WA Independent Market Operator

Investigation into the power system incident of 28 November 2007

March 2008

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1. INTRODUCTION

1.1 BACKGROUND

The Independent Market Operator (IMO) is required by Clause 3.8.2 of the Market Rules to coordinate an investigation into incidents which are notified to it by System Management under Clause 3.8.1 and which the IMO considers to have had, or had the potential to have had, a significant impact on the effectiveness of the market.

Clause 3.8.1 in turn requires that

> System Management must notify the IMO of any incidents in the operation of equipment comprising the SWIS that:
>
> (a) endangers Power System Security or Power System Reliability to a significant extent; or
>
> (b) causes significant disruption to the operation of the dispatch process set out in clauses 7.6. and 7.7.

System Management notified the IMO on 29 November 2007 that such an event had occurred on Wednesday 28 November 2007 and the IMO considered that the notified event either had a significant impact on the effectiveness of the market or had had the potential to have done so.

The IMO engaged the PA Consulting Group as an Independent Expert under Clause 3.8.2 (d) to provide a report on the incident to the IMO. The IMO has

- received that report,
- consulted as necessary with System Management and Market Participants and
- prepared this report for publication under clause 3.8.3 of the Market Rules.

1.2 NATURE OF THE INCIDENT

The following description of the nature of the incident is quoted from the report from System Management to the IMO referenced DSM# 4295165.

> On 28 November 2007 at 13:41 WST the SWIS generation was 2719MW. The generator with the largest output was Cockburn Power Station which was generating 239MW. System Management controllers scheduled 211MW of spinning reserve in order to meet the spinning reserve criteria, requiring at least 168MW of spinning reserve to be scheduled.
>
> Alinta Wagerup Gas Turbine 1 was generating 170 MW and tripped off the system. This resulted in the system frequency falling.
>
> The behaviour of some generator facilities did not meet dispatch, ancillary service requirements after the trip of the Alinta generator. Subsequently at approximately 13:46 WST the system frequency had fallen to 48.75 Hz causing some involuntary load shedding of domestic customers.
>
> At 13:49 WST an emergency operating state was declared.

After standby generators were started at approximately 13:56 WST the system frequency had returned to 50.00 Hz.

At 14:17 WST the emergency operating state was withdrawn and replaced with a high risk operating state.

The frequency recovered to 50 Hz at 13:56:44 PM. The frequency recovered to 49.8 Hz at 13:53:28 PM. Spinning Reserve recovered at 13:50 PM. The event was therefore considered to have ended at 13:53:28 when both system frequency had returned to normal frequency range 50Hz ± 0.2 Hz and full spinning reserve had been recovered.

A chart of the power system frequency is shown below.

