SYSTEM OPERATOR

REPORT

REVIEW OF 19TH JUNE GENERATION SHORTFALL

JULY 2006

TRANSPOWER

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PREPARED BY – DERRICK WESTENRA & MURRAY HENDERSON

REVIEWED BY- JOHN CLARKE

APPROVED – KIERAN DEVINE

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1. Purpose

The purpose of this report is to review 19th June generation shortfall event as noted in the Transpower letter to the Hon David Parker dated 28 June 2006

The report seeks to determine what factors on 19th June contributed to the shortfall of generation at 17:34 on that evening. In particular, it considers the changes in availability of generation the previous day and on the day, as well as the advice provided to participants by the System Operator.

A comparison of generation availability on the 29th June 2006 with that on 19th June 2006 is also included. This comparison seeks to identify the differences between the evenings of 19th June with the 29th June.2006 when an all time system demand peak was recorded..

2. Introduction - 17:30 Trading Period June 19th

The total electricity demand for all of New Zealand during the evening peak on June 19th was the highest ever experienced at that date[1]. The New Zealand average supplied MW recorded over the half hour period from 17:30 to 17:59 (the 17:30 market trading period) on June 19th was 6,630MW. This half-hour average supplied demand exceeded the previous record by 117MW, set in August 2004. The step increase in electricity demand experienced in the evening peak of June 19th was not the result of a uniform incremental trend in demand growth over preceding weeks.

In the June 19th 2006 17:30 trading period there was a shortage of offers of generation to meet the demand for electricity. By 17:34 insufficient generation offers were available to meet power system requirements – that is, to supply load, provide reserve energy and cover system frequency keeping.

By 17:34, although every generator that had offered to generate had been dispatched, the power system frequency was unable to be maintained and accordingly the system operator declared a Grid Emergency at 17:34, for the period 17:34 to 20:00. A Grid Emergency is a situation (defined in the Electricity

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[1] The NZ supplied MW record set in the 17:30 trading period of June 19th of 6,630MW was exceeded by a new 6,748MW record for the same trading period on June 29th. This subsequent peak was managed without recourse to power system emergency warnings or notices.

Governance Regulations and Rules) where the System Operator can take a range of actions (under Part C of the rules) to maintain the stability of the power system. The term has a 'technical' meaning within the electricity industry.

Following the declaration of the Grid Emergency the System Operator took appropriate actions to mitigate the potential impacts of the shortfall in generation offers as set out in the Emergency Planning section of the System Operators Policy Statement in Part C of the rules (EGRs). One of these actions was to suspend the North Island and South Island contingent event (CE) instantaneous reserve requirement. The North Island CE reserve requirement was suspended from 17:34 through 19:50; the South Island CE reserve requirement was suspended from 17:34 through 18:46. This action by the System Operator allowed system demand continue to be met but at a much increased risk of demand being shed if there was an incident on the power system.

The instantaneous reserves to cover a CE are calculated, and scheduled such that should the single biggest contributor to energy provision in the power system (usually either a generator or single transmission circuit) become unavailable, there are sufficient reserves scheduled to cover the loss in energy[2]. The suspension of the CE reserve requirement allows offered generation that had been dispatched to cover the CE risk, to instead be dispatched to meet more pressing energy requirements in lieu of shedding demand.

A decision to suspend the CE reserve requirement is not taken lightly by the System Operator. While it will 'free' up generation offers otherwise used for reserves to be dispatched to meet energy requirements instead (thereby deferring the need for immediate load shedding), should a subsequent event occur then it is highly likely that automatic load shedding of up to 32% of system demand will occur to maintain a stable power system and avoid cascade failure of the system.

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[2] In addition to the CE reserve requirement a reserve requirement is also calculated and scheduled to meet the extended contingent event (ECE) risk. The ECE reserve requirement is calculated as being the total HVDC flow less unoffered reserve available to the system operator, i.e. automatic under-frequency load shedding (AUFLS). The ECE reserve requirement will never be suspended as to do so would expose the power system to an unacceptable level of security and almost certain cascade failure of the power system and blackout should the HVDC link fail.

3. Cleared Generator and Reserve Offers for 17:30 Trading Period June 19th

The analysis in the report is based on the final pricing solution for the 17:30 trading period. It should be noted that while it was necessary to suspend the CE reserves due to the instantaneous system load in real time at 17:34 hrs, when final pricing was run (in accordance with the rules) full reserves dispatch was used for the trading period. This is because full reserves were dispatched at the start of the period at 17:30 on the evening. In real time power system the dispatch of reserves ceased during the trading period as noted. In final pricing a "feasible" pricing solution for the 17:30 trading period could only be achieved by reducing the reserve requirement by 20 to 30 MW over that calculated to meet power system requirements.

The following chart details the generator energy and reserve offers from the final pricing solution for the 17:30 trading period on June 19th.

