Reserves in the NZEM

Abstract:

Reserve is the largest constraint in the operation of the transmission system after the requirement to service load. It has the potential to greatly influence the way the transmission system is operated and the cost of providing energy. However, the Rules of the NZEM encompass only some of the structure of the Reserve Market leaving responsibility with the Grid Operator who arranges the provision, dispatch and pricing of reserve. Incorporated into the NZEM is a market to be "available to provide reserve" and the allocation mechanism which does this, the SPD model. Absent are the mechanisms by which reserve can be optimally dispatched. At present there is a lack of transparency in this area to insure that the market operates in an optimal manner. Current arrangements appear to favour generators, the traditional providers of reserve, who receive a reserve availability payment, payment at the energy price for any reserve provided (collected through the NZEM Clearing Manager) and a reserve rental by way of the nodal price calculations. Purchasers will only receive a reserve availability payment by way of the NZEM but may suffer an externality in the energy market if the reserve price is positive.

Introduction

Purpose of the paper

The primary purpose of this paper is to provide transparency to a number of aspects of the market for reserves. In this regard the paper is primarily educational. It is hoped that the information contained in the paper will provide Market Participants with the ability to better understand how the NZEM market works, especially as it relates to and is affected by the market for reserves. Indeed the amount of reserves and the way in which they are procured has wide ranging implications that reach to virtually every level of grid user.

This paper does not recommend any changes to the NZEM Rules. However, it is anticipated that by providing a solid introduction to the topic, Market Participants will be better equipped to evaluate the current market rules and in so doing will be more likely to recommend Rule changes that increase the efficiency of the market.

What are reserves?

Developing a simple definition of reserves is a difficult task and it is easier to work from what service reserves provide. Reserves are needed in case something happens - a contingent event - that causes frequency to drop to a point where the system is in danger of collapsing. The contingent event is created by the failure, for whatever reason, of either generation or transmission plant. In terms of its effect on frequency, a contingent event should not be confused with the normal fluctuations that result from load switching on and off.[1] Controlling frequency for the latter reason is called frequency keeping and this is considered to be a different service than the provision of reserves. In practice, however, the separation between the two products is not as clear cut as this. When frequency begins to fall the system will respond and it doesn't matter whether the plant has been scheduled as "frequency keeping" or as a reserve provider. This leads to a definition of reserves as the capability to respond to a contingent event.

Reserves are not homogeneous, they can be provided by generation coming on line or by load going off line - either action will have the effect of stabilising system frequency.

[1] The "normal" fluctuations that occur as a result of demand and supply equating in real time are accommodated by frequency keeping, which is different in definition to the role of instantaneous reserves.

Background

In the event of generation units, or part of the transmission system becoming unavailable at any instant there must be sufficient capacity to compensate for such events to maintain frequency. The reserve market is designed to ensure there is capacity available to cover such risks, either by quickly providing additional energy (generator reserve) or by reducing the amount of energy being drawn off the grid (purchaser reserve). Prior to the introduction of the Scheduling, Pricing and Dispatch Model (SPD) on 1 October 1996 there was no dynamic interaction modeled between energy and reserve markets. Generation was scheduled independent of reserve with long term reserve contracts arranged with Trans Power. The transmission system was then operated in a manner compatible with the reserve contracts negotiated. The requirement to have reserve capacity available is now the most significant constraint in scheduling. This reflects the role of the Grid Operator in maintaining a secure transmission system and ensuring an uninterrupted supply of energy.

What is Reserve?

There are two types of reserve in the operation of the transmission system, frequency reserve and instantaneous reserve. Frequency reserve relates to the maintenance of "normal frequency" between 49.8Hz and 50.2Hz[2]. Instantaneous reserve relates to the management of frequency outside these bounds in relation to contingent events.

Frequency reserve has historically been managed by the appointment of a frequency keeping station. This station would automatically respond to variations to frequency arising from the dynamic nature of the transmission system[3]. However the response to frequency will occur automatically from stations whether appointed frequency keeper or not. This is due to automatic responses designed to protect against plant damage from frequency dropping or rising. Instantaneous Reserve differs from frequency reserve in that it is dispatched manually.

Instantaneous reserve provides the capacity to be able to meet failures of the generation and transmission whilst maintaining a pre-defined quality of supply. When a unit of the generation or transmission system trips off line there becomes a deficit in the amount of energy required to service load. This is defined as an under-frequency contingent event. This imbalance causes frequency to decay requiring a fast response if frequency is to be maintained within the requirements of the Grid Operating Security Policy (GOSP). These requirements are currently set at 48Hz for a contingent event, for which disconnection of demand is the main concern, and at 45Hz for an extended contingent event, for which system collapse is the main concern and disconnection of supply may occur.

Instantaneous Reserve is the tool whereby contingent events are managed without any involuntary disconnection of demand[4]. Hence reserve is the provision of capacity to increase generation or the agreement to decrease load to balance supply and demand and maintain frequency.

[2] Normal frequency is defined in the "Grid Operating Security Policy and Underlying Codes", Trans Power New Zealand Limited, May1996. Normal frequency provides for a greater quality of supply than the statutory limits in the Electricity Regulations 1993 clause 47 impose. The statutory limits for frequency are the range of 49.25Hz to 50.75Hz.

[3] Such dynamic events are plant coming on or off line, load changing and transmission lines coming in and out of service.

[4] A response to a contingent event will comprise both an automated response (frequency reserve) and a manual dispatch of reserve(instantaneous reserve).

Why is reserve required?

Reserve is required to ensure a seamless quality supply of energy. This has a range of benefits. Purchasers benefit from maintaining a continuous supply of energy at a consistent frequency. Generators benefit from a secure transmission system as any business does from having a good distributor. Generation units may sustain damage if operated outside predetermined frequencies and units are configured to trip off when thresholds are reached. These limits are defined in the connection contracts for the Trans Power network. The coordination and management of these limits is important as generation units tripping off line in response to a contingent event increase the burden upon remaining units to arrest and restore the frequency. Connection contracts for purchasers give disconnection rights to the Grid Operator for the management of frequency.

New Zealand has a comparatively high reserve requirement. This is an artifact of previous investments made using alternative criteria to a marginal pricing regime. Investments were made a long distance from load being serviced requiring a high capacity low loss system to transport this energy.

The externalities inherent in networks mean that there are many beneficiaries from maintaining a secure transmission system. Difficulties in the pricing of externalities leads to uneven distributions of costs. This gives rise to the free-rider problem with cost burdens falling inequitably.

Relationship with GOSP and NZEM

The GOSP and underlying Grid Operating Codes set out the way in which the transmission system is to be operated. A key feature of this document is the identification and management of contingent events. Management of contingent events is a function that Trans Power has assumed and is an issue that is not fully covered by the NZEM rules. Trans Power's Statement of Corporate Intent provides the governance structure for Trans Power and should not be viewed as a regulatory instrument of the Government. Despite this, part of the reserve market has been incorporated into the NZEM rules. This is the market for "being available" to provide reserve which has a large role in the determination of nodal prices.

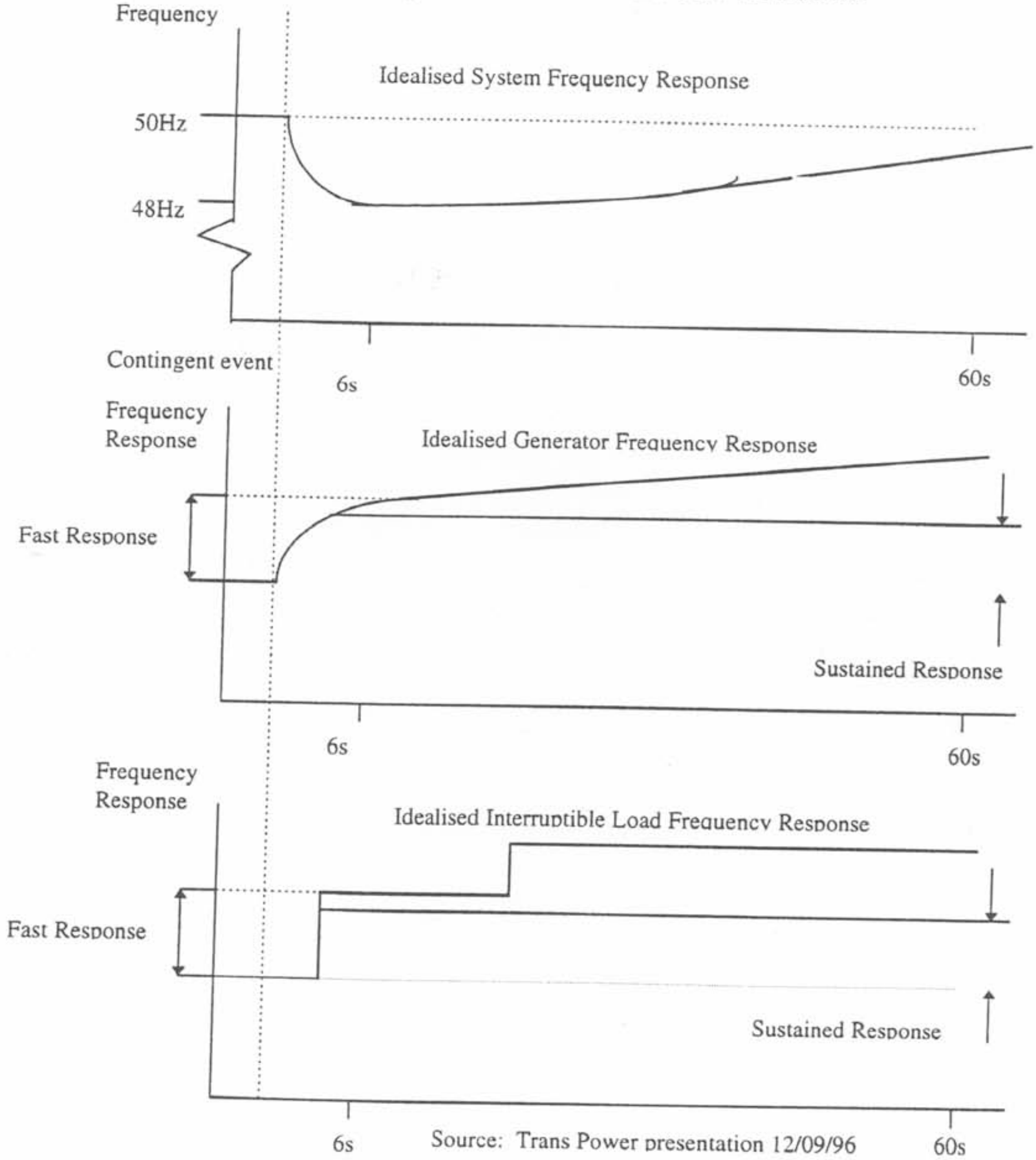
The inclusion of part of the reserve market in the NZEM reflects the interrelationship between the energy and reserve markets and creates a powerful tradeoff between these markets. In achieving the optimal pricing solutions the objective is to minimise the total cost of energy plus reserve availability. This is not the cost of the actual reserve provided. SPD is only designed to ensure that there is sufficient reserve available for the largest single contingency. This is in combination with the Fcalc model which determines the reserve factors in SPD Hence when a contingent event occurs cost is not necessarily minimised.