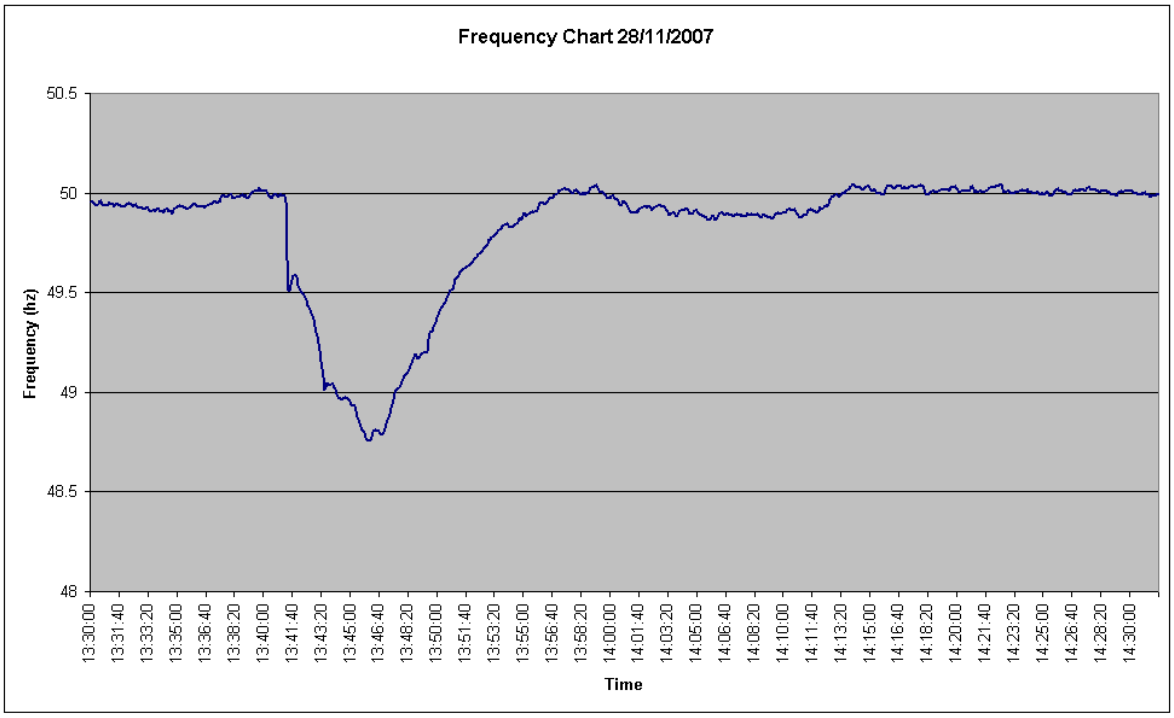

Figure 1: SWIS frequency on 28 February 2007

1.3 REVIEW PROCESS

In the course of this review, PA considered the following questions

- Of System Management:
  - Did System Management correctly dispatch the ancillary services with respect to current System Management policies, practices and operating instructions?
  - Did System Management correctly manage the incident when it occurred with respect to current System Management policies, practices and operating instructions?
  - Did System Management comply with the requirements of the Market Rules?
  - Are System Management's policies, practice and models appropriate for scheduling and dispatching ancillary services?

- Of Western Power

– The WP Technical Rules require that plant that is to be connected to the network provide data for simulation studies (3.2.4). Is this data ever validated, both at commissioning and thereafter? If so, when was the last time this data was validated for the generating units in the SWIS?

– The WP Technical Rules require that generation units have an immunity to frequency excursions (3.3.3.3 (b)). How has this been determined in the past (excluding the November incident)?

– The WP Technical Rules require a certain control range (3.3.4.4(c)). When was the last time this was validated for each unit in the SWIS and how was it validated?

– Which part of Western Power has the responsibility of enforcing the provisions of the Technical Rules? My reading is that the factors identified above are the responsibility of Western Power Networks.

– Which part of Western Power is responsible for the provision of the AGC facilities between Western Power and the market participants? If the responsibility is shared between System Management and Western Power Networks, how is the responsibility shared? In particular, who has the responsibility that

  · An AGC control signal is passed to the market participant?

  · The control signal is the appropriate signal?

  · The market participant reacts correctly to that control signal?

  · That the status of the Energy Management System that contains the AGC module is maintained so that it is up-to-date?

- . Of the IMO:

– Did the IMO comply with all Rules requirements following the incident?

– Do the Reserve Capacity requirements have any influence on the short term reserve capacity of power plant?

- Of Market Participants:

– Did all Market Participants "behave" correctly both before and after the incident? For example, did they follow dispatch instructions/order correctly both before and after the incident?

– Did the market participants' power plant perform correctly with respect to

  · The System Management's instructions/orders?

  · The performance specified in the Connection Agreement with Western Power Networks?

2. IMO PERFORMANCE

2.1 IMO'S REQUIREMENTS

The IMO's requirements with respect to this incident are essentially peripheral and consist of:

1. Carrying out an investigation and publishing a resulting report (clause 3.8.1);
2. Approving System Management's Annual Ancillary Services Plan and budget;
3. Settling any outcomes of the incident; and
4. Setting the requirements for ancillary services.

The IMO has carried out its responsibilities under item 1 by commissioning PA to carry out this investigation.

The IMO has carried out its responsibilities under item 2 by approving the 2007-08 System Management Annual Ancillary Services Plan on 29 June 2007.

The settlements process performed by the IMO has been shown to correctly settle the market outcomes resulting from the incident, thus satisfying item 3.

Of these items, item 4 is the most relevant to this incident.

At present, the ancillary services requirements are set out in Clauses 3.10 and 3.11 of the market Rules. The Rules also require that at least every five years the IMO must review the ancillary services requirements (Clause 3.15.1). This has not been done in the first year of the Rules, nor need it have been done in the market's first year of operation. However, it is now timely that the IMO institute a review of the ancillary services with completion within the current year.

In addition, the IMO have responsibilities under Chapter 4 Reserve Capacity Rules of the market rules to test the capability of generation units. However, the IMO only tests that the units can generate up to their Reserve Capacity Limit which may be less than its name plate capacity adjusted for the ambient temperature. We note that under the Market Rules, the IMO can conduct tests to verify standing data prior to a facility registration or in connection to changes in Standing Data. So far the IMO has determined that these tests are not necessary and has relied instead on tests required to be performed in connection with the Facility's Arrangement for Access (i.e. in accordance with Western Power's technical rules these being the performance requirements which are relevant .

3. MARKET PARTICIPANT PERFORMANCE

Confidentiality constraints prevent a detailed analysis of the performance on the part of market participants to be made public.

While much of the plant in service at the time of the incident performed as expected, as the analysis of the System Management performance explains, the incident was exacerbated by the unanticipated adverse response of a number of participants' plant.

This unanticipated performance is the subject of continuing analysis by both the market participants and System Management.

