IN THE DISPUTE RESOLUTION PANEL AT MELBOURNE

(Constituted for a determination as to compensation under Rule 3.16.2 of the National Electricity Rules)

BETWEEN

Lake Bonney Wind Power Pty Ltd (ABN 48 104 654 837)

Woodlawn Wind Power Pty Ltd (ABN 38 139 165 610)

(together **"Infigen"**)

and

Australian Energy Market Operator

(**"AEMO"**)

INFIGEN WRITTEN SUBMISSIONS TO THE DISPUTE RESOLUTION PANEL

A. Glossary

1. Terms used in these submissions that are defined in the National Electricity Rules, version 52 (***Rules***) have the meaning that is given to those terms in the *Rules*, unless the context requires otherwise.

2. Terms that are defined in the Glossary in Chapter 10 of the *Rules* are italicised in these submissions.

3. Other terms and acronyms have been defined for the purposes of these submissions, with the definition appearing in bold where the defined term is first used.

B. Infigen

4. Each of Lake Bonney Wind Power Pty Ltd and Woodlawn Wind Power Pty Ltd is, and was at all material times:

   (a) a *Market Participant*; and

   (b) registered under rule 2.2 of the *Rules* as a *Generator*.

5. Each of the relevant *generating units* of the affected wind farms is, and was at all material times, classified as:

   (a) a *market generating unit* under clause 2.2.4 of the *Rules*; and

   (b) a *semi-scheduled generating unit* under clause 2.2.7 of the *Rules*.

6. The affected wind farms to which the application for compensation relates are listed in Schedule 1 (**Infigen Wind Farms**), together with details of the date from which the relevant *generating units* were classified as *semi-scheduled generating units*.

7. In these submissions, Lake Bonney Wind Power Pty Ltd and Woodlawn Wind Power Pty Ltd are referred to collectively as "**Infigen**".

C. Application for determination as to compensation

8. On 7 June 2012, AEMO declared under clause 3.8.24(a)(2) of the *Rules* that a *scheduling error* had occurred which affected a number of wind farms, including the Infigen Wind Farms.

9. Clause 3.16.2(a) of the *Rules* provides that, where a *scheduling error* occurs, a *Market Participant* may apply to the *dispute resolution panel* (***DRP***) for a determination as to compensation.

10. Infigen seeks a determination by the *DRP* that compensation is payable from the *Participant compensation fund* under clause 3.16.2 of the *Rules* for Infigen's renewable energy certificate (**REC**) losses in respect of the *scheduling error*.

11. The DRP has agreed to consider as a preliminary question whether or not as a matter of principle compensation can be paid from the *Participant compensation fund* for REC losses where the *sent out generation* of a renewable energy *Generator* is reduced by a *scheduling error*. If the *DRP* determines that compensation is payable for Infigen's REC losses under clause 3.16.2 of the *Rules*, additional submissions will be made regarding the amount of compensation that Infigen submits should be awarded.

D. Background

12. AGL Hydro Partnership ABN 86 076 691 481 provided a notice of dispute to the *Adviser* in respect of the *scheduling error* (**AGL Notice**). A copy of the AGL Notice is attached in Schedule 2.

13. Infigen, AEMO, and a number of other affected *Market Participants* are seeking compensation under clause 3.16.2 of the *Rules* in respect of the *scheduling error*, and have agreed on the compensation that they submit the *DRP* should determine is payable in respect of the spot market losses of the affected *Generators*. This includes agreement on the number of megawatt hours (**MWh**) by which the *sent out generation* of the Infigen Wind Farms was reduced by the *scheduling error*.

14. Infigen and AEMO have not reached an agreed position on whether the *DRP* should award compensation to Infigen for its REC losses arising from the reduction in the *sent out generation* caused by the *scheduling error*.

15. Under a fast track process implemented by the *Adviser*, a *DRP* with Peter Gray S.C. as its single member has been constituted to determine the compensation payable in respect of the *scheduling error* for the spot market losses of the relevant affected *Generators.*

16. Infigen, AEMO, and the other parties to the *DRP* process for that component of the compensation claim, have made joint submissions to that *DRP* (**Joint Submissions**). A copy of the Joint Submissions is attached in Schedule 3.

17. Infigen issued an *Adviser referral notice* under clause 8.2.5(a) of the *Rules* in respect of the REC loss component of the compensation claim, which is the subject of this *DRP*

process, on 1 November 2012. A copy of that *Adviser referral notice* is attached in Schedule 4.

18. The Joint Submissions set out background on a range of matters that are also relevant to the component of the compensation claim that is before this *DRP*, including background on the *scheduling error*, the operation of the National Electricity Market (**NEM**), the *central dispatch* process, and the rules relating to *semi-scheduled generating units*.

E. National Electricity Rules

Applicable version of National Electricity Rules

19. The National Electricity Rules are made under Part 7 of the National Electricity Law (**NEL**).[1]

20. The current version of the National Electricity Rules is version 52, which came into effect on 1 November 2012.

21. A number of earlier versions of the National Electricity Rules, beginning with version 27, are applicable to periods during which Infigen and other *Generators* were affected by the *scheduling error*. The relevant versions, and the dates during which each version was in effect, are set out in the Joint Submissions.

22. Consistent with the approach adopted in the Joint Submissions, references in these submissions to the "***Rules***" are references to version 52 of the National Electricity Rules.

23. As set out in the Joint Submissions, there have been no amendments to the National Electricity Rules since version 27 that materially affect the matters relevant to the *DRP*'s determination.[2]

Principles of interpretation

24. Schedule 2 of the NEL sets out a number of principles governing the manner in which the NEL and *Rules* are to be interpreted.[3] The principles in that *Schedule* will apply in interpreting the NEL and *Rules* unless displaced by a contrary intention appearing in the NEL or *Rules*.[4]

25. The *Acts Interpretation Act 1901* (Cth) and interpretation legislation applying in the state and territory jurisdictions that have adopted the NEL do not apply to the NEL or the *Rules*.[5]

26. Consideration may only be given to extrinsic material relating to the NEL and *Rules*, including, amongst other things:

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1 As contained in a Schedule to the *National Electricity (South Australia) Act 1996* (SA) and adopted in other jurisdictions under adopting legislation enacted in those jurisdictions.

2 This includes the amendments that took effect upon the commencement of version 52.

3 See NEL, section 3.

4 NEL, Schedule 2, clause 1. See also *Application by United Energy Distribution Pty Limited* [2012] ACompT 1 at [58].

5 *Application by United Energy Distribution Pty Limited* [2012] ACompT 1 at [61(h)].

(a) in relation to the NEL, explanatory notes and memoranda, second reading speeches or official records of parliamentary debate; and

(b) in relation to the *Rules*, draft or final rule determinations and documents relied upon or adopted by the Australian Energy Market Commission in making a draft or final rule determination;

where:

(c) the relevant provision is ambiguous or obscure;

(d) the ordinary meaning of the provision leads to a result that is manifestly absurd or unreasonable; or

(e) to confirm the interpretation conveyed by the ordinary meaning of the provision.[6]

27. In determining whether consideration should be given to such extrinsic material, and in determining the weight to be given to that material, regard is to be had to:

(a) the desirability of a provision being interpreted as having its ordinary meaning;

(b) the undesirability of prolonging proceedings without compensating advantage; and

(c) other relevant matters.[7]

28. The interpretation of a provision of the NEL or *Rules* that will best achieve the purpose or object of the NEL is to be preferred,[8] but neither this provision, nor those dealing with extrinsic material:

> *... authorise a wholesale redrafting of the relevant provision. The quest is always to find the correct interpretation of that provision, not to embark upon an exposition of the interpreter's view of what the relevant provision should mean.*[9]

29. In a case where the words in the NEL or *Rules* can be interpreted according to their ordinary meaning without producing absurd results, that interpretation should prevail. In those circumstances, extrinsic material can only be used to confirm the interpretation conveyed by the ordinary meaning, and not to justify an alternative interpretation, whether reasonable or not, that is not conveyed by the ordinary meaning of the provision.

F. Renewable Energy Act and Renewable Energy Certificates

Objectives of the Renewable Energy Act

30. The Commonwealth Renewable Energy Target (**RET**) is established by the *Renewable Energy (Electricity) Act 2000* (Cth) (**Renewable Energy Act**).

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[6] NEL, Schedule 2, clause 8.

[7] NEL, Schedule 2, clause 8(3).

[8] NEL, Schedule 2, clause 7. This applies whether or not the purpose is expressly stated in the NEL.

[9] *Application by United Energy Distribution Pty Limited* [2012] ACompT 1 at [61(d)]. See also at [244].

31. The objects of the Renewable Energy Act are to encourage the additional generation of electricity from renewable sources, reduce emissions of greenhouse gases in the electricity sector, and ensure that renewable energy sources are ecologically sustainable.[10]

32. The Renewable Energy Act seeks to achieve these objectives by providing for the issue of RECs for eligible generation of electricity from renewable sources, and requiring certain liable entities to surrender a specified number of RECs for "relevant acquisitions" of electricity during a year.

