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

AGL Hydro Partnership (ABN 86 076 691 481) and **Australian Energy Market Operator Limited (ABN 94 072 010 327)**

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 33) (***Rules***).[1] For ease of reference these terms are italicised in these submissions. Unless the context dictates otherwise, terms defined in the *Rules* have the same meaning in these submissions as in the *Rules*.

B. Application

3. Australian Energy Market Operator Limited (**AEMO**) has determined, under Rule 3.8.24(a)(2) of the *Rules*, that a *scheduling error* occurred on 19 and 20 November 2009. The *scheduling error* affected the Oakey Power Station in Queensland.

4. AGL Hydro Partnership (**AGL**) is and was, at all material times, registered by AEMO as a *Market Generator* and a *Scheduled Generator* in respect of the Oakey Power Station.

5. Under Rule 3.16.2 of the *Rules,* AGL may 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 AGL for its loss from the *Participant compensation fund*;[2] and

   (c) the manner and timing of that payment.[3]

C. AEMO and the National Electricity Market (NEM)

6. Sections C to I set out background information regarding the operation of the NEM and the effect of constraints. This is included to provide necessary context to the DRP. At the suggestion of AEMO, and so as to provide consistency for the DRP, these sections are taken from parts of the joint submission to the DRP by Macquarie Generation and NEMMCO[4] in April 2008. We gratefully acknowledge this source.

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

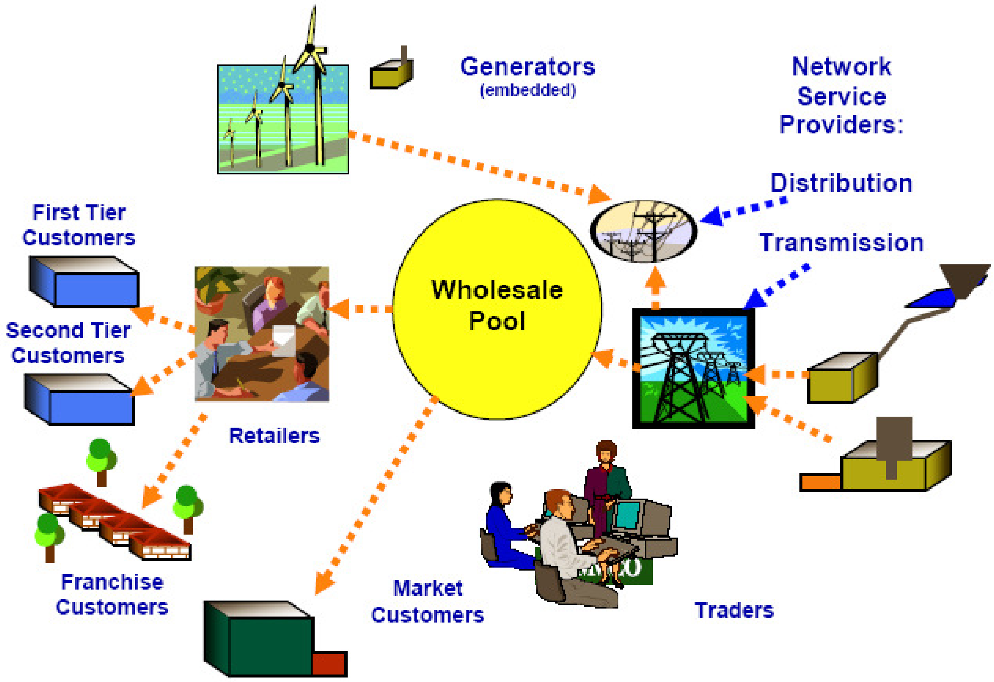
[1] Being the applicable version of the *Rules* at all material times.
[2] Rule 3.16.2 (b) and (d)
[3] Rule 3.16.2(i).
[4] As AEMO was known at the time.

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

8. 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.

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

Figure 1 – The National Electricity Market



10. 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. Also, all Generators whose capacity is greater than 30MW must participate in a central dispatch process operated by AEMO, which controls when and how much power they may send into the *NEM*.