The reserve market has also been segmented into fast and sustained reserve, by no means distinct products. Fast reserve has a 6 second response time and sustained reserve has a 60 second response time. Reserve providers are also required to provide a prolonged response of around 15 minutes to assist in restoring the system. The real concern is the expected response of frequency along a time continuum as opposed to responses at discrete points in time.

The requirement for two complementary reserve markets serves to increase the impact upon the energy market by adding two costs to covering a contingent event. Both costs will feed through into the reserve component of energy price..

Frequency Response

The idealised responses of frequency to contingent events are shown below. The idealised generator and purchaser responses show the impact on frequency. These responses differ due to the methods used to interrupt load and increase generation. Load is interrupted in blocks, a discrete manner, whereas generation is increased on a continuum.

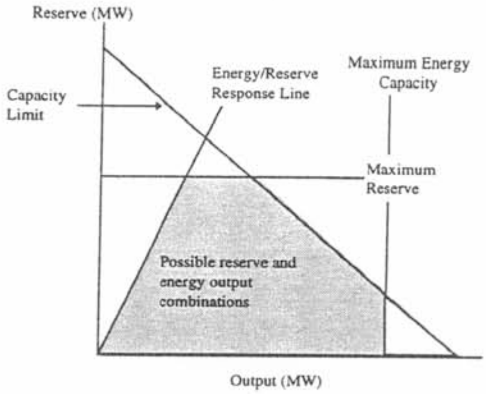


Source: Trans Power presentation 12/09/96

The idealised system frequency response shows the fall in frequency being arrested in the first instance and then restored over a time continuum.

Reserve Offers Both generators and purchasers may offer reserve. There are implications for the energy market, and therefore the energy price for which type is offered. A generator reserve offer is made conditional upon the level of output of a generation unit or station. This means that energy and reserve compete for total capacity. Purchasers face no such linkage in the reserve market with reserve offers independent of the level of load.

Generator reserve links the reserve and energy markets by way of the physical relationship between plant capacity and reserve availability. This has been reproduced in the SPD model by way of the "inverted bathtub" relationship. This gives the possible combinations of energy and reserve for a unit or station: An example of this is outlined below[5]:



The features of this diagram relate to the interaction of energy and reserve offers. The Partly Loaded Spinning Reserve (PLSR) offer contains the following information[6]:

1. The maximum amount of reserve offered.
2. Energy Reserve Response Line. This is the percentage of capacity to devote to reserve. The amount of reserve available is proportional to the level of generation.
3. A reserve offer price.

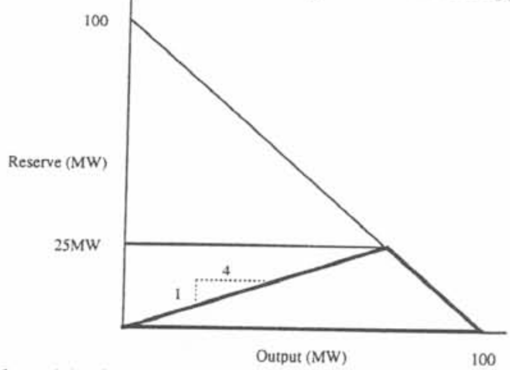
The PLSR offer interacts with the energy offer, which contains the maximum energy offered, to provide the shaded area of possible energy and reserve combinations. If the energy offer is less than full capacity the maximum energy line moves left removing a triangle of energy/reserve combinations in the lower right corner. The capacity limit means that output plus reserve cannot exceed unit/station capacity.

[5] A more complete description of this relationship is available in "The New Zealand Reserve Market _ The Relationship Between Reserve Offers and Reserve Price", Trans Power New Zealand Ltd, 3 February 1997.

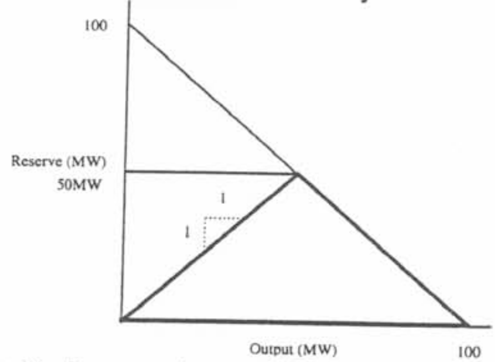
[6] Partly Loaded Spinning Reserve is generator reserve which can be provided by both Hydro and Thermal units. It relies upon a generation unit being partly loaded and spinning, producing energy, so that it can provide reserve at a moments notice.

Example An example of an PLSR reserve offer for a generation unit with a capacity of 100 MW, which is all offered in the energy market, in 3 bands is given below:

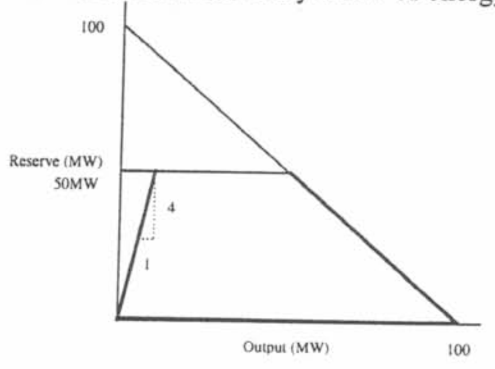
The first offer band is for a maximum of 25MW of reserve where there may not be more than 1MW of reserve for every 4MW of energy.



The second offer band is for a maximum of 50MW of reserve where there may not be more than 1MW of reserve for every 1MW of energy.



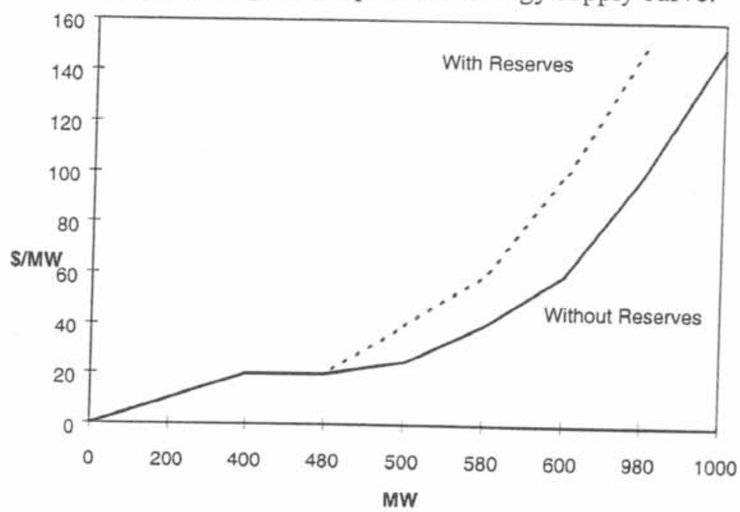
The third offer band is for a maximum of 50MW of reserve where there may not be more than 4MW of reserve for every 1MW of energy.



How much reserve is scheduled will depend on the relative price of energy and reserve, both for this generation unit and also in relation to other generation unit offers. If the price of energy increases through the three price bands capacity becomes more expensive. The cost of leaving this capacity idle to provide reserve is traded off against the cost producing energy. The converse to this is that as the reserve price increases more capacity can be freed up to provide reserve. Thus a series of complex tradeoffs is gone through to determine the lowest total cost schedule.

Hence the SPD model is required to take the following factors into account when scheduling energy and reserve:

1. The relative costs of producing energy and providing reserves for a generation unit. (PLSR generator reserve is scheduled conditional on generation, i.e. No generation offer, no reserve.)
2. Scheduling reserve removes capacity from the energy market thereby influencing the shape of the energy supply curve.



The band between 480 MW and 500 MW is removed from the energy market to be available to provide reserve. This moves the supply curve to the left.

3. The greater of
   a) HVDC transfer,
   b) A Huntly unit's generation and,
   c) A New Plymouth unit's generation.

   may be the contingent event[7]. This means that there must be sufficient reserve available to cover the contingent event which these may define[8]. Hence the cost of increasing energy from these sources must be traded off against the cost of the additional risk that these sources create.

Embedded generators may offer generator reserve in the form of interruptible load. Decreasing load at a grid exit point is equivalent to increasing generation within the local network. This removes the physical relationship between generation and reserve capacities from the SPD model.