Amendments to the Renewable Energy Act

33. The RET commenced in January 2001. It was then known as the Mandatory Renewable Energy Target. A series of amendments have been made to the Renewable Energy Act since its commencement. These include the *Renewable Energy (Electricity) Amendment Act 2009* (Cth) which, amongst other things, increased the renewable energy targets underpinning the scheme, and provided for the RET to operate as a single national scheme in place of existing and proposed state-based renewable energy target schemes that previously operated, or were proposed to operate, in parallel with the Commonwealth scheme.[11]

34. A number of significant amendments to the Renewable Energy Act made by the *Renewable Energy (Electricity) Amendment Act 2010* (Cth) came into effect on 1 January 2011. Those amendments included providing in the Renewable Energy Act for two different kinds of RECs:

    (a) large-scale generation certificates (**LGCs**), which may be created by "accredited power stations"; and

    (b) small-scale technology certificates (**STCs**), which may be created in relation to "small generation units" and solar water heaters.

35. Those amendments effectively separated the market for STCs from the market for LGCs (prior to 1 January 2011, RECs from all sources were part of a single REC market).

36. The form of RECs that are relevant to this compensation claim are RECs that were entitled to be created in respect of the generation of electricity by the Infigen Wind Farms. Since the 1 January 2011 amendments, that entitlement is an entitlement to create LGCs. The new provisions that deal with STCs are not relevant to this compensation claim.

37. For each of Lake Bonney 2 and Lake Bonney 3 wind farms, the *scheduling error* affected the output of the relevant *semi-scheduled generating unit* during periods that fell both before and after 1 January 2011. For Woodlawn wind farm, the *scheduling error* only affected the output of the *semi-scheduled generating unit* in periods that occurred after 1 January 2011.

38. As a result, for Lake Bonney 2 and Lake Bonney 3, the *scheduling error* resulted in a reduced entitlement to create both pre-1 January 2011 RECs and LGCs. For Woodlawn, the *scheduling error* resulting in a reduced entitlement to create LGCs.

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10 Renewable Energy Act, section 3.

11 The state-based legislation included the *Victorian Renewable Energy Act 2006* (Vic), which commenced on 1 January 2007.

39. While the amendments to the Renewable Energy Act that commenced on 1 January 2011 have changed the terminology used and separated the REC market into two separate components, they have not materially affected the key provisions of the Renewable Energy Act establishing the entitlement of the Infigen Wind Farms to create RECs (including LGCs) in respect of their *sent out generation*, or the ability of persons who create RECs or LGCs from accredited renewable energy power stations to sell those RECs to realise a financial benefit from the generation of electricity from an eligible renewable energy source.

40. In these submissions, unless the context requires otherwise, the term "**REC**" is used to refer to RECs generally (including pre-1 January 2011 RECs created from accredited power stations, and LGCs).

41. References in these submissions to "**LGCs**", and to provisions in the Renewable Energy Act that, as amended, use the terminology "**LGCs**", should be read as references to RECs created from accredited power stations, whether pre-1 January 2011 RECs created from accredited power stations, or LGCs created from 1 January 2011 onwards.

Legislative right to create LGCs from accredited power stations

42. Section 18(1) of the Renewable Energy Act establishes the legislative entitlement for accredited power stations to create LGCs. Prior to 1 January 2011, section 18(1) of the Renewable Energy Act established a right of accredited power stations to create RECs in identical terms.

43. Section 18(1) provides that the "nominated person" for an "accredited power station" may create an LGC for each whole MWh of electricity generated by the power station during a year that is in excess of the power station's "1997 eligible renewable power baseline".

44. A power station is eligible for accreditation under Part 2, Division 3 of the Renewable Energy Act if the power generated by the power station is generated from an "eligible energy source".

45. "Eligible energy source" is defined in section 5(1) of the Renewable Energy Act to include an "eligible renewable energy source". Under section 17(1)(e), wind is classified as an "eligible renewable energy source".

46. RECs that have been created and registered in accordance with the Renewable Energy Act may be transferred to any person.[12]

47. Demand for LGCs is established as a result of a legislative requirement for certain "'liable entities" to acquire and surrender LGCs in respect of their acquisitions of electricity, in order to avoid being subject to a shortfall charge.[13] A person is a "liable entity" if the person makes a "relevant acquisition of electricity" during a calendar year.[14] The number of LGCs that a liable entity must surrender to avoid a shortfall charge depends, in part, on the "renewable power percentage" prescribed for the relevant year for the purposes of section 39 of the Renewable Energy Act. This number, which must be set taking into account the "required GWh of renewable source electricity" for each year specified in

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12 Renewable Energy Act, section 27.

13 Renewable Energy Act, section 36.

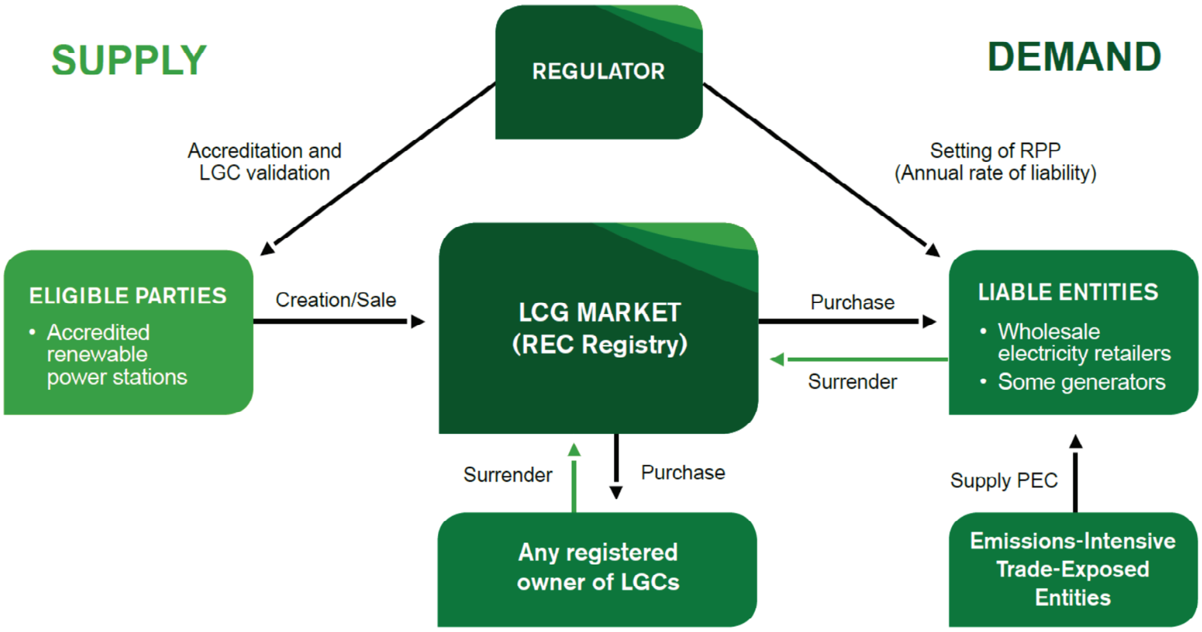
14 Renewable Energy Act, section 35. The meaning of "relevant acquisition of electricity" is set out in section 38.

section 40 of the Renewable Energy Act, effectively operates to ensure that a specified quantity of electricity is generated from renewable sources each year, with that quantity escalating each year until 2020.

48. The shortfall charge is set under the *Renewable Energy (Electricity) (Large Scale Generation Shortfall Charge) Act 2000 (Cth)* and is currently $65 per MWh.

49. Figure 1 depicts the way in which the LGC market operates. Prior to 1 January 2011, the market for RECs created from "accredited power stations" operated in a materially similar manner.

Figure 1 – LGC market



Source: Clean Energy Regulator

50. The large-scale component of the RET is "technology neutral" in the sense that it is designed to allow the most economically competitive forms of large-scale renewable energy generation to meet the demand established by the scheme. Wind has been the largest contributor to the large-scale component of the RET,[15] and electricity generation from wind has increased significantly during the period that the Renewable Energy Target[16] has been in place. For example, in the five years to 2009-10, annual growth in wind generation has averaged 40 per cent.[17]

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15 Climate Change Authority, Renewable Energy Target Review, Issues Paper, August 2012 (**CCA Issues Paper**), page 20.

16 Including the Mandatory Renewable Energy Target, as the scheme was known prior to the 2009 amendments.

17 CCA Issues Paper, page 11.

51. The revenue received from the creation and sale of LGCs is critical to the economic viability of wind farms. The RET is intentionally designed to increase the competitiveness of renewable energy generation from sources like wind relative to non-renewable sources and thereby "accelerate deployment" of renewable generation technologies that would not otherwise be deployed based on expected revenue from wholesale trading alone.[18]

52. The Climate Change Authority's Renewable Energy Target Review Issues Paper uses the following hypothetical example to demonstrate the way in which a wind farm's commercial viability within the wholesale market depends on the combined effect of the wholesale price and the LGC price:[19]

> *In relation to prices, certificate prices under the RET can be viewed as the "top up" level of subsidy required to make renewable energy viable. For example, say a wind farm's average cost of production is $80/MWh. If the wholesale price of electricity was $40/MWh, the wind farm would need an extra $40/MWh to be viable. The price of certificates under the RET would need to be at least $40 in order for the wind farm to be commercially viable.*

53. The LGC price has generally been in the range of $35 to $40 per LGC since the RET was separated on 1 January 2011.[20] The shortfall charge, currently at $65 per MWh, would be expected to act as a cap on the price of LGCs if the price were to increase above the range within which LGCs have historically traded. The level of the effective price cap would be the amount of the shortfall charge after being adjusted for tax.[21]

Accreditation of Infigen Wind Farms

54. As at 8 November 2012, each of the Infigen Wind Farms is an accredited power station listed in the Register of Accredited Power Stations maintained by the Clean Energy Regulator in accordance with sections 135 and 138 of the Renewable Energy Act.