11. 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.

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

(a) Queensland;

(b) New South Wales (which incorporates the Australian Capital Territory);

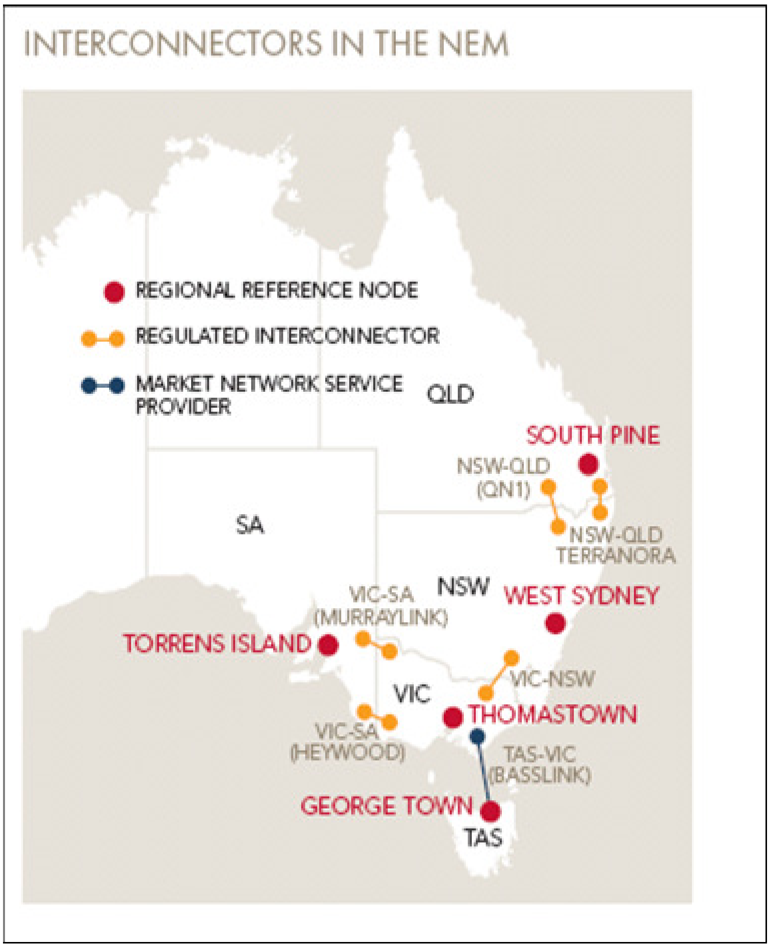
(c) Victoria;

(d) South Australia; and

(e) Tasmania.

13. 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



14. 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.

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

(a) *Scheduled Generators*, who 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*, who 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*.

16. AGL is and was at all material times registered as both a *Market Generator* and a *Scheduled Generator*. That is, it sells its output through the *NEM*, and its output is controlled by the *central dispatch* process.

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 AEMC.

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.[5]

23. To participate in the *central dispatch* process, *Scheduled Generators* must submit *dispatch offers* to AEMO to generate electricity[6]. 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*.[7]