[7] It is not clear how non-market participants which may be the contingent event are treated. By generating through an inelastic profile they would not be subject to a risk/reserve trade-off. This means that the non-market participants may define the contingent event thereby imposing a reserve cost on the market, i.e. free-ride on the risk/return trade-off.

[8] If Huntly is generation is 250MW there must be at least 250 MW of reserve available (assuming a 1:1 relationship between risk and required reserve). Hence, if only 100MW of reserve is available output at Huntly and New Plymouth will be restricted to 100MW as will the risk of the HVDC.

Influence on Energy Price

The Energy Price

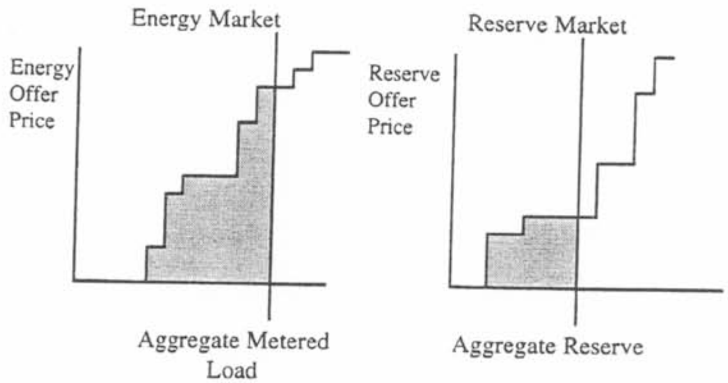
In determining final and provisional prices the SPD model minimises the objective function which is total cost of servicing aggregate metered load. The total cost is the sum of energy and reserve cost. Resulting from this are the modelled line flows and losses.

The objective function that minimises total cost for pricing is (see Appendix 2 for an explanation of this representation):

$$Minimise \sum_{g \in OFFERS} \sum_{j=1}^{GenerationOfferBlocks_g} Generation_{g,j} \times GenerationOfferPrice_{g,j}$$

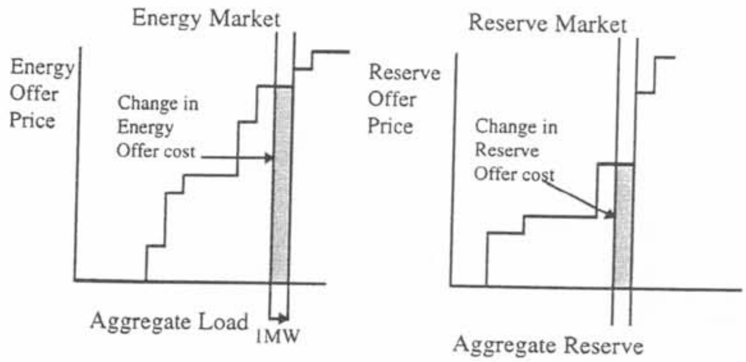
$$+ \sum_{r \in RESERVEOFFERS} \sum_{j=1}^{ReserveOfferBlocks_g} Reserve_{r,j} \times ReserveOfferPrice_{r,j}$$

The first argument is the sum of all of the cleared energy offers. The second argument is the sum of the cleared reserve availability offers. This can be represented graphically as the shaded areas in the following offer stacks:



Nodal Prices

Once the minimum total cost optimisation has been run to give the optimal generation configuration nodal prices are determined. Nodal prices are then calculated by running comparative statics[9]. Comparative statics involves increasing the load at a node by 1MW whilst holding all other load constant. The increase in total cost of having to service an additional MW of load, at that node, is defined as the marginal price at that node. This will occur for all other nodes to determine their nodal prices. This can be represented graphically as:



Hence the nodal price is the cost of redistributing generation and reserve configuration to service this additional hypothetical MW of load. In the diagram above both the energy cost and reserve cost increase, this need not be the case as there may be no additional reserve requirements in servicing an additional MW of load.

Another way of expressing this is:

$$MC = \Delta TC = \Delta EC + \Delta RC$$

Where:

MC = *Marginal Cost*
TC = *Total Cost*
EC = *Energy Offer Cost*
RC = *Reserve Offer Cost*

This relationship is additively separable meaning the prices in SPD may be decomposed into an energy and reserve cost component.

[9] Comparative statics is the comparison of two static equilibria.

Example

The following simplified example demonstrates how the marginal price is determined by the interaction of the two markets:

Let *Node A* be a node with load of *2MW* and the total cost is *$40,000*. Running the SPD model, *ceteris parabus*, but with load of 3MW at *Node A*, the total cost increases to *$40,040*. The increase in total cost of *$40* is the energy price at *Node A* for *2MW*.

Summary of Results:

Price at Node A	Load at Node A	Total Cost	Energy Offer Cost	Reserve Offer Cost
$40.00 MWh	2MW	$40000	$39000	$1000
>=$40.00 MWh	3MW	$40040	$39038	$1002

This increase in total cost of *$40* will come through a rebalancing of energy and reserve to achieve the lowest cost outcome, in the example this is through a $38 increase in total energy costs and a $2 increase in total reserve costs (These figures are for illustrative purposes only).

A Merit Order? Marginal pricing means that thinking in terms of a "merit order", when looking for which station should be brought on to service additional load, is outdated. The response required to service an additional MW of load at Haywards will bear little relation to an additional MW at Dargaville. A redistribution of current generation is likely to occur to accommodate this additional load with some generation units backed off energy to provide reserve and vice versa thereby minimising the cost of supply to the country.

This pricing methodology applies to both point of injection (GIP) onto the grid as well as exit(GXP) however they may be interpreted differently.

- GXP Price: represents the cost of supplying that node with an additional MW of energy. It is the cost of redistributing generation and reserve to accommodate this additional MW.

- GIP Price: represents the cost of effectively reducing the amount of energy offered at a node by a MW. It is the opportunity cost of replacing this 1MW of energy in the transmission system. Where reserve has been scheduled for a GIP the effects on this are also taken into account. The nodal price at a GIP it is not simply the offer price at that GIP.

Effects of the Reserve Market

The formulation of the reserve market creates rentals[10] via the energy market. This is through the marginal pricing mechanism used in the energy market. The rental can be defined as accruing through two effects, a price and a quantity effect.

The price effect is a pure rental accruing from the increase in energy price caused by an increase in the reserve component of total cost. The quantity effect is the change in the quantity component of the supply curve through the setting aside of offered generation capacity to provide reserve and the limiting of the HVDC transfer and risky generation output because of the relative costs of reserve and energy. Supply and demand curves are used in Figures 1 and 2 to show the influence of reserves in SPD.

[10] A rental is difference between the cost of producing a unit of a good and the price received for a good.

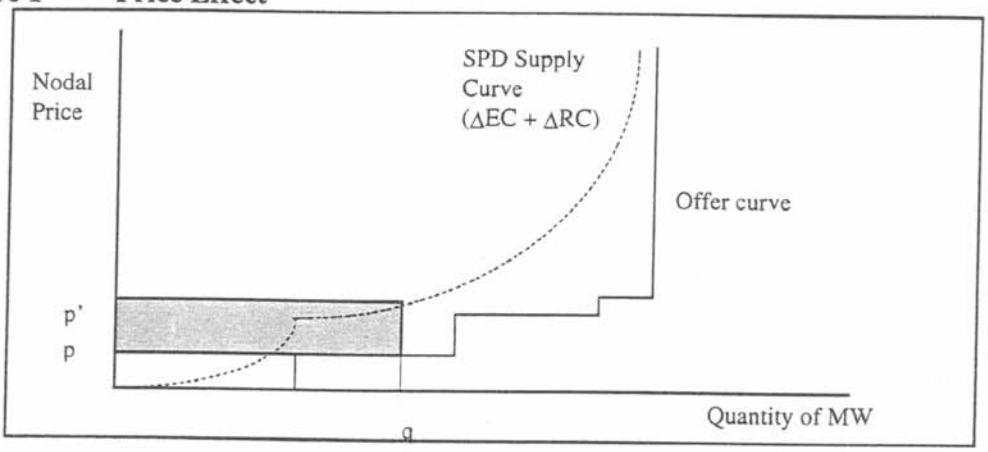
Effect of Reserve on the Nodal Price

The price effect of reserves is the change in the total reserve cost component of the marginal price. This arises due to the requirement that there must be sufficient reserve available to cover the largest contingent event. The implication of this is that energy is scheduled contingent on there being sufficient reserve available. This cost is incorporated into the supply curve generated by SPD in Figure 1, $\Delta EC + \Delta RC$. The offer curve is the stack of generator offers at the offer prices.

As shown in figure 1 a pure rental of **(p'-p)*q** accrues for **q** MW of generation.

Using the example in the marginal pricing section there is an energy payment representing the generation offer of $38MWh plus a rental payment arising from reserves of $2MWh. That is, p= $38 and p'=$40 per MWh.

Figure 1 Price Effect



The SPD supply curve is more continuous in nature as SPD calculates a price for each MW of energy. The stepwise offer stack represents generation being offered in bands (or blocks).