55. The date of accreditation for each Infigen Wind Farm is set out in the table below.

Wind farm	Accreditation date
Lake Bonney 2	2 July 2007
Lake Bonney 3	28 May 2010
Woodlawn	31 May 2011

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18 See, for example, Greg Combet, Minister Assisting the Minister for Climate Change, Renewable Energy (Electricity) Amendment Bill 2009 (Cth), Second Reading Speech, House of Representatives, *Debates*, 17 June 2009, page 6251.

19 CCA Issues Paper, page 17.

20 CCA Issues Paper, page 42.

21 CCA Issues Paper, page 27. The tax-adjusted shortfall charge represents the expected level of the price cap because the cost of a liable entity acquiring an LGC is tax deductible, whereas the cost of paying the shortfall charge is not.

G. Compensation under clause 3.16.2 of the *Rules*

56. Under clause 3.16.2(b) of the *Rules*, where a *scheduling error* occurs, the *DRP* is empowered to determine both that compensation is payable to *Market Participants* from the *Participant compensation fund*, and the amount of that compensation.

57. Clause 3.16.2(d) of the *Rules* further provides that:

> A *Scheduled Generator* or *Semi-Scheduled Generator* who receives an instruction in respect of a *scheduled generating unit* or *semi-scheduled generating unit* (as the case may be) to operate at a lower level than the level at which it would have been instructed to operate had the *scheduling error* not occurred, will be entitled to receive in compensation an amount determined by the *dispute resolution panel*.

58. The existence of the *Participant compensation fund* should be understood within the context that AEMO has statutory immunity in Part 9 of the NEL, including for acts and omissions in the performance or exercise, or purported performance or exercise, of a function or power of AEMO under the NEL or *Rules*, unless done in bad faith or through negligence.[22] Clause 3.16.2(j) of the *Rules* further provides that, to the maximum extent permitted by law, *AEMO* is not liable in respect of a *scheduling error* except out of the *Participant compensation fund.* Compensation payable out of the *Participant compensation fund* will therefore often be the only form of redress a *Market Participant* has for its losses from a *scheduling error*.

59. The *DRP* is required by clause 3.16.2(h) of the *Rules,* in determining the level of compensation to which a *Market Participant* is entitled in relation to a *scheduling error*, relevantly, to:

    (a) use the *spot price* as determined under rule 3.9 of the *Rules*;

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

    (c) 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 that year if no compensation payments for *scheduling errors* had been made during that year.

60. The *DRP* is also to determine the manner and timing of payments from the *Participant compensation fund*.[23]

H. REC losses caused by compliance with *dispatch instruction*

61. As described in section F above, the entitlement of an “accredited power station” to create LGCs under the Renewable Energy Act is a direct function of the quantity of electricity actually generated by that power station.

62. One LGC may be created under the Renewable Energy Act for each MWh of generation by an accredited power station above its 1997 baseline level.[24]

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22 NEL, section 119.

23 Clause 3.16.2(i) of the *Rules*.

63. Infigen's compliance with AEMO's instruction to operate its *semi-scheduled generating units* at a lower level than the level at which it would have been instructed to operate the *generating units* had the *scheduling error* not occurred reduced the quantity of electricity generated by those units (as agreed by AEMO in the Joint Submissions), directly resulting in a reduced entitlement to create LGCs.

64. As set out in sections I and J of these submissions below, clause 3.16.2 of the *Rules* provides for compensation to be awarded to a *Semi-Scheduled Generator* for losses caused by the *Semi-Scheduled Generator*'s compliance with an erroneous *dispatch instruction* issued by AEMO.

65. Infigen therefore submits that the compensation determined by the *DRP* to be payable to Infigen from the *Participant compensation fund* under clause 3.16.2 of the *Rules* in respect of the *scheduling error* should include an amount for Infigen's loss arising from its reduced entitlement to create LGCs from electricity generated by the Infigen Wind Farms.

I. Common law meaning of "compensation"

66. The meaning of the term "compensation" at common law, has been firmly established by the High Court as a matter of general principle applicable to, for example, the determination of compensatory damages in tort or contract.

67. The general principle to be applied is that the "compensation" that an injured party should receive is the amount that would put that party is the same position in which it would have been if the relevant wrong or event had not occurred (but not more than the person has lost).

68. For example, in *Butler v Egg and Egg Pulp Marketing Board*,[25] Taylor and Owen JJ expressed the "general principle" in the following way:

> *That principle is that the injured party should receive compensation in a sum which, so far as money can do so, will put him in the same position as he would have been in if the contract had been performed or the tort had not been committed.*

69. As authority for this principle, Taylor and Owen JJ cited the judgment of Lord Blackburn in *Livingstone v Rawyards Coal Company*,[26] which in part reads:

> *I do not think there is any difference of opinion as to its being a general rule that, where any injury is to be compensated by damages, in settling the sum of money to be given for reparation of damages you should as nearly as possible get at that sum of money which will put the party who has been injured, or who has suffered, in the same position as he would have been in if he had not sustained the wrong for which he is now getting his compensation or reparation.*

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24 Renewable Energy Act, section 18(1). The amount of electricity generated by an accredited power station is determined in accordance with regulations 13 to 16 of the *Renewable Energy (Electricity) Regulations 2001* (Cth).

25 (1966) 114 CLR 185 at 119.

26 (1880) 5 App. Cas. 25 at 39.

70. The principle has been repeatedly affirmed in subsequent judgments of the High Court including, for example, by Mason CJ and Dawson, Toohey and Gaudron JJ in *Haines v Bendall*,[27] who cited *Butler v Egg and Egg Marketing Board* in support of that principle.[28]

71. This well established common law principle is relevant to establishing the nature of the "compensation" that a *DRP* may determine is payable to a *Market Participant* under clause 3.16.2 of the *Rules* in respect of a *scheduling error*, but needs to be applied taking into account the specific words used in clause 3.16.2 the *Rules*.

J. Meaning of "compensation" under clause 3.16.2 of the *Rules*

72. When the specific provisions of clause 3.16.2 of the *Rules*, including clause 3.16.2(d) of the *Rules* (which is set out in paragraph 57 of these submissions) are taken together with the firmly established general common law principle applicable to the recovery of compensation, it is apparent that:

   (a) compensation is payable to a *Semi-Scheduled Generator* who receives an instruction in respect of a *semi-scheduled generating unit* to operate at a lower level than the level at which it would have been instructed to operate had the *scheduling error* not occurred; and

   (b) *prima facie*, that compensation should include, at a minimum, the *Semi-Scheduled Generator's* losses caused by its compliance with that erroneous instruction.

73. This *prima facie* basis for compensation is subject to the additional factors that the *DRP* is expressly required to take into account under clause 3.16.2(h) of the *Rules*, as set out in paragraph 58 of these submissions.

74. There is no foundation in the words of clause 3.16.2 of the *Rules*, or that can be drawn from general principles of common law compensation, that would justify an interpretation that non-spot market losses of a *Market Participant* are, as a matter of principle, not compensable under clause 3.16.2 in a case where those losses are caused by the *Market Participant's* compliance with AEMO's erroneous *dispatch instruction*. More specifically, there is nothing in clause 3.16.2, save for the discretionary factors in clause 3.16.2(h), that would exclude the recovery of REC losses incurred as a direct result of compliance with the erroneous *dispatch instruction*.

75. Although previous *DRP* decisions are not binding on this *DRP*, there is no inconsistency between the approach set out in these submissions and that adopted in *DRP* decisions relating to an application by Snowy Hydro Limited (**Snowy**) for compensation from the *Participant compensation fund* in respect of a *scheduling error* (**Snowy Application**).

76. Whether clause 3.16.2 of the *Rules* precludes recovery of non-spot market losses was addressed in a decision of a *DRP*, consisting of Sir Anthony Mason AC KBE QC, Mr G Thorpe and Mr K Brown dated 1 February 2007, relating to the Snowy Application. The *DRP* was asked to determine the question "*whether the DRP is limited to considering spot*

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27 (1991) 172 CLR 60 at 63.