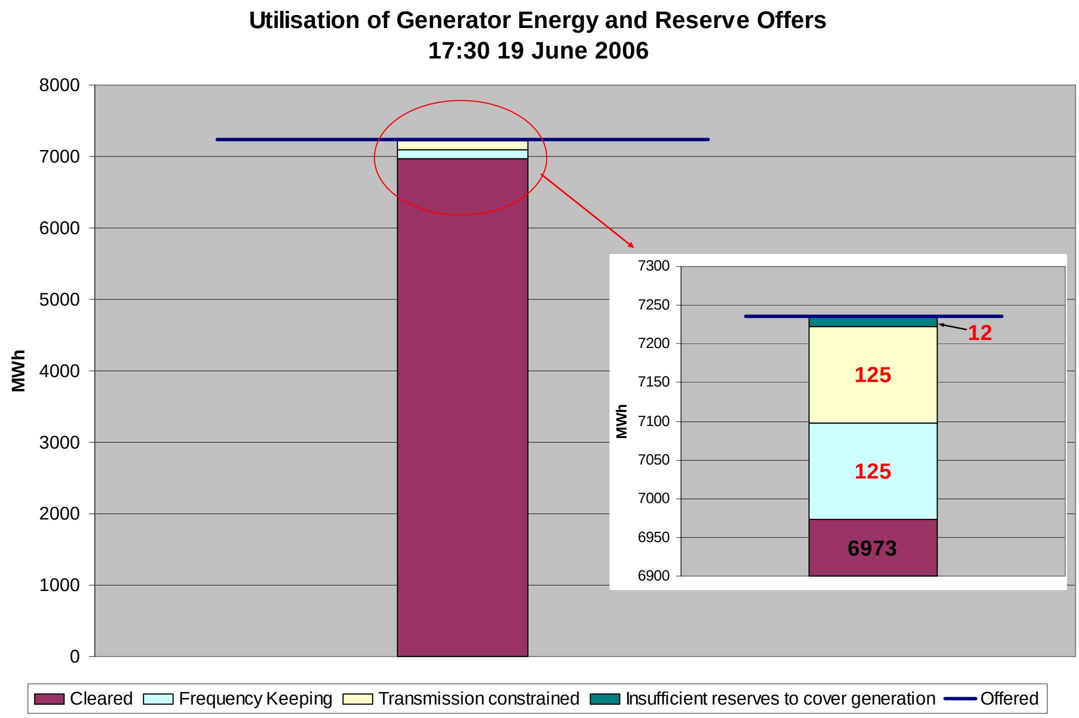

Figure 1 Final Pricing – Utilisation of generator energy and reserve offers

In final pricing all available generator offers for energy and reserve were utilised over the 30 minute period.

The generation "stack" above includes a blue coloured band of generation allocated for frequency keeping purposes. This band is required so that the frequency keeper (one in each island) has the ability to increase generation output to maintain frequency within the prescribed limits. In the 17:30 trading period on June 19th the total frequency keeping band (North and South Islands combined) was 125MW.

Generation reserved for frequency keeping is not dispatched to meet demand. In the 17:30 trading period most of it was used prior to action taken to release reserve generation for energy to meet demand as a by product of the frequency keeping role. With the system at its limit prior to suspending the dispatch of CE reserves, as load increased there was a corresponding drop in frequency. To attempt to return the frequency to its prescribed level the frequency keeper will have automatically increased generation and by default meet the increased load. In this way the frequency keeper was, while managing frequency, also contributed to increasing energy availability.

The yellow coloured generation band reflects the effect of a planned transmission outage of one of the Maraetai Whakamaru circuits. This restricted the amount of generation offered that could be utilised (transferred) out of the Maraetai and Waipapa power stations. This resulted in 125MW of offered generation being unable to be utilised. It is noted that a further 45 MW of generation at Maraetai was not available and therefore not offered.

In the feasible final pricing solution for the 17:30 trading period the reserves available to meet the CE risk requirement were insufficient to allow the full dispatch of all the Otahuhu C power station offers. Accordingly the generation offers that were able to be utilised were restricted back by 12 MW to the highest generation risk (MW output) that was able to be covered by reserves. The limitation of generation due to insufficient reserves or the optimisation of energy and reserve costs reducing the output of the largest generator is a key system feature in normal operation. The CE reserve requirements exist to ensure that the loss of the single biggest contingent risk should not result in system instability or load shedding. If the CE risk is not covered by the reserve that is available then load shedding is a possibility if the CE risk trips.

4. How did the situation on 19th June arise?

This section reviews the notices issued to alert participants and the generation changes made on the day. It refers to the various generation schedules produced by the System Operator as part of advising participants and the System Operator of the likely generation requirements and market prices ahead of dispatch. An explanation of the different schedules used is attached in Appendix A.

a) Standby Reserve Notices

At least every six hours a Security Dispatch Schedule (SDS) is produced by the System Operator. A "Standby Residual Check" (SRC) is performed on the SDS results.

The Standby Residual Check summates the energy and reserve offers for each trading period in turn. The SRC calculation then removes the single largest source of generation input within the schedule (the 'risk' – to reflect a contingent event – usually one of the two large CCGT generators). It then compares the remaining generation with the forecast electricity demand requirements. That is, the check calculates the resultant generation offers and load balance if the single largest generation unit input into the power system is lost. When this calculation results in a deficit of energy and reserve offers, a Standby Reserve notice is issued to the market.

