM_T2.T2	TIM1101	TIM0111	26	19	73%
TIM_T3.T3	TIM1101	TIM0111	26	19	73%
BEN_T5.T5	BEN2201	BEN1005	232	- 170	73%
BRY_T2.T2	BRY0661	BRY0111	37	27	73%
ARA_WRK.1	ARA2201	WRK2201	112	81	72%
TIM_T4.T4	TIM1101	TIM0111	28	20	71%

Table 2 illustrates the loading against the equation constraints being enforced for the same TP. Three of these constraints have a higher loading factor (94 – 96%) than the individual lines and circuits shown in Table 1.

Table 2 Loading on equation constraints during peak demand

Name	Formula	Limit	Value	Loading
KAW_MAT_W_P_1	-1.08*KAW_MAT1.1+-1*KAW_MAT2.1	110	106	96%
LIV_WTK_1_W_P_1A	-1.38*LIV_WTK.1+-0.23*ISL_TKB.1	453	428	94%
ARI_HAM_W_P	1*ARI_HAM1.1+-0.094*HAM_WKM.1	62	58	94%
LIV_WTK_1_W_P_2A	-1.36*LIV_WTK.1+-0.31*CYD_TWZ2.2	442	394	89%
BPE_TKU_1&2_W_P_2of2	-1.3*BPE_TKU1.1+-0.51*BPE_TKU2.1	320	284	89%
AVI_WTK_1_W_P_1A	1.38*AVI_WTK.1+-0.23*ISL_TKB.1	445	390	88%
AVI_WTK_1_W_P_2A	1.36*AVI_WTK.1+-0.32*CYD_TWZ2.2	444	358	81%
EDG_KAW_1_W_TEMP_1	-1.04*EDG_KAW1.1+-0.65*EDG_KAW2.1	60	43	71%
KIN_TRK_1_W_P_1	-1.05*KIN_TRK1.1+-0.07*HAM_WKM.1	63	44	70%
MGM_MST_1_or_MGM_WDV_1_WELLINGTON_STABILITY_O_1_z	1*BPE_HAY1.1+1*BPE_HAY2.1+-1*HAY_LTN1.1+1*BPE_WIL1.2	940	640	68%
KIN_TRK_1_W_P_2	-1.05*KIN_TRK1.1+-0.54*KIN_TRK2.1	64	41	64%
HWA_ABSS_DISABLED_REACTOR_IN_W_P_1OF2_z	1.054*HWA_WVY1.1+-0.037*BPE_BRK1.1	65	40	62%
MAN_INTERTRIP_DISABLED_STABILITY_P_1	1*MAN_NMA1.1+1*MAN_NMA2.1+1*MAN_NMA3.1+-1*INV_MAN.1	845	421	50%
CYD_ROX_1&2_W_P	1.28*CYD_ROX1.1+0.9*CYD_ROX2.1	526	257	49%
HWA_ABSS_DISABLED_REACTOR_IN_OR_OUT_W_P_1_z	1.03*HWA_SFD1.1+1*HWA_WVY1.1	62	30	49%
TMU_RUNBACK_DISABLED_W	-1.049*HAM_KPO1.2+-1*HAM_KPO2.2	75	26	34%
OHK_WRK_1_W_P_2A_z	-1.24*OHK_WRK.1+-0.85*WKM_PPI_WRK.2	471	153	32%
OHK_WRK_1_W_P_A_z	-1.3*OHK_WRK.1+-0.88*ATI_WKM.1	483.5	96	20%
FHL_RDF_1&2_W_P_1_z	-1.03*FHL_RDF2.1+-0.94*FHL_RDF1.1	66.1	10	15%
ATI_WKM_1_W_P_B_z	-1.24*ATI_WKM.1+-0.95*OHK_WRK.1	470	62	13%
HWA_ABSS_DISABLED_REACTOR_IN_W_P_2OF2_z	-1.054*HWA_SFD1.1+-0.038*BPE_BRK1.1	67	9	13%
ROX_T10_W_P_z	-1*ROX_T10.T10+-0.598*GOR_ROX.1	57	3	5%

These loadings are only relevant for the specific circumstances during that TP. Despite the fact that they occurred during the peak demand period in 2008, we cannot extrapolate this data to suggest that these same lines and equations will be most likely to constrain during 2009. A different mix of demand, generator offers and parts of the grid undergoing maintenance as well as commissioning of any upgrades will give an entirely different pattern.

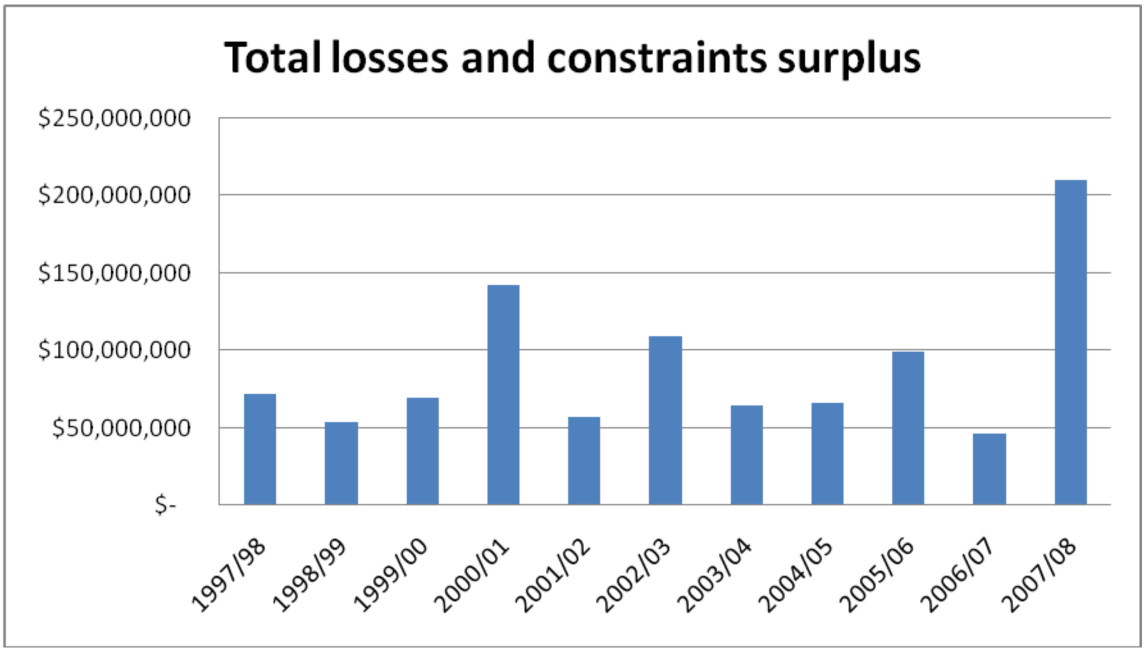
We use this example to illustrate some of the complexity involved in assessing the likelihood of constraints occurring at any particular time.

Going back to our causes of constraints Section 1.2 ii **Limits to the capacity of lines and transformers** to carry electricity. The above data illustrates that the issue is more complex than just matching expected power flows against the total capacity of the grid.

3.2 Trend in the constraints surplus

Another useful guide to the future is to look at the past trend in the grid surplus. The raw data, refer Figure 2, would suggest that there has been no real improvement in the losses and constraints surplus in recent years.

Figure 2 Losses & constraints surplus



A key driver of the volatility of these figures, however, is the electricity prices rather than the actual incidence of grid constraints. To gain a better perspective on the numbers we have:

i. Separated out the surplus arising from losses and the HVDC in order to get an estimate of the actual constraints surplus, and
ii. Divided the monthly constraints surplus by the average monthly price[4].

The process we used to derive our estimate of the breakdown of the pool surplus between losses and constraints on the AC and HVDC networks is presented in the Appendix, Section 6.

[4] It would be more accurate to adjust the surplus by the average price for each time period, but for the purpose of illustration the less precise but simpler adjustment is adequate.

Figure 3 below shows the Losses and constraints surplus split out between the AC network and HVDC link losses and constraints. The data is by calendar year.