28 See also, for example, *Skelton v Collins* (1966) 115 CLR 94 at 128.

market losses when making an award of compensation from the Participant compensation fund".[29] The *DRP* answered that question "*No*".[30]

77. In doing so, the *DRP* considered two arguments presented by NEMMCO for limiting compensation under clause 3.16.2 to spot market losses:

(a) that such a limitation was imposed by clause 3.16.2(d) (of version 1 of the National Electricity Rules),[31] which provided that, in determining the level of compensation, the spot price to be used is that determined under rule 3.9; or

(b) alternatively, in exercising its discretion to determine the compensation payable from the *Participant compensation fund*, the *DRP* should limit that compensation to spot market losses.[32]

78. The *DRP* rejected both arguments, observing that "*compensation for losses in addition to spot market trading losses is payable out of the Fund, in the absence of an express exclusion of, or limitation on, the recovery of such losses*".[33]

79. In a subsequent decision dated 29 August 2007, a *DRP* consisting of Sir Anthony Mason AC KBE QC, Mr G Thorpe and Mr G E Fitzgerald AC QC held that, while a *Market Participant* is not entitled to compensation for its total loss in the course of its operations from a *scheduling error*, it is entitled to compensation for loss caused by the *Market Participant*'s compliance with an instruction to operate a *generating unit* at a lower level than the level at which it would have been instructed to operate the *generating unit* had the *scheduling error* not occurred.[34]

80. At paragraph 36 of that decision, the Panel stated:

> *... Snowy is not entitled to compensation from the fund for all its losses from NEMMCO's scheduling errors. Subject to discretionary considerations ... Snowy is entitled to compensation for its losses caused by its compliance with NEMMCO's instruction to operate its relevant scheduled generating units at lower levels than the levels at which each would have been instructed to operate if the scheduling errors had not occurred but only those losses.*

81. Clause 3.16.2(h)(3) of the *Rules* is in materially similar terms to the provision considered by the *DRP* relating to the Snowy Application and described in paragraph 77(a) of these submissions.[35] There is similarly nothing in clause 3.16.2(h)(3) of the *Rules* that would

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29 *Snowy v National Electricity Market Management Company Limited* (hereafter, **NEMMCO**), Decision of the Dispute Resolution Panel, 1 February 2007, paragraph 5(b).

30 *Snowy v NEMMCO*, Decision of the Dispute Resolution Panel, 1 February 2007, paragraph 103.

31 In the Snowy decision dated 1 February 2007, the *DRP* applied version 1 of the National Electricity Rules. The equivalent of clause 3.16.2(d) of version 1 of the National Electricity Rules is clause 3.16.2(h)(3) of the current *Rules*. A table setting out where each paragraph of clause 3.16.2 of version 1 of the National Electricity Rules finds its equivalent in clause 3.16.2 of the current *Rules* is included in Schedule 5.

32 *Snowy v NEMMCO*, Decision of the Dispute Resolution Panel, 1 February 2007, paragraphs 97-103.

33 *Snowy v NEMMCO*, Decision of the Dispute Resolution Panel, 1 February 2007, paragraph 101.

34 *Snowy v NEMMCO*, Decision of the Dispute Resolution Panel, 29 August 2007. See, for example, paragraphs 29, 33 and 36 of the decision.

35 See the table in Schedule 5.

support an interpretation that compensation payable under clause 3.16.2 is limited to spot market losses.

82. In the final *DRP* decision relating to the Snowy Application dated 18 October 2007, the *DRP* awarded Snowy compensation for both spot market losses, and losses incurred by Snowy under settlement residue distribution agreements with NEMMCO.[36]

K. Compensation amounts

83. Should the *DRP* determine that Infigen is entitled to receive compensation under clause 3.16.2 of the *Rules* in respect of its REC losses, Infigen will make further submissions on the amount of the compensation that should be awarded, including on the matters the *DRP* is required to take into account relating to the status of the *Participant compensation fund* under clause 3.16.2(h) of the *Rules*.

L. Costs

84. Infigen submits that the DRP should allocate costs of this component of the compensation claim equally between Infigen and AEMO in accordance with clause 8.2.8(a) of the *Rules*. Infigen submits that none of the parties has unreasonably prolonged or escalated the dispute or otherwise increased the costs of these proceedings, as contemplated by clause 8.2.8(b) of the *Rules*.

DATED: 8 November 2012

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MINTER ELLISON
Solicitors for Infigen

These submissions were settled by Peter Hanks QC

36 *Snowy v NEMMCO*, Decision of the Dispute Resolution Panel, 18 October 2007, paragraphs 32-33.

Schedule 1

INFIGEN WIND FARMS AFFECTED BY THE *SCHEDULING ERROR*

Affected Generator	Wind Farm	Region	MW	Semi-Scheduled from
Infigen	Lake Bonney 2	SA	159.0	9 September 2010
	Lake Bonney 3	SA	39.0	2 July 2010
	Woodlawn	NSW	48.3	3 May 2011

Schedule 2

AGL NOTICE

NEM Dispute Resolution
preserving relationships

The purpose of this document is to request a DRP award compensation from the Participant Compensation Fund in circumstances where AEMO has declared a scheduling error and there is agreement between the applicant and AEMO on the methodology for calculation of loss.

Send to:
Shirli Kirschner
National Electricity Market
Resolution Adviser
M | 0411 380 380

Compensation for a Scheduling error which has been declared by AEMO

Name of Participant(s) *(add pages if needed)*: AGL Hydro Partnership
ABN: 86 076 691 481
Address: AGL, Level 22 101 Miller Street North Sydney NSW 2060
Contact: Alex Cruickshank Title: Head of Energy Regulation
Phone: 03 8633 6026
Email: acruicks@agl.com.au

AEMO: Australian Energy Market Operator Ltd
ABN: 94 072 010 327
Address: Level 22 530 Collins Street Melbourne Vic 3000
Contact: Brian Nelson Title: Senior Manager Electricity Market Performance
Phone: 02 9239 9132
Email: brian.nelson@aemo.com.au

3 Other participants who may be affected: Other wind farms (AEMO has list)

4 State in which the dispute is to be heard: Victoria

5 Amount of compensation sought: (details to follow in submission) approx $250,000

6 Copy of Scheduling Error Report attached: Provided by AEMO.

Schedule 3

JOINT SUBMISSIONS

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 SUBMISSION TO THE DISPUTE RESOLUTION PANEL

AGL Hydro Partnership (ABN 86 076 691 481)	(**AGL Hydro**)
EnergyAustralia Pty Ltd (ABN 99 086 014 968)	(**EA**)
Lake Bonney Wind Power Pty Ltd (ABN 48 104 654 837) and **Woodlawn Wind Pty Ltd** (ABN 38139 165 610)	(**Infigen**)
Pacific Hydro Clements Gap Pty Ltd (ABN 87 109 911 097)	(**Pacific Hydro**)
Snowtown Wind Farm Pty Ltd (ABN 76 109 468 804)	(**Trustpower**)
and	
Australian Energy Market Operator Limited (ABN 94 072 010 327)	(**AEMO**)

A. Glossary

1. AGL Hydro, EA, Infigen, Pacific Hydro and Trustpower are together referred to as the **Affected Generators**, each of whom owns or operates one or more **Wind Farms** listed in Schedule 2.

2. The italicised terms used in this submission and its attachments are defined in the National Electricity Rules (***Rules***).[1] 'Rule' followed by a number refers to a provision of the *Rules*.

3. Other terms and acronyms are defined in bold where they are first used in this submission. For convenience, they are also listed here:

AWEFS	Australian Wind Energy Forecasting System
Dispatch Procedure	AEMO's 'Power System Operating Procedure – Dispatch', version 74, dated 1 July 2012
DRP	*dispute resolution panel*
ECM	*energy conversion model*
MW / MWh	megawatt / megawatt hour

[1] Section C addresses the question of which versions of the Rules are relevant to the period during which the *scheduling error* impacted the Affected Generators.

NEL	National Electricity Law
NEMDE	*NEM* dispatch engine
NSP	*Network Service Provider*
SCADA	Supervisory Control and Data Acquisition
TNSP	*Transmission Network Service Provider*
UIGF	*unconstrained intermittent generation forecast*
"what-if" dispatch level	See paragraph 67
"what-if" UIGF	See paragraph 67

B. Application

4. Each Affected Generator is, and was at all material times, registered as a *Market Generator* and a *Semi-Scheduled Generator* for the Wind Farm(s) listed in Schedule 2.

5. On 7 June 2012, AEMO declared under Rule 3.8.24(a)(2) that a *scheduling error* had occurred which affected the Wind Farms.

6. Rule 3.16.2(a) permits the Affected Generators 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 each Affected Generator from the *Participant compensation fund*;[2] and

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

C. Rules

7. The current version of the *Rules* (version 52) came into effect on 1 November 2012. Previous versions of the National Electricity Rules are applicable to periods during which the Affected Generators were impacted by the *scheduling error*.

8. The applicable versions of the National Electricity Rules and the dates during which each version was in effect, are set out in the table below.