The Standby Reserve notice is therefore a warning to the market that if a contingent event (the largest expected credible loss of energy into the power system) occurred then post the event a Grid Emergency would exist. There may not be sufficient energy and reserve available to return the system to a secure state without load shedding.

Typically the largest credible event considered is the loss of one of the two large combined cycle gas turbines, Otahuhu CCGT or Taranaki Combined Cycle. Either of these two units tripping results in the loss of approximately 370MWh of offered energy. At times of high north power transfer from the South Island to North Island, the largest credible event (CE) becomes the loss of HVDC Pole 2.

Accordingly, Standby Reserve notices advise participants of the projected deficit, the implications of the shortfall and that the "situation can be alleviated by participants revising their demand and generation offers". A Standby Reserve notice is distributed for participant information; it does not require or mandate that participants undertake any action, unlike a Grid Emergency notice.

The Standby Residual Check calculation does not account for any transmission constraints that effectively reduce the offers that are able to be used. Therefore the Standby Reserve notice describes a ‘best case scenario’ and, when viewed as such, shows the sum of all offers made (useable or not) is insufficient to cover the projected requirements - forecast load, reserve, frequency keeping, and losses.

For the evening peak of 19th June three Standby Reserve notices were issued to the market; 13:36 on the 18th June, 03:05 on the 19th June, and 14:47 on the 19th June. The shortfalls forecast for the 17:30 trading period were approximately 70MWh. 90MWh, and 110MWh respectively.

It should be noted that the first Standby Reserve notice was issued approximately 28 hours in advance of the 17:30 trading period on June 19th. The second notice (with an increased shortfall) was issued approximately 14½ hours prior to the beginning of the 17:30 trading period on June 19th. These first two warnings were given to the market in excess of the 12 hour window typically required to allow thermal generation plant to warm up and become fully operational. However, because the impact of transmission outages are not included in the Standby Residual Check calculation the Standby Reserve notices under reported the potential shortage situation by 125 MW. The actual situation was worse than that reported to the industry in the Standby Reserve notices.

Standby Reserve notices have been issued on regular occasions over the years, typically at times of high system demand coinciding with outages of large generation plant or when thermal plant is not offered.

If the advised deficit generation to cover a contingent event in a Standby Reserve notice approaches 300 MW, it indicates a strong likelihood of insufficient generation in real time without a contingent event. Industry response in the period ahead of dispatch will be critical to avoid insufficient generation for dispatch. On 19 June, the ability to avoid a position of insufficient generation for dispatch was due to several factors including the sudden unavailability of generation at Tokaanu as described in the next section.

The table below compares the changes in energy offers and shows that no discernable net change in energy offers by participant occurred in response to the Standby Reserve notices.

	Total Energy Offers (MWh)	Forecast energy deficit (MWh)
13:14 18th June SDS	7,443	
13:36 18th June SRC issued		70
02:35 19th June SDS	7,450	
03:05 19th June SRC issued		90
13:19 19th June SDS	7,449	
14:47 19th June SRC issued		110
17:29 19th June dispatch schedule	7,473[3]	

Table 1 – Total offers available and SRC deficit for three SDS runs for the 17:30 trading period

Table 1 shows the total offered MW available for the three SDS runs that were used to generate the three Standby Reserve notices for June 19th. It also shows the projected shortfall in offers that was calculated in each SDS solution and notified in the Standby Reserve notice. The differences between the total energy offers reflects the change in offers made in the period in between the running of each SDS schedules. The table also shows the offers available in the first dispatch schedule for the 17:30 trading period on June 19th. Note that at no stage did the offers submitted increase sufficiently to cover the projected SRC deficit.

b) Generation changes on the day - Tokaanu Bona Fide offer reduction – an unplanned event

At 16:45 the energy and reserve offers for Tokaanu were revised as a result of reports of dislodged lake weed restricting generation. Prior to 16:45 Tokaanu was offering its maximum generation output of 240MWh as a combination of energy and

[3] To allow valid comparison this figure has been adjusted to include 190MWh that was not available at Tokaanu due to bona fide operational reasons. This event is detailed further in a following section.

reserve. At 16:45 the maximum station output offered was reduced to 100MWh beginning trading period 17:00. At 17:26 the maximum output available from Tokaanu was further reduced to 50MWh.