Quantity Effect

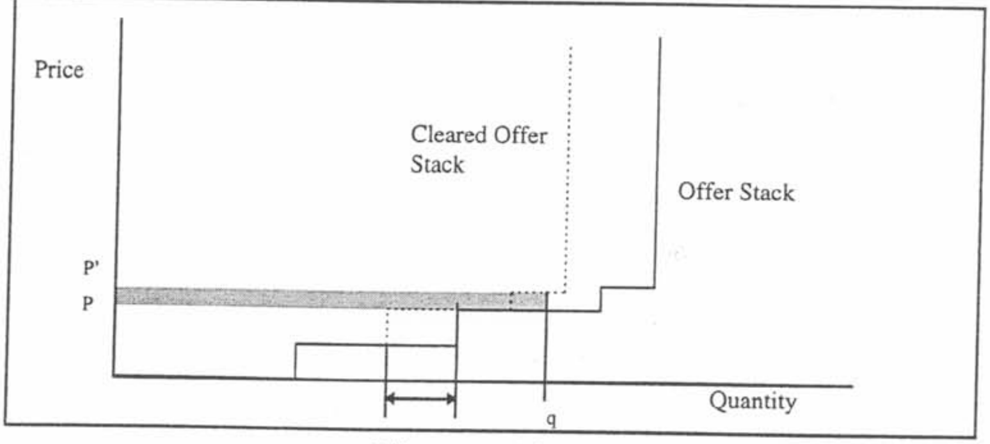
The energy market graph below shows the rentals accruing through the quantity effects of reserves. The quantity effect of reserves is a change in the shape of the supply curve, and underlying offer stack, rather than just a leftward shift. This is due to offers being withdrawn from the energy market for the following reasons:

1. The backing off of risky generation and transmission (HVDC) due to the risk/reserve tradeoff[11].
2. To be available to provide generator reserve capacity.

The offer stack shows the energy prices calculated without a reserve market. The cleared offer stack shows the energy prices when the reserve market is included.

The result of these effects is that generators receive the rental payments in the shaded area **(p'-p)*q**.

Figure 2 Quantity Effect



Offers removed from the energy market

[11] In the lowest total cost solution of SPD risky generation and transmission may be backed off to reduce the amount of reserve that is required to be available given the relative costs of risky generation/transmission and reserve. A component is considered "risky" when it defines the contingent event.

Reserve and the HVDC

The largest potential risk in the transmission system is the HVDC. For the HVDC to be operating at full capacity there will need to be around 530MW of reserve available at the receiving end of the cable[12]. There is currently around 150MW of interruptible load being offered in the North Island. This means that close to 400MW of generator reserve will be required for the HVDC to be operating at capacity[13]. Removal of this capacity from the North Island creates an artificial shortage of energy as seen from the quantity effect[14].

Once the HVDC has been identified as the contingent event or risk a tradeoff will occur in determining where the next MW of energy will be sourced from[15]. For a North Island node that tradeoff is the cost of producing an additional MW in the North Island versus the cost of producing an additional MW in the South Island and having additional reserve available (in the North Island) to cover the increased level of risk across the HVDC.

Hence, if energy prices in the South Island are lower than the North, the reserve market in the North Island will determine the level of HVDC transfer by the way in which reserve is offered and priced. A dominant position in the North Island reserve market may have many undesirable effects for North Island consumers[16]. A generator that has a dominant position in the North Island Reserve market and has generation interests in the South Island has the ability to affect positively their profits from both sources as well as affect negatively those of their competitors by manipulating offers for both energy and reserve.

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[12] This is arrived at through the following calculation(for a South-North transfer):

$$HVDC\ Reserve = (HVDC^R - OL)*RF$$

Where:

$HVDC^R$ = HVDC MW received at Haywards
OL = Overload capacity of Pole 1
RF = Reserve Factor
$HVDC\ Reserve$ = Amount of reserve to cover the HVDC

As the sustained reserve (60 second) reserve factor is set to 1 it is likely to be the binding factor (Provided the fast (6 second) reserve factor is less than 1.) The maximum that can be received at Haywards is 1240MW less around 90MW losses. Maximum overload capacity of Pole 1 is assumed to be 620MW (332 with a half pole outage).

[13] Having 400MW of generator reserve scheduled removes 400MW of energy producing capacity.

[14] It is in PCMPs interest to create excess capacity thereby creating more competition between generators.

[15] This is a simplification. The additional MW will arise from a variety of sources and trade-offs.

[16] In fact the effects of having the HVDC constrained will be desirable for South Island purchasers, who will face lower energy prices, and undesirable for North Island purchasers, who face a higher energy cost. However, total cost will be minimised when reserve does not form a binding constraint.

Price signals in such situations will create incentives for entry into a competitive reserve market. Incentives for entry into the North Island reserve market are very strong for South Island generators who have potential generation and sales constrained by the North Island reserve market.

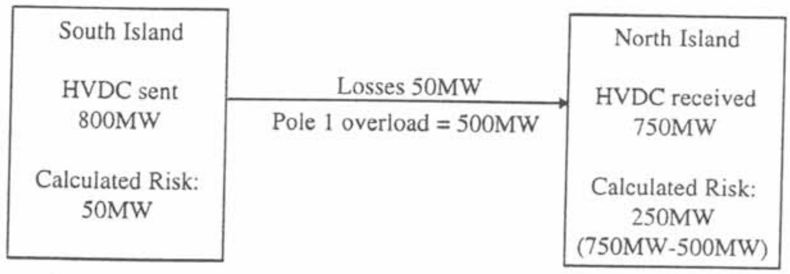
North and South Island Reserve Markets

The reserve areas in the SPD model are independent. This is a strict application of the convention that the component which defines the contingent event cannot be scheduled to provide reserve as this increases the potential risk[17]. For this reason there are two reserve markets which has implications for the South Island. There is no sharing of reserve between the North and South Islands in the SPD model.

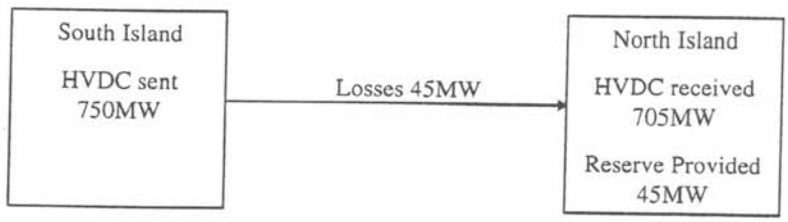
In reality the HVDC may be ramped up to provide reserve in another island. Hence the requirement to have two reserve markets may be overly onerous given the actual operation of the transmission system, i.e. the HVDC may be backed off in one island and reserve provided in the other. Where the HVDC is operating in a South to North transfer there may only be the requirement for one reserve market, the North Island, if the HVDC transfer is greater than the South Island risk. For a South Island contingency the HVDC transfer may simply be backed off. This reduction in transfer is then replaced by North Island reserve. This would reduce the cost of the reserve market by spreading the cost of reserve between two islands where there would normally be two reserve markets with costs accruing by island.

[17] The reserve scheduled by the risky component will also be at risk.

A numerical which illustrates how the HVDC can be used to provide reserve where the HVDC transfer is greater than the South Island risk is outlined below. This is for a South to North transfer of 800MW. (Loss amounts and Pole 1 limits are for illustrative purposes only).



If a contingency in the South Island of 50MW occurred the response to this could be:



Such a response of backing off the HVDC and using North Island reserve is potentially the lowest cost solution to a contingency in the South Island

In this case 50MW of South Island reserve could be replaced by 45MW of North Island reserve. In this example it is assumed that generator risk in the North Island is less than 205MW, that way the dispatcher will still have sufficient reserve available in the North Island should a contingent event occur whilst covering a South Island contingent event.

Whether this is an optimal decision will depend on the relative prices of reserve, frequency response and the reduction in cost from having 50MW of reserve capacity in the South Island available for generation. Using this rationale a South Island reserve market may only be required when the South Island risk is greater than the HVDC transfer and the North Island risk[18]. The current formulation in SPD treats the North and South Island markets as independent when they may be operated as one market reducing the inefficiencies of holding generation capacity aside to provide reserve. Lack of transparency prevents the market from knowing why reserve decisions are made.

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[18] Related to this is the issue of the contingent event being unable to provide reserve. Future investments in generation capacity look set to see potential generator risk rise above 250 MW. This may decrease the incidence of the HVDC defining the risk.

Costs of Reserve: Empirical Evidence

Quantifying the reserve constraint

The requirement for reserves has been identified as the most significant constraint on the operation of the transmission system. This section attempts to quantify the implications of this constraint and the resulting rentals and welfare effects. This is done through contrasting the situations of having a risk-less generation and transmission system to the constrained scenario as it occurred in the days under examination.

A sample has been taken to attempt to calculate the cost of the reserve market. This sample will be limited due to there being only six months of NZEM operation with the SPD model. Another weakness of this is that the NZEM focuses upon the cost of making reserve available as opposed to the cost of actually using reserve. There are costs to both. Only the cost of making reserve available is covered in this analysis.

In an attempt to gain a representative sample the following days were selected:

21 December 1996 (Saturday)
22 January 1997 (Wednesday)
11 February 1997 (Tuesday)
9 March 1997 (Sunday)
17 March 1997 (Monday)
20 March 1997 (Thursday)

For these days the total energy payments to generators and total reserve availability payments were calculated based upon the scheduled generation calculated by SPD. There are no displays in SPD of this information meaning all calculations were required to be done manually. This has imposed limitations on sample size and the level of analysis. For this reason generator payments, for which there are around 36 GIP, were used instead of purchaser payments, for which there are around 200 GXP. Reserve availability payments were calculated assuming that those scheduled to be available for reserve would be paid the spot reserve price. The reserve factors used are attached as an appendix.

Methodology

The final price schedule provides a base case against which to quantify the affects of reserve in the market. This schedule gives the optimal generation and reserve configuration to meet actual load from which the final energy prices arise.

The case of no reserve being required aims to demonstrate what the cost will be in a risk-less world, thereby deducing the cost of the risk/reserve constraint. By pricing risk as cost less, reserves will have no influence on the shape of the supply curve. This is equivalent to the case where all reserve is being provided by interruptible load at a zero price (And the amount of reserve offered is greater than or equal to the largest possible contingency).

The method used to calculate the effects without reserves is to set reserve factors and the minimum island risk to zero. Reserve Factors are the multipliers that give the number of units of reserve required to meet each unit of risk. The fast reserve factors are calculated by Fcalc based upon the expected response of frequency given the risk. For sustained reserve the multipliers are 1. A caveat to this approximation is that generators may have structured their offers differently if not offering reserve. Therefore by using generator offers formulated to allow for reserve some bias will be introduced into the calculations.