4. SYSTEM MANAGEMENT RESPONSE TO THE INCIDENT

The requirements placed on System Management with respect to the incident are set out in Clauses 3.1 – 3.15 and Chapter 7 of the Market Rules.

These requirements can be separated into two parts:

- Those requirements which are operational, and
- Those requirements which are supportive.

4.1 OPERATIONAL REQUIREMENTS

These requirements are associated with the day to day operation of the SWIS under both normal and abnormal conditions and are found in Chapters 3 and 7.

Examination of the System Management voice communications log indicates that response by the System Management operations staff to the incident was appropriate under the circumstances. Under similar conditions, the response of operations staff to a single contingency is well practiced. However, in this case, the expected result did not eventuate and the operations staff had to review what was actually occurring and then respond to the new set of circumstances.

The IMO is satisfied that while all those participants involved in the incident might not have seen the System Management response in the same light, the management of the incident appears to have been in line with good industry practice.

4.2 SUPPORTIVE REQUIREMENTS

The supportive requirements are set out in Clauses 3.10, 3.11 and 3.12 of the Market Rules.

4.2.1 Reserve dispatch requirements

Clause 3.10 sets out the levels of ancillary services which are to be dispatched, together with the conditions under which relaxations may be in order. The ancillary service of interest here is the "Spinning Reserve Service" (Clause 3.10.2(a)) which requires that

> "the level must be sufficient to cover the greater of:
>
> i. 70% of the total output, including parasitic load, of the generation unit synchronised to the SWIS with the highest total output at that time; and
> ii. the maximum load ramp expected over a period of 15 minutes"

The generation unit synchronised to the SWIS with the highest total output at that time was the Cockburn Unit 1 with a gross load of 239 MW. The total spinning reserve scheduled was 201 MW, which is greater than the required minimum of 167 MW (70% of 239 MW) due to plant being partially loaded.

Therefore, System Management had complied with the requirement of Clause 3.10.2(a) of the market rules.

4.2.2 The quality of the ancillary service provided

The Market Rules are silent on the quality of the ancillary services provided other than the requirement in Clause 3.9.3 that

> Spinning Reserve response is measured over three time periods following a contingency event. A provider of Spinning Reserve Service must be able to ensure the relevant Facility can:
>
> a. respond appropriately within 6 seconds and sustain or exceed the required response for at least 60 seconds; or
>
> b. respond appropriately within 60 seconds and sustain or exceed the required response for at least 6 minutes; or
>
> c. respond appropriately within 6 minutes and sustain or exceed the required response for at least 15 minutes,
>
> for any individual contingency event.

This clause places the quality obligation on the provider of the ancillary services and there appears to be nothing else that places a quality requirement on System Management.

This silence as to the quality of ancillary services will be picked up in Chapter 5 of this report

4.3 WAS THE SPINNING RESERVE DISPATCH EXPECTED TO BE SUFFICIENT?

Regardless of the requirement that the dispatch spinning reserves be at least 70% of the largest output on the SWIS, would this level of reserve have been sufficient?

At 13:41 when the Alinta Wagerup GT 1 tripped, there was 201 MW of spinning reserve being carried. This was spread as shown in Figure 2 below.

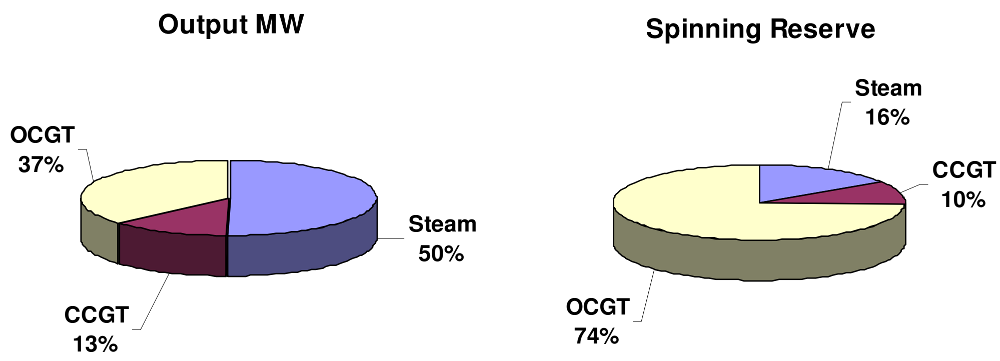

Figure 2: Relative proportions of unit output and spinning reserve

As is obvious, the majority of the spinning reserve was carried on the open cycle gas turbines at the time of the incident, although we note that at times significant sinning reserve is carried on GT plant due to their rapid response.

Subsequent analysis has indicated that had all reserve operated as expected the frequency would have recovered as shown below in Figure 3.

