IN THE DISPUTE RESOLUTION PANEL AT MELBOURNE
(Constituted for a determination as to compensation under Rule 3.16.2 of the National Electricity Rules)

JOINT SUBMISSIONS TO THE DISPUTE RESOLUTION PANEL

Synergen Power Pty Ltd (ABN 66 092 560 819) (**Synergen**)

and

Australian Energy Market Operator Limited (ABN 94 072 010 327) (**AEMO**)

A. Glossary

1. A number of terms and acronyms are used throughout these submissions.

2. Many of the terms used in these submissions are defined in the National Electricity Rules (Version 38) (***Rules***) and these are italicised for ease of reference.

3. Unless the context dictates otherwise, terms defined in the *Rules* have the same meaning in these submissions as in the *Rules* and a reference to a 'Rule' followed by a number means a provision of the *Rules*.

B. Application

4. AEMO has determined under Rule 3.8.24(a)(2) that a *scheduling error* occurred from 19 May 2009 until 14 January 2010. The *scheduling error* affected the Mintaro Gas Turbine Station in South Australia.

5. Synergen is and was, at all material times, registered as a *Market Generator* and a *Scheduled Generator* in respect of the Mintaro Gas Turbine Station.

6. Rule 3.16.2 permits Synergen to apply to the Dispute Resolution Panel **(DRP**) for a determination as to compensation in respect of the *scheduling error*. The matters to be determined by the DRP are:

   (a) whether compensation is payable;

   (b) the amount of compensation to be paid to Synergen for its loss from the *Participant compensation fund*;[1] and

   (c) the manner and timing of that payment.[2]

C. AEMO and the National Electricity Market (NEM)

7. Sections C to G set out background information regarding the operation of the *NEM* and the effect of constraints. This is included to provide context to the DRP.

8. AEMO operates and manages the *NEM*. The *NEM* is essentially two things: the physical infrastructure that keeps electricity flowing from producers to consumers,

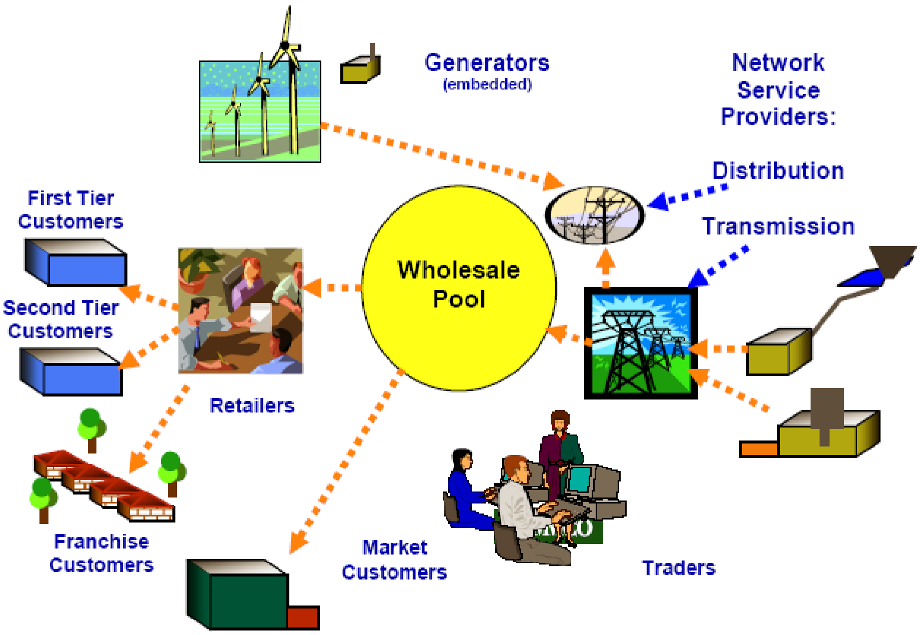
[1] Rule 3.16.2 (b) and (d)
[2] Rule 3.16.2(i).

and a notional wholesale pool (or spot market) to which producers sell, and from which purchasers buy, electricity.

9. Electricity cannot be stored economically; it must be dynamically produced to satisfy demand that varies instantaneously. The *NEM* facilitates the instantaneous matching of supply and demand through a centrally coordinated process managed by AEMO, called 'central dispatch'.

10. Figure 1 depicts the relationships between different participants in the *NEM*.

Figure 1 – The National Electricity Market



11. The *NEM* is a gross pool. This means that all *Generators* whose power output enters the grid must 'sell' their output via the market conducted by AEMO, unless they are embedded in a *distribution network* and they have already sold their output to the local retailer for that network or to a Customer located at the same *connection point*.

12. In geographic terms, the *NEM* covers the supply of electricity to South and Eastern Australia. It operates on one of the world's longest *interconnected power systems*, a distance of more than 4,000 kilometres.

13. The *NEM* is divided into five *regions* for *market* pricing purposes. They are:

(a) Queensland;

(b) New South Wales (incorporating the Australian Capital Territory);

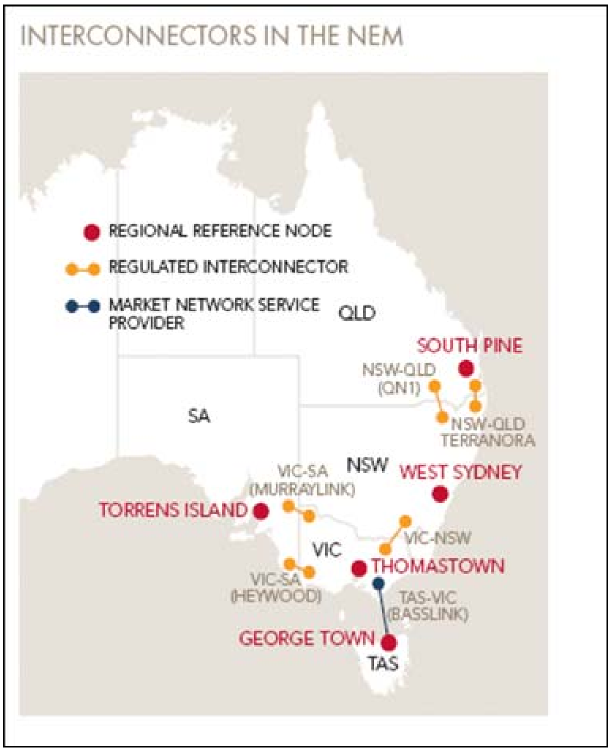
(c) Victoria;

(d) South Australia; and

(e) Tasmania.