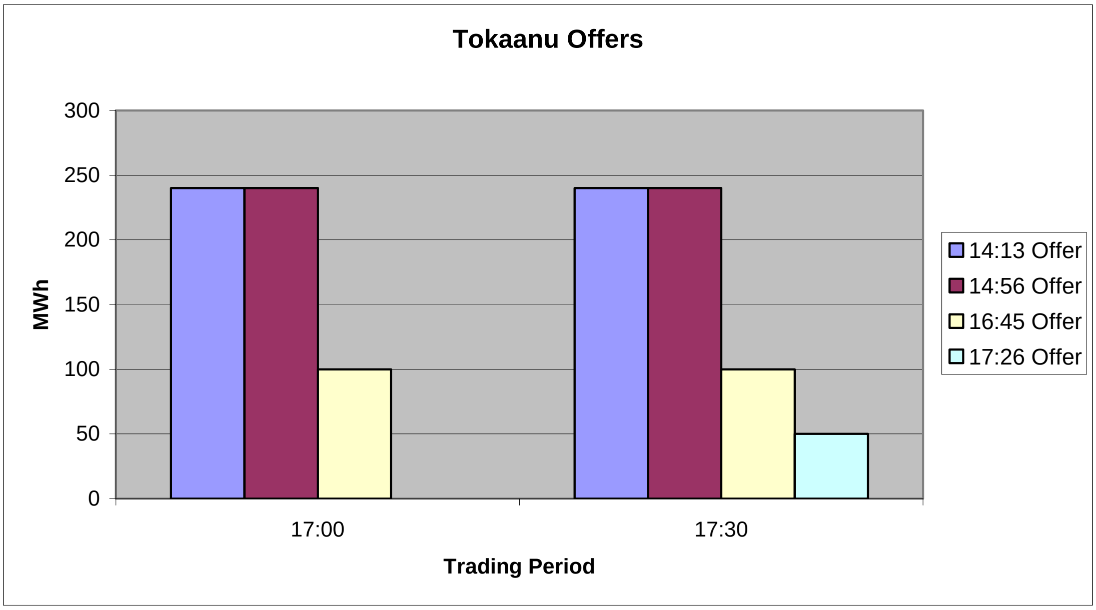

Figure 2 – The bona fide reduction in Tokaanu offers. The columns show the total offers made for the 17:00 and 17:30 trading periods on June 19th. The colour of the columns indicates the time that the offer was made.

It was the final 50 MW reduction in available generation at Tokaanu at 17:26 that triggered the Grid Emergency processes. With this change there was no longer going to be sufficient generation to meet real time load, reserves and frequency keeping requirements.

5. Review of Load Forecast Accuracy

This section reviews the accuracy of the load forecast used by the System Operator in its assessment through advance schedules of likely dispatch conditions on the evening of 19th June. If the load forecast used by the System Operator in the SDS and SPDQ schedules had been significantly in error then market participants could have been misled as to the potential situation.

Security Dispatch Schedule Load Forecasting

The following graph (figure 3) shows the load forecast (for the 17:30 trading period on Monday June 19th) some 28 hours earlier in the 13:14 Sunday June 18th SDS. Also shown on the graph is the New Zealand system load (or demand) for the 17:30 trading period. The actual system load is taken as 10 second samples from Transpower's SCADA.

The SDS and PDS schedules described in Appendix A run at 13:00 each day and look ahead 36 hours. The schedules run at 13:00 on Sunday 18th June are the first opportunity for the System Operator and market participants to assess the likely situation for the following day.

The load forecast used in the SDS is projected as the expected average demand over the half hour trading period. This is the same approach used in the final pricing calculation. Actual demand varies continually within a trading period; by definition the peak load within that trading period will always be higher than the average.

At 28 hours in advance of the 17:30 June 19th trading period, the System Operator load forecast was 99.6% of the actual average load figure used in final pricing. The load forecast was 98.9% of the peak load figure recorded during the trading period.

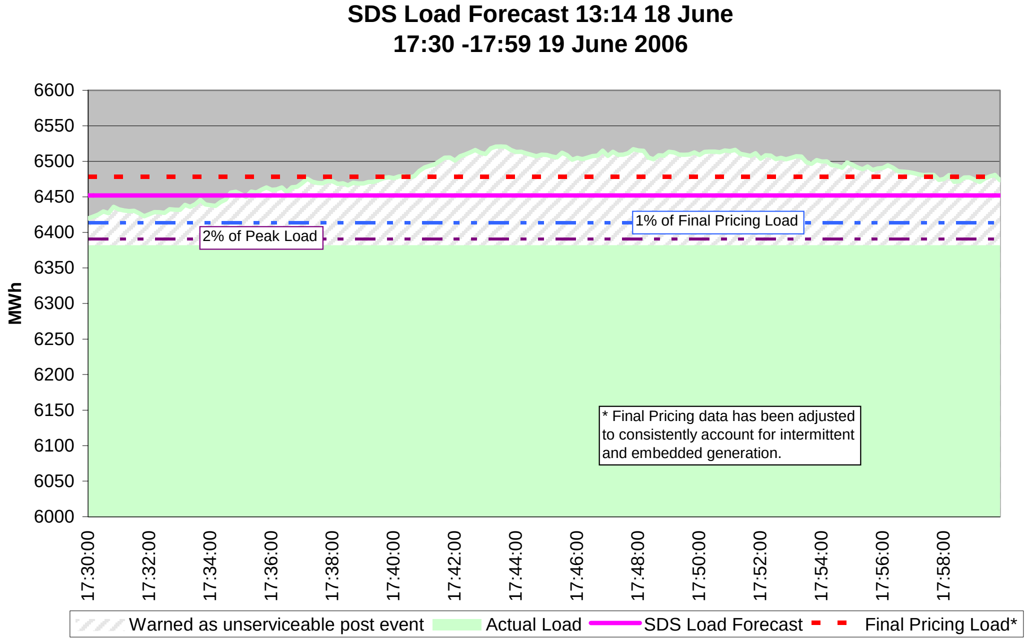

Figure 3 - Graph of the SDS load forecast at 13:14 18th June.