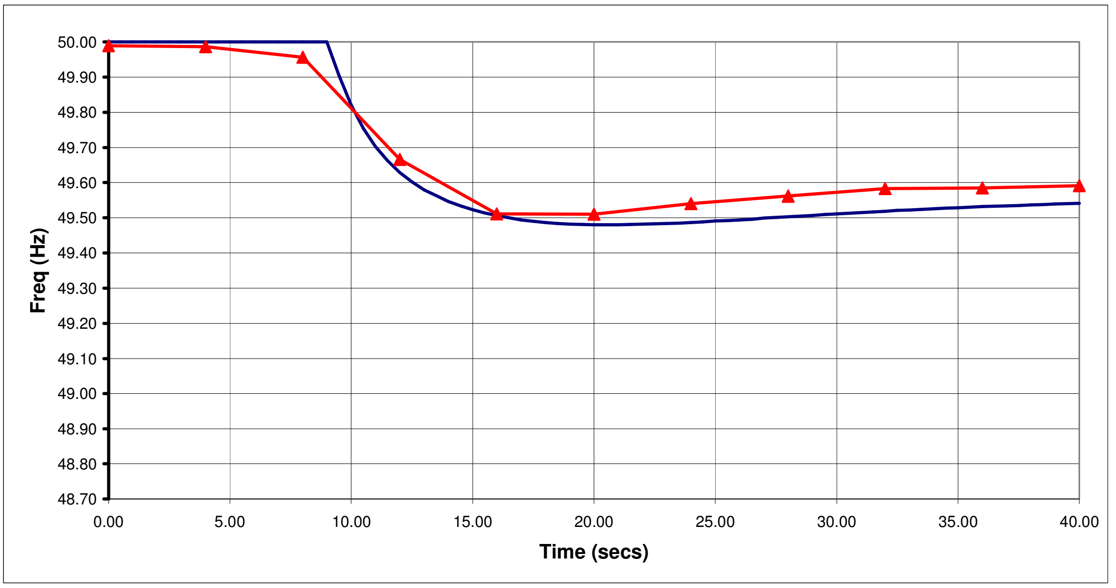

Figure 3: Expected and actual short term response to the incident

Here the blue trace is the simulation how the frequency was expected to react while the red trace shows the actual frequency trace.

This suggests that the initial dispatch of the reserves was such that this particular loss of generation was adequately covered by the spinning reserves. However, it must also be noted that the loss of generation of 117 MW was significantly less than the covered risk of 168 MW. Further, this simulation and those below are for a period of 40 seconds only while much of the lack of continued performance on the part of open cycle generation plant occurred after this.

Had the Cockburn unit tripped, the expected frequency drop would be to 49.10 Hz as shown below with the reserves as scheduled at the time the frequency would have dropped to 49.35 Hz which is an acceptable response.

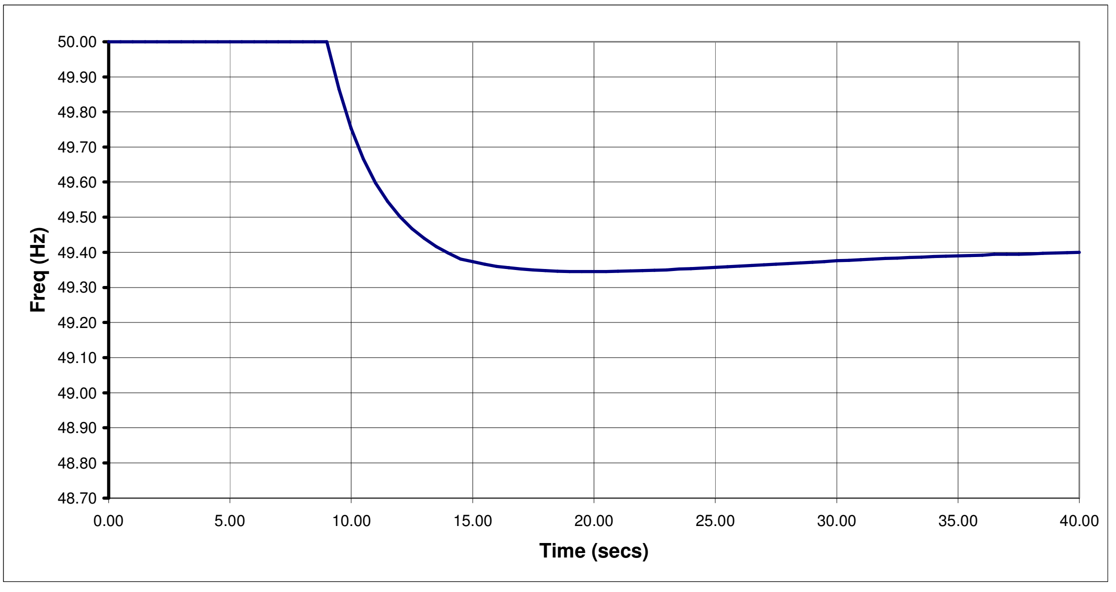

Figure 4: Cockburn trip with reserve as scheduled.