14. Each *region* is connected to its adjacent *regions* by *interconnectors*, which are a series of *transmission lines* that facilitate the flow of electricity between *regions*. Figure 2 shows the *interconnectors*:

Figure 2 – Interconnectors in the NEM



15. A number of different types of organisations can participate in the *NEM*. These are called *Registered Participants*. Some are registered in their capacity as providers of infrastructure, such as *Network Service Providers* (**NSPs**) while others participate in the wholesale electricity exchange as *Market Participants*, buying and selling electricity.

16. The *Rules* allow potential participants in the *NEM* to register in a number of different categories. For example:

    (a) *Scheduled Generators* participate in the *central dispatch* process. Generally, these are *Generators* with *generating units* whose *nameplate rating* is greater than 30 MW.

    (b) *Non-Scheduled Generators* are typically *Generators* with *generating units* whose *nameplate rating* is less than 30 MW and do not participate in the *central dispatch* process.

    (c) *Generators* that sell all of their electricity into the *spot market* are registered as *Market Generators*. *Market Generators* are paid the *spot price* applicable at their *network connection* for each *trading interval* during which they supply electricity to the *market*. A *Generator* that sells its entire output to either a *Local Retailer* or consumer located at the same *connection point* is classified as a *Non-Market Generator*.

D. The regulatory framework

17. The *NEM* is regulated by the National Electricity Law (**Law**), a schedule to the *National Electricity (South Australia) Act 1996* that has been extended to each of the *participating jurisdictions* through the use of a co-operative legislative scheme.

The *Rules* were made under the Law; subsequent changes are approved by the Australian Energy Market Commission.

18. Under the Law, AEMO has two core functions: power system operator, and wholesale market operator.

19. As power system operator, AEMO is concerned primarily with meeting standards of security and reliability. *Power system security* refers to the *power system's* capacity to continue operating within defined technical limits even in the event of the *disconnection* of a major *power system* element, such as an *interconnector* or large *generating unit*. *Power system* reliability refers to the *power system's* capacity to supply sufficient energy to meet consumer demand.

20. As market operator, AEMO facilitates the wholesale trading of electricity through a centrally co-ordinated *dispatch* process.

E. Central dispatch

21. *Central dispatch* refers to the centrally-managed process of *dispatching* electricity to meet demand. AEMO manages this process in accordance with Chapter 3 of the *Rules*.

22. *Central dispatch* should aim to maximise the value of *spot market* trading on the basis of *dispatch offers* and *dispatch bids* (that is, the lowest cost *generating units* needed for electricity supply to meet demand are *dispatched*) subject to a number of matters, such as network *constraints* and *power system security* requirements.[3]

23. To participate in the *central dispatch* process, *Scheduled Generators* must submit *dispatch offers* to AEMO to generate electricity[4]. These offers must be submitted by 12:30 EST on the day before trading will occur. In each *dispatch offer*, *Scheduled Generators* must make an offer to provide a certain number of megawatts (**MW**) of electricity for each of the 48 *trading intervals* in the *trading day* and may make offers for up to ten *price bands* for each *generating unit*.[5]

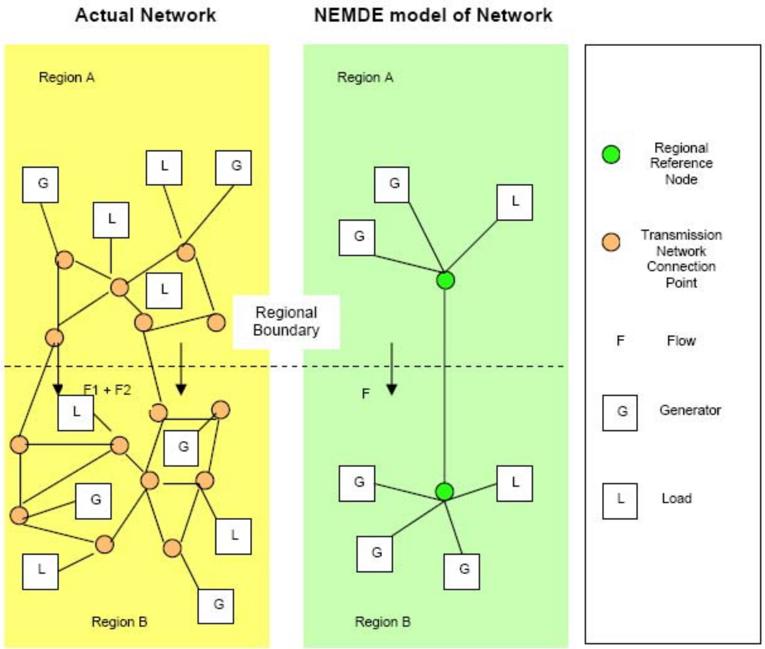
24. A *Generator* can own one or more *generating units*. Unless AEMO approves an application to aggregate these into a single entity for bidding purposes, AEMO receives bids for, and then determines loading levels (*dispatch instructions*) on an individual *generating unit* basis.

25. *Dispatch offers* are processed by a computer system called the National Electricity Market Dispatch Engine (**NEMDE**).