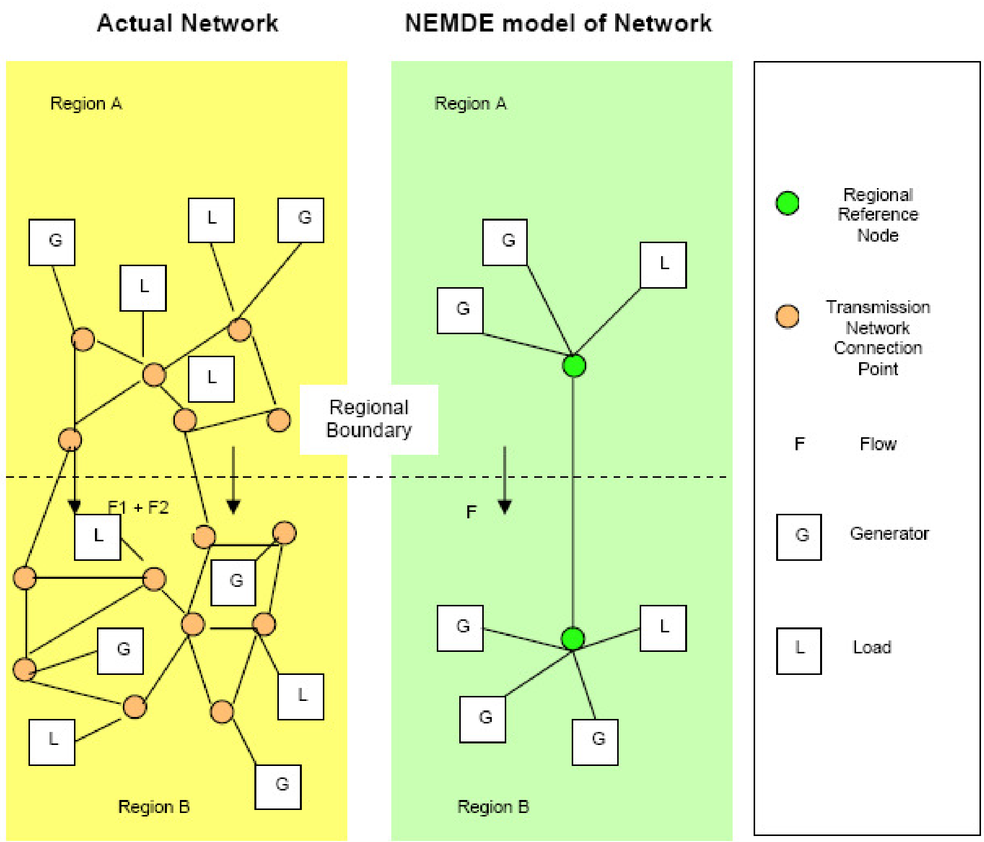
24. A *Generator* can own one or more *generating units*. Unless AEMO approves an application to aggregate these into a single entity for bidding purposes, AEMO receives bids for, and then determines loading levels (*dispatch instructions*) on an individual *generating unit* basis.

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

[5] Rule 3.8.1(b).
[6] Rule 3.8.2(a).
[7] Rule 3.8.6(a).

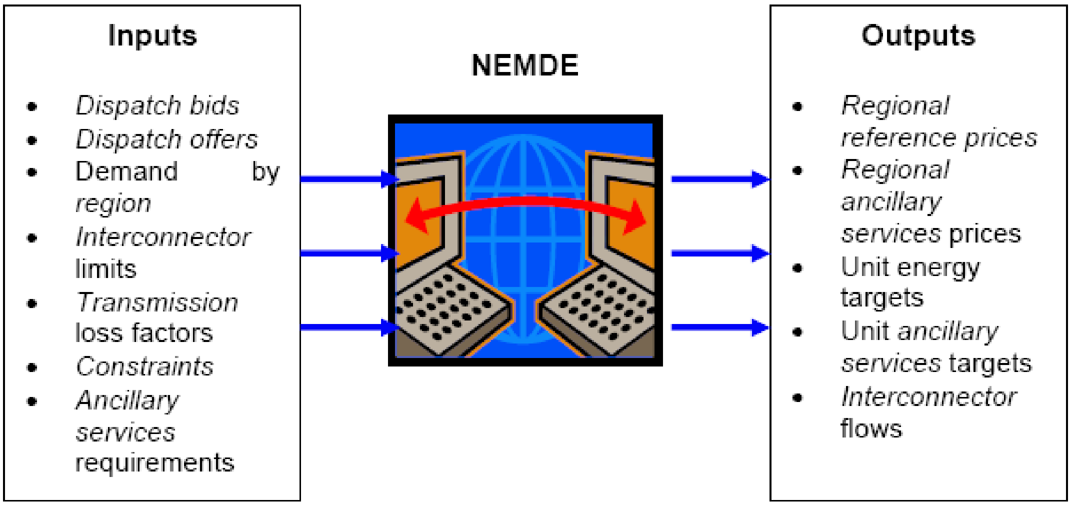
26. NEMDE is based on a constrained optimisation program that uses linear programming techniques that represent the *power system* in a manner that is reflected in Figure 3:

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 (*market price cap*) and the lowest is -$1,000 per MWh (*market floor price*).[8] *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*.