Hence, we may believe that had all plant responded to the drop in frequency and had continued to respond as it was expected that they would, the frequency excursion would have been successfully managed without concern. It was the unanticipated lack of continued response by the gas turbine plant that exacerbated the incident.

4.4 AGC PERFORMANCE

Although Western Power are responsible for providing the AGC facilities, System Management are responsible for its settings and use.

We have been advised that it is System Management policy to keep the AGC in its control mode throughout a low frequency incident with the AGC switching to a non-control mode only when the frequency drops to 47.5 Hz. This appears to be unusual as in all other jurisdictions we are familiar with, the AGC switches to no-control mode at a relatively small frequency drop to ensure that there is no conflict between the corrective governor response and the AGC control.

The points noted in the report from System Management associated with the AGC appear to have stemmed from the AGC still being in its control mode during the incident and conflicting with the governor controls. However we do not find this conflict to have directly exacerbated the incident.

5. ANALYSIS

5.1 WHY DID THE FREQUENCY NOT RECOVER?

The SWIS is a small power system containing a relatively high proportion of gas turbines, either in open cycle or closed cycle plant.

Due to its small size, the SWIS is also a frequency sensitive power system in that a loss of generation will result in a noticeable drop in the power system frequency. The extent of this frequency drop is managed by scheduling an appropriate level of spinning reserve and interruptible load as is standard industry practice.

The level of spinning reserve scheduled at 13:30 on 28 November was in excess of that required to cover the largest contingency. However, it proved to be insufficient to allow the power system frequency to recover without requiring automatic shedding of consumer load.

All market participants are required under both the Market Rules and Western Power's Technical Rules to supply a considerable level of plant performance data. This data is used by Western Power, acting as Western Power Networks, to ensure that the connection of the plant will not degrade the security and reliability of the SWIS. It is also relied upon by System Management when receiving advice on the dynamic performance of the power system from their colleagues in Western Power.

Had all plant performed as had been predicted on the basis of their standing data, the low frequency experienced on 28 November would have recovered without the necessity of shedding consumer load.

The non-operation of some interruptible load, by itself, was not sufficient to cause the addition of load shedding.

Why, then, did the frequency not recover?

The direct cause of the continued low frequency and associated consumer load shedding is the unanticipated inability of some generation units to make good their spinning reserve.

Those plant that were unable to make good their spinning reserve were either open cycle gas turbines or combined cycle gas turbine plant. This should not be surprising because it is well known that these plant have an inherent disability when the frequency drops.

As was made obvious in August 1996 when the Malaysian power system suffered a major blackout, single shaft gas turbines have a pronounced tendency to reduce output under low frequency conditions. However, this tendency does not appear to be necessarily well known by power system operators. Although it has been well documented, much of the useful documentation is not in the professional journals so is not necessarily brought to the attention of those who need to know.

Two of the most useful documents available are:

- "Seminar on Generation Mix and Grid System Reliability and Stability", Institute of Engineers, Malaysia, 17 October 1996

- "Frequency Standards Preliminary Report to the GSC, Appendix Six, Performance of thermal plant at low frequencies", 21 June 2001, New Zealand Grid Security Committee.

Both make it clear that when the power system frequency drops,

- the alternator slows because it runs in synchronism with the power system frequency
- which slows the speed of the GT compressor turbine reducing the pressure and volume of air being fed to combustion chamber
- while at the same time the governor system is increasing the fuel supply to the combustion chamber
- so that the fuel burns "rich"
- and the exhaust temperature rises so that
- the exhaust over temperature protection ramps back the fuel supply
- thus reducing the unit's MW output.

Although this effect can be mitigated through the design and setting of the gas turbine's control systems, it can only be prevented by the use of dual shaft gas turbines.

Further, the steam turbines which are the second stage in a CCGT are unable to increase their output as the frequency drops because, as has been noted:

- "The steam/water circuit operates largely in a sliding pressure mode with turbine generator valves wide open: (thus there is not the capability which conventional steam units have of rapidly opening governor valves to access the stored energy in the steam drum);
- "With no duct firing, the energy source for the HRSG is the GT exhaust, and the heat available is determined by the GT performance and constraints; and
- "The heat transfer processes within the HRSG are convective, and relatively slow compared with the radiant heating that results from ramping up the firing in conventional units. Even if duct firing is installed, the response time is relatively slow - minutes rather than seconds.

"Typically the GT provides about two thirds of a CCGT's power output and the steam turbine one third. With the inherent "sluggishness" of the steam cycle, the percentage responsiveness (as a percentage of rated capacity) of a CCGT unit to frequency excursions is reduced in the same proportion"[1].