Another scenario with which to contrast this with is the situation of no reserve offered. Such a situation will require all contingent events to be eliminated. Huntly and New Plymouth Generation will be constrained to zero and the HVDC transfer will be limited to the Pole 1 overload capacity. In reality other units may define the risk but they have been omitted from the SPD model as they are relatively insignificant and will merely add to complexity. Instead they have been incorporated by way of the minimum island risk figures. These will have to be set to zero to allow a feasible solution for the model. The results of this simulation can be broadly interpreted as the benefit of generators offering reserve. If the HVDC was operating above the pole 1 overload capacity and both Huntly and New Plymouth were generating the North Island energy price would rise considerably and the South Island price fall as a result of having no reserve available[19]. Unfortunately this analysis was not able to be undertaken due to difficulties removing the reserve offers from the model.

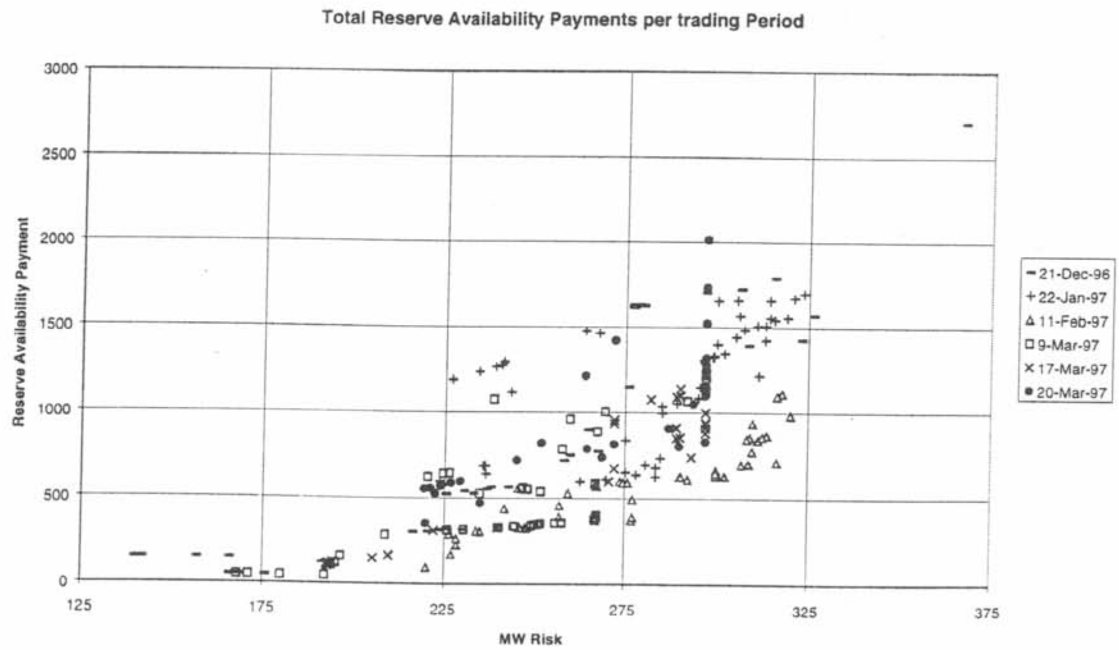
[19] The South Island price would fall as the HVDC would become constrained at the Pole 1 overload limit by the unavailability of reserve.

Caveat

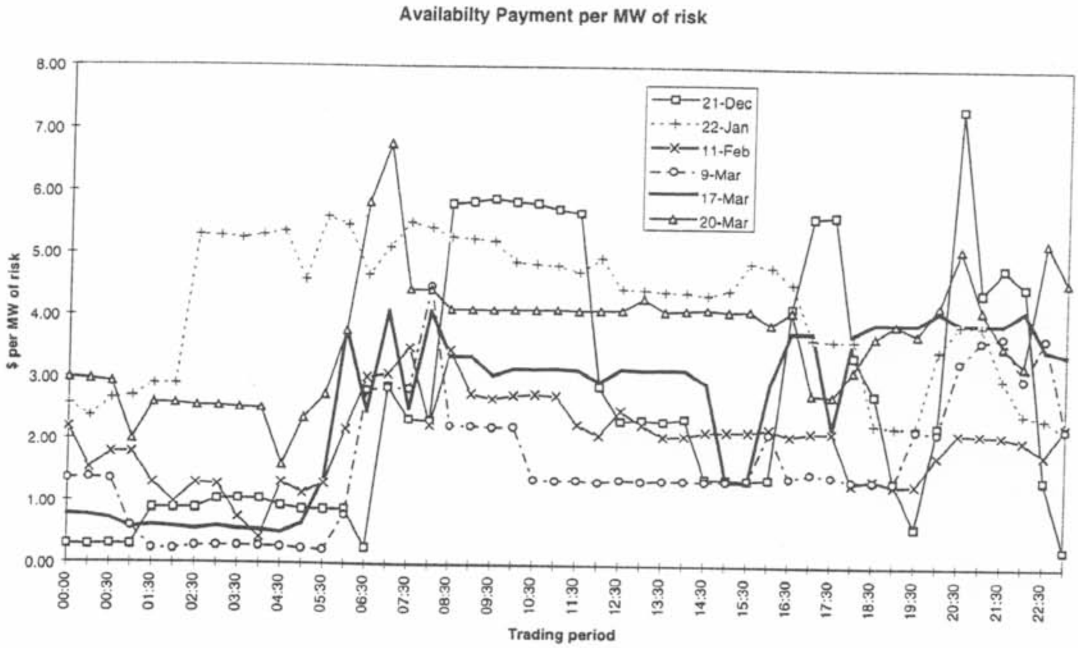
A weakness of the empirical approach undertaken is the interaction of instantaneous MW injection and ramp rates. Actual instantaneous MW injection provides a starting point for the SPD model. If the transmission system was being scheduled and operated in a different manner these starting points are likely to be different. Hence using these actual values introduces bias. Using the Scheduling module on SPD would have helped reduce this bias as only one snapshot of instantaneous MW injection is used, for the first period of the schedule. However the Pricing module of SPD was used, where instantaneous MW injection is used to initialise every trading period, introducing bias. This was minimal as the interaction between ramp rates and instantaneous MW injection is not yet constrained by "time based ramping" as intended. Instead the model assumes that ramping is instantaneous.

Availability Payments

The graph below shows the total reserve availability payments per trading period graphed against the calculated risk. The reserve availability payments are the quantity of cleared reserve (divided by 2 to put into appropriate units) calculated by multiplying by the appropriate reserve price (which is denominated in $/MWh). Total reserve payments are the sum of 6 second and 60 second payments across both islands per trading period. The MW risk the sum of the North and South Island risks identified by SPD.

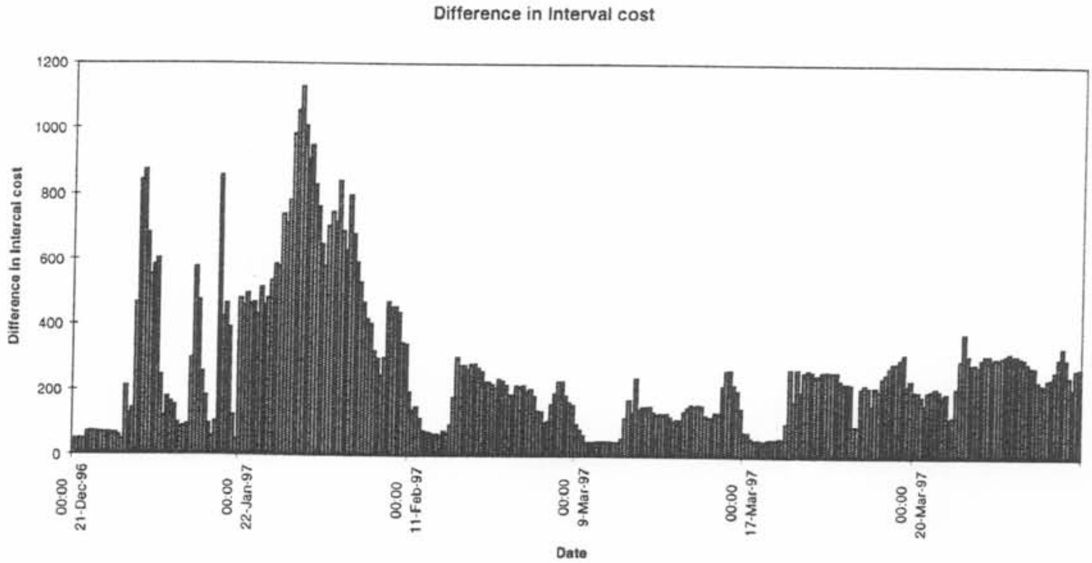


The average risk is 261MW which means than on average it is the HVDC which defines the risk[20]. Availability payments per unit of risk have been graphed against trading periods to show the volatility inherent in the reserve market.



[20] Huntly, with a capacity of 250MW per unit, and New Plymouth, with a capacity of 116MW, generation units are also able to define the risk.