26. NEMDE is based on a constrained optimisation program that uses linear programming techniques that represent the *power system* in a manner that is reflected in Figure 3:

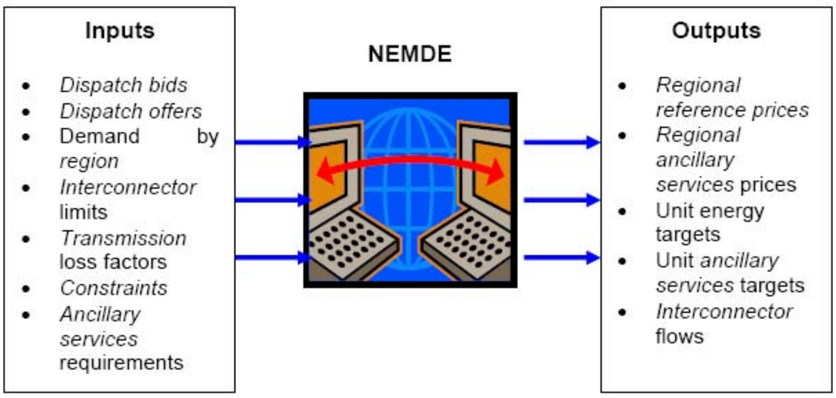
[3] Rule 3.8.1(b).
[4] Rule 3.8.2(a).
[5] Rule 3.8.6(a).

Figure 3 – How NEMDE Represents the Interconnected Network



27. AEMO forecasts electricity consumption in each *region*, identifies the capability of the *transmission network* to transmit electricity, and captures the present state of the *power system* from information provided by *Transmission Network Service Providers* (**TNSPs**). AEMO then determines the *generation* outputs for each *Generator* according to an overall optimisation process that is specified in the *Rules* and, in practice, performed by NEMDE. A simplified form of this optimisation process is depicted in Figure 4:

Figure 4 – NEMDE Optimisation Process



28. The optimisation process attempts to maximise the value of electricity traded and produces a *spot price* in each *region* that represents the marginal price of producing the next increment of electricity at that location.

29. The highest price *Scheduled Generators* can offer is $10,000 per MWh for the *trading intervals* occurring up 30 June 2010 and $12,500 per MWh for *trading*

intervals occurring after 1 July 2010 (*market price cap*) and the lowest is -$1,000 per MWh (*market floor price*).[6] *Scheduled Generators* must specify other technical matters in their *dispatch offers*, such as their rate of change for increasing or decreasing their output in MW/minute (*ramp rate*).

30. AEMO sends *Scheduled Generators* a *pre-dispatch schedule* every 30 minutes. A *pre-dispatch schedule* is essentially a forecast that gives *Scheduled Generators* an indication of when they will be *dispatched*, and for what level of output they will be *dispatched* for the *trading intervals* in the next two days. *Scheduled Generators* then have the opportunity to *rebid* the MW capacity that they can produce and other technical aspects of their capacity right up to five minutes before the event, but cannot change the prices for the ten *price bands* they have selected.

31. NEMDE sends the *Scheduled Generators* electronic *dispatch instructions* to increase or reduce the quantity of electricity they produce for each *dispatch interval*.

32. NEMDE will process all the data it has available to achieve the lowest cost and most efficient outcome taking into account *power system* limitations. In general, and without considering the impact of *constraints*, *ramp rate* and other limitations for each *dispatch interval, Scheduled Generators* will be *dispatched* in ascending *price band* order until enough electricity has been produced to meet the demand for electricity for that *dispatch interval*.

33. The *spot price* for a *trading interval* is the average of the six *dispatch interval* prices within that *trading interval*.

34. All of the *Generators dispatched* during that *trading interval* will be paid the *spot price* times their *loss factor* for the energy they have produced in that *trading interval*, even if their *dispatch offers* were for a lower price. Any *Generators* whose offers were too expensive and were not needed to meet the demand were not *dispatched* and, consequently, do not get paid. In this way, the wholesale exchange encourages competition between *Scheduled Generators*.

F. Impact of power system security on dispatch

35. Rule 3.8.1 requires AEMO to manage *central dispatch* in order to balance supply and demand while using reasonable endeavours to maintain *power system security* and to maximise the value of *spot market* trading.

36. Rule 4.3.2 requires AEMO to use its reasonable endeavours, as permitted under the *Rules*, to achieve the *power system security responsibilities* in accordance with certain principles. One such principle is that, to the extent that this is practicable, the *power system* should be operated such that it is and will remain in a *secure operating state*. The requirements for the *power system* being in a *secure operating state* are that, in AEMO's reasonable opinion, it is in a *satisfactory operating state* and that it will return to a *satisfactory operating state* following the occurrence of any *credible contingency event*.[7] The *power system* will be in a *satisfactory operating state* if certain parameters are satisfied, such as frequency and voltage.

[6] Rules 3.9.4(b) and 3.9.6(b).
[7] Rule 4.2.4.

37. The effect of this requirement is that the *power system*'s physical limits can impact which *Scheduled Generators* are dispatched, not just their *dispatch prices*. For example:

(a) *power system plant*, such as *interconnectors* and *transmission lines*, can only carry a certain amount of electricity before they become overloaded;

(b) *power system plant* may require planned *outages* to enable their owners/operators to service and maintain them; and

(c) *power system plant* may experience unplanned failures (trip).

38. To identify potential *constraints* on the *power system* arising from the non-availability of *power system* assets, *Scheduled Generators* and NSPs are required to notify AEMO of planned *outages* for up to two years in advance. The impact of these is included in the *Medium Term Projected Assessment of System Adequacy* published by AEMO on a weekly basis. In addition, every two hours, AEMO publishes the *Short Term Projected Assessment of System Adequacy*, which includes the impact of expected *outages* for the next seven days.