The forecast load is shown as well as the average metered load in final pricing load and the actual load. The striped area represents the actual load that was forecast as being unserviceable from the Standby Residual Check should a contingent event happen.

A contributing factor to the slight underestimation of North Island load was the outage that occurred in the Auckland region on 12th June. Load forecasts involve daily profiles; for example load patterns on a Monday are different to a Friday. As a result, the load profile for Auckland did not reference 12 June. Instead it referenced Monday May 29th as Monday 5th June was the Queen's Birthday holiday. This reference point reflected somewhat milder Auckland weather than on 19th June and adversely affected the accuracy of the load forecasting for the Auckland region, and therefore the overall New Zealand load forecast. Despite this, as already noted, the load forecast 28 hours ahead was within 2% of the peak load over the half hour and 1% of the actual average load.

Figure 4, below graphically represents the Standby Residual Check notice issued at 13:36 on June 18th. It also includes (with the benefit of hindsight) the unavailability of 315MWh of generation (125MWh at Maraetai/Waipapa and 190MWh at Tokaanu). As can be seen with actual generation unavailability included in figure 4 the both forecast load and peak actual load do not fall within the serviceable load limit. The CE risk in this example has been set at 370MWh.

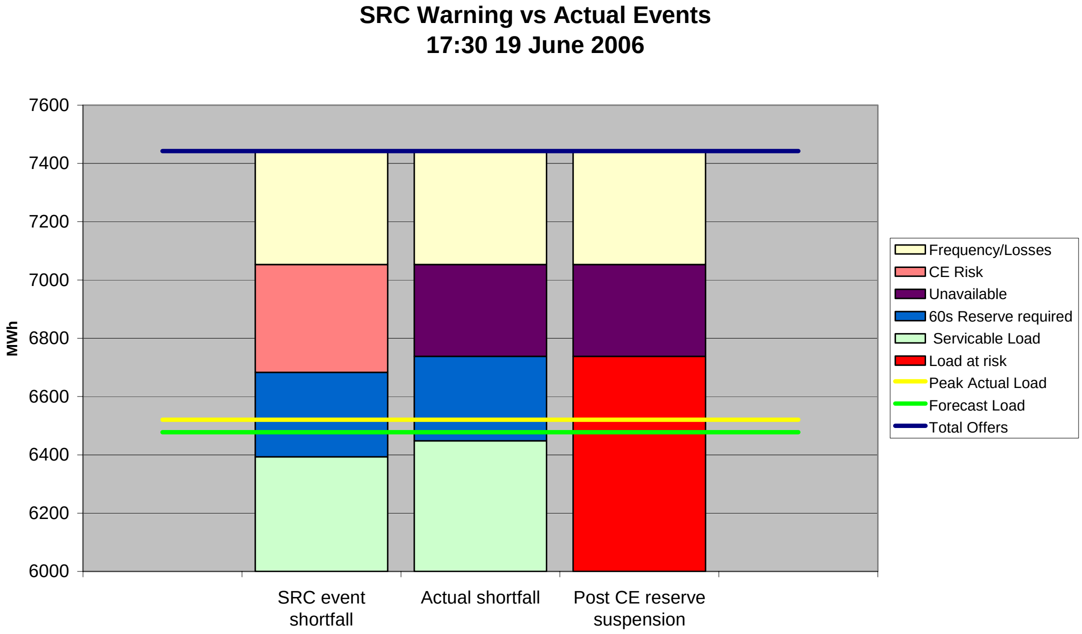

Figure 4 – Graphical representation of the 13:36 Standby Residual Check warning, the actual shortfall, and the effect of suspending the CE reserve requirement at 17:34.

The yellow band shows the generation offers required to meet the system frequency keeping requirement and the system losses. In the SRC event shortfall column the peach band represents the CE risk that was being covered: 370MWh has been used. The blue band represents the amount of reserve that would be required to be provided by generators to cover the CE risk. The forecast load is not within the green band that represents the serviceable load limit. In the Actual shortfall and Post CE reserve suspension columns the plum band represents the offers that were unavailable due to the bona fide reduction at Tokaanu and the transmission outage restricting utilisation of offers at Maraetai and Waipapa. Again, the forecast load does not sit within the serviceable load band. In the Post CE reserve suspension (i.e. post 17:34) column there is no 60s Reserve required to be provided by generation offers indicating the additional energy available when reserve dispatch ceased under the Grid Emergency declared at 17:34.

However, it should be noted that while the load has been met, it is "at risk". Should a subsequent system event occur then it is highly likely that automatic load shedding of up to 32% of system demand will occur to maintain a stable power system.[4]

As shown in figure 4 the cumulative system events that occurred on 19th June were comparable to losing the largest generator (a CE) immediately prior to the 17:30 trading period. The cumulative total of the offers deficit (existing 70MWh shortfall in offers, 125MWh unavailable due to a transmission constraint, and 190MWh due to operational issues at Tokaanu) had the same effect as losing 370MWh from a single generator.