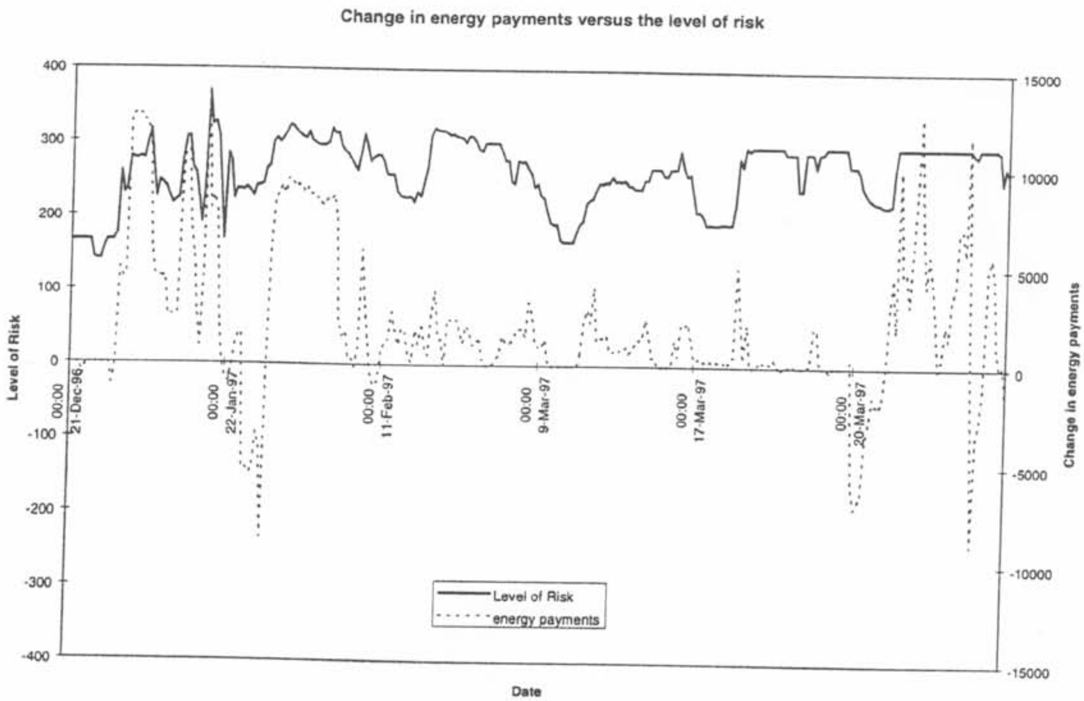
Having quantified the cost of reserve availability the next step is to calculate the reduction in total costs from not having any reserve required. The interval cost graph below represents the reduction in costs, not payments, from having no reserve requirement. The interval costs are the underlying drivers in SPD objective function and are the sum of energy offer costs and reserve offer costs.



Each bar in the graph is the reduction in interval cost per trading period from not having a reserve requirement. (These costs have been converted into payment amounts by dividing MW quantities by 2.) These cost reductions accrue from:

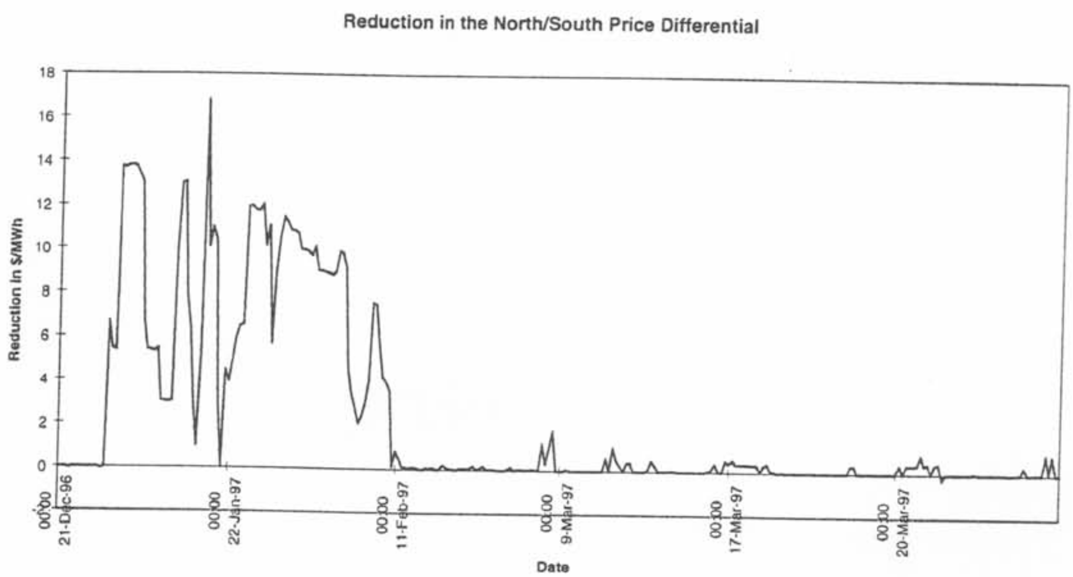
1. Not scheduling any reserve thereby increasing energy generation capacity influencing the shape of the supply curve .
2. Allowing cheaper generation, to be scheduled when it was previously constrained by reserve. This applies to the HVDC, Huntly and New Plymouth.

Given that there are cost reductions of not requiring reserve the next step is to gauge the effect on energy payments. The graph below shows the change in total energy payments to generators resulting from having no risk in the transmission system. (Reserve availability payments are not taken into account, i.e. energy payments are being compared to energy payments) As is obvious from the graph payments have sometimes increased as a result of not having any risk modeled(This is where the dashed line becomes negative). This is explained by there being two reserve areas the North and South Islands. Prices will tend together as the reserve constraint on the HVDC is removed. This may cause generator energy revenues to either increase or decrease.



The energy payments line in the above graph represents the decrease in energy revenues from not having any risk. The total level of risk has also been plotted to display the correlation between the energy and reserve markets. The other pieces of information necessary to properly interpret this graph are the price differentials between the North and South Islands, taken at Haywards and Benmore respectively. These are displayed on the following page.

Comparing the reduction in energy price differential between the North and South Islands with reduction in generator energy payments price with there is a strong correlation. Another factor that must be taken into account in interpreting this differential is the hydrological situation. The hydro capacity of the South Island is an important variable. Hydro capacity is lower through February and March increasing energy costs for the South Island and lowering the price differential between the islands.



Summary

The empirical examples have been used to stress the influence of the reserve market upon the energy market. Whilst not a complete analysis, it has shown the large distributional effects arising from the reserve constraint.

Market Efficiency

Economic Efficiency

The previous sections have shown how the reserve and energy markets interact in the determination of price and ultimately cashflows. From this analysis it is apparent that an inadequate market structure in one market will feed through into the other. There are obvious benefits for consumers in having a competitive reserve market.

Reserve Market Incentives

Interaction between the reserve and energy markets provide clear incentives to market participant types. Generators as a class will benefit in the energy and reserve market from a positive non-zero reserve price, whereas Purchasers benefit in the energy market from a zero reserve price. How these benefits accrue is explained below.

GCMPs benefit from a non-zero reserve price by way of a rental in the energy market whether they are offering reserve or not. This is because nodal prices include an energy and reserve cost component. Generators with cleared reserve offers also receive an availability payment for the reserve market and payment at the market energy price of any reserve provided. Obviously there is an opportunity cost in not using this reserve capacity for production and also an operating away from a fixed point, the most efficient operating position for a particular generation unit.

PCMPs are unlikely to benefit from a non-zero reserve price in the energy market as the nodal price includes an reserve cost component[21]. PCMPs may wish to game the reserve market when hedged against energy prices. This is unlikely to be an optimal long term strategy. It requires the PCMP to have the marginal MW of reserves and sufficient market share to influence price.

PCMPs benefit from a zero price in the reserve market in that it does not feed through to a rental in the energy market. With a zero reserve price generators will still receive the energy price for any reserve which they provide but will not receive an availability payment for leaving capacity idle.

[21] The basis of this statement is that as the quantity of interruptible load must be less than or equal to the load at any GXP(unless there is embedded generation) the payment for reserve availability is likely to be less than the resulting increase in energy price from a non-zero reserve price. This depends upon the level of influence reserve has in the nodal price (if any).

Reserve Contracting

The current model formulation is designed to foster competition and provide price signals to the market that may be acted upon. This appears to be the case for generators who are compensated by the market for keeping reserve capacity, by way of the reserve market, and for any MW of reserve required, by way of the energy market. However market signals for Purchasers are less clear. For Purchasers it is optimal to have an interruptible load availability price of zero as this minimises the externality on the energy market. This raises the question of how are PCMPs compensated for interrupting their load?

NZEM Market Rules do not provide for payments for load interrupted by purchasers. This forces PCMPs into alternative contracting arrangements. There are currently two contracting arrangements available to those wishing to offer reserve. Either they can enter a long term contract with Trans Power or offer directly into the reserve market. This is outlined by Trans Power in a discussion paper titled, "The New Zealand Reserve Market - An Introduction" (3 February 1997).

"3.3 Efficient Dispatch........

- *The reserve supply may receive a financial incentive by selling Trans Power a long term contract to supply reserve. All interruptible load is provided in this manner.*

- *The reserve supply can offer reserve into the reserve market each day and receive the short-term market price for reserve."*

Page 8

The optimal contract for a PCMP wishing to gain a payment for switching off load, rather than just being available to switch off load, is a long term supply contract. However, market signals may be suppressed if contracting arrangements do not provide a clear pass through to participants of the level of rentals available in the reserve market. That is there may be no incentive for PCMPs to enter this market.

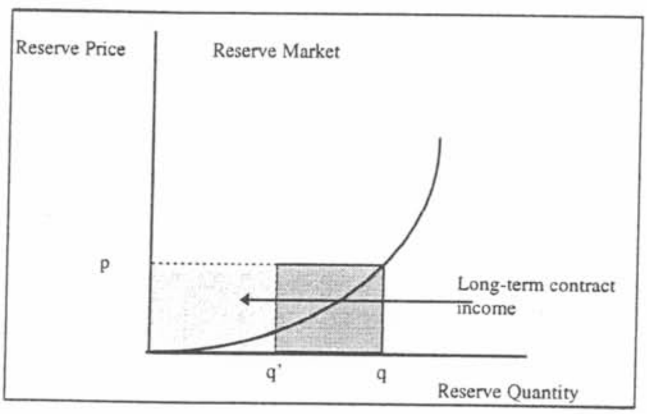
Reserve payment arrangements are further outlined on page 10 of the aforementioned Trans Power document.