This behaviour is not shown in simulation of these plant done by Western Power Networks which was based on the standing data supplied.

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[1] Page 14 of Frequency Standards Preliminary Report to the GSC, Appendix Six, Performance of thermal plant at low frequencies", 21 June 2001, New Zealand Grid Security Committee.

5.2 THE USE OF CODIFIED RESERVE REQUIREMENTS

Codes, or codified requirements, may be considered a means for no-engineered designs[2]. That is, codified requirements have the advantage that they are simple to understand and to implement. However, it is important to understand the limitations inherent in the codified requirements and to know when they do not apply.

Most power system operators have a codified requirement to describe the level of operating reserves required. That is, the reserve requirement is stated in terms such as that for the SWIS

> "the level must be sufficient to cover the greater of:
>
> i. 70% of the total output, including parasitic load, of the generation unit synchronised to the SWIS with the highest total output at that time; and
>
> ii. the maximum load ramp expected over a period of 15 minutes;"

However, such a codified requirement may either

- provide insufficient reserve to prevent an unacceptable frequency drop, or
- provide more reserve than is actually required.

In a large power system – say, greater than 20,000 MW – this codification of the reserve requirement is not too important because the primary function of the reserves is no longer to prevent a frequency collapse. Further, should more reserves than are necessary be provided, the additional cost as a proportion of the total cost of generation is not likely to be significant.

However, in a small power system, such as the SWIS, the principal function of the operating reserves is to prevent a frequency collapse in the event of a loss of generation. Under these circumstances the quality of the reserves provided is crucial.

On 28 November, a larger than usual proportion of the spinning reserve was carried on gas turbine plant. It is reasonable to assume that had System Management known of the inherent problems with these plant, they would not have relied on them to the extent that they did.

That they did not is due to two factors:

- no one in System Management involved in the scheduling and dispatch of the plant had sufficient power system dynamic expertise to recognise that there might be a problem, and
- the plant as defined in the standing data would apparently have provided a sufficient response for the power system to recover anyway.

In this respect, even if System Management had had access to a dynamic simulation model to check the response of plant, this would not have helped them.

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[2] Professor Paul Jennings, Caltech.

Therefore, while the codified reserve requirements did not of themselves cause the sustained low frequency, it may be argued that had the requirements required System Management to take a greater interest in the dynamic performance of the SWIS and of the plant within the SWIS, the nature of the reserve scheduling might have raised concerns prior to the incident.

5.3 RESPONSE OF PARTIES

5.3.1 The IMO

In asking the questions posed in section 1.3 we have:

Did the IMO comply with all Rules requirements following the incident?	Yes
Do the Reserve Capacity requirements have any influence on the short term reserve capacity of power plant?	No not directly as there is a distinction between the registered reserve capacity and the physical capacity available from each unit with the former usually being the smaller.

5.3.2 Market Participants

In answering the questions posed in section 1.3, we have

Did all Market Participants "behave" correctly both before and after the incident? For example, did they follow dispatch instructions/order correctly both before and after the incident?	Yes, to the best of their ability
Did the market participants' power plant perform correctly with respect to • The System Management's instructions/orders? • The performance specified in the Connection Agreement with Western Power Networks	Yes and No. Some interruptible load failed to trip and some plant did not perform as expected by System Management on the basis of the performance set out in their Standing Data. Although they did comply with the requirements of Technical Rule 3.3.3.3(b) Immunity to Frequency Excursions, the quality of their response is in question.

5.3.3 System Management

In answering the questions posed in section 1.3, we have

Did System Management correctly dispatch the ancillary services with respect to current System Management policies, practices and operating instructions	Yes
Did System Management correctly manage the incident once it occurred services with	Yes

respect to current System Management policies, practices and operating instructions	
Did System Management comply with the requirements of the Market Rules	Yes
Are System Management's policies, practice and models appropriate for scheduling and dispatching ancillary services	No, in the light of this incident, account should be taken of the expected response of differing plant types
The Western Power Technical Rules require that plant that is to be connected to the network provide data for simulation studies (3.2.4). Is this data ever validated, both at commissioning and thereafter? If so, when was the last time this data was validated for the generating units in the SWIS?	The data is validated at commissioning but does not appear to be revalidated there after.
The Western Power Technical Rules require that generation units have immunity to frequency excursions (3.3.3.3 (b)). How has this been determined in the past (excluding the November incident)?	All units did comply with the requirements of 3.3.3.3 (b) during this excursion
The WP Technical Rules require a certain control range (3.3.4.4(c)). When was the last time this was validated for each unit in the SWIS and how was it validated?	This control range does not appear to have been revalidated after commissioning
Which part of Western Power has the responsibility of enforcing the provisions of the Technical Rules?	Western Power Networks
Which part of Western Power is responsible for the provision of the AGC facilities between Western Power and the market participants? If the responsibility is shared between System Management and Western Power Networks, how is the responsibility shared?	Western Power Networks provides the facilities and System Management is responsible for operation and maintenance of the AGC software.