[8] Rules 3.9.4(b) and 3.9.6(b).

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. AEMO's obligation under Rule 3.8.1 of the *Rules* is 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. AEMO is required by Rule 4.3.2 of the *Rules* 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*.[9] The *power system* will be in a *satisfactory operating state* if certain parameters are satisfied, such as frequency and voltage.

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.

[9] Rule 4.2.4.

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.

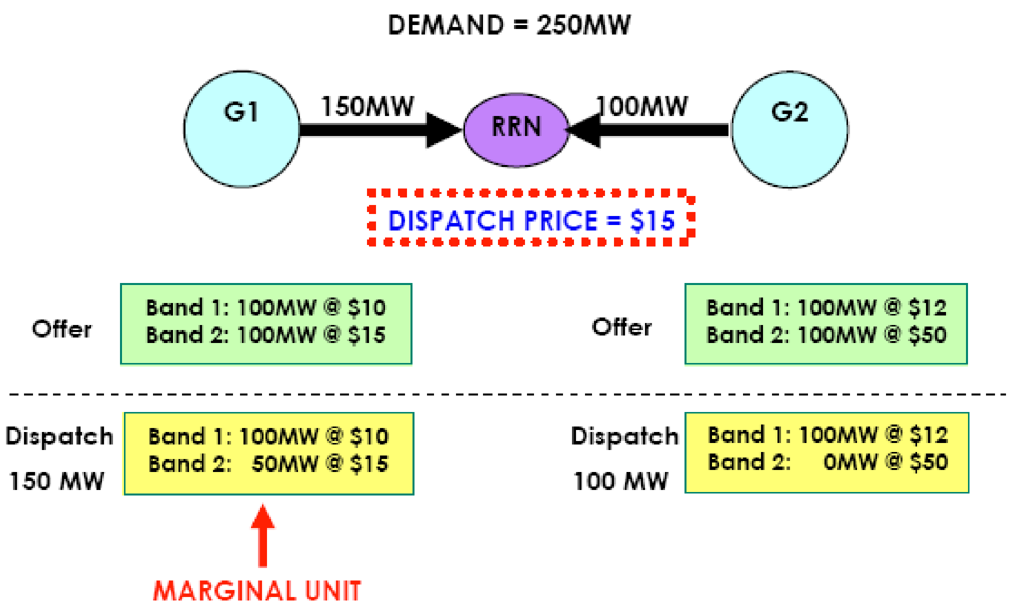
44. The need for constraint equations by NEMDE to model what the *transmission network* is capable of doing gives rise to certain risks for *Market Participants*:

(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

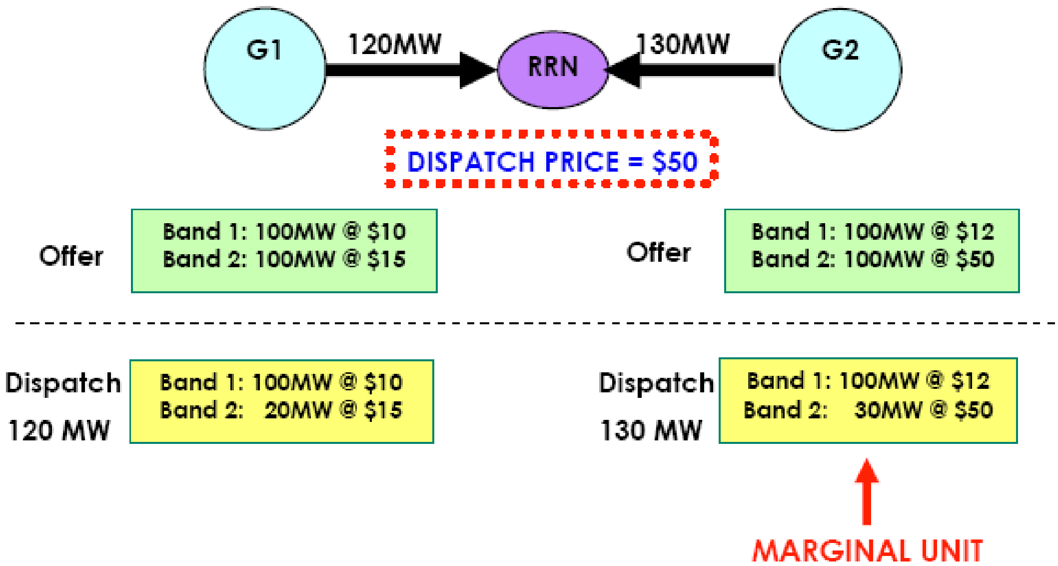


46. If this simple situation were to be complicated by the existence of a *constraint* on the *transmission line* linking Generator G1's *generating unit* to the *power system* such that flow on that *transmission line* had to be limited to 120MW or less, AEMO would formulate a constraint equation to 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 in order 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. Oakey generation units

52. AGL operates the Oakey Power Station. The Station has 2 operating units.

53. On 19 November and 20 November 2009, Units 1 and 2 were in service.

I. The events of 19 and 20 November 2009

54. AEMO determined, in accordance with Rule 3.8.24(a)(2) of the *Rules*, that a *scheduling error* occurred for the following *dispatch intervals*:

    (a) 14:55 hours to 17:05 hours on 19 November 2009; and

    (b) 10:55 hours to 13:15 hours on 20 November 2009.

55. AEMO has prepared a report in respect of the *scheduling error* titled 'Scheduling Error Report, Middle Ridge-Tangkam 731 Line Outage: 19 & 20 November 2009'. The report describes the occurrence of the *scheduling error* and is reproduced in Schedule 1 of these submissions.

56. For the purposes of this application, AGL has agreed to use the findings of AEMO regarding the duration of the *scheduling error*, in calculating its loss. However, for the purposes of any future *scheduling error* determinations, AGL wishes to reserve its position as to whether the method applied by AEMO in determining the duration of the scheduling error is in accordance with the *Rules*.

J. Calculation of AGL Energy's loss

57. The magnitude of the loss incurred by AGL as a result of this *scheduling error* has been calculated by AGL based on reductions in output (as generated MW) shown in the tables below:

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

    (a) the *ramp rates* for the calculation are based on the *ramp rates* set out in Schedule 2; and

    (b) the *loss factor* is assumed to be 0.9305 in accordance with those *published* by AEMO for the financial year 2009/2010.

59. In making its determination, the DRP must use the *spot prices* determined by the *central dispatch* process pursuant to Rule 3.9.[10]

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

    Loss = ((Expected output-Actual output)*TLF*Spot Price) - Avoided Fuel Cost

61. The *loss factor* is as set out in paragraph 58(b).

62. AGL seeks compensation to cover its full loss of $571,935.06. AEMO agrees with this calculation of AGL's loss arising from the *scheduling error*.

63. The detailed calculations of this loss are contained in the spreadsheets attached in Schedule 2.

K. Interest

64. AGL does not seek payment of interest on its loss as part of this application. However, for the purpose of any future applications for compensation in respect of *scheduling errors* AGL wishes to reserve its position as to whether interest can be included in an amount of compensation ordered to be paid by a DRP from the *Participant compensation fund* under the Rules.

L. Participant compensation fund

65. Under Rule 3.16.1 of the *Rules*, AEMO is required to 'maintain, in the books of the corporation, a fund called the *Participant compensation fund* for the purpose of paying

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

compensation to *Scheduled Generators* ... as determined by the *dispute resolution panel* for *scheduling error*s…'.

66. AEMO is required to pay to the *Participant compensation fund* the component of Participant fees under Rule 2.11 attributable to the *Participant compensation fund*. The overall funding requirement for the fund 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 fund at the end of the financial year.