"Reserve providers either see a fixed price for reserve as defined by a long-term supply contract with Trans Power, or offer reserve on a daily basis in the spot market and would expect to be paid the marginal price, this being defined as to equal or exceed the per unit fee, or offer price, for reserve offers which are taken up. This is the case under present arrangements. Reserve which is supplied to Trans Power under long-term supply contract, such as interruptible load, is offered into the reserve spot market by Trans Power at an offer price set by Trans Power. Those who provide reserve under contract are not paid the reserve spot price described here.""

Page 10

Trans Power will collect the reserve availability payments for long-term contracts whose reserve capacity Trans Power has offered into the reserve spot market. This is shown in figure 3 where **q'** is the amount of interruptible load offered into the market by Trans Power.

Figure 3 **Revenue from Long-term contracts**



Incentives to provide reserve

Trans Power plays a large role in the reserve market, acting as a broker to PCMPs collecting rentals in exchange for writing a long-term contract. Depending upon brokerage margins and contract specification there is the potential and also the incentive to distort the pass through of price signals. The following market rationale may not hold true:

"If inadequate incentives are provided to provide reserve then the ensuing reserve shortage will limit the amount of energy that can be dispatched in a secure manner. As a consequence, the market would be prepared to pay more for reserve, increasing the incentives to provide reserve."

Page 9

The interpretation of this is that when the cost of reserves is high, Trans Power will have to pay more for long term contracts. For the provision of reserve to be competitive there will need to be two markets, a market for dispatch and a market for availability, there are different costs to both.

Availability versus Dispatch

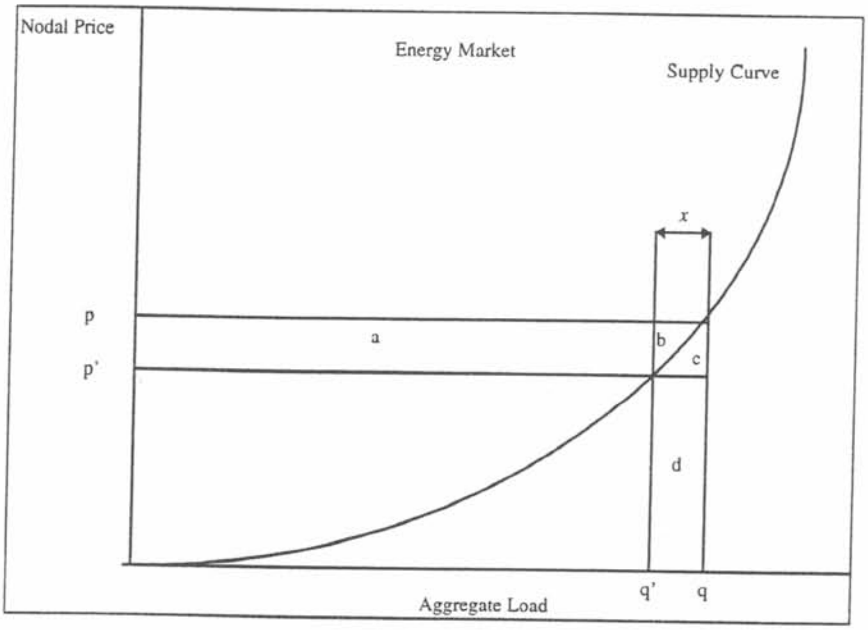
The Reserve Market defined in the NZEM does not capture the costs of providing reserve. It does not consider the cost of dispatching reserve, at least not for PCMPs. Once reserve has been scheduled as available an additional optimisation is required to dispatch reserve for under-frequency events less than the largest contingency modeled[22]. How this is undertaken will have a significant cost impact on the NZEM.

Dispatching reserve calls for some very complex calculations if undertaken on an economic basis. The cost of holding load constant and using GCMP reserve must be traded off against that of reducing load and giving a payment to the PCMP who has interrupted load. This is displayed graphically in Figure 4.

[22] Once reserve is scheduled as available it can be considered a sunk cost hence another optimisation is required to see which is optimal to dispatch.

Figure 4 below shows is that for a contingent event of size x for which interruptible load was dispatched the aggregate load will decrease thereby affecting price. This is shown by price decreasing from p to p' leading to a transfer from producer to consumer surplus of the area "a". This amount "a" is the maximum amount that consumers would be willing to pay the provider of the interruptible load.

Figure 4



If interruptible load was not used then the cost of generator reserve must be less than the area "a". The cost of using generator reserve is a incremental cost of the differential between the cost of energy produced from the contingent event and the cost of the reserve provider. If the contingent event occurs at Node A and reserve is provided from Node B then the cost can be written as:

$$\text{Cost} = (P^b * Q^b) - (P^a * Q^a)$$

Where:

Q^a = Size of contingent event.
Q^b = Amount of reserve provided.
P^a = Nodal Price at Node A.
P^b = Nodal Price at Node B or relevant offer band price (whichever is greater due to constrained on payments)

Note that $Q^a \neq Q^b$ due to differing locations[23].

[23] For example a contingency in the Waikato of 50MW may require 50 MW of reserve if provided from Huntly. Provided from Lake Waikaremoana 55 MW may be required.

Costs of Dispatching Reserve

Deficiencies in the NZEM formulation mean that PCMPs may be unable to be competitive in the current reserve market. Ideally, PCMPs should submit an offer price per unit of interruptible load for the actual interruption of load. This would allow a "merit order" for dispatching reserve to be created. Lack of transparency with regard to the decision criteria used to dispatch reserve has the potential to impose costs and inefficiencies.

The cost structure for dispatching reserve is not the same as the cost structure for scheduling the availability of reserve. This is not reflected in the rules of the NZEM with current settlement arrangements creating a bias towards the dispatch of GCMP reserve. This creates an incentive problem for Trans Power,. As Reserves Manager, Trans Power can either levy the market to pay the cost of dispatching PCMP reserve or alternatively dispatch GCMP reserve irrespective of cost.

Current NZEM settlement arrangements mean that GCMPs will be paid the energy price (or offer price, whichever is greater) for any reserve dispatched. No such arrangements exist in the NZEM for PCMPs whose load has been interrupted.

Conclusion

The reserve market is central to the determination of energy price. The requirement to provide reserve forms a constraint on how energy is able to be supplied and at what cost. There cannot exist a competitive energy market without a competitive reserve market, this is evident from the operation of the nodal pricing mechanism. The intimate relationship between the two markets means that if there are distortions in one market then there will be flow of these inefficiencies to the other. Transparency is key in ensuring appropriate signals arise from the reserve market to insure that it is competitive. This is currently lacking.

The Rules of the NZEM focus on availability to provide reserve and fail to deal with the actual provision of reserve. There are costs to both. This has not been incorporated into the market. Disadvantaged by this are PCMPs, who pay via the energy market for high reserve costs but are not compensated by way of the NZEM market mechanism for actual reserve provided. It is a fallacy that the entire cost of the reserve market is apportioned between certain generators and transmission links which create the contingent events or risk . It has been shown that reserve availability is being paid for by PCMPs through the nodal prices calculated and generator reserve through the NZEM settlement process.

In summary this paper has demonstrated that:

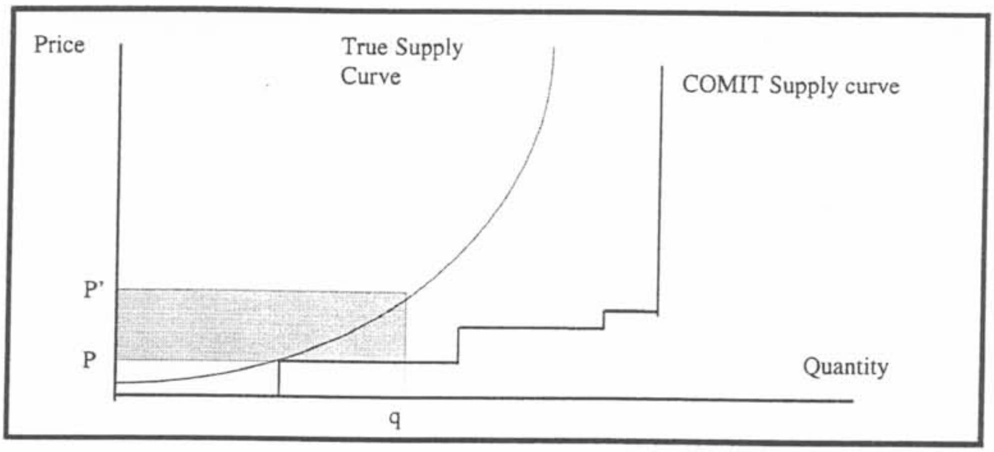
- *there is a potential flaw in the structure of the market.* Market power in the reserve market will cause both energy and reserve prices to be higher than those that would eventuate in a competitive market.
- *there are flaws in the market design.* By defining and providing contingencies on both islands the costs of reserve are higher than they would be if there was only a single contingency. Additionally by focusing on the availability of reserve rather than on the actual provision of reserve the NZEM creates a problem. NZEM does not provide any guidelines as to how reserves are actually dispatched and whether this is done in a least cost fashion. Moreover, the NZEM Rules provide no guidance as to how to restore the system to the situation it was in prior to the contingent event.
- *there are flaws in the implementation of the market.* Interruptible load is discriminated against because of its dissimilar characteristics from generation. The manner in which Trans Power offers interruptible load is not transparent and may not allow the demand side to fully capture the economic value of their contribution to the provision of reserves. Moreover, the way in which contingent events are dealt with and how the system is restored is not transparent or auditable. This lack of transparency may translate to higher costs to the industry when reserve is provided.