5.4 HOW NOT TO HAVE A REPEAT OCURRENCE

To avoid a repeat occurrence of this incident a number of things should happen.

5.4.1 Test all plant against their standing data

The standing data for all plant should be verified by test, preferably at regular intervals. Specific attention should be given to:

- The name plate capacity of the generator, expressed in MW
- The dependence of capacity on temperature at the location of the facility

- The sent out capacity of the generator, expressed in MW
- The governor control system parameters
- The excitation system parameters

Where possible, these tests should both be done without prior warning to the owner and without additional cost. For example, plant that is in service on a day when the temperature is around 41°C should be instructed to go to rated output at that temperature for a sufficient sustained period to demonstrate that capability.

5.4.2 Update standing data used for dynamic simulations

On the basis of both the tests set out in 5.3.1 and on the basis of the demonstrated behaviour of plant during the incident of 28 November,

- the dynamic models of the plant in the SWIS should be updated, and
- new guidelines proposed to more effectively schedule spinning reserves.

5.4.3 Provide more advanced tools to System Management

In addition to 5.3.2, it would help System Management check their scheduling of spinning reserve if they were to have access to a simple dynamic model of the frequency response of the SWIS. Such a model should account for the known behaviour of the differing types of plant. These could utilise existing models and be either at a system level (Excel) or an individual plant level (MatLab plus Simulink).

The use of such tools may also be expected to increase the power system dynamic knowledge of System management staff.

5.4.4 Review the use of AGC during low frequency events

Although not the principal contributor to the extended low frequency, the use of the AGC throughout a period of low frequency is not usual operating practice. The general practice is to switch the ACG to a non-controlling mode after a relatively minor drop in frequency so as to avoid conflicting control signals from the AGC and the governor controls.

The current practice of System Management should be reviewed in this light.

6. CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSIONS

The Western Australian SWIS is somewhat unusual in that its capacity is split almost 50:50 between steam plant and gas turbine plant

This high proportion of gas turbine plant is made up from predominantly single shaft plant which is known for its inherent tendency to reduce output during periods of low frequency.

However, this was not accounted for by System Management when dispatching the spinning reserves for two reasons:

- The System Management staff was not aware of this tendency on the part of the gas turbines because the dynamic studies had been carried out by the staff of Western Power Networks and not by System Management staff.
- The standard for determining the spinning reserve, as set in the market rules, does not distinguish between types of plant. It simply requires that the spinning reserve be at least 70% of the highest generation unit output at the time.

It is probable that dispatching the spinning reserve as had been the standard practice would be sufficient under most circumstances. However, at 1341 hours on 28 November (the time of incident) there was a higher than usual proportion of gas turbine plant operating due to planned outages on steam plant. In addition, there was only one interruptible load provider available and dispatched, which in the event did not trip.

Nevertheless, simulations indicate that had all plant performed as their dynamic performance data, as set out in the Western Power Technical Rules, would indicate then the incident was survivable without the necessity for customer load shedding.

From this we conclude that the values held in the Standing Data do not correctly reflect the actual performance of all plant.

6.2 RECOMMENDATIONS

6.2.1 PA recommendations

Following our investigation of the low frequency incident of 28 November 2007, noting that some of the following recommendations may already be under action, PA recommends that:

1. System Management immediately review the use of each plant type for the provision of spinning reserves taking into account the demonstrated performance of each plant type.
2. System Management immediately prepare an Ancillary Services Specification which sets out the expected performance of participants' plant that is to provide ancillary services.

– All plant which supply ancillary services be tested to verify the performance of that plant against the System Management Ancillary Services Specification.

3. System Management immediately review

– The performance of the AGC system during the incident of 28 November,

- The continued use of the AGC under low frequency conditions, and
- The monitoring of the performance of the AGC and controlled plant to set it on a formal basis.

4. The IMO undertake a study of the Ancillary Service Standards and the basis for setting Ancillary Service Requirements under Clause 3.15.1 of the Market Rules.

5. System Management take an active interest in the dynamic performance of the SWIS, recognising that it is the responsibility of System Management to ensure the reliable and secure operation of the SWIS, by either

- Having an dynamic analysis capability within System Management, or
- Having regular discussions with any provider of such capability, such as Western Power Networks, under a service agreement that places the obligation on the provider to provide prompt support to System Management requests.

ATTACHMENT A

ACTION PLAN IN RESPONSE TO PA'S RECOMMENDATIONS

The IMO has approached System Management about the 5 recommendations made by PA. System Management and the IMO will carry out the following actions in response to these recommendations.