Figure 3 Estimated composition of the losses and constraints surplus by year

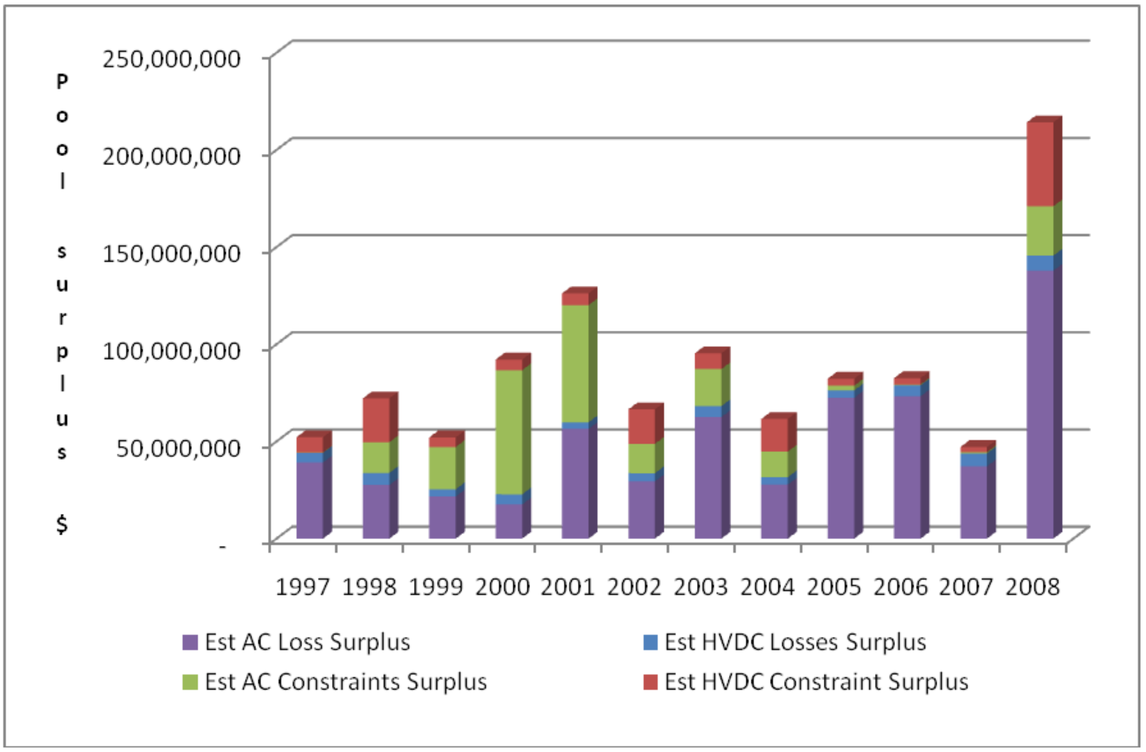


Figure **4** below highlights the constraints surplus only, and separates this between the AC network and HVDC link. The I bars on the chart indicate the approximate margin of error in the process of deriving the constraints surplus. The estimates for 2005 – 2007 are within the margin of error in the analysis[5].

[5] This occurs because we have not used the power flows on every line for every trading period to separate out the losses and constraints surplus.

Figure 4 Estimated AC Network and HVDC Link Constraints Surplus

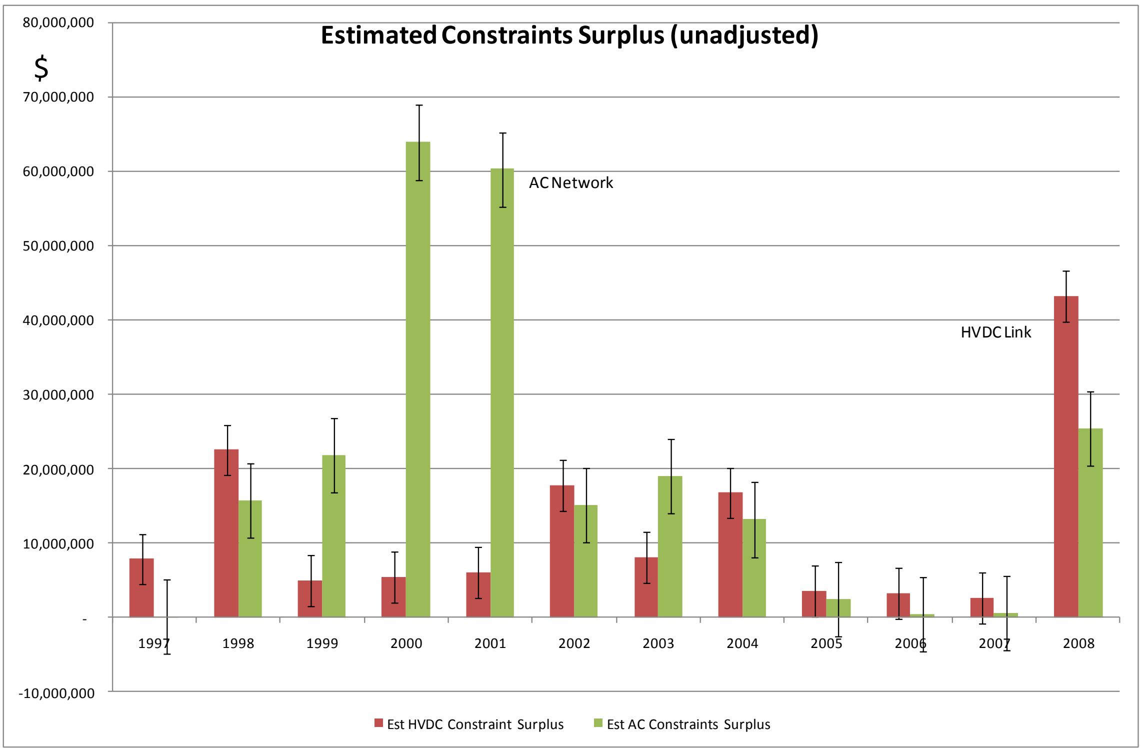
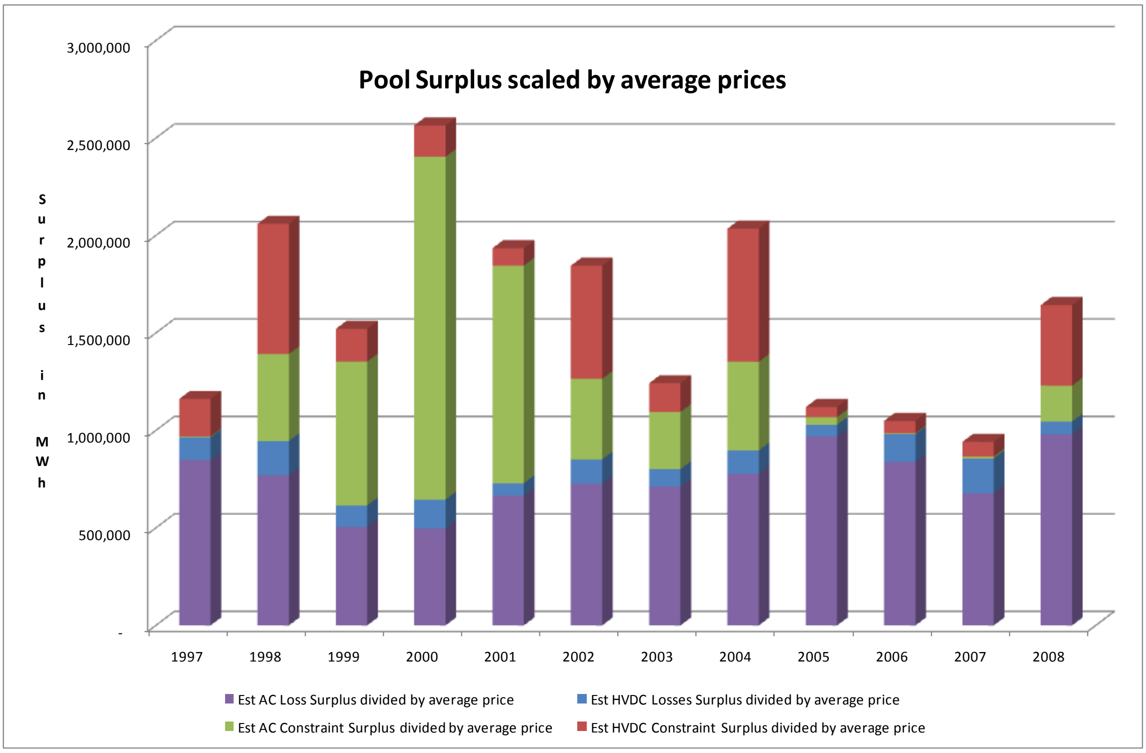


Figure 4 that the constraints surplus from both the AC network and HVDC link had declined over the period 2000-2001 through to 2007, but the extreme price events of 2008 again created a large constraints surplus.