G. Constraints

39. TNSPs provide AEMO with limit equations that are reviewed and used by AEMO to develop constraint equations to ensure that *transmission lines* are operated within their limits and that the *power system* is secure.

40. Limitations on the *power system* are represented in NEMDE as a series of mathematical constraint equations.

41. There are constraint sets containing constraint equations that represent the *power system* for 'system normal' conditions and many others to represent a range of single and multiple *transmission* circuit *outages*.

42. The constraint sets that are invoked at any particular time are selected from a library to approximate the *power system* conditions at that time.

43. Constraint sets are used by NEMDE to model what the *transmission network* is capable of doing during each *dispatch interval* in an effort to ensure that *power system security* is maintained.

44. The need for constraint equations by NEMDE to model what the *transmission network* is capable of doing gives rise to certain risks for *Market Participants*:

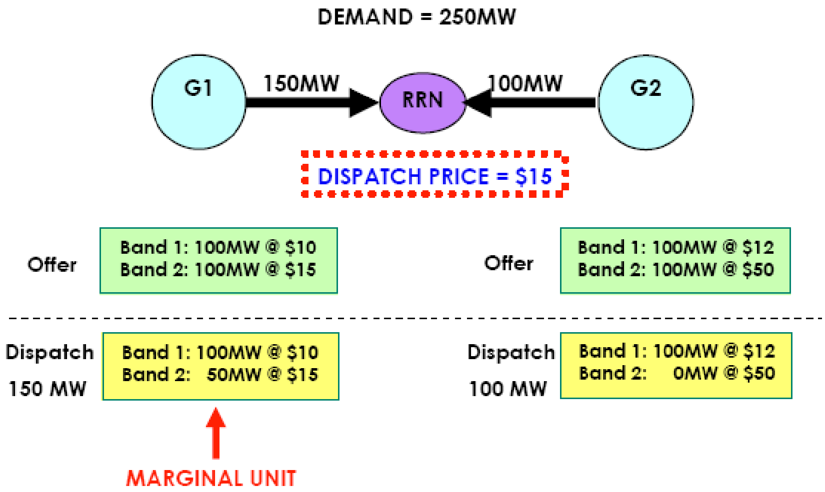
(a) Volume risk – *Generators* might not be able to generate as much electricity as they had anticipated due to *constrained transmission lines*; and

(b) Price risk – *constraints* can cause price separation between *regions*. This means that, in any *trading interval*, *Market Participants* can be affected by more than one *spot price*.

45. How these risks manifest in practice is best illustrated by way of example: Figure 5 shows two *generating units* in a *region* whose demand is fixed at 250MW. Generator G1 offers its capacity of 150MW in two bands: 100MW @$10 and 100MW @$15; Generator G2 offers its capacity of 100MW in two bands: 100MW @$12 and 100MW @$50. Generator G1 is *dispatched* first for 100MW @$10, and then Generator G2 is *dispatched* for 100MW @$12. The remaining 50MW is

dispatched at the next cheapest price, which is G1's offer @$15, which also determines the *dispatch price* for that *dispatch interval*.

Figure 5 – Example

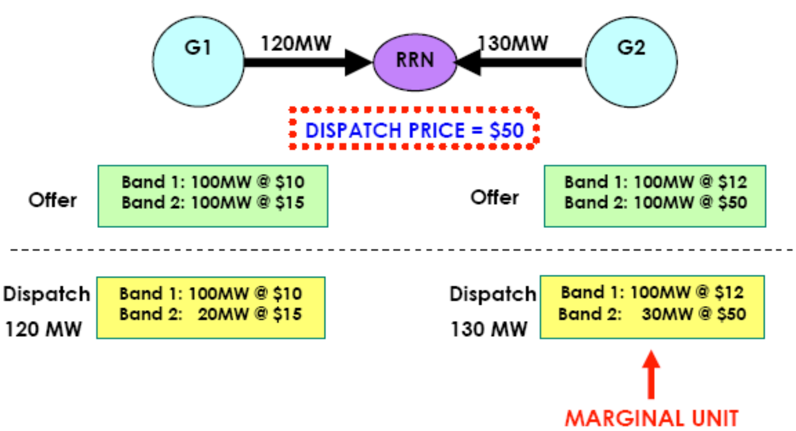


46. If this simple situation were to be complicated by the existence of a *constraint* on the *transmission line* linking Generator G1's *generating unit* to the *power system* such that flow on that *transmission line* had to be limited to 120MW or less, AEMO would formulate a constraint equation to address this. The simplest form of constraint equation could be formulated as follows:

G1 <= 120MW

47. If G1 <= 120MW were to be used by NEMDE, demand would be met in the following way: Generator G1 would *dispatch* 100MW @$10, then Generator G2 would *dispatch* 100MW @$12 but because the *constrained transmission line* can only carry an extra 20MW, Generator G1 would only be permitted to *dispatch* another 20MW @$15, with the remaining 30MW coming from Generator G2 @$50. The *dispatch price* for the *dispatch interval* would be $50. This is illustrated in Figure 6:

Figure 6 – Example (continued)



48. At times, NEMDE will be forced to *dispatch Scheduled Generators* into higher *price bands* than would otherwise be required because of the constraint equations that are invoked at the time, so as to ensure that the *power system* is not

overloaded and demand is met. Accordingly, the constraint equations in each *dispatch interval* may determine whether a *Scheduled Generator* is *constrained-on* or *constrained-off* in order to maintain *power system security*.

49. When a constraint equation is having an effect on the *dispatch* of a *Generator* and it is being complied with (or satisfied mathematically) it is referred to as 'binding'. If there is no feasible solution to the *dispatch* of *generation* that can satisfy all the applicable constraint equations, one or more of them will be breached (or not satisfied mathematically). When this occurs, the relevant constraint equations are said to be 'violating'.