Version	Start Date	End Date
27	31 March 2009	15 April 2009
28	16 April 2009	27 May 2009
29	28 May 2009	30 June 2009

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

30	1 July 2009	31 August 2009
31	1 September 2009	14 October 2009
32	15 October 2009	11 November 2009
33	12 November 2009	11 March 2010
34	12 March 2010	24 March 2010
35	25 March 2010	12 May 2010
36	13 May 2010	21 June 2010
37	22 June 2010	1 August 2010
38	2 August 2010	15 September 2010
39	16 September 2010	5 January 2011
40	6 January 2011	19 January 2011
41	15 March 2011	23 March 2011
42	24 March 2011	20 April 2011
43	21 April 2011	30 June 2011
44	1 July 2011	13 July 2011
45	14 July 2011	9 November 2011
46	10 November 2011	21 December 2011
47	22 December 2011	14 March 2012
48	15 March 2012	4 April 2012
49	5 April 2012	1 July 2012
50	2 July 2012	1 August 2012
51	2 August 2012	31 October 2012
52	1 November 2012	N/A

9. The amendments to the Rules that have been made since Version 27 came into force do not alter the effect of the provisions cited in these submissions in a manner which is material to the matters relevant to the DRP's determination in respect of the *scheduling error*.[4]

[4] Rule 8.2.6C(e), which provides that the DRP must determine the real questions in controversy between the parties, and is not bound by the parties' formulation of those questions, was inserted into the National Electricity Rules in Version 30.

D. AEMO and the National Electricity Market (NEM)

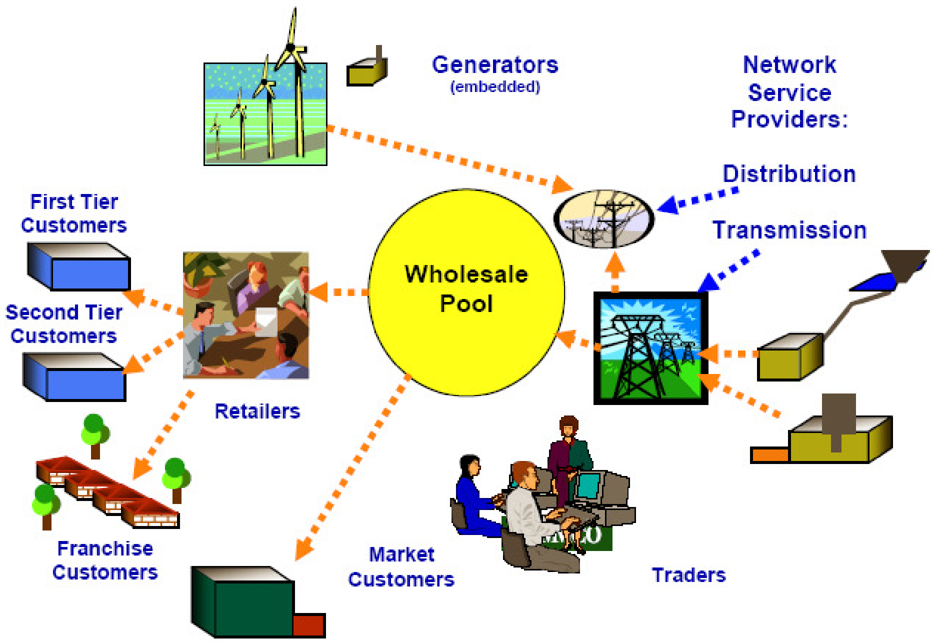
10. Sections C to F set out background information regarding the operation of the *NEM* and how *Semi-Scheduled Generators* operate in the *NEM*. This is included to provide context to the DRP.

11. AEMO operates and manages the *NEM*. The *NEM* is essentially two things: the physical infrastructure that keeps electricity flowing from producers to consumers, and a notional wholesale pool (or spot market) to which producers sell, and from which purchasers buy, electricity.

12. 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*.

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

Figure 1 – The National Electricity Market



14. 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*.

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

16. The *NEM* is divided into five *regions* for *market* pricing purposes:

(a) Queensland;

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

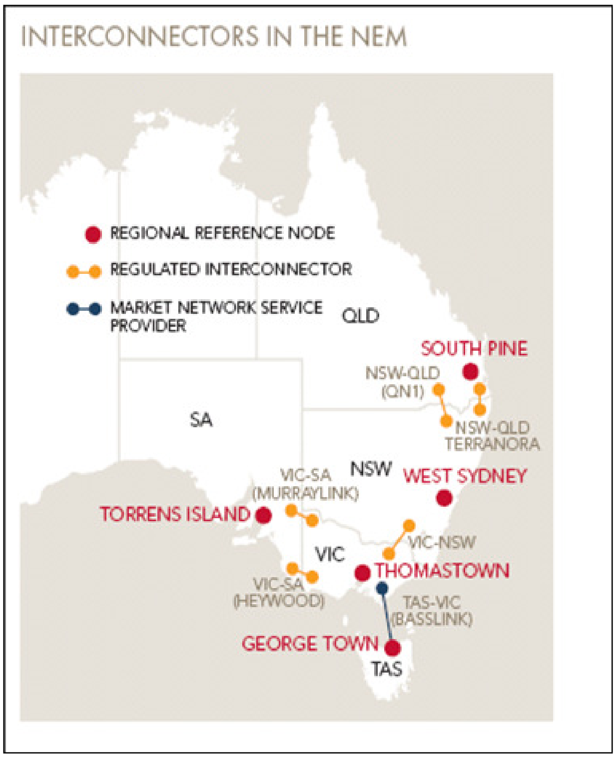
(c) Victoria;

(d) South Australia; and

(e) Tasmania.

17. 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



18. 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.

19. The *Rules* allow producers of electricity 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) *Semi-Scheduled Generators* are *Generators* in respect of which a *generating unit* is classified as a *semi-scheduled generating* unit. Typically, this occurs where:

(i) a *generating unit* has a *nameplate rating* greater than 30 MW, or a group of generating units *connected* at a common *connection point* have a combined *nameplate rating* greater than 30 MW; and

(ii) the output of the relevant *generating unit* is *intermittent* (such as for wind farms);

(d) *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*.

E. The regulatory framework

20. The *NEM* is regulated by the National Electricity Law (**NEL**), a schedule to the *National Electricity (South Australia) Act 1996* (SA) that applies in each of the *participating jurisdictions* through a co-operative legislative scheme. The *Rules* are made and enforced under the NEL.

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

22. 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.

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

F. Central dispatch

24. *Central dispatch* refers to the AEMO-managed process of *dispatching* electricity to meet demand, in accordance with Chapter 3 of the *Rules*.

25. *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]

[5] Rule 3.8.1(b).

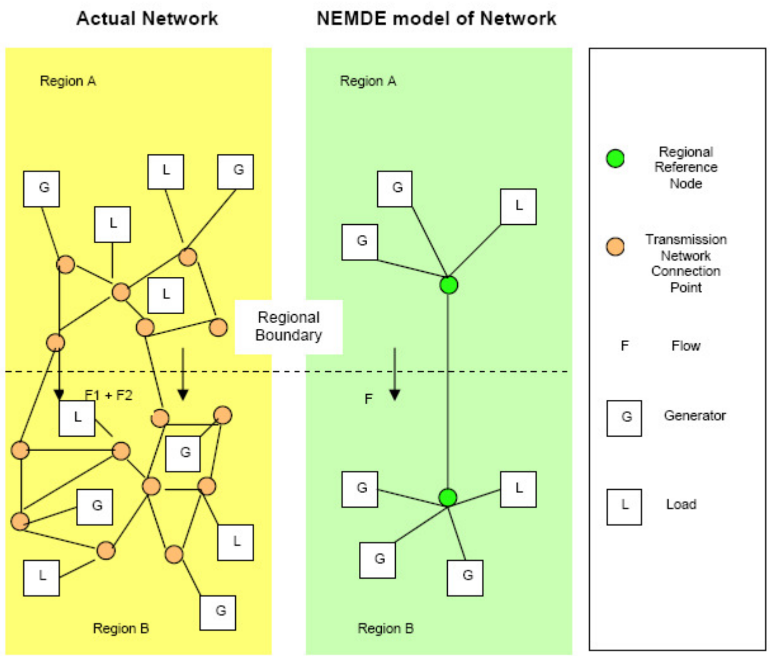
26. To participate in *central dispatch*, *Scheduled Generators* must submit *dispatch offers* to AEMO to generate electricity[6]. In each *dispatch offer*, *Scheduled Generators* must make an offer to provide a certain number of megawatts (**MW**) of electricity for each of the 48 *trading intervals* in the *trading day* and may make offers for up to ten *price bands* for each *generating unit*.[7] All prices in *price bands* are locked in at 12:30 EST on the day before trading commences, but MW quantities associated with those *price bands* can be modified at any time prior to dispatch.

27. 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. The basis upon which two or more *generating units* may be registered as a single *semi-scheduled generating unit* is described in section G below.

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

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

Figure 3 – How NEMDE Represents the Interconnected Network

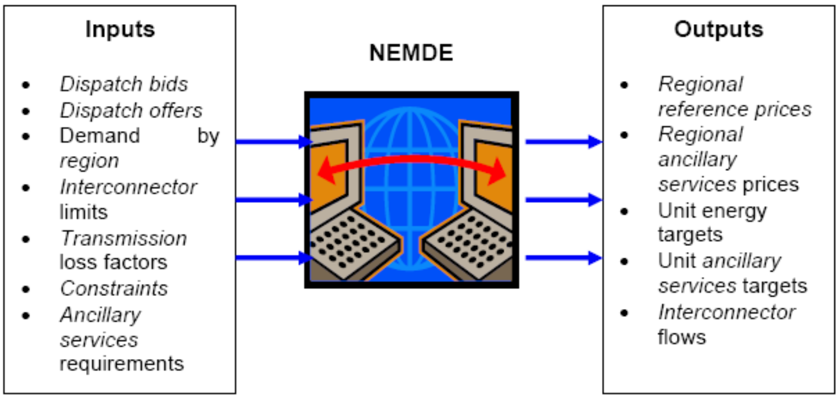


30. AEMO forecasts electricity consumption in each *region*, identifies the capability of the *transmission network* to transmit electricity, and captures the present state of the *power system* from information provided by

[6] Rule 3.8.2(a).
[7] Rule 3.8.6(a).