Of course, the possibility of high price periods have not disappeared, but we should not assume that 2008 is going to be a high frequency event. We also know that the unplanned outage of Pole 1 on the HVDC link is the primary cause for the surplus arising on the HVDC link.

Figure 3, but they are scaled by the average monthly electricity price. This gives an appreciation of the 'volume' of MWh impacted by losses and constraints before the impact of high prices in the dry years. This analysis indicates that the very high pool surplus in 2008 was more a result of the very high prices than an extraordinary incidence of grid constraints.

Figure 5 Estimated losses and constraints surplus divided by average monthly prices



It is apparent from Figure 5 that in terms of MWh, constraints on the AC network in 2008 were still well below the peaks from 1998 through until 2004.

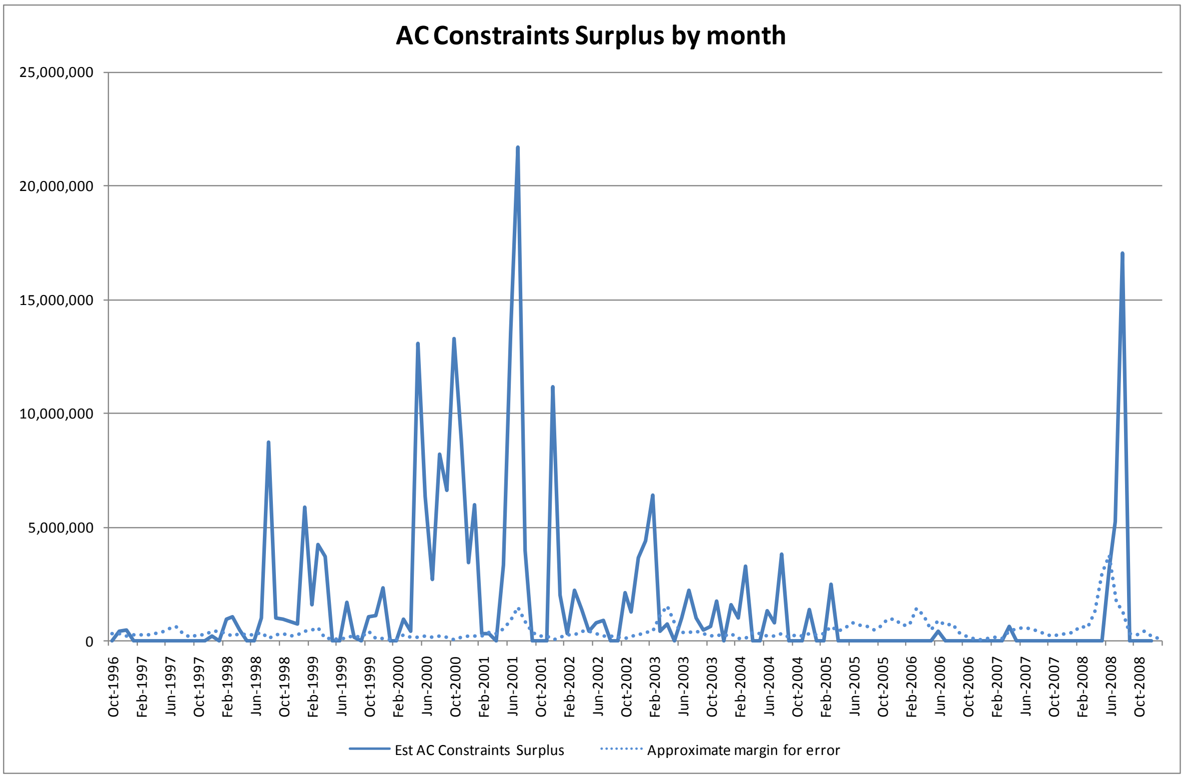
Figure 6 below focuses entirely on our estimate of the AC Constraints surplus. This chart shows the monthly data, and the typical volatility of the impact of constraints on the AC network is clearly illustrated (the figures are not adjusted by average prices.)

The spikes in the years where we experienced dry spells are noticeable, particularly in 2001, 2003 and 2008. These spikes in constraints are combined with the impact of prices that are already high because of concerns over hydro reserves.

We have not undertaken a line by line analysis of where the constraints surplus is being generated, but we believe that much of this surplus is generated by the constraint on southwards power flows from BPE to Wellington[6] and also potentially power flows out of Taranaki. This constraint is described in more detail in Figure 6.

[6] Time was not available during this study to confirm this by calculating surpluses on all lines.

Figure 6 Estimated AC Constraints surplus by month



3.3 Generation and demand

The margin between generation capacity and demand on a regional basis also impacted on the pool surplus over the past ten years, just as it will impact on the pool surplus in the future. With the exception of Whirinaki, almost all of the most significant new generation projects built over the past ten years have been built near major load centres, or close to the core grid through the central NI.

The timing and nominal size of the projects is as follows:

- **Generator Commissioning MW capacity (nominal)**
- Tararua 1 Mar-99 32
- Otahuhu B Jan-00[7] 385
- Mokai Feb-00 94
- Tararua 2 May-04 36
- Huntly p40 Jun-0448
- Whirinaki Jun-04155
- Te Apiti Nov-04 90
- Tararua 3 Jan-07120
- Huntly e3p Mar-07 385
- White Hills Mar-07 76
- Kawerau Aug-08 90

[7] The effective commissioning date of Otahuhu B power station was delayed through technical; problems.

It is noticeable that, except for White Hills, all of this capacity has also been built in the NI. At the same time there has been significant demand growth in the SI.

This concentration on the NI has increased the expected need for significant southward power flows during dry periods.

Our estimate of the monthly AC network constraints surplus during 2008 jumped from $5m in July 2008 to $17m in August 2008. This was despite a drop in average prices from July to August. We believe the limitations on southwards power flows from BPE into Wellington became critical in August because we had a combination of:

- the commissioning of the 90MW geothermal scheme at Kawerau on 31 July 2008[8];
- high inflows into the Waikato hydro system, and
- low hydro storage in the SI.

The key point here is that the timing and location of new generation has a significant impact on both the AC network and the HVDC link constraints surplus.

3.4 Spring washer rule

In 2007 the EC introduced a new pricing rule to reduce the impact of ‘spring washer’ prices occurring in the final pricing run. The rule allows for marginally relaxing the value of a binding constraint when spring washer pricing effects occur. This relaxation of the binding constraint can have a marked effect on reducing final prices and the subsequent AC constraints surplus arising from that event. We have not attempted to quantify the impact of that change, but are aware that it has been used and has had the desired effect on a number of occasions.

In effect, this rule has the same effect as reconfiguring the grid after the event to minimise the impact of binding constraints.

3.5 Examples of constraints

In the time frame available for this study we have only been able to highlight a few examples of constraints and their causes. These serve to illustrate some of the issues that we raise, but we do not hold them to be representative of all constraints arising in the grid from time to time.

BPE_HAY

During periods when the SI hydro generators are conserving water there are typically high southwards power flows from the NI, particularly during low demand periods. These power flows are constrained by a need to maintain voltage stability in the Wellington region, which has no significant generation. The southwards power flows into Wellington are limited by the following equation constraint applied in SPD:

1*BPE_HAY1.1+1*BPE_HAY2.1+-1*HAY_LTN1.1+1*BPE_WIL1.2 < 900[9]

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[8] Being a base load plant, Kawerau made a significant difference to supply and prices in the NI during low demand periods.

[9] The actual limit is adjusted by the System Operator as conditions change.