50. There are usually several thousand constraint equations that, in total, define the 'space' or 'envelope' that the *dispatch* solution can lie within for the *power system* to be secure.

51. When the *power system* configuration changes, such as when a *transmission* circuit is taken out of service, a new set of constraint equations must be invoked for that particular situation. AEMO's policy is to invoke outage constraint equation sets 'on top' of (ie in addition to) the system normal set of constraint equations. This policy assumes that the *technical envelope* for an *outage* is more restrictive that the system normal envelope and avoids the risks of identifying, concurrently revoking, and ultimately re-invoking the system normal set of constraint equations.

H. The scheduling error

52. AEMO determined in accordance with Rule 3.8.24(a)(2) that a *scheduling error* occurred from 19 May 2009 until 14 January 2010.

53. The *scheduling error* is constituted by an incorrect formulation of a constraint equation designed to maintain the flow on the Mintaro-Waterloo *transmission line* below its continuous rating.

54. This constraint equation has impacted the output of the Mintaro Gas Turbine Station by reducing its output to a lower level than would have been the case had the constraint equation been formulated correctly.

55. AEMO has prepared a Market Event Report titled 'Scheduling Error Report Affecting Dispatch of Mintaro Gas Turbine Station'. The report describes the occurrence of the *scheduling error* and is reproduced in **Schedule 1**.

I. Calculation of Synergen's loss

56. The magnitude of the change in output incurred by Synergen as a result of this *scheduling error* has been calculated by AEMO based on reductions in *dispatch* targets (as generated MWh) shown in the table below:

Date	Reductions (MWh)	Increases (MWh)
29 May 2009	1.5	0.4
10 November 2009	7.5	0.0
11 November 2009	6.0	0.0
19 November 2009	8.4	5.3
16 December 2009	1.8	0.0

11 January 2009	27.0	1.8
TOTAL	**52.2**	**7.5**

57. The magnitude of the loss incurred by Synergen as a result of this *scheduling error* has been calculated by AEMO based on reductions in *dispatch* targets (as generated MWh) and published *spot price* shown in the table below:

Date	Reductions	Increases
29 May 2009	$152.28	$38.03
10 November 2009	$9,076.71	$0.00
11 November 2009	$7,863.56	$0.00
19 November 2009	$52,785.93	$10,010.53
16 December 2009	$234.61	$0.00
11 January 2009	$198,470.60	$20,140.92
TOTAL	**$268,583.69**	**$20,140.92**

The net reduction in income from the *spot market* is $248,442.77.

58. These reductions were calculated on the basis of the following assumptions:

(a) recalculating the *dispatch* outcome (in MW) with the correct constraint equation substituted for the incorrect constraint equation and comparing this to the original *dispatch* outcome (in MW) is a reasonable estimation of the difference between expected output and actual output (in MWh); and

(b) the *loss factor* is assumed to be 0.969 in accordance with those *published* by AEMO for the financial year 2009/2010 and 0.9664 for the financial year 2008/2009.

59. In making its determination, the DRP must use the *spot prices* determined by the *central dispatch* process pursuant to Rule 3.9.[8]

60. The loss incurred by Synergen during the *scheduling error* period is calculated using the following formula for each *trading interval* within the period of the declared *scheduling error*:

Loss = ((expected output - actual output) * loss factor * spot price) - avoided fuel cost

61. The detailed calculations of the first part of this formula are contained in the spreadsheets attached in **Schedule 2**.

62. The incorrectly formulated constraint equation resulted in the Mintaro Gas Turbine Station's output being at a lower level than would have been the case had the constraint equation been formulated correctly. On this basis, the avoided fuel cost is $1,583.00.

63. Synergen seeks compensation to cover its full loss of **$**246,858.78 (being $248,442.77 - $1,583.99). AEMO agrees with this calculation of Synergen's loss arising from the *scheduling error*.

[8] Rule 3.16.2(h)(3).

J. Participant compensation fund

64. AEMO is required by Rule 3.16.1 to 'maintain, in the books of the corporation, a fund called the *Participant compensation fund* for the purpose of paying compensation to *Scheduled Generators* ... as determined by the *dispute resolution panel* for *scheduling error*s…'.

65. AEMO is required to pay to the *Participant compensation fund* the component of *Participant fees* attributable to the *Participant compensation fund*. The overall funding requirement for each financial year is the lesser of:

    (a) $1,000,000; and

    (b) $5,000,000 minus the amount that AEMO reasonably estimates will be the balance of the *Participant compensation fund* at the end of the financial year.[9]

66. Any interest paid on money held in the *Participant compensation fund* also accrues to and forms part of the *Participant compensation fund*.[10]

67. AEMO must prepare and *publish* before the beginning of each financial year a budget of the revenue requirements for AEMO for that financial year.[11] The budget must take into account and separately identify projected revenue requirements in respect of the funding requirements of the *Participant compensation fund* in accordance with Rule 3.16.[12] The projected revenue requirements in respect of the funding requirements of the *Participant compensation fund* must only be recovered from *Scheduled Generators*, *Semi-Scheduled Generators* and *Scheduled Network Services Providers*.[13]

68. AEMO must also develop, review and *publish* the structure (including the introduction and determination) of *Participant fees* for such periods as AEMO considers appropriate.[14] The *Participant fees* should recover the budgeted revenue requirements for AEMO determined under Rule 2.11.3.[15]

69. NEMMCO determined the structure of *Participant fees* for the period 1 July 2006 to 30 June 2011.[16] NEMMCO determined that the budgeted revenue requirements in respect of the *Participant compensation fund* will be allocated to *Scheduled Generators* and *Scheduled Network Service Providers* and levied using a combination of historical capacity and historical energy scheduled, where:

    (a) 50% will be collected on the basis of MWh of energy scheduled or *metered* in the previous calendar year; and

    (b) 50% will be collected on the basis of the higher of the greatest registered capacity and highest notified maximum capacity in the previous calendar year.