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. This process is repeated for every 5 minute *dispatch interval*. A simplified form of this optimisation process, as it applies at a general level, is depicted in Figure 4. Further details of the *dispatch process* as it applies to *semi-scheduled generating units*, including how AEMO takes into account the *available capacity* of a *semi-scheduled generating unit* as part of that process, is set out in Section G.

Figure 4 – NEMDE Optimisation Process



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

32. The highest price *Scheduled Generators* can offer is $12,500 per MWh[8] (*market price cap*) and the lowest is -$1,000 per MWh (*market floor price*).[9] *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*).

33. 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* 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 *price bands* they have offered.

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

---

[8] Increased to $12,900 per MWh from 1 July 2012
[9] Rules 3.9.4(b) and 3.9.6(b).

35. 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 demand in that *dispatch interval*.

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

37. All of the *Generators dispatched* during that *trading interval* will be paid the *spot price* times their *loss factor* for the energy they 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 *Generators*.

G. Semi-Scheduled Generation

The *Rules* introduced a new category of *Generator*, the *Semi-Scheduled Generator*, on 31 March 2009.

Classification of semi-scheduled generating units

38. The process by which a *generating unit* is classified as a *semi-scheduled generating unit* is set out in Rule 2.2.7. As a general rule, a *generating unit* with a *nameplate rating* of 30 MW or greater, or which is part of a group of *generating units connected* at a common *connection point* with a combined *nameplate rating* of 30 MW or greater, must be classified as a *semi-scheduled generating unit* where the output of the *generating unit* is *intermittent*.[10] AEMO may approve this classification for smaller *intermittent generating units* on such terms and conditions as AEMO considers appropriate.[11]

39. A person must not classify a *generating unit* as a *semi-scheduled generating unit* unless it has obtained AEMO's approval to do so.[12] AEMO must approve a request for classification of a *generating unit* as a *semi-scheduled generating unit* if it is satisfied of the following matters:[13]

    (a) the output of the *generating unit* is *intermittent*;[14]

    (b) the person has submitted data in accordance with the requirements to provide *bid and offer validation data* in Schedule 3.1 of the Rules;

[10] Rule 2.2.7(a).
[11] Rule 2.2.7(e)
[12] Rule 2.2.7(b).
[13] Rule 2.2.7(c).
[14] '*Intermittent*' is defined in Chapter 10 of the Rules to refer to a *generating unit* whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability.

(c) the person has submitted an *energy conversion model* (**ECM**) which contains the information described in guidelines *published* by AEMO for that purpose under Rule 2.2.7(d); and

(d) the person has adequate communications and telemetry to support the issuing of *dispatch instructions* and the audit of responses.

40. The ECMs provided *by semi-scheduled generators* are in the form of a data template, with the data used as an input into a mathematical model that defines how an *intermittent* energy source, such as wind, is converted by a *semi-scheduled generating unit* into electrical output (ie to forecast the electrical power output from a wind turbine based on the forecast of wind speed).

41. The date upon which each of the relevant *generating units* or groups of *generating units* of the Affected Generators were registered as *semi-scheduled generating units* is set out in the final column of the table in Schedule 2.

Dispatch of semi-scheduled generating units

42. A *Semi-Scheduled Generator* must operate a *semi-scheduled generating unit* in accordance with the *central dispatch* process under Chapter 3 of the Rules (described generally in section E above).[15]

43. The Rules distinguish between two different forms of *dispatch interval* for *semi-scheduled generating units,* which are treated differently in AEMO's *central dispatch* process:

(a) *semi-dispatch intervals*; and

(b) *dispatch intervals* that are not *semi-dispatch intervals*.

44. Under the Rules, a *semi-dispatch interval* is a *dispatch interval* for which either:

(a) a *network constraint* would be violated if the *semi-scheduled generating unit*'s *generation* were to exceed the *dispatch level* specified in the related *dispatch instruction* at the end of the *dispatch interval*; or

(b) the *dispatch level* specified in that *dispatch instruction* is less than the UIGF at the end of the *dispatch interval*,

and which is notified by AEMO in that *dispatch instruction* to be a *semi-dispatch interval*.

45. Semi-*Scheduled Generators* participate in the *central dispatch* process by submitting offers, but effectively operate as though they were *Non-Scheduled Generators* unless AEMO declares a *semi-dispatch interval* for a *semi-scheduled generating unit*. During a *semi-dispatch interval* the output for that *semi-scheduled generating unit* must not exceed a *dispatch level* specified by NEMDE.

[15] Rule 2.2.7(h).

46. In operating the *central dispatch process* under Rule 3.8, the specific matters to which AEMO's obligation in Rule 3.8.1(b) to aim to maximise the value of *spot market trading* is subject include, in respect of *semi-scheduled generating units*, *constraints* identified by the *unconstrained intermittent generation forecast* (**UIGF**).[16]

47. The requirement for AEMO to develop a UIGF is established in Rule 3.7B, which provides that AEMO must prepare a forecast of the *available capacity* of each *semi-scheduled generating unit* (to be known as the UIGF) for the purposes of, amongst other things, *dispatch*.[17]

48. In preparing a UIGF under Rule 3.7B, AEMO must take into account the following matters:[18]

    (a) the maximum *generation* of the *semi-scheduled generating unit* provided by the *Semi-Scheduled Generator* as part of its *bid and offer validation data*;[19]

    (b) the *plant availability* of the *semi-scheduled generating unit* submitted by the *Semi-Scheduled Generator* under Rule 3.7B(b);

    (c) the information obtained for the *semi-scheduled generating unit* from the *remote monitoring equipment* in Rule S5.2.6.1;

    (d) the forecasts of the energy available for input into the electrical power conversion process for each *semi-scheduled generating unit*;

    (e) the ECM for each *semi-scheduled generating unit*;

    (f) the assumption that there are no *network constraints* otherwise affecting the *generation* from that *semi-scheduled generating unit*; and

    (g) the timeframes of, amongst other things, *dispatch.*

49. A UIGF should therefore forecast the total electrical *power* output from available *semi-scheduled generating uni*ts, based solely on the forecast *power* input to its *intermittent* energy conversion process and ignoring any *constraints* on its electrical *power* output, such as *network* limitations.

50. The data that is used to produce *dispatch instructions* for *semi-scheduled generation* is processed by a number of systems. The UIGF data for wind generators is determined by the Australian Wind Energy Forecasting System (**AWEFS**).

51. The manner in which AEMO *dispatches semi-scheduled generating units,* and its use of AWEFS in preparing a UIGF, is set out in the 'Power System Operating Procedure – Dispatch', version 74, dated 1 July 2012, made for the purposes of Rule 4.10 (**Dispatch Procedure**).[20]

[16] Rule 3.8.1(b)(2)(ii).
[17] Rule 3.7B(a)(2).
[18] Rule 3.7B(c).
[19] Rule 3.7B(c)(1), which was inserted in version 42 of the Rules, effective from 24 March 2011.
[20] Dispatch Procedure, section 25 (Attachment 3). This section was added to version 70 of the Dispatch Procedure on 6 October 2011 and there have been no material amendments since that date.

52. The Dispatch Procedure provides that specified SCADA inputs are to be used by AWEFS in preparing a UIGF, including MW output, wind speed, wind direction, number of turbines in service, and the 'control system set-point' (the latter of which is stated to be 'desirable but not mandatory' for a *Semi-Scheduled Generator* to provide).[21] This SCADA data is the 'primary input' for preparing a UIGF, but the Dispatch Procedure also provides that where these inputs fail, AWEFS will not use this data, and will revert to using forecast weather and turbine availability information to produce a five minute ahead dispatch forecast. The forecast information specified in the Dispatch Procedure for this purpose is the 'number of turbines available' and the 'upper MW limit'.[22]

53. AEMO is required under Rule 2.2.7(d) to develop and *publish* guidelines setting out the information to be contained in ECMs. AEMO *published* the ECM initial guidelines (which remain current) on 28 April 2009. During the consultation on these guidelines as part of the implementation process for the *Semi-Scheduled Generator* arrangements, and in response to submissions by potential *Semi-Scheduled Generators*, AEMO made the provision of the 'control set-point' information as part of the ECM optional (as is now reflected in the Dispatch Procedure). In hindsight, this decision appears to be the cause of an unintended impact on the manner in which *semi-scheduled generating units* are *dispatched*.