Figure 7 shows the key equation constraints on TP24 on 26 August 2008. It appears that this constraint was binding at that time, as was the BPE_TKU line. (Our model shows the binding constraints being at 103% of their ratings. This is because our solution is based on slightly different demand data to the final pricing run in SPD)

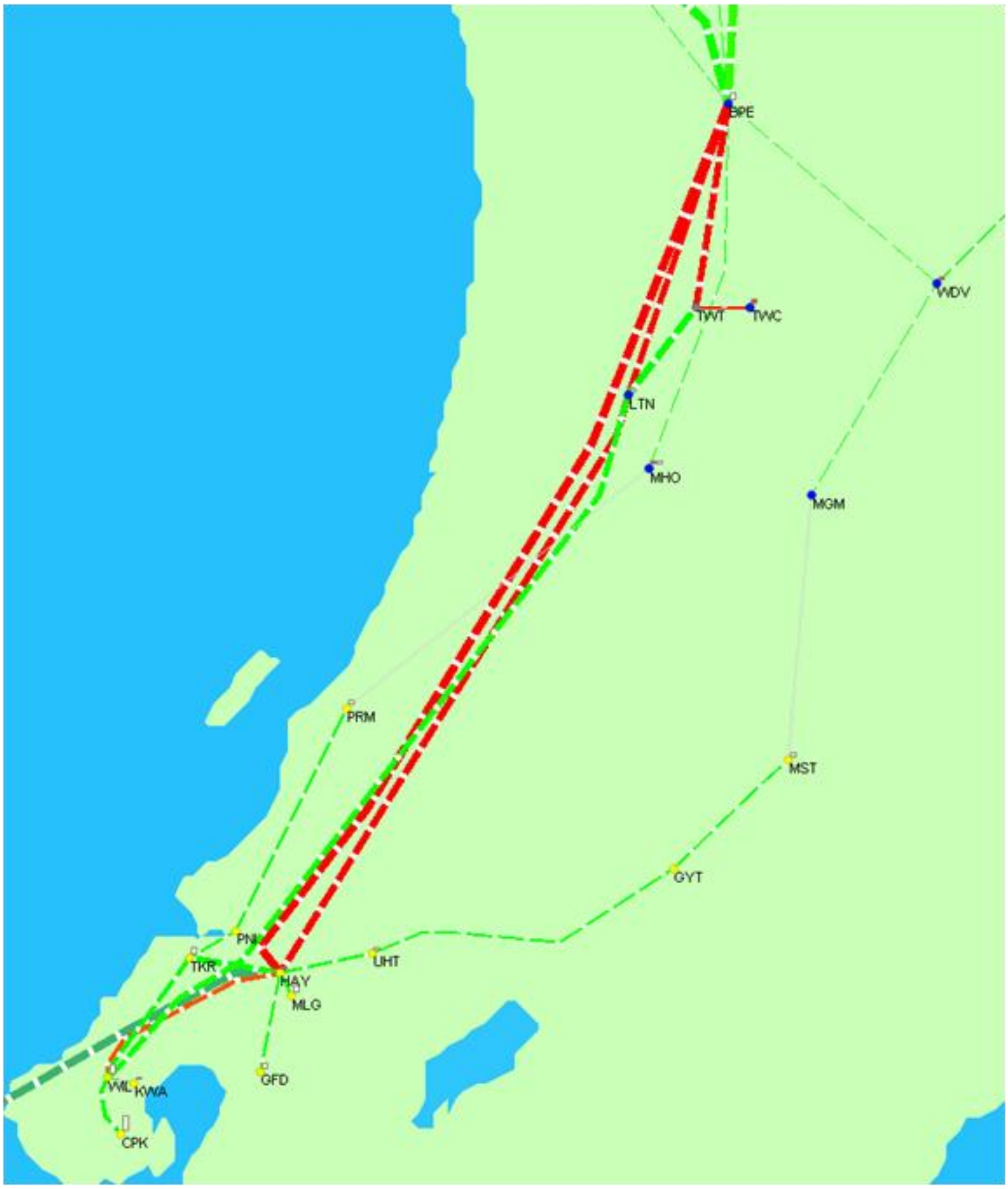
The price at BPE in this example was $28.46, while the price at HAY was $175.83. The surplus created across the constraint in that one trading period was approximately $136,000.

Figure 7 Loading of key equation constraints on 26 August 2008 TP24

Name	Formula	Limit	Value	Loading
MGM_MST_1_or_MGM_WDV_1_ WELLINGTON_STABILITY_O_1_z	1*BPE_HAY1.1+1*BPE_HAY2.1+-1*HAY_LTN1.1+1*BPE_WIL1.2	900	923	103%
BPE_TKU_1&2_W_P_2of2	-1.3*BPE_TKU1.1+-0.51*BPE_TKU2.1	330	339	103%
KAW_MAT_W_P_1	-1.08*KAW_MAT1.1+-1*KAW_MAT2.1	110	108	98%
EDG_T4&T5_W_O_1	-1*KAW_T13.T13+0.68*EDG_OWH.1	102	97	95%
HWA_ABSS_DISABLED_REACTOR_ IN_W_P_1OF2_z	1.054*HWA_WVY1.1+-0.037*BPE_BRK1.1	65	45	69%
TMU_RUNBACK_DISABLED_W	-1.049*HAM_KPO1.2+-1*HAM_KPO2.2	75	43	58%
HWA_ABSS_DISABLED_REACTOR_ IN_OR_OUT_W_P_1_z	1.03*HWA_SFD1.1+1*HWA_WVY1.1	62	25	41%
KIN_TRK_1_W_P_2A	-1.05*KIN_TRK1.2+-0.5*KIN_TRK2.2	67	29	43%

Figure 8 illustrates the lower NI network and the GXPs immediately affected by BPE_HAY equation constraint.

Figure 8 Map highlighting price differences in lower NI, 26 August 2008, TP24



This situation occurred frequently in July and August 2008. It is an illustration of the second cause of constraints that we referred to in Section 1.2 ii **Limits on groups of lines and transformers, defined by security issues.**

MGM_WDV

On 29 April 2007 there was a planned outage on the HVDC link. When prices were calculated for TP37 the line between MGM and WDV was constrained. This caused a 'spring washer' effect, and the price at MGM was $38,000. The EC chose to invoke the new spring washer rule that was to be introduced later in 2007, and the resulting final price at MGM was recalculated to be $190.47.

An alternative scenario is that with the planned outage of the HVDC link, Transpower could have opened (disconnected) the MGM_MST circuit while the HVDC link was down. In that case the spring washer effect would not have occurred at all, and prices at MGM and MST would only have reached around $150 in TP37.

We assume that the trade-off made by the System Operator in this situation is that disconnecting the MGM_MST line may also have reduced the desired security settings in the lower NI.

Without detailed analysis, putting aside the clear limitations of the MGM_MST line, this situation could be the result of the factors referred to in Sections 1.2: iv.b **ancilliary equipment to open & close circuits**, or vi **performance of the System Operator**, or vii The system operators **systems, policies and procedures**.

East Cape

The only significant generation in the East Cape region is at Waikaremoana (injecting at TUI) As long as there is adequate transmission capacity between Hawkes Bay and East Cape (on RDF_TUI) then generation at Waikaremoana competes with the rest of the market. In 2000 there was a period of several weeks in May when the transmission capacity northwards to Waikaremoana and the East Cape was constrained due to grid maintenance. At this time the price at Waikaremoana and the East Cape region was at around $800 for significant periods of time. Over May 2000 the average price at GIS was $192.67, while BEN, HAY and OTA averaged at around $40.

This is an example of both Section 1.2 v **Lines and equipment maintenance activities and** viii **the behaviour of market participants, particularly generators**.

Cromwell – Twizel

The limit on southwards power flows between the Waitaki Valley and the Clutha Valley includes the following equation:

1.28*CYD_ROX1.1+0.9*CYD_ROX2.1 < 526 MW

It is rare for this equation to constrain, but it can result in a significant cost to any net purchaser of electricity in Southland when it does constrain. Meridian and Contact are the major generators in this region with the Manapouri and Clutha schemes respectively. In general, we believe that Meridian operates the Manapouri power station in a way that it minimises the risk of the southwards power flows constraining.

This is an example of Section 1.2 viii **the behaviour of market participants, particularly generators**, where the generator is actively endeavouring to avoid the constraint from binding.

Wairakei Triangle

Energy Link has at times undertaken detailed analysis of existing and potential constraints on power flows through the Wairakei Triangle. This area is also of interest because Transpower is proposing to build a new line from WRK to WKM, replacing the existing line.

The power flows are complex in this region because of the combination of five grid injection points, a loop in the grid, and high through flows. Under ‘normal’ operating conditions, we do not expect the lines in this region to constrain. Difficulties immediately arise however whenever there is a requirement to reduce the capacity on any of the circuits. This will generally be for maintenance purposes, but could also result from equipment or lines outages. The issue in this area, with current generation and load patterns, is not so much the lack of capacity under normal conditions, but rather the lack of redundancy in the network.