The three SRC notices issued relating to the 17:30 June 19th trading period warned that should a contingent event occur there would be insufficient offers to return the system to a secure state without system operator intervention. In fact, the changes to offers that were made by participants provided no net benefit. In reality three events coincided to create a situation similar to a contingent event:

- a pre existing shortage of offers to cover a CE
- Maraetai and Waipapa generation could not be fully utilised due to a transmission outage
- bona fide operational reasons reduced Tokaanu's output.

As forecast in the Standby Reserve notices, when the equivalent of a contingent event occurred there were insufficient offers to return the system to a secure state without System Operator intervention. As previously noted it was necessary to declare a Grid Emergency and suspend the CE reserve requirement until such time as there were sufficient offers available to meet the total system requirements of load, reserve, and frequency keeping.

[4] At 17:34 when the CE reserve requirement was suspended an additional 34MWh had been offered. However this increase was insufficient to clear the deficit between system requirements and offers. This increase in offers was the result of increased offers at several stations. The size of the increase was however offset by a decrease in offers at some plant.

6. Comparison of 19th with 29th June

To establish if there is a risk of repeat generation shortfalls over winter peaks this year, a review of generation offered on 19th June with that on 29th June is instructive.

A comparison of these two dates is relevant because on June 19th there was a shortage of energy and reserves yet on June 29th the greatest ever New Zealand power system demand of 6,748 MW was supplied without incident. The peak demand on the 28th was an increase of 118 MW in comparison to 19 June and 235 MW (3.6%) more than the previous record, in August 2004.

As shown previously, on 19 June every MWh of generator supplied energy and reserve offered was accounted for in the final pricing solution for the 17:30 trading period. The following chart details the generator energy and reserve offers from the final pricing solution for the 17:30 trading period on June 29th.

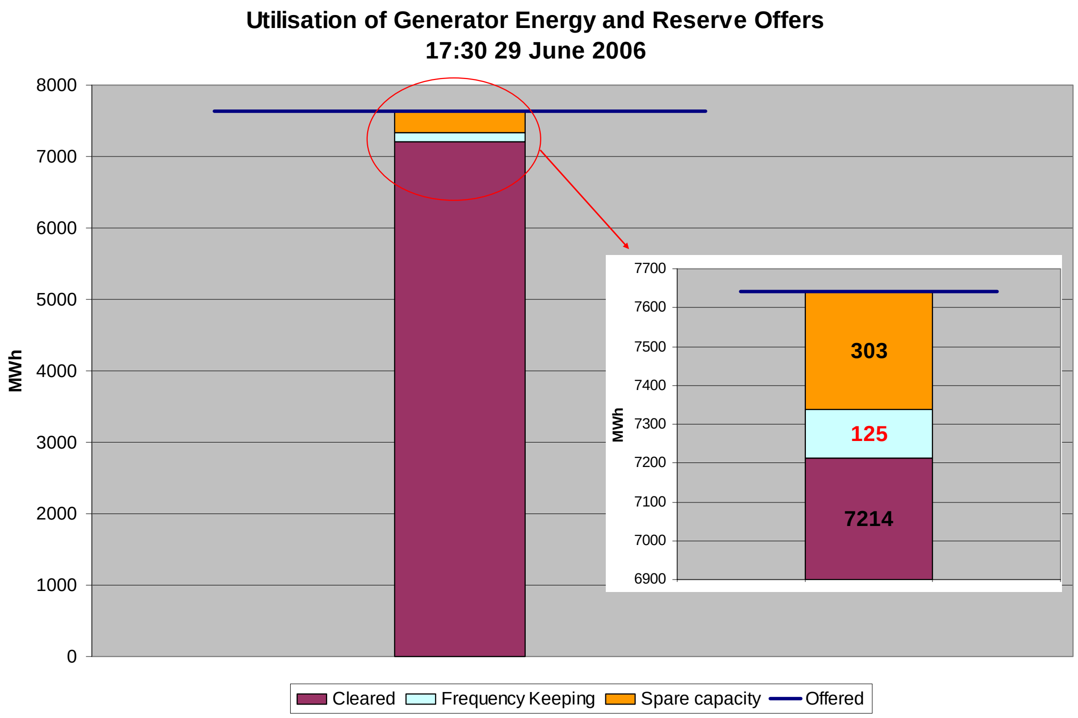

Figure 5 – Final Pricing – Utilisation of generator energy and reserve offers

In 29 June final prices the increase in demand was catered for by increased offers being made available to the System Operator. In additional there was an effective increase of a further 125MWh due to the return of the Maraetai_ Whakamaru circuit that had limited Maraetai and Waipapa generation on June 19th.