54. AWEFS uses the control set-point sent in real-time to AEMO to determine whether actual output has been reduced by a *constraint* equation.[23] Where that control set point data is provided, AWEFS will revert to using forecast weather and turbine availability information to determine the UIGF where a output has been effected by a *constraint* equation. However, in the absence of a control set-point, AWEFS effectively assumes the output reduction is due to a reduction in wind, and fails to revert to using forecast weather and turbine availability information in determining the UIGF.As noted, AEMO is required under Rule 3.7B(c)(6) to create a UIGF for each *semi-scheduled generating unit* on the assumption that there are no *network constraints* otherwise affecting *generation.*

55. The lack of a control set-point has resulted in AWEFS ignoring this assumption.[24]

H. The scheduling error

56. Rule 3.8.24(a) provides that a *scheduling error* is any one of the following circumstances:

    (a) the DRP determines under Rule 8.2 that AEMO has failed to follow the *central dispatch* process set out in Rule 3.8;[25]

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[21] Dispatch Procedure, section 25.1 (Attachment 3).
[22] Dispatch Procedure, section 25.1.
[23] Limitations on the *power system* are represented in NEMDE as a series of mathematical constraint equations.
[24] Had the Wind Farm control set-point been provided, this would allow AWEFS to ignore the Wind Farm's output in the previous *dispatch interval* (if approximately equal to the control set-point value) and provide an UIGF based on actual wind speed and the number of turbines available.

(b) AEMO declares that it failed to follow the *central dispatch* process set out in Rule 3.8;[26] or

(c) AEMO determines under Rule 3.9.2B(d) that a *dispatch interval* contained a manifestly incorrect input.[27]

57. On 7 June 2012, AEMO declared in accordance with Rule 3.8.24(a)(2) that it failed to follow the *central dispatch* process set out in Rule 3.8 with respect to the *dispatch* of the Wind Farms, and that a *scheduling error* had therefore occurred.

58. The *scheduling error* is constituted by AEMO having incorrectly determined UIGFs for *Semi-Scheduled Generators* during certain *dispatch intervals*.

59. AEMO considers that, following the introduction of semi-scheduled generation on 31 March 2009, it is required to apply the UIGF in *central dispatch* by virtue of Rule 3.8.1(b)(2)(ii) and that the UIGF is a key input to *central dispatch*. *Central dispatch* applies the UIGF as an upper limit on NEMDE's calculation of *dispatch level* for the relevant *semi-scheduled generating unit*.

60. Where a *semi-scheduled generating unit* is affected by a *network constraint* and the next *dispatch interval* is a *semi-dispatch interval* for that *semi-scheduled generating unit* for the same reason, AWEFS incorrectly determined the UIGF, as it would not have ignored the reduction in output from the previous *dispatch interval*. Hence, the UIGF did not ignore *constraints* on electrical *power* output, such as *network* limitations. At times, this error results in a lower UIGF (and hence *dispatch level*), than would otherwise be calculated based on prevailing wind conditions.

61. AEMO has prepared a Market Event Report titled 'Scheduling Error Report Incorrect Unconstrained Intermittent Generation Forecasts for Semi-Scheduled Generators'. The report describes the occurrence of the *scheduling error* and is provided in Schedule 1 to this submission.

I. Dispatch intervals affected by the scheduling error

62. In any given *dispatch interval*, the output of a Wind Farm will only have been potentially affected by the *scheduling error* in certain circumstances. Other operational and economic conditions that applied to that Wind Farm will determine whether the Wind Farm would have been able to generate at a higher level than the limit imposed by the incorrect UIGF.

63. The following principles are agreed by the parties for the purposes of determining the affected dispatch intervals:

(a) The earliest date on which the *scheduling error* could have occurred for a Wind Farm is when it was classified as a *semi-scheduled generating unit*.

[25] Rule 3.8.24(a)(1).
[26] Rule 3.8.24(a)(2).
[27] Rule 3.8.24(a)(3).

(b) The *scheduling error* could no longer occur for a Wind Farm from the date and time at which AEMO applied the control set-point for that Wind Farm to AWEFS for the calculation of a correct UIGF.

(c) The *scheduling error* only occurred in *semi-dispatch intervals* where a Wind Farm was affected by a *network constraint*, excluding the first in a series of *semi-dispatch intervals* where that *network constraint* applied. This is because the Wind Farm's UIGF for the first *semi-dispatch interval* is correctly based on initial output which is not yet affected by the network constraint.

(d) The *scheduling error* only occurred in *semi-dispatch intervals* where the UIGF was less than the Wind Farm's actual generating capacity. That is, if the UIGF did not act to limit a Wind Farm's output, the *scheduling error* does not affect the Wind Farm.

(e) The *scheduling error* only occurred in *semi-dispatch intervals* where some of the Wind Farm's capacity was offered at *dispatch offer* prices lower than the *spot price*, otherwise the Wind Farm would not have been *dispatched* by reason of its uneconomic bid, not by reason of the *scheduling error*.

J. Calculation of compensation – overview

64. Rule 3.16.2 provides that where a *scheduling error* occurs:

(a) a Market Participant may apply to the DRP for a determination as to compensation;[28] and

(b) the DRP may determine that compensation is payable to *Market Participants* and the amount of any such compensation payable from the *Participant compensation fund*.[29]

65. A *Semi-Scheduled Generator* who receives an instruction in respect of a *semi-scheduled generating* unit to operate at a lower level than the level at which it would have been instructed to operate had the *scheduling error* not occurred is entitled to receive in compensation an amount determined by the DRP.[30]

66. The DRP must therefore determine the compensation payable in respect of a Wind Farm that, as a result of the *scheduling error*, was *dispatched* at a lower level than it would have been had the *scheduling error* not occurred.[31]

67. In order to determine the amount of this compensation payable to each Affected Generator, it is necessary to establish the following values for each affected *semi-dispatch interval*:

(a) the actual output of the Wind Farm;

[28] Rule 3.16.2(a).
[29] Rule 3.16.2(b).
[30] Rule 3.16.2(d).
[31] Rule 3.16.2(d)

(b) the UIGF that would have applied if *network constraints* had not been taken into account – referred to as the **"what-if" UIGF**;

(c) the level at which the Wind Farm would have been *dispatched* if the "what-if" UIGF had been applied in *central dispatch*, with all conditions not impacted by the *scheduling error* remaining unchanged – referred to as the **"what-if" *dispatch level***;

(d) the applicable *intra-regional loss factor* for the Wind Farm; and

(e) the applicable *spot price*.[32]

68. Part J of this submission sets out the principles which the parties have agreed should be applied in determining those values in relation to this *scheduling error*.

K. Calculation of compensation – principles for determining inputs

69. The following compensation principles have been agreed by the parties for the purposes of quantifying an Affected Generator's spot market losses for this particular *scheduling error*:

(a) The calculation of the "what-if" UIGF must be based on the data actually available for each 5-minute *semi-dispatch interval*, using:

(i) SCADA inputs actually received for the purposes of determining wind speed and wind turbine availability (subject to paragraph (b)); and

(ii) AWEFS standing data actually used, which includes information from the ECM.[33]

(b) If SCADA data for turbines available (as required under the ECM) was not provided for a Wind Farm, the SCADA data for turbines in operation will be used instead. For the Lake Bonney 2 and 3 Wind Farms, the calculation of turbines available will be based on the sum of turbines in operation and additional 'turbines paused' SCADA data actually provided to AEMO, which can be aggregated to derive turbine availability.

(c) The "what-if" UIGF for a Wind Farm cannot exceed its actual capacity (assuming unlimited wind) based on the number of wind turbines available[34] for *dispatch* during the relevant *semi-dispatch intervals*.

(d) For reasons of practicality, the impact of the *scheduling error* on a Wind Farm's output during a period after a *constraint* has been lifted will not be included for the purpose of calculating an Affected Generator's loss.

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[32] Rule 3.16.2(h)(3) requires the *dispute resolution panel* to use the *spot price* determined under Rule 3.9 in determining compensation.

[33] The data used by AWEFS in the *dispatch* process for *semi-scheduled generating units* is discussed in Section G, at paragraph 52.

[34] Or turbines in operation where turbines available SCADA data is either not provided or cannot be derived from data provided to AEMO (see paragraphs (a) and (b)).

(e) The “what-if” dispatch level is taken to equal the “what-if” UIGF unless the Wind Farm would not have achieved the “what-if” UIGF due to the relative economics of the Wind Farm compared to other generators within the network constraint. Other *Generators* competing for access to the *constrained* transmission line may have displaced the output of the Wind Farm because they were cheaper within the constraint. However, it is not possible to re-create with certainty the exact conditions that would have occurred absent the *scheduling error*, nor is it practical to attempt this for many thousands of affected *dispatch intervals* over 3 years. The parties have therefore agreed for the purposes of this claim to assume that the “what-if” dispatch level is:

(i) for each affected *semi-dispatch interval* in which the *regional spot price* was $300/MWh or more, the maximum *dispatch level* of the Wind Farm resulting from a re-run of the original NEMDE *dispatch* calculation with only the following changes:

(A) substitute the UIGF with the “what-if” UIGF for each affected Wind Farm; and

(B) substitute the initial MW with the “what-if” dispatch level calculated by the NEMDE re-run for the previous *dispatch interval*, for the Wind Farm and for all other *scheduled generating units*, *semi-scheduled generating units* and *interconnectors* within the *network constraint* which caused the *semi-dispatch interval* to be set; and

(ii) for all other affected *semi-dispatch intervals*, the same as the “what-if” UIGF (determined in accordance with the principles in paragraph 69(a) to (c).