We expect that the new line planned by Transpower will be built in parallel with the existing line and there would be minimal maintenance outages occurring as part of the construction project. In this case we would not expect to see significant constraints arising specifically as part of that work. However, if the existing assets were to be upgraded, then there could have been times when some circuits were going to be offline and constraints would then be likely to occur in the region while the work was being undertaken.

This is an example of Section 1.2 ix **anticipating potential constraints** and x **the ability to change the grid**.

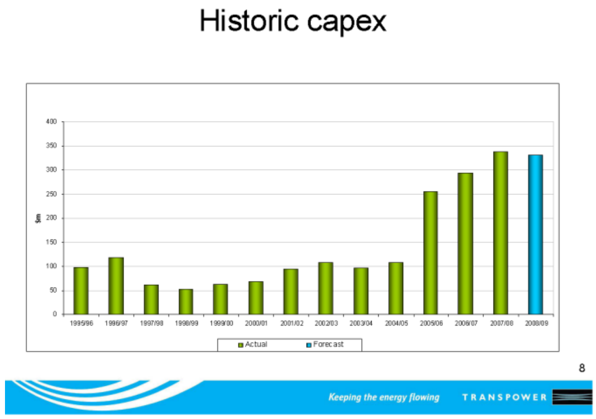
This example also helps to illustrate the uncertainty when making any estimate on the likelihood and magnitude of constraints surpluses in the future.

3.6 Our conclusion from the past trends

Transpower has highlighted that there was little investment in the Grid during the 1990’s, and not a great deal since then, in relationship to the overall expenditure that is now planned.

Yet it is apparent, and highly significant, from our analysis that there has been an overall reduction in constraints on the AC network since 2004.

We suggest a number of reasons for this in the following sections.



3.6.1 The first solutions are the easiest and cheapest

It seems that there were a significant number of constraints that were occurring in the Grid prior to 2005 that have now been resolved relatively easily and cheaply. These ‘tactical upgrades’ include:

- upgrading the thermal limits on lines by improving the ground clearances on parts of those lines,
- replacement of some key transformers, or installation of ancillary equipment,
- bussing lines at key locations to reduce outage risks,
- changing the points of injection for generation.

Transpower began to implement these changes some years ago, and parts of this first stage of improvement are still underway. We expect to see some further reductions in constraints arising from such changes, but not with nearly the same impact as the early projects.

The next stage of upgrades is much more expensive, will involve greater lead times, and will deliver relatively less improvement in the short term. The investment required is reflected in Transpower's upgrade plan and involves construction of whole new lines and substations.

3.6.2 New generation

The impact of new generation build since 2000 has been mixed. The concentration of new build in the NI, combined with the HVDC outage, probably contributed to the large AC constraint surplus in 2008. Otherwise the new generation has been built close to load and the central 'backbone' of the Grid through the NI. The grid in the NI has generally been able to handle the local power flows and the growing demand in Auckland to date.

3.6.3 Accountability and transparency

We do not believe that all of the improvements since 2004 have come from physical changes in the grid or generation. Changes in the industry have meant that Transpower's role is now more transparent. With the increased availability of data and improvements in tools used by or available to generators, the actions of the Grid Owner and the System Operator have also become increasingly transparent.

Transpower does not face direct costs from the incidence of constraints, but the existence and work of the Electricity Commission has probably helped to clarify expectations in regard to grid capacity and operation of the market. This has no doubt contributed to the pressure for Transpower to plan for grid upgrades.

We also understand that Transpower is now consulting over the timing of its maintenance work in an effort to reduce the likelihood of constraints occurring.

A specific example of improvements being made by the System Operator includes the introduction of the Simultaneous Feasibility Test (SFT) as part of its Market Systems upgrade project. We quote the System Operator's expectations for the SFT (http://www.systemoperator.co.nz/new-market-systems):

SFT allows the SO to determine and implement thermal security constraints dynamically, with an objective of providing better management of constraints in real time operation and enabling a more secure, efficient and cost effective use of grid capabilities. It is one of the significant improvements delivered by the MSP project and by better managing constraints accuracy will improve overall power system efficiency.

4 Future trends and influences

4.1 Grid investment

Proposed new investment in the electricity grid has accelerated due to a combination of factors:

- A push from Government to enable greater penetration by renewable generation;
- Response to blackouts caused by equipment failure;
- A wide range of new generation proposals being mooted; and
- Most recently, a push to use infrastructure spending as a tool to maintain economic activity.

4.2 Generation investment

The EC's SOO report highlights a range of new generation scenarios and various grid options associated with those scenarios. These have been costed on a Net Present Value basis and the results are presented in Table 22, on page 171 of the report. We have copied this below.

Table 22 NPVs of pre-tax costs in the market development scenarios (committed transmission projects are excluded)

Discount rate (real, pre-tax)	Scenario	Generation NPV (2007 $m)	Transmission NPV (2007 $m)	Total NPV (2007 $m)
Five percent	Sustainable Path	36,129	1,093	37,222
	South Island Surplus	35,743	1,055	36,798
	Medium Renewables	30,763	1,114	31,877
	Demand-side Participation	33,093	1,059	34,152
	High Gas Discovery	32,554	1,044	33,598
Seven percent	Sustainable Path	27,016	779	27,795
	South Island Surplus	26,711	754	27,465
	Medium Renewables	23,314	787	24,101
	Demand-side Participation	24,705	757	25,462
	High Gas Discovery	24,487	747	25,234

The highest NPV for transmission investment in this table, under the EC's central discount rate of 7%, is $1,044million. The spread between the highest and lowest cost generation options is $3,702million. The spread in potential generation costs is therefore approximately three times the total cost of the grid upgrades.

This statistic suggests to us that future investment decisions are likely to favour grid upgrades to carry electricity from likely generation developments, rather than the alternative of seeing generation projects favoured in lieu of grid upgrades.

The current debate over the proposed upgrade of grid capacity through Auckland (the NAaN project) is an example of such a decision being considered today. We are not taking a view on that specific proposal, but the above numbers to suggest that that potentially in many cases significant investment in grid capacity will be justified through the savings that can be achieved in lower cost options for new generation.

4.3 Intermittent generation

At any particular point in time, generation from wind farms presents essentially the same load on the grid as other forms of generation. (There are some ancillary issues around voltage support and reserves but within the scope of this discussion they are of lesser significance.)

What is significant, however, is that the grid potentially needs to have the capacity to carry 100% of the output from wind farms and other generation sources within a region at any point in time. At the same time the grid must have the capacity to carry the output from alternative generation sources when the wind is not blowing. The result is that a comparatively greater investment in the grid is likely to be required with a high penetration of new wind farms. This is illustrated in the SOO table above.

At the same time, with a growing number of consented sites for wind generation, the lead time for building wind farms falls to around two years or so, which is a shorter lead time than is required for major new grid projects.

The economics of many prospective wind farm projects is currently marginal. With an improvement in the value of the NZ$ and pricing of wind turbines, this could change quite quickly and result in a rapid expansion of wind farms at some point in the future.

It is likely therefore that there will be parts of the Grid that are not designed to transport the total net generation output from some regions. For example, in Southland/Otago we have the prospect of generation from all of the following sources:

Nominal capacity MW

- Manapouri (hydro): 840
- White Hills (wind): 58
- Waiwera Downs (wind): 120 (Stage 1 only)
- Slopedown (wind): 150
- Roxburgh & Clyde (hydro): 700
- Hawea gates (hydro): 17
- Mahinerangi (wind): 200
- Project Hayes (wind): 200 (Stage 1 only)
- Mount Maungatua (wind): 20
- And other smaller schemes n.a.
  - TOTAL 2,300
  - Less:

- Regional peak demand 1,000
- **Potential net power exports 1,300**

Will the lines between Clutha Valley and Waitaki Valley be upgraded to transport the potential peak generation output, less demand, of 1,300 MW northwards, or should we assume that the hydro power stations will be forced to reduce output (or even spill) when the wind farms are operating at capacity and demand is low?

Another significant aspect of wind generation is that from time to time it is likely to result in large shifts in the pattern of power flows. This can lead to changes in the values of line and equation constraint limits required in SPD.