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9 See Rule 3.16.1(c).
10 Rule 3.16.1(e).
11 Rule 2.11.3(a).
12 Rule 2.11.3(b)(8).
13 Rule 2.11.3(b)(8).
14 Rule 2.11.1(a).
15 Rule 2.11.1(b)(2).
16 See http://www.aemo.com.au/registration/128-0050.pdf

70. AEMO may charge a *Registered Participant* the relevant components of *Participant fees* by giving the *Registered Participant* a statement setting out the amount payable by that *Registered Participant* and the date for payment.[17] In the case of *Market Participants*, AEMO may, alternatively, include the relevant amount in the final statements described in Rule 3.15.15.[18] A *Registered Participant* must pay to AEMO the net amount stated in the relevant statement by the date specified by AEMO.[19]

71. In making its determination, the DRP must:

    (a) consider the claim for compensation by reference to the reduction in the loading level at which a *generating unit* operated due to the *scheduling error*;

    (b) use the *spot price* determined under Rule 3.9;[20]

    (c) take into account the current balance of the *Participant compensation fund* and the potential for further liabilities to arise during the year;[21] and

    (d) recognise that the aggregate liability in any year in respect of *scheduling errors* cannot exceed the balance of the *Participant compensation fund* that would have been available at the end of the year if no compensation payments for *scheduling errors* had been made during that year.[22]

72. In a decision of the DRP dated 24 April 2008 in a claim for compensation from the *Participant compensation fund* by Macquarie Generation, it was held that the reference to 'liabilities' in Rule 3.16.2(h)(4) is a reference to actual liabilities that will have created a clear balance in the *Participant compensation fund*.[23] The DRP also accepted that the reference to 'year' in Rule 3.16.2(h) is a reference to a financial year.[24]

73. As at 16 September 2010, the *Participant compensation fund* has a balance of $3,280,280.77.

74. Since the commencement of the market there have been three payments made from the *Participant compensation fund*. These are as follows:

    (a) $438,892.00 to Snowy Hydro Limited as compensation for a *scheduling error* that occurred on 31 October 2005;

    (b) $4,544,638.00 to Macquarie Generation as compensation for a *scheduling error* that occurred on 22 October 2007; and

    (c) $571,935.06 to AGL Hydro as compensation for a *scheduling error* that occurred on 19 & 20 November 2009.

75. There have been no other claims for compensation for *scheduling error*s since the last payment and AEMO has not declared any further *scheduling errors*.

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[17] Rule 2.11.2(a).
[18] Rule 2.11.2(b).
[19] Rule 2.11.2(c).
[20] Rule 3.16.2(h)(3)
[21] Rule 3.16.2(h)(4).
[22] Rule 3.16.2(h)(5).
[23] See paragraph 24.
[24] See paragraph 15. A 'financial year' is defined in Chapter 10 of the *Rules* as the period commencing on 1 July in one calendar year and terminating on 30 June in the following calendar year.

76. The *Adviser* issued a notice on 21 September 2010 to the DMS contacts regarding the receipt of a claim against the *Participant compensation fund* in respect of this *scheduling error* and asked that any other claimants for this incident inform her of their claim by 23 September 2010. No further claims were notified.

77. If the compensation was paid for the full amount of Synergen's loss, the balance in the *Participant compensation fund* would be $3,033,421.99.

78. Accordingly, there is no reason why full payment of Synergen's loss should not be made.

K. Costs

79. For the purposes of this claim, Synergen and AEMO submit that the costs of these proceedings (other than the legal costs of the parties) should be borne equally by them and that each of them should bear their own legal costs.

80. It is submitted that the DRP should not exercise any discretion it may have under Rule 8.2.8(b) to allocate costs on a different basis as neither Synergen, nor AEMO, has unreasonably prolonged or escalated a dispute or otherwise increased the costs of these proceedings.

DATED:

SCHEDULE 1

MARKET EVENT REPORT

SCHEDULE 2

CALCULATION OF SYNERGEN'S LOSS

Dispatch Interval	Mintaro actual output (MW) A	Mintaro expected output (MW) B	Difference (MWh) C=(B-A)/12	Spot price ($/MWh) D	Loss factor E	Loss ($) C*D*E
29/05/2009 08:05	80.44	88.89	0.70	103.1	0.9664	70.16
29/05/2009 08:10	80.7	89	0.69	103.1	0.9664	68.91
29/05/2009 08:15	81.06	82.65	0.13	103.1	0.9664	13.20
29/05/2009 08:20	81.09	79.7	-0.12	103.1	0.9664	-11.54
29/05/2009 08:25	81.42	80.03	-0.12	103.1	0.9664	-11.54
29/05/2009 08:30	81.82	80.02	-0.15	103.1	0.9664	-14.95
10/11/2009 14:35	53.37	56.74	0.28	116.3	0.969	31.65
10/11/2009 14:40	60	74	1.17	116.3	0.969	131.48
10/11/2009 14:45	63.04	74	0.91	116.3	0.969	102.93
10/11/2009 14:50	63.49	74	0.88	116.3	0.969	98.70
10/11/2009 14:55	63.37	74	0.89	116.3	0.969	99.83
10/11/2009 15:00	64.17	74	0.82	116.3	0.969	92.32
10/11/2009 15:05	63.64	74	0.86	3460.43	0.969	2894.89
10/11/2009 15:10	63.99	74	0.83	3460.43	0.969	2797.09
10/11/2009 15:15	67.31	74	0.56	3460.43	0.969	1869.38
10/11/2009 15:20	70.57	74	0.29	3460.43	0.969	958.44
11/11/2009 14:35	56.25	59.5	0.27	55.77	0.969	14.64
11/11/2009 14:40	58.15	70.17	1.00	55.77	0.969	54.13
11/11/2009 14:45	62.52	72.82	0.86	55.77	0.969	46.39
11/11/2009 14:50	62.49	74	0.96	55.77	0.969	51.83
11/11/2009 14:55	65.5	74	0.71	55.77	0.969	38.28
11/11/2009 15:00	65.36	74	0.72	55.77	0.969	38.91
11/11/2009 15:05	65.68	74	0.69	5062.11	0.969	3400.93
11/11/2009 15:10	67.57	74	0.54	5062.11	0.969	2628.36
11/11/2009 15:15	70.11	74	0.32	5062.11	0.969	1590.10
19/11/2009 12:00	38.9	51.71	1.07	68.99	0.969	71.36
19/11/2009 12:05	52.03	58.37	0.53	79.6	0.969	40.75
19/11/2009 12:10	65.33	55.73	-0.80	79.6	0.969	-61.71
19/11/2009 12:15	53.68	45.58	-0.68	79.6	0.969	-52.06
19/11/2009 12:20	55.44	49.65	-0.48	79.6	0.969	-37.22
19/11/2009 12:25	53.73	52.56	-0.10	79.6	0.969	-7.52
19/11/2009 12:30	53.33	44.52	-0.73	79.6	0.969	-56.63
19/11/2009 12:35	48.5	45.18	-0.28	319.21	0.969	-85.58
19/11/2009 12:40	49.69	42.96	-0.56	319.21	0.969	-173.47
19/11/2009 12:45	46.27	44.33	-0.16	319.21	0.969	-50.01
19/11/2009 12:50	46.5	45.77	-0.06	319.21	0.969	-18.82
19/11/2009 12:55	45.88	44.82	-0.09	319.21	0.969	-27.32
19/11/2009 13:00	47.87	46.43	-0.12	319.21	0.969	-37.12
19/11/2009 13:05	49.28	50.4	0.09	1306.75	0.969	118.18
19/11/2009 13:10	50.64	50.49	-0.01	1306.75	0.969	-15.83
19/11/2009 13:15	50.38	52.95	0.21	1306.75	0.969	271.19
19/11/2009 13:20	52.27	53.33	0.09	1306.75	0.969	111.85
19/11/2009 13:25	54.68	53.98	-0.06	1306.75	0.969	-73.86
19/11/2009 13:30	55.1	58.36	0.27	1306.75	0.969	344.00
19/11/2009 13:35	59.06	60.69	0.14	4616.24	0.969	607.60
19/11/2009 13:40	61.29	61.03	-0.02	4616.24	0.969	-96.92

Dispatch Interval	Mintaro actual output (MW) A	Mintaro expected output (MW) B	Difference (MWh) C=(B-A)/12	Spot price ($/MWh) D	Loss factor E	Loss ($) C*D*E
19/11/2009 13:45	62.16	64.5	0.20	4616.24	0.969	872.26
19/11/2009 13:50	64.75	65.72	0.08	4616.24	0.969	361.58
19/11/2009 13:55	65.3	63.45	-0.15	4616.24	0.969	-689.61
19/11/2009 14:00	65.46	67.21	0.15	4616.24	0.969	652.33
19/11/2009 14:05	68.53	68.43	-0.01	6777.81	0.969	-54.73
19/11/2009 14:10	68.62	68.54	-0.01	6777.81	0.969	-43.78
19/11/2009 14:15	69.23	72.63	0.28	6777.81	0.969	1860.85
19/11/2009 14:20	71.3	69.98	-0.11	6777.81	0.969	-722.45
19/11/2009 14:25	68.93	73	0.34	6777.81	0.969	2227.54
19/11/2009 14:30	66.08	73	0.58	6777.81	0.969	3787.37
19/11/2009 14:35	69.61	67.01	-0.22	8396.44	0.969	-1762.83
19/11/2009 14:40	70.59	73	0.20	8396.44	0.969	1634.01
19/11/2009 14:45	69.93	73	0.26	8396.44	0.969	2081.50
19/11/2009 14:50	69.96	71	0.09	8396.44	0.969	705.13
19/11/2009 15:35	40.68	40.22	-0.04	9999.77	0.969	-371.44
19/11/2009 15:40	34.37	32.45	-0.16	9999.77	0.969	-1550.36
19/11/2009 15:45	29.03	24.05	-0.42	9999.77	0.969	-4021.26
19/11/2009 15:50	31.01	31.01	0.00	9999.77	0.969	0.00
19/11/2009 15:55	31.01	31.01	0.00	9999.77	0.969	0.00
19/11/2009 16:00	30.6	32.4	0.15	9999.77	0.969	1453.47
19/11/2009 16:05	30.87	33.56	0.22	9999.77	0.969	2172.13
19/11/2009 16:10	31.21	39.34	0.68	9999.77	0.969	6564.82
19/11/2009 16:15	30.7	36.48	0.48	9999.77	0.969	4667.24
19/11/2009 16:25	68.04	71	0.25	9999.77	0.969	2390.15
19/11/2009 17:00	53.32	71	1.47	9999.77	0.969	14276.27
19/11/2009 17:05	64.17	71	0.57	9998.4	0.969	5514.34
16/12/2009 13:25	54.97	60.32	0.45	90.76	0.969	39.21
16/12/2009 13:35	72.23	74	0.15	135.63	0.969	19.39
16/12/2009 13:55	69.14	70	0.07	135.63	0.969	9.42
16/12/2009 14:00	67.39	70	0.22	135.63	0.969	28.59
16/12/2009 14:05	67.01	70	0.25	159.28	0.969	38.46
16/12/2009 14:10	68.55	70	0.12	159.28	0.969	18.65
16/12/2009 14:15	68.81	70	0.10	159.28	0.969	15.31
16/12/2009 14:20	66.76	70	0.27	159.28	0.969	41.67
16/12/2009 14:25	68.14	70	0.16	159.28	0.969	23.92
11/01/2010 12:35	44.55	47.48	0.24	234.71	0.969	55.53
11/01/2010 12:40	46.27	54.12	0.65	234.71	0.969	148.78
11/01/2010 12:45	52.3	51.46	-0.07	234.71	0.969	-15.92
11/01/2010 12:50	53.19	58.28	0.42	234.71	0.969	96.47
11/01/2010 12:55	56.63	54.46	-0.18	234.71	0.969	-41.13
11/01/2010 13:00	54.42	54.52	0.01	234.71	0.969	1.90
11/01/2010 13:05	56.28	55.76	-0.04	5551.71	0.969	-233.12
11/01/2010 13:10	57.71	53.76	-0.33	5551.71	0.969	-1770.79
11/01/2010 13:15	55.93	58.83	0.24	5551.71	0.969	1300.07
11/01/2010 13:20	58.97	55.22	-0.31	5551.71	0.969	-1681.13
11/01/2010 13:25	55.69	56.64	0.08	5551.71	0.969	425.89
11/01/2010 13:30	55.6	55.94	0.03	5551.71	0.969	152.42
11/01/2010 13:35	54.22	53.28	-0.08	8524.97	0.969	-647.09
11/01/2010 13:40	53.75	53.25	-0.04	8524.97	0.969	-344.20
11/01/2010 13:45	56.28	54.36	-0.16	8524.97	0.969	-1321.71
11/01/2010 13:50	56.51	51.96	-0.38	8524.97	0.969	-3132.18
11/01/2010 13:55	53.79	55.72	0.16	8524.97	0.969	1328.60