The change in the MWh's offered by generators between the two dates is set out in figure 6 below.[5]

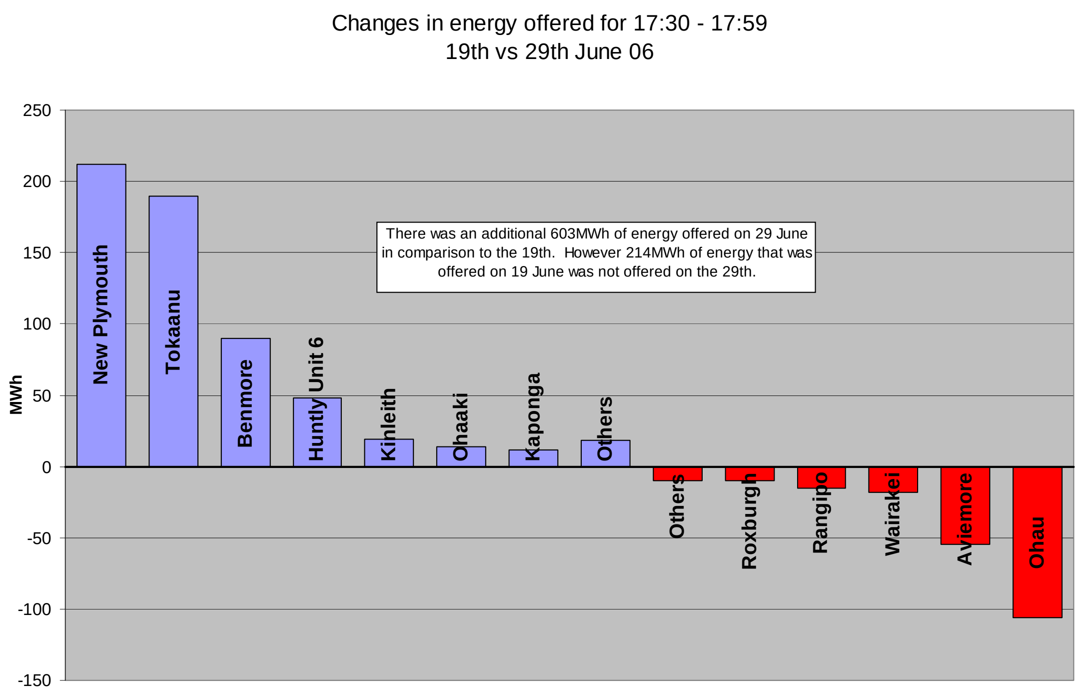

Figure 6 – A comparison of the changes in available offers 19th June and 29th June

The graph in Figure 6 is a comparison between the energy offered on 19th and 29th June. The blue bars show generation by station offered on 29 June but not offered on 19 June. The red bars show generation not offered on 29 June but offered on 19 June. The graph does not include generation that was not offered to the System Operator on either date. For example, there is an additional 100MW capacity at New Plymouth and 45 MW at Maraetai that was notified as not available and therefore not offered on either date.

[5] Data from the final pricing solution.

7. Is the 19 June situation a unique occurrence?

An almost identical sequence of events to those on 19th June occurred during the last week of June in winter 2004.

A Grid Emergency occurred due to a shortfall in generation at evening peak. On this occasion the TCC generator was not offered. It was again not possible to cover the CE reserve risk at the evening peak. On that day a notified deficit in Standby Residual coupled with operational problems for generators at the time along with a restriction in HVDC transfer capability were all factors in the Grid Emergency. The industry response on subsequent days in June 2004 averted a repeat of the Grid Emergency and the power system went on to cope with the then record winter peak demand later in August 2004 without incident.

8. How does this situation arise and how is it managed in other power systems?

The New Zealand power system is not typically capacity constrained. That is, there is more generation capacity than peak system demand. However there have been occasions when the only remaining spare generation capacity available is slow-starting thermal generation plant. Such plant may not be offered to the market for a variety of valid reasons. There are no formal market mechanisms outside of price signals to ensure sufficient generation is available on standby to cover situations like 19 June.

With the high predominance of fast starting hydro plant in New Zealand there is a traditional reliance on:

- availability of additional fast starting plant
- a voluntary response from participants to Standby Reserve alerts

Other markets dominated by slow-starting generation technologies have formal capacity markets or other arrangements to secure additional generation to cover system events. If the events of 19 June (noting the similar events in June 2004), are seen as an unacceptable risk, then appropriate commercial incentives and processes are needed to ensure available capacity is offered.

As explained, the Standby Residual Check considers generation adequacy if the largest offered generator is lost from the power system. This is a more dynamic refinement of the capacity margin tests often used to gauge generation adequacy in other larger markets. A Standby Residual Check result showing a deficit at winter evening peak is an alert that there is likely to be less than 5% of the total offered generation remaining undispatched. A notice of a 300 MW deficit is an alert that the margin will be only 1%. Clearly given the expected errors in load forecasting there is likely to be a shortfall in generation in this second case. As evident from the 19 June and 2004 events the Standby Residual test is not only an advisory on the impact of the loss of the largest generator. It also gives information on remaining undispatched generation. The loss of the largest generator can be a proxy for the combination of a series of smaller events that can and do occur in real time power system operation.

9. Proposed system operator improvements

The System Operator is aware of several issues that have been highlighted by the events of June 19th. Interim improvements to System Operator processes include;

- more wider and clearer communication of Standby Reserve alerts. For example: wider publication of the Standby Reserve notice; including a graphical representation of the warning (these might be similar to the graphs presented in this document)

- revised internal processes to take an account of the impact of planned transmission outages on offered generation and adjust the Standby Residual Check calculations, if and when possible with the scope of the existing System Operator tool set.