An example of the way the wind generation can impact on grid settings is in the lower NI. Currently power transfers southwards from BPE to Wellington are limited by an equation constraint due to voltage stability issues (refer Section 3.3). We suspect, but only Transpower can confirm, that when West Wind is operating that constraint will be able to be relaxed to some degree, perhaps by as much as the output from West Wind. If that is the case, then potentially more electricity could be transmitted across the HVDC when West Wind is operating than would otherwise be the case. The difficulty is that such settings must track the output of the wind farm on a continuous basis, which itself can creates risks. This would not be an easy setting to manage, and it would only be relevant during periods of high southwards power flows in the lower NI.

In our AC constraints surplus projections therefore we have allowed for the possibility that new wind generation will create a constraints surplus on the AC network.

4.4 Role of the System Operator

The dispatch of electricity on the Grid is a dynamic process. For instance, the Grid must be managed to cater for maintenance work and changing patterns of power flows over time. The System Operator must monitor these changes and amend variables in SPD on a semi-continuous basis.

The priority for the System Operator is to ensure that the ‘lights stay on’. We suggest that this results in an element of conservatism in setting constraint values in SPD. Supporting this view, we see every month situations where the pricing run of SPD finds binding constraint that means that a solution for part of the grid is infeasible. As a result the offending constraint is usually relaxed to reflect the approximate dispatch of electricity and enable a price to be calculated. (This is covered under the EGRs.).

The following notice is a recent example of relaxing a constraint in the pricing run of SPD:

Infeasibility Situation Notice Pursuant to the Electricity Governance Rules Part G, Section V, Rule 3.6, prices were calculated yielding an infeasibility situation:	
Trading Date:	04/02/2009
Infeasibility 1:	
Periods Affected:	07:30, 08:00 and 13:00
Unit Affected:	APS0111
Cause:	Deficit Generation
System Operator Response 1:	05/02/2009
Action:	Constraint times on APS_T1.T1, COL_OTI1.2 and COL_OTI1.3 revised to remove infeasibility
Issue:	3

In these cases the actual power flows were clearly feasible at the time of dispatch ("the lights stayed on"), but the settings in SPD for the pricing run could not calculate a viable solution without an adjustment of the relevant constraint limits. Rule 3.8 (Part G, Section V of the EGRs) provides that in these cases: *the **system operator**, must exercise reasonable endeavours to resolve the **provisional price situation** and to provide revised data to the **pricing manager**.*

As the proportion of generation coming from wind increases, we can expect greater variations of power flows over short time frames. As well as requiring increase in core grid capacity, it may also require the System Operator to adjust its settings in SPD more frequently.

Transpower has also indicated that it will begin trialling more dynamic grid management tools[10]. A possible example of this is using temperature gauges on key lines so that their thermal ratings can be adjusted in accordance with changing ambient temperatures, i.e. in very cold conditions lines can carry higher loads without overheating or sagging below tolerance levels.

Such methods could be useful in better utilising existing grid resources, but they also add to the complexity of the System Operator's role.

[10] 'Transpower assesses 'Smart Grid' technologies' – GRID, December 2008

We have not reviewed the System Operator's operations in any detail for this study, but the Market Systems Project being implemented by Transpower may well provide some significant improvements to matching the pricing run in SPD with the physical capability of the grid to carry the load.

5 Projections

We do not believe that constraints in the AC network will disappear. But improvements in both Grid capacity and the application of pricing calculations in SPD lead us to the view that persistent constraints will become less significant.

This is made on the assumption that major grid investment decisions will be implemented to minimise the incidence of constraints. For example, this includes:

- Resolving power flows southwards from BPE and across the HVDC (this is already in the programme of work),
- Upgrading the Wairakei triangle without extended constraints while the work is undertaken,
- Lines capacity will be adequate through Auckland to ensure that no generator north of Auckland can exploit a constraint to force very high prices during peak periods.

On a more generic basis, new generation around the regions can be just as likely to reduce the incidence of a constraints surplus as create one. While parts of the grid may not have the capacity to carry all of the net generation, it is frequently in the generators' interests to avoid the lines constraining and causing a significant price difference occurring across the potential constraint.

We have therefore focussed on the 'big picture' scenarios that might cause constraints to occur and have put some values and probabilities on these.

5.1 Low impact constraints

Our analysis of the historical data indicates that the incidence of regional constraints in the pricing calculations across smaller parts of the network are either minimal or they are falling under the 10% margin of accuracy in our historical analysis. If these constraints were persistent we would have expected to have seen continuing evidence of them in prices.

We suspect that one factor in this improved trend is a greater awareness by Transpower in scheduling its maintenance work in recent years. We understand that in 2008 there were 1,000 occasions when transmission components had to be taken off line for servicing, and 25% of these were rescheduled because power loadings were different to what had been anticipated.

Transpower however advise[11] that they are finding it increasingly difficult to schedule grid maintenance work because of increasing loadings. Summer used to be a low demand period when maintenance could be undertaken. Summer loads have however increased through greater use of air conditioning systems and irrigation in particular.

[11] Patrick Strange, National Power Conference February 2009

Transpower is therefore finding increasing incidences where maintenance work may cause constraints to occur. In many cases the maintenance is deferred, but this will not always be the best solution.

Based on this, we have projected an increase in such costs over the next four years. After that we expect to see benefits coming from Transpower's projects to improve its maintenance and control systems. These include the:

- MSP, the Market Systems project, which is due to be implemented this year;
- TMP, which upgrades communications links to sub-stations using fibre optics, and
- SMS, the substation management project and use of smart technology.

Based on the historical constraints data, our best estimate of the incidence of constraints rentals arising from this cause is around \$0.5 - \$1.0 m per annum.

5.2 High impact constraints

We regard high impact constraints to be those set of circumstances that can lead to an AC constraints surplus in the millions of dollars in any month.

To assess the potential impact of these we have categorised four types of events:

- **2008** type circumstances, with a major hydro shortage accompanied by a mismatch of generation capacity and demand;
- **New generation** being built ahead of grid capacity and generation and load falling in different regions. This is possible with a rush to build new wind farms, but it is unlikely to last beyond 2-3 years in each case because:
    - The owner of each wind farm is expected to be cognisant of the issues before the project is built;
    - The grid may be upgraded after the project is completed;
    - It is also possible for other generators to compensate during high wind output to avoid lines constraining.
- **Demand growth** in some regions exceeding all planning expectations. This could relate to a large region like the upper SI, or a much smaller region like Golden Bay.
- **Force Majeure**, where some catastrophic event occurs to a major generator or to part of the grid. Examples of such events include: transformer outage at Huntly, HRSG problems at Otahuhu, towers blown over on HVDC, gas outages at Maui, asbestos at New Plymouth.

In our analysis we have assumed that each category is statistically independent, i.e one or more of these factors can arise in any one year. To each of these categories we have assigned:

- A potential cost in terms of \$million in any one event over a year, and
- A probability of occurrence in any year.

Clearly making such an assessment is quite subjective, but to the extent possible we use the past trends as our best guide to the future. Our base case assumptions are shown in Table 3 below.

Table 3 Assessed probability and cost of AC constraint events

Year		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2008 event	Probability	1/60	1/20	1/20	1/20	1/60	1/60	1/80	1/80	1/80	1/80	1/80	1/80
	Cost $m	25	25	25	25	25	25	25	25	25	25	25	25
New generation	Probability	1/20	1/15	1/10	1/5	1/4	1/4	1/4	1/4	1/4	1/4	1/4	1/4
	Cost $m	5	5	5	5	5	5	5	5	5	5	5	5
Regional load growth	Probability	1/20	1/10	1/5	1/5	1/5	1/5	1/5	1/5	1/5	1/5	1/5	1/5
	Cost $m	1	1	1	1	1	1	1	1	1	1	1	1
Force Majeure	Probability	1/20	Improvement 5% p.a.										
	Cost $m	10	10	10	10	10	10	10	10	10	10	10	10
Maintenance issues	Probability	9/10											
	Cost $m	2.0	2.5	3.0	3.5	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0

We have determined our probabilities in Table 3 based on the following considerations:

2008 event: This year we are commencing with high levels of hydro storage. In 2010 – 2012 there is still a significant possibility of low SI lake levels. With the assumed upgrade of the HVDC in 2013 this risk becomes less significant, and with a further upgrade in 2014 the constraint on southwards power flows from BPE is eased considerably. The potential constraints surplus is benchmarked against 2008. The construction of one or more wind farms in the SI will also reduce the likelihood of such events by 2015 or so. The 2008 experience suggests that a constraints surplus in excess of $20m is possible.