Recommendation 1

> *System Management immediately review the use of each plant type for the provision of spinning reserves taking into account the demonstrated performance of each plant type.*

System Management has commenced review of the frequency dependency of the capacity of each of the gas turbine generators involved in the frequency event of 28 November 2007. When completed capacities of all affected generators will be adjusted for spinning reserve purposes to reflect their maximum expected generation capacities in peak mode with temperature control in effect at the lower reference frequency - corresponding to the first stage of UFLS.

Recommendation 2

> *System Management immediately prepare an Ancillary Services Specification which sets out the expected performance of participants' plant that is to provide ancillary services.*
>
> *All plant which supply ancillary services be tested to verify the performance of that plant against the System Management Ancillary Services Specification.*

Clause 3.9.3 of the Market Rules defines the spinning reserve ancillary service response measurement periods. Using these definitions System Management has commenced analysis of data recordings of past frequency events to determine actual Verve Energy generator responses and to benchmark the spinning reserve performance of all Verve Energy generators. The benchmarking exercise will provide a more detailed basis for spinning reserve requirements and identifying potential shortfalls to be filled by future procurement of ancillary services competitively. It will also help embed the method of measurement of spinning reserve performance based on data recorded by Western Power into System Management processes. As all the data required for the spinning reserve analysis is automatically collected by the PI historian during each actual frequency event further testing is not considered necessary by System Management.

Recommendation 3

> *System Management immediately review*
>
> – *The performance of the AGC system during the incident of 28 November*

System Management has reviewed the performance of the AGC system during the event of 28 November and identified specific actions to overcome identified inconsistencies in its behaviour during that event. Specific findings have been made for each generator which was controlled by AGC during the event. In summary the main issues that impacted on the AGC performance were as follows:

1. Significant differences between generator capacities calculated by the SCADA programme TALC and actual generator capacities. These differences were worsened by the drop in GT capacity as the frequency declined (see response to Recommendation 1). System Management is pursuing telemetry of operating limits calculated by the on-site generator control computer which is expected to provide a much more accurate value than TALC can provide.

2. Disruption of the control and monitoring signals between the SCADA RTU and the control system for one of the generators. System Management is working with the generator operator to identify and correct the source of the loss of control and monitoring signals.

3. Governor droop overriding AGC pulse controls on the GTs with a 2.5% governor droop setting. System Management will commission studies to determine the optimal droop setting for GTs providing spinning reserve and AGC control. Once settings are determined System Management will work with the GT operator to implement the new settings.

System Management immediately review

– *The continued use of the AGC under low frequency conditions*

Currently AGC suspension does not occur until system frequency reaches a limit of 47.5 Hz. This frequency corresponds to the 10 second target recovery time requirement for a multiple contingency event in the Technical Rules. Under the Technical Rules if the frequency remains below 47.5 Hz for more than 10 seconds then the connected generation is not expected to ride through the frequency disturbance. Because of interference from operation of generator protection systems continued operation of AGC in these circumstances would not be wanted and AGC is suspended. However inside these limits System Management believes that suspension of AGC is unnecessary and that suspending it would slow down restoration of normal frequency as all corrective action would need to be manual. System Management recommends continued operation of AGC during any frequency disturbance that lies within the target recovery times in the Technical Rules.

System Management immediately review

– *The monitoring of the performance of the AGC and controlled plant to set it on a formal basis.*

As part of the Ancillary Services Plan, which includes future procurement of ancillary services, System Management is defining AGC performance criteria and developing a monitoring protocol for all facilities providing ancillary services. The benchmarking exercise detailed in Recommendation 2 will be used to identify the standards for each facility, and future performance will be compared to that standard following each system disturbance.

Recommendation 4

> *The IMO undertake a study of the Ancillary Service Standards and the basis for setting Ancillary Service Requirements under Clause 3.15.1 of the Market Rules.*

In accordance with the Market Rules, at least once in every five year period starting from Energy Market Commencement, the IMO, with the assistance of System Management, must carry out a study on the Ancillary Service Standards and the basis for setting Ancillary Service Requirements. The IMO currently proposes to commence the first review in the second half of 2008.

Recommendation 5

> *System Management take an active interest in the dynamic performance of the SWIS, recognising that it is the responsibility of System Management to ensure the reliable and secure operation of the SWIS, by either*
>
> – Having a dynamic analysis capability within System Management, or
>
> - Having regular discussions with any provider of such capability, such as Western Power Networks, under a service agreement that places the obligation on the provider to provide prompt support to System Management requests.

System Management will undertake examination of the dynamic performance of the SWIS to ensure reliable and secure operation as part of the study by the IMO of the Ancillary Services Standards and setting Ancillary Service Requirements commencing in the second half of 2008. System Management has already commissioned some preliminary feasibility studies and the results will be made available to the IMO for its study of Ancillary Service Standards and setting Ancillary Service Requirements.