Short term improvements for industry consideration could include:

- changes to the EGR's to make the issuing of a Standby Residual notice a Formal Notice with obligations on participants to respond to the notice. For example, there could be similar requirements placed on participants when a Standby Residual notice is issued to those that presently exist when a Grid Emergency Notice is issued. A Grid Emergency Notice requires that generators, retailers and distributors reconsider their offers/bids, etc

- holding an industry workshop to build an understanding on the purpose and intent of Standby Reserve notices. This workshop would also be used to identify any further changes that would elicit a more informed response to avert situations similar to the evening of 19 June.

Recommendations for more formal review are:

- consider the need for more formal arrangements for participants to make available sufficient spare generation offers to cover credible power system scenarios

- identify if an adequate margin of sufficient undispatched fast starting generation will continue to be available in the future to cover system events.

This review should consider the impact of the increasing reliance on larger thermal plant to cover peak demand. The likely additional impact of the commitment of flexible fast starting generation technologies to cover the variability intermittent generation in the future should also be reviewed.

10. Summary

a. The cause of the generation shortfall on the evening of 19 June was the cumulative effect of an unplanned reduction in generation availability in real time, generation being unavailable due to transmission outage and a previously notified lack of generation offers to fully cover the loss of the largest generator.

b. Load shedding was avoided by suspending the dispatch of reserves for a contingent event under a Grid Emergency. This put the power system at risk of automatic load shedding of up to 32% of North island demand if another event had occurred.

c. Load forecast information used up to 28 hours ahead of the event to alert participants of was well within acceptable accuracy.

d. The notice issued understated the potential severity of the reserve generation shortfall the process as it does not account for generation unavailability due to transmission outages.

e. There was no net participant response of any magnitude to the informational notices sent by the System Operator in the 28 hours prior to the event.

f. New Zealand does not rely on formal processes to ensure sufficient reserve generation is offered to the System Operator to cover sudden changes in generation availability due to system events, weather events or operational problems encountered by participants.

g. Some interim internal process improvements are planned by the System Operator.

h. As a short term improvement the System Operator recommends that notification of a generation reserve shortfall require a mandated response from participants, both Generation and Demand.

i. In the longer term the traditional reliance on sufficient reserve generation through voluntary response by participants could be reviewed, given the increased future reliance on thermal and wind generation technologies. Options that could be considered are:

- mandatory generation and/or demand offering/biding, (including demand management such as ripple control) – this is a requirement in similar markets such as in Australia
- a forward capacity market to facilitate availability of slow starting large thermal generators at peak times
- a financial option such as capacity "call option".

Appendix A - Schedule information produced by the System Operator

The various schedules produced by the System Operator to identify forecast generation quantities and prices are detailed below. Some schedules are produced as a requirement of the EGRs, while others are produced to meet the System Operator's own requirement to verify the security of the power system.

There are six production schedules produced by the System Operator's Scheduling, Pricing and Dispatch (SPD) software at different times in the day, both ex-ante and ex-post (before and after real time). They are:

1. The Pre-Dispatch Schedule (PDS), also known to the market as the Forecast Prices. This is a schedule run every two hours from 13:00 each day out a day ahead. As well as generation offers, the PDS uses demand bids provided by purchasers as its demand forecast. It is the schedule for producers to indicate their costs of supply and purchasers to indicate at what price they are prepared to pay to supply their demand. This schedule is published to the market every time it is produced.
2. The Security Dispatch Schedule (SDS) uses the same inputs as the PDS, except purchaser bids. It instead uses Transpower's own demand forecast rather than purchaser bids. This schedule is used by the System Operator to assess security including the Standby Residual Check (SRC). The schedule is run every six hours starting from 13:00 for the new scheduling day. It is not published to the market.
3. The Schedule of Dispatch Prices and Quantities (SDPQ) uses exactly the same inputs as the SDS in 2 above and is commonly known in the market the schedule of Dispatch Prices. It is run every half hour for the current trading period and the next seven forecast trading periods – ie out four hours. This schedule is published to the market.
4. The Dispatch Schedule (commonly known as Real Time Dispatch or RTD) is the schedule from which the system operator dispatches all generation and reserve in the power system in real time. This schedule is published to the market.
5. The Real Time Pricing (RTP) schedule, also known to the market as 5 Minute Prices, is produced shortly after the completion of each five-minute period and used the same inputs as RTD above except that the forecast load in RTD is replaced by the actual power system load in the five-minute period just

completed. This schedule is the first ex-post (after dispatch) indication of final prices. This schedule is published to the market.

6. The Final Pricing schedule is produced by the Pricing Manager the next day. This uses generation offers, the average metered load for each 30 minute trading period along with the final information on transmission configuration, generation levels, and reserve requirements at the start of the trading period. The final price sets the prices for which generators and reserve providers are paid. It also establishes what purchasers (retailers) have to pay for their offtake in each trading period. The Pricing Manager publishes this schedule to the market.