New generation: New generation currently being built does not give us any cause for concern with respect to constraints on the AC network. There is however potential of wind projects causing constraints by 2011 and beyond, particularly as wind projects can be built relatively quickly once the consents are available. We don't think the incidence of constraints rentals will be excessive as the projects would not be built if they were. In a significant proportion of cases we also expect that those constraints that may occur will be mitigated by generator behaviour.

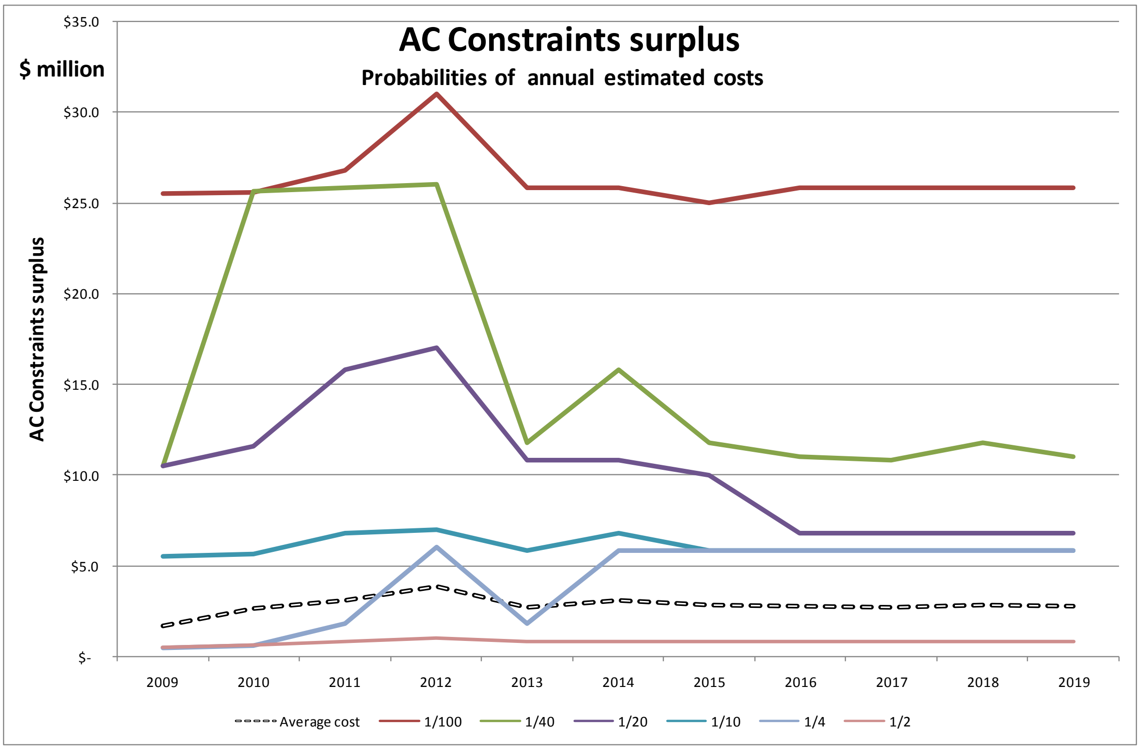
Our estimated constraints surplus of $5m would also equate to a significant loss of value to any one generation project.

Regional load growth: This is very difficult to estimate, but increases in load will not be instantaneous, and the grid can be upgraded to catch up with the changes. Major plant outages, such as that at Tiwai, can create challenges however.

Force majeure: Events may occur with a frequency greater than our assessed probability of 1/20, but not all events will result in a constraints surplus. The estimated constraints surplus arising of $10m per event is scaled against historical patterns. We have assumed that this risk will decline as the new investment in the grid results in reduced reliance on old equipment.

By combining these assumptions, we have then derived an estimate of the potential AC constraints surplus for each year from these causes. These results are illustrated in Figure 9 below:

Figure 9 AC Constraints Surplus: Probability of costs



The chart illustrates the potential cost and their probability. Based on our assumptions the overall probability of generating any significant AC Surplus in excess of $2 million any one year is less than ½, or 50%, while there is a 1/40 chance of exceeding $25 million in any one year, up until 2012. In 2013 we anticipate a significant reduction in the dry year risk and impact of the southwards power flows from BPE due to the planned upgrade of the HVDC link and associated equipment. This reduces the overall risk quite significantly. Similarly in 2014 as the second phase of the HVDC upgrade is implemented.

The overall expected value (average cost) of the AC Constraints surplus is significantly less than $5 million p.a., but as we highlight, there is a realistic possibility of the cost exceeding that by many times in any particular year. The data for Figure 9 is provided in Table 4.

Table 4 AC Constraints surplus- percentiles

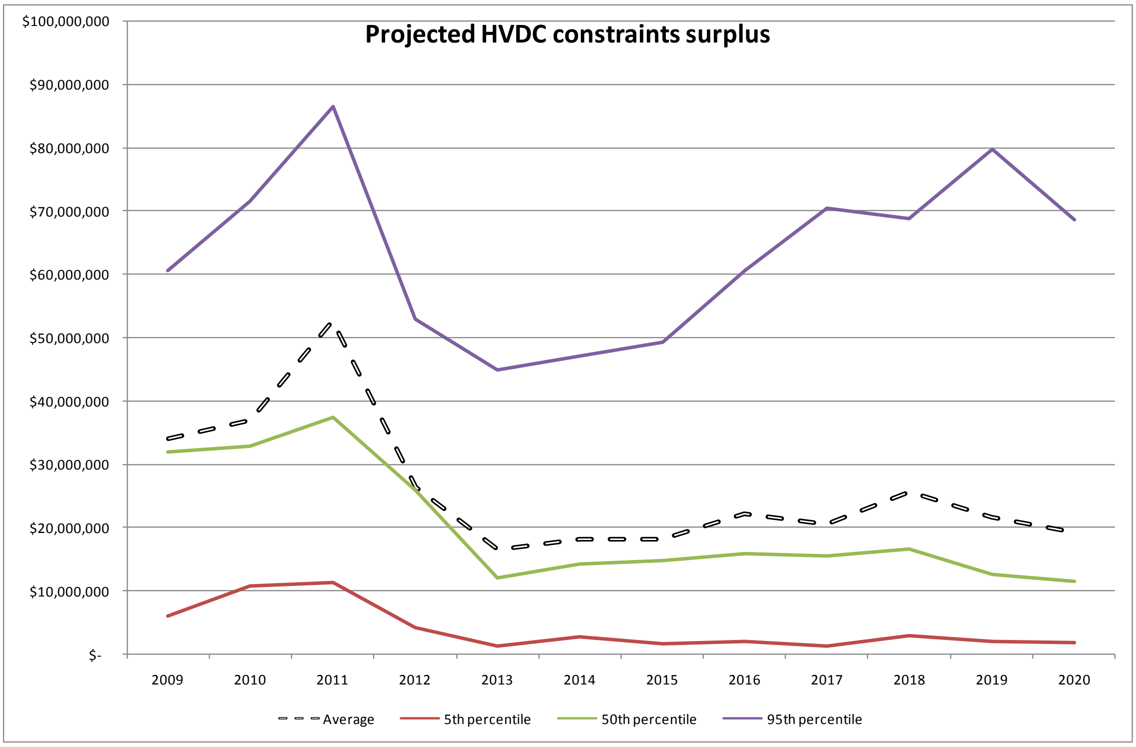
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Average cost	$ 1.7	$ 2.6	$ 3.1	$ 3.8	$ 2.7	$ 3.0	$ 2.8	$ 2.8	$ 2.7	$ 2.8	$ 2.8	$ 2.7
99.0%	$ 25.5	$ 25.6	$ 26.8	$ 31.0	$ 25.8	$ 25.8	$ 25.0	$ 25.8	$ 25.8	$ 25.8	$ 25.8	$ 25.8
97.5%	$ 10.5	$ 25.6	$ 25.8	$ 26.0	$ 11.8	$ 15.8	$ 11.8	$ 11.0	$ 10.8	$ 11.8	$ 11.0	$ 10.8
95.0%	$ 10.5	$ 11.6	$ 15.8	$ 17.0	$ 10.8	$ 10.8	$ 10.0	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8
90.0%	$ 5.5	$ 5.6	$ 6.8	$ 7.0	$ 5.8	$ 6.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8
80.0%	$ 0.5	$ 1.6	$ 1.8	$ 6.0	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8
75.0%	$ 0.5	$ 0.6	$ 1.8	$ 6.0	$ 1.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8
50.0%	$ 0.5	$ 0.6	$ 0.8	$ 1.0	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8

5.3 HVDC Constraints surplus

The HVDC constraints surplus is strongly related to the relative hydro storage in the SI and the capacity of the HVDC link. We have used scenario modelling in EMarket[12] to assess the impact of the HVDC constraining given the pattern of historic hydro inflows.