67. Any interest paid on money held in the *Participant compensation fund* also accrues to and forms part of the *Participant compensation fund*.[11]

68. A 'financial year' is the period commencing on 1 July in one calendar year and terminating on 30 June in the following calendar year.[12]

69. AEMO must prepare and *publish* before the beginning of each financial year a budget of the revenue requirements for AEMO for that financial year.[13] 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.[14] 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*.[15]

70. AEMO must also develop, review and *publish* the structure (including the introduction and determination) of Participant fees for such periods as AEMO considers appropriate.[16] The Participant fees should recover the budgeted revenue requirements for AEMO determined under Rule 2.11.3.[17]

71. NEMMCO determined the structure of Participant fees for the period 1 July 2006 to 30 June 2011.[18] 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.

72. 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.[19] In the case of *Market Participants*, AEMO may, alternatively, include the relevant amount in the final statements described in

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[11] Rule 3.16.1(e).
[12] Chapter 10.
[13] Rule 2.11.3(a).
[14] Rule 2.11.3(b)(8).
[15] Rule 2.11.3(b)(8).
[16] Rule 2.11.1(a).
[17] Rule 2.11.1(b)(2).
[18] See http://www.aemo.com.au/registration/128-0050.pdf
[19] Rule 2.11.2(a).

Rule 3.15.15.[20] A *Registered Participant* must pay to AEMO the net amount stated in the relevant statement by the date specified by AEMO.[21]

73. 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;[22]

(c) take into account the current balance of the *Participant compensation fund* and the potential for further liabilities to arise during the year;[23] 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.[24]

74. In the decision of the DRP dated 24 April 2008 on the Macquarie Generation application it was held at paragraph 24 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*. The DRP also accepted at paragraph 15 of that decision that the reference to 'year' in Rule 3.16.2(h) is a reference to a financial year.

75. The *Participant compensation fund* currently has a balance of $3,446,017.

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

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

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

77. There has been one other claim for compensation for *scheduling error*s since then. Although the claim has not been formally assessed at this stage, its quantum is not expected to exceed $1 million.

78. The *Adviser* issued a notice on 17 March 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 19 March 2010. No further claims were notified.

79. If the compensation was paid for the full amount of AGL's loss, the balance in the *Participant compensation fund* would be $2,874,082. Even if the other expected claim amounts to $1 million, there will still be a substantial balance left in the *Participant compensation fund*.

80. Accordingly, full payment of AGL's loss is appropriate taking into account the current balance of the *Participant compensation fund* and the low likelihood of any further actual liabilities being incurred this financial year.

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[20] Rule 2.11.2(b).
[21] Rule 2.11.2(c).
[22] Rule 3.16.2(h)(3)
[23] Rule 3.16.2(h)(4).
[24] Rule 3.16.2(h)(5).

M. Costs

81. For the purposes of this compensation claim AGL and AEMO submit that the costs of this process (other than the legal costs of the parties) should be borne equally by them and that each of them should bear its own legal costs. 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 AGL, nor AEMO, has unreasonably prolonged or escalated a dispute or otherwise increased the costs of the DRP proceedings.

82. For the purposes of any applications for compensation in respect of future *scheduling errors,* AGL reserves its position as to whether an application for compensation from the *Participant Compensation Fund* is a dispute under the Rules or subject to Rule 8.2.8.

DATED: 2 June 2010

SCHEDULE 1

SCHEDULING ERROR REPORT FOR 19 AND 20 NOVEMBER 2009

SCHEDULE 2

CALCULATION OF AGL'S LOSS

1. AGL's loss has been calculated as set out in the two confidential spreadsheets attached.

1.1 The first attachment, 'Oakey Sched Error Data', sets out the detailed workings and calculations for total loss of pool revenue.

1.2 The second attachment, 'Oakey Final Fuel Cost', sets out the avoided fuel costs in respect of diesel and gas.

2. The reductions set out in paragraph 57 of the submissions were calculated based on the ramp rates as bid (11MW/Min).