Dispatch Interval	Mintaro actual output (MW) A	Mintaro expected output (MW) B	Difference (MWh) C=(B-A)/12	Spot price ($/MWh) D	Loss factor E	Loss ($) C*D*E
11/01/2010 14:00	52.91	54.41	0.13	8524.97	0.969	1032.59
11/01/2010 14:05	51.46	51.37	-0.01	7618.06	0.969	-55.36
11/01/2010 14:10	54.54	53.18	-0.11	7618.06	0.969	-836.62
11/01/2010 14:15	57.15	66.58	0.79	7618.06	0.969	5800.94
11/01/2010 14:20	57.2	62.14	0.41	7618.06	0.969	3038.88
11/01/2010 14:25	54.27	62.58	0.69	7618.06	0.969	5111.97
11/01/2010 14:30	55.09	59.73	0.39	7618.06	0.969	2854.33
11/01/2010 14:35	53.36	59.68	0.53	9100.77	0.969	4644.49
11/01/2010 14:40	53.28	58.69	0.45	9100.77	0.969	3975.74
11/01/2010 14:45	52.63	58.88	0.52	9100.77	0.969	4593.04
11/01/2010 14:50	53.39	61.54	0.68	9100.77	0.969	5989.33
11/01/2010 14:55	55.53	61.32	0.48	9100.77	0.969	4255.00
11/01/2010 15:00	54.41	62.52	0.68	9100.77	0.969	5959.94
11/01/2010 15:05	55.88	60.24	0.36	9100.77	0.969	3204.11
11/01/2010 15:10	53.9	63.09	0.77	9100.77	0.969	6753.61
11/01/2010 15:15	54.62	61.23	0.55	9100.77	0.969	4857.60
11/01/2010 15:20	53.77	60.88	0.59	9100.77	0.969	5225.05
11/01/2010 15:25	55.38	60.79	0.45	9100.77	0.969	3975.74
11/01/2010 15:30	55.66	63.37	0.64	9100.77	0.969	5665.98
11/01/2010 15:35	54.78	61.48	0.56	9115.57	0.969	4931.75
11/01/2010 15:40	54.65	64.41	0.81	9115.57	0.969	7184.16
11/01/2010 15:45	56.21	62.22	0.50	9115.57	0.969	4423.85
11/01/2010 15:50	54.55	61.31	0.56	9115.57	0.969	4975.92
11/01/2010 15:55	56.91	64.34	0.62	9115.57	0.969	5469.09
11/01/2010 16:00	55.77	64.82	0.75	9115.57	0.969	6661.54
11/01/2010 16:05	57.09	67.52	0.87	9100.77	0.969	7664.87
11/01/2010 16:10	59.66	74	1.20	9100.77	0.969	10538.28
11/01/2010 16:15	60.61	74	1.12	9100.77	0.969	9840.14
11/01/2010 16:20	61.92	74	1.01	9100.77	0.969	8877.44
11/01/2010 16:25	59.8	74	1.18	9100.77	0.969	10435.40
11/01/2010 16:30	60.69	74	1.11	9100.77	0.969	9781.35
11/01/2010 16:35	60.05	74	1.16	4640.59	0.969	5227.45
11/01/2010 16:40	60.88	74	1.09	4640.59	0.969	4916.43
11/01/2010 16:45	63.34	74	0.89	4640.59	0.969	3994.60
11/01/2010 16:50	63.31	69.85	0.54	4640.59	0.969	2450.72
11/01/2010 16:55	64.58	72.8	0.69	4640.59	0.969	3080.26
11/01/2010 17:00	69.14	74	0.41	4640.59	0.969	1821.18
11/01/2010 17:05	69.68	74	0.36	6099.82	0.969	2127.86
11/01/2010 17:10	72.25	74	0.15	6099.82	0.969	861.98
11/01/2010 17:15	73.42	74	0.05	6099.82	0.969	285.69
11/01/2010 17:20	71.97	74	0.17	6099.82	0.969	999.90
11/01/2010 17:25	72.83	74	0.10	6099.82	0.969	576.30
11/01/2010 17:30	72.18	74	0.15	6099.82	0.969	896.46
11/01/2010 17:35	73.11	71.56	-0.13	104.89	0.969	-13.13
Net Loss			**44.74**			**248442.77**