The projections are based on Energy Link's quarterly electricity Price Path projections.

Figure 10 Projection of HVDC Constraints Surplus



These results compare with the following estimated historical HVDC Constraints surplus:

	2000	2001	2002	2003	2004	2005	2006	2007	2008
$m	5.5	6.0	17.8	8.1	16.8	3.6	3.3	2.6	43.2

From 2008 through 2012 we only have Pole 2 operating on the HVDC. The average constraints surplus from 2013 appears to be reasonably consistent with the historical data prior to 2008. In 2010 and 2011 there appears to be a significant risk of a high surplus arising across the HVDC link. While 2008 was related to southwards power flows, the more significant contributor to the constraints surplus on the HVDC is high northwards power flows when there are high inflows into the SI hydro lakes. This is evident in 2002 and 2004.

[12] Energy Link's large scale model of the New Zealand electricity supply system and wholesale market.

We note, however, that Generator strategies will have a significant impact on the actual outcome. It is apparent for instance that with today's high lake levels in the SI that the generators are avoiding causing large price difference between the SI and NI. The modelling results do not tend to reflect such strategies.

6 Appendix - Deriving the breakdown of the losses and constraints surplus

The pool surplus (often referred to as the losses and constraints rentals) is an amount of money left over in the spot market each month, and on an annual basis has ranged between \$53.5 million and \$210 million since October 1997. Although other amounts contribute to the surplus on a month-by-month basis, in principle the surplus is equal to the total receipts from purchaser participants less total payments to generator participants, and arises due to the use of marginal prices in our spot market, combined with the transport of power over lines (which include transformers) in the grid.

The monthly surplus always has a substantial component which arises due to losses during transport from generation to load - the 'losses surplus' – and in many months this is the vast majority (if not all) of the total surplus. But there are also months when the surplus is significantly greater than the losses surplus, the difference being the 'constraints surplus.'

When price difference across lines are greater than those due to the impact of losses alone, a constraint surplus is created, and is commonly caused by either a line reaching its limit (the line is often said to 'be constrained'), or when the HVDC link sets the reserve risk in the island receiving power on the line (it is often said the HVDC link is 'constrained by reserves'.)

It is important to bear in mind that the power flow data underlying the losses and constraints surplus are the flows calculated by the SPD model during the final pricing run, not the actual flows on the grid at dispatch time. That said, it is probably fair to say that the two sets of flow data (actual versus optimal) have moved closer together as dispatch and related systems have improved over the years.

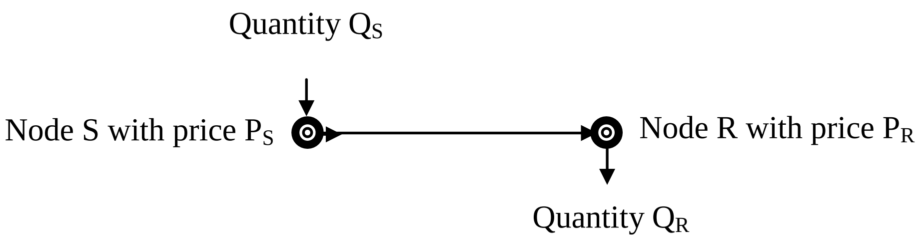
When there are no constraints binding, the total losses surplus is directly proportional to total losses on the grid. The multiplier on the total losses can be thought of as the marginal offer price, i.e. losses surplus, SL = marginal offer price × total losses. Thus, all other things being equal, when prices rise the losses surplus rises.

The constraint surplus on an individual line is a function of the flow in the line and the price difference across the line. When a line constrains then one more generator comes on the margin downstream of the constraint and the price difference (over and above that due to losses) becomes a linear function of the two marginal offer prices. The linkage between offer prices and surplus is not as clear cut for the constraint surplus as it is for the losses surplus, but it is often the case that average prices increase substantially when lines constrain and thus they increase in line with an increase in the constraints surplus.

When the total surplus is greater than the losses surplus then a constraints surplus must be present. This simple fact allows surplus calculations to be used as a proxy for constraint activity.

6.1 Trading period surplus

The total surplus for a month is the sum of the surpluses in each trading period within the month, which in turn are the sum of the individual surpluses on all the lines that make up the grid used in the final pricing run for the particular period.



For a line connecting two nodes S, the sending node, and R, the receiving node, the surplus is given by

$$S = P_R Q_R - P_S Q_S \qquad [1]$$

where PR and PS are final spot prices in \$/MWh, QS is the net MWh quantity flowing into node S (and also the amount flowing out of S along the line to R), and QR is the net MWh quantity flowing out of R (and also the quantity flowing into R from S.)

QS and QR differ by the loss[13] on the line, LSR, which is given by the formula

$$L_{SR} = \frac{RQ_R^2}{100} \qquad [2]$$

where R is the resistance of the line and 100 is a scale factor required due to the use of the dimensionless ‘per unit’ system for specifying voltage, resistance and other parameters in the power system.

Ignoring constraints, and treating the HVDC link as one line, the price difference across the link is given approximately[14] by

$$P_R = P_S \left(1 + \frac{2RQ_R}{100}\right) \qquad [3]$$

which is to say that the price difference is equal to the price at the sending end of the link times the marginal losses on the link.

It is entirely possible to calculate the total surplus and the losses surplus for every line in the grid over an extended period, but for this study we had limited time and needed to go back to the start of the spot market in October 1996. So we focused on monthly

[13] The losses calculations in SPD are based on the so-called ‘DC’ power flow approximation to AC power flow. In SPD, which is a linear program, losses on each AC line are also modelled in 3 linear tranches, and 6 tranches on the HVDC link. The calculated Q_S and Q_R flows in SPD do not explicitly include losses (as they would in an AC power flow) so the losses are modeled as additional demand at node R.
[14] This simple formula does not hold for lines that are in a loop in the grid.

surpluses, and on separating the HVDC and total AC constraint surpluses out from the total monthly losses surplus.

The actual surplus is available from data that we have collected from the spot market since 1996. The data includes the monthly surplus, spot prices, monthly spot sales and purchases, and actual flows on the HVDC link. The losses surplus was calculated using the formula

$$S_L \approx \text{min(Average price at Benmore, Haywards, Otahuhu)} \times \text{(monthly sales – monthly purchases)}$$

There a number of inaccuracies in this approximation, so if the losses surplus is larger than the actual surplus then it is set to equal the actual surplus. Using the minimum of the three monthly average prices increases the chances of approximating the average marginal offer price for the month.

Subtracting the estimated losses surplus from the actual surplus gives the total constraints surplus, which was further separated in to an HVDC constraints surplus and an AC surplus estimate.

The HVDC surplus was calculated for each month using half hourly data - the prices at Benmore and Haywards, the resistance of the combined link15, and the actual flow on the HVDC link – and equation [1], but after using equation [2] to estimate QS in each trading period. The HVDC losses surplus was obtained using equation [1] but with PS (the price at the receiving end of the link) calculated using equation [3], i.e. assuming the link is not constrained.

These calculations were done for all trading periods in each month and then totaled for each month. Subtracting the estimated losses surplus from the total HVDC surplus gave the estimated HVDC constraints surplus. Finally, the HVDC surplus was subtracted from the estimated total constraints surplus to give the estimated AC constraints surplus, which was then set to zero if it came out negative.

There are a number of approximations and assumptions in the analysis of monthly surpluses, but these are likely to be around the 5% level when aggregated over a month, and do not detract from the trends evident in the final results.

[15] Until recently, the HVDC link has consisted of two poles in parallel which were modelled using the resistance of the equivalent single pole.