Appendix 1: COMIT Supply Curves

Supply Curves "Supply curves" have been made available to the market on COMIT for some months now. These are considered to be poor indicators of the cost of supply and prices. The "supply curves" displayed are simply the stack of generation offers for each island referenced back to either Benmore or Haywards by the forecast location factor for that trading period. What they fail to include are:

1. HVDC transfers;
2. System losses;
3. The removal of offered generation from the energy market for the reserve market;
4. That energy prices include both a energy and reserve component;
5. AC line constraints; and
6. Constraints on generation by a risk/reserve tradeoff.

The influence of these factors is will lead to a supply curve similar to the graph below. This has been drawn for one island assuming that there is no HVDC.



The difference between the supply curves for the quantity **q**, **p'-p** multiplied by the quantity **q** is the total rental payment accruing. This indicates that the reserve market can lead to significant rentals being collected through the energy market. An unrelated point is that there is a bias towards constrained off rather than constrained on payments calculated in the NZEM. The constrained amounts are calculated with reference to offers (the COMIT supply curve) and the market price(The true supply curve). These are derived from the actual supply curve.

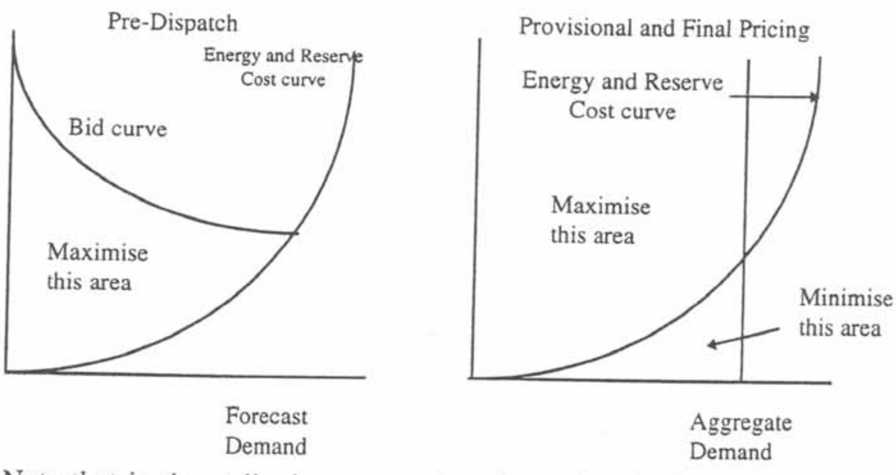
Appendix 2: The Objective Function

The objective function shown on page 11 looks slightly different to what is specified in the Rule of the NZEM. This is because the objective function used in producing provisional and final prices differs from the objective function used in preparing the pre-dispatch schedule. This arises due to there being elasticity in demand allowed for in purchaser bids, used for scheduling, whereas demand is inelastic when preparing provisional and final prices with the metered load.

This representation in the Rules of the NZEM, is to maximise:

$$\begin{aligned} NetBenefit = & \sum_{p \in BIDS} \sum_{j=1}^{PurchaseDidBlocks_g} Purchase_{gpj} \times PurcahseBid\,\Pr ice_{p,j} \\ & - \sum_{g \in OFFERS} \sum_{j=1}^{GenerationOfferBlocks_g} Generation_{g,j} \times GenerationOffer\,\Pr ice_{g,j} \\ & - \sum_{r \in RESERVEOFFERS} \sum_{j=1}^{\mathrm{Re}\,serveOfferBlocks_g} \mathrm{Re}\,serve_{r,j} \times \mathrm{Re}\,serveOffer\,\Pr ice_{r,j} \end{aligned}$$

In the pricing model where aggregate purchases are known there are no bids. Hence the first term is infinite and the maximisation of net benefit becomes the minimisation of the offer cost plus the reserve cost[24], i.e.



Note that in the stylised representation above that the Purchaser Bid and Energy and Reserve offer curves have been drawn as continuous curves for ease of illustration. In reality these are discrete with bids and offers being for blocks.

If bids are perfect then provisional prices will be the same as forecast prices.

[24] With demand modelled as inelastic consumer surplus becomes infinite. Therefore a maximisation of Net Benefit which is the sum of producer and consumer surplus becomes a minimisation of energy and reserve offer cost.

Appendix 3: Reserve Factors used in empirical study

		North Island		South Island		risk	risk	HVDC Pole 1
		6s	60s	6s	60s	SI min	NI min	overload capacity
21/12/96 00:00	21/12/96 06:30	0.91	1.00	0.95	1.00	50	0	516
21/12/96 07:00	21/12/96 14:30	0.80	1.00	0.95	1.00	50	0	516
21/12/96 15:00	21/12/96 16:30	0.64	1.00	0.95	1.00	50	0	516
21/12/96 17:00	21/12/96 18:30	0.86	1.00	0.95	1.00	50	0	516
21/12/96 19:00	21/12/96 22:30	0.71	1.00	0.95	1.00	50	0	516
21/12/96 23:00	21/12/96 23:30	0.55	1.00	0.95	1.00	50	0	516
22/01/97 00:00	22/01/97 00:30	0.76	1.00	1.02	1.00	50	0	516
22/01/97 01:00	22/01/97 02:30	1.08	1.00	1.02	1.00	50	0	516
22/01/97 03:00	22/01/97 04:30	1.34	1.00	0.82	1.00	50	0	516
22/01/97 05:00	22/01/97 06:30	1.36	1.00	0.82	1.00	50	0	516
22/01/97 07:00	22/01/97 08:30	0.89	1.00	0.89	1.00	50	0	516
22/01/97 09:00	22/01/97 18:30	0.80	1.00	0.85	1.00	50	0	516
22/01/97 19:00	22/01/97 22:30	0.70	1.00	0.85	1.00	50	0	516
22/01/97 23:00	22/01/97 23:30	0.60	1.00	0.85	1.00	50	0	516
11/02/97 00:00	11/02/97 08:30	0.79	1.00	0.84	1.00	80	0	516
11/02/97 09:00	11/02/97 10:30	0.78	1.00	0.84	1.00	80	0	516
11/02/97 11:00	11/02/97 12:30	0.68	1.00	0.84	1.00	80	0	516
11/02/97 13:00	11/02/97 14:30	0.69	1.00	0.84	1.00	80	0	516
11/02/97 15:00	11/02/97 16:30	0.75	1.00	0.84	1.00	80	0	516
11/02/97 17:00	11/02/97 20:30	0.71	1.00	0.84	1.00	80	0	516
11/02/97 21:00	11/02/97 22:30	0.78	1.00	0.76	1.00	80	0	516
11/02/97 23:00	11/02/97 23:30	0.93	1.00	0.72	1.00	80	0	516
9/03/97 00:00	9/03/97 00:30	0.53	1.00	0.78	1.00	52	0	332
9/03/97 01:00	9/03/97 04:30	0.58	1.00	0.78	1.00	52	0	332
9/03/97 05:00	9/03/97 06:30	0.97	1.00	0.78	1.00	52	0	332
9/03/97 07:00	9/03/97 08:30	0.97	1.00	0.77	1.00	52	0	332
9/03/97 09:00	9/03/97 10:30	0.73	1.00	0.78	1.00	52	0	332
9/03/97 11:00	9/03/97 12:30	0.59	1.00	0.63	1.00	52	0	332
9/03/97 13:00	9/03/97 16:30	0.70	1.00	0.71	1.00	52	0	332
9/03/97 17:00	9/03/97 18:30	0.65	1.00	0.71	1.00	52	0	332
9/03/97 19:00	9/03/97 22:30	0.68	1.00	0.55	1.00	52	0	332
9/03/97 23:00	9/03/97 23:30	0.68	1.00	0.61	1.00	52	0	332
17/03/97 00:00	17/03/97 00:30	0.72	1.00	0.76	1.00	52	0	332
17/03/97 01:00	17/03/97 02:30	0.76	1.00	0.88	1.00	52	0	332
17/03/97 03:00	17/03/97 04:30	0.70	1.00	0.94	1.00	52	0	332
17/03/97 05:00	17/03/97 06:30	0.72	1.00	1.05	1.00	52	0	332
17/03/97 07:00	17/03/97 08:30	0.59	1.00	0.88	1.00	52	0	332
17/03/97 09:00	17/03/97 10:30	0.43	1.00	0.78	1.00	52	0	332
17/03/97 11:00	17/03/97 12:30	0.42	1.00	0.78	1.00	52	0	332
17/03/97 13:00	17/03/97 16:30	0.47	1.00	0.78	1.00	52	0	332
17/03/97 17:00	17/03/97 18:30	0.67	1.00	0.78	1.00	52	0	332
17/03/97 19:00	17/03/97 23:30	0.62	1.00	0.78	1.00	52	0	332

20/03/97 00:00	20/03/97 00:30	0.55	1.00	0.77	1.00	52	0	516
20/03/97 01:00	20/03/97 04:30	0.60	1.00	0.77	1.00	52	0	332
20/03/97 05:00	20/03/97 06:00	0.62	1.00	0.77	1.00	52	0	332
20/03/97 06:30	20/03/97 06:30	0.62	1.00	0.77	1.00	52	0	516
20/03/97 07:00	20/03/97 08:30	0.80	1.00	0.77	1.00	52	0	516
20/03/97 09:00	20/03/97 10:30	0.70	1.00	0.81	1.00	52	0	516
20/03/97 11:00	20/03/97 20:30	0.70	1.00	0.73	1.00	52	0	516
20/03/97 21:00	20/03/97 22:30	0.70	1.00	0.65	1.00	52	0	516
20/03/97 23:00	20/03/97 23:30	0.80	1.00	0.65	1.00	52	0	516