(f) Compensation is payable based on the difference between the “what-if” dispatch level determined under paragraph (e) and the actual UIGF that applied to the Wind Farm in the affected *semi-dispatch interval*.

(g) The quantity calculated under paragraph (f) is multiplied by the *intra-regional loss factor* to give the compensable quantity (in MWh).

(h) The spot market loss for each Wind Farm for each affected *semi-dispatch interval* is the compensable quantity calculated under paragraph (g) multiplied by the *spot price*.

(i) If the *spot price* for an affected *semi-dispatch interval* is negative, the calculation under paragraph (h) will result in a payment to the market (that is, a credit in the overall compensation calculation).

L. Compensation amounts

70. AEMO has calculated the amount of compensation that would be payable to each Affected Generator in respect of its spot market losses, based on the principles in Part J. The calculations are agreed by the Affected Generators and are set out in separate confidential claim schedules submitted by each

of them. The aggregate amount claimed by all Affected Generators is $1,314,670. Infigen has also sought compensation for certain non-spot market losses in respect of the same scheduling error. As this aspect of compensation has not been agreed with AEMO it will be the subject of separate submissions.

M. Participant compensation fund

71. 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…'.

72. 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.[35]

73. Any interest paid on money held in the *Participant compensation fund* also accrues to and forms part of the *Participant compensation fund*.[36]

74. AEMO must prepare and *publish* before the beginning of each financial year a budget of the revenue requirements for AEMO for that financial year.[37] 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.[38] 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*.[39]

75. AEMO must also develop, review and *publish* the structure (including the introduction and determination) of *Participant fees* for such periods as AEMO considers appropriate.[40] The *Participant fees* should recover the budgeted revenue requirements for AEMO determined under Rule 2.11.3.[41]

76. AEMO has determined the structure of *Participant fees* for the period 1 July 2011 to 30 June 2016.[42] AEMO determined that the budgeted revenue requirements in respect of the *Participant compensation fund* will be allocated to *Scheduled Generators, Semi-Scheduled Generators* and

[35] See Rule 3.16.1(c).
[36] Rule 3.16.1(e).
[37] Rule 2.11.3(a).
[38] Rule 2.11.3(b)(8).
[39] Rule 2.11.3(b)(8).
[40] Rule 2.11.1(a).
[41] Rule 2.11.1(b)(2).
[42] See http://www.aemo.com.au/en/About-AEMO/Energy-Market-Registration/Current-Energy-Market-Budget-and-Fees/Structure-of-Participant-Fees-in-the-National-Electricity-Market-July-to-June

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.

77. 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.[43] In the case of *Market Participants*, AEMO may, alternatively, include the relevant amount in the final statements described in Rule 3.15.15.[44] A *Registered Participant* must pay to AEMO the net amount stated in the relevant statement by the date specified by AEMO.[45]

78. 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;[46]

(c) take into account the current balance of the *Participant compensation fund* and the potential for further liabilities to arise during the year;[47] 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.[48]

79. 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*.[49] The DRP also accepted that the reference to 'year' in Rule 3.16.2(h) is a reference to a financial year.[50]

80. The *Participant compensation fund* currently has a balance of $5,450,565.

[43] Rule 2.11.2(a).
[44] Rule 2.11.2(b).
[45] Rule 2.11.2(c).
[46] Rule 3.16.2(h)(3)
[47] Rule 3.16.2(h)(4).
[48] Rule 3.16.2(h)(5).
[49] See paragraph 24 of the decision.
[50] See paragraph 15 of the decision. 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.

81. Since the commencement of the market there have been four 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.

(d) $246,858.78 to Synergen Power Pty Ltd as compensation for a *scheduling error* that occurred between 19 May 2009 and 14 January 2010.

82. Since the last payment a *scheduling error* under Rule 3.8.24(a)(2) or (3) has occurred on six other occasions, but no claims for compensation have been made except as referred to in paragraph 70.

83. The *Adviser* contacted each *Semi-Scheduled Generator* in the *NEM* on 19 July 2012 regarding a potential claim against the *Participant compensation fund* in respect of this *scheduling error*. A claim notice was received from AGL Hydro on 23 July 2012. The Adviser held a teleconference with the DMS contacts of all *Semi-Scheduled Generators* on 22 August 2012. All but one of them has made a claim for compensation and these are the Affected Generators. The Adviser gave notice to all DMS contacts of the referral of this matter to the DRP on 31 October 2012. No other person has elected to join the proceedings.

84. If the compensation was paid for the full amount claimed in aggregate by the Affected Generators), the balance in the *Participant compensation fund* would be $4,135,895.

85. Accordingly, there is no reason why full payment of the loss of the Affected Generators should not be made.

N. Costs

86. For the purposes of this claim, AEMO and the Affected Generators have agreed that the costs of these proceedings (other than the legal costs of the parties) should be allocated on a basis that reflects both their relative involvement in the dispute resolution process and their expected compensation entitlement, as set out in the DRP agreement for this matter entered into on or about 12 November 2012. Each party will bear its own legal costs.

87. It is submitted that the DRP should allocate costs as agreed by the parties in accordance with Rule 8.2.8(a)(ii). The parties agree that none of the parties has unreasonably prolonged or escalated a dispute or otherwise increased the costs of these proceedings.

DATED: [7] November 2012

SCHEDULE 1

MARKET EVENT REPORT

SCHEDULING ERROR REPORT

INCORRECT UNCONSTRAINED INTERMITTENT GENERATION FORECASTS FOR SEMI-SCHEDULED GENERATORS

PREPARED BY: Electricity Market Performance

DATE: 7 June 2012

FINAL

Disclaimer

Purpose

This report has been prepared by the Australian Energy Market Operator Limited (AEMO) for the sole purpose of declaring a scheduling error under clause 3.8.24 (a)(2) of the National Electricity Rules.

No reliance or warranty

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Abbreviations and Symbols

ABBREVIATION	TERM
AWEFS	Australian Wind Energy Forecasting System
DI	Dispatch Interval
NER	National Electricity Rules
SCADA	Supervisory Control and Data Acquisition
TNSP	Transmission Network Service Provider
UIGF	Unconstrained intermittent generation forecast

Contents

1 Summary

In some circumstances, the Australian Wind Energy Forecasting System (AWEFS) has produced unconstrained intermittent generation forecasts (UIGFs) that are significantly less than that suggested by prevailing wind conditions[1] for some wind farms in some circumstances. This issue has resulted in the overly restrictive capping of the output from these semi-scheduled generating units by the central dispatch process, typically during periods of network congestion.

In December 2011, a participant approached AEMO in relation to this issue and the dispatch of its wind farm in Victoria. Following investigations, the issue was traced to the absence of certain real-time SCADA[2] information required by AWEFS to produce the correct UIGF[3].

AEMO has consequently determined that under these circumstances it has failed to follow the central dispatch process set out in rule 3.8 of the National Electricity Rules (NER) and declares that a scheduling error has occurred. Specifically, the scheduling error occurred for a wind farm during semi-dispatch intervals where:

- the wind farm's dispatch level was capped by its UIGF and was less than its available capacity, and
- the interval followed a semi-dispatch interval where the wind farm was involved in a binding or violated network constraint.

The affected period for each wind farm is from its classification as a semi-scheduled generating unit until the necessary real-time information was provided and used by AWEFS to produce the correct UIGF.

Under NER clause 3.16.2 (a), Market Participants affected by a scheduling error may apply to the dispute resolution panel established under NER clause 8.2.6A for a determination as to compensation.

2 Purpose of the UIGF

As part of the semi-dispatch arrangements introduced on 31 March 2009, AEMO must prepare and make available at all times a UIGF for each semi-scheduled generating unit [4] that takes into account, among other things, the real-time information provided to AEMO in accordance with its energy conversion model and the assumption that there are no network constraints otherwise affecting its generation.

These forecasts are then applied in the central dispatch process as an upper limit on the unit's calculated dispatch level, as required by NER clause 3.8.1 (b)(2)(ii). Under NER clause 3.8.23 (b), the relevant generator must cap its output at or below this level by the end of the relevant dispatch interval if its semi-dispatch cap flag is also set for that interval (a semi-dispatch interval). Otherwise the generator is free to operate at any level.

3 Design of the UIGF

In the 5-minute dispatch time frame the UIGF is, absent any network constraint, based on the measured SCADA output from the wind farm, which is more reliable than a weather model-based forecast. That is, the forecast for the next five minutes will be close to the actual output for the previous five minutes.

[1] This issue relates only to the 5-minute dispatch process, noting AWEFS also produces forecasts for the 5-minute Pre-dispatch, Pre-dispatch and PASA time frames
[2] Supervisory Control and Data Acquisition – a computer-based system for the real-time capture and storage of power system measurements and the monitoring and control of the power system
[3] AEMO has since requested, and largely been provided with, this information
[4] In accordance with NER clauses 3.7B (c) and (d)

However, if there is a network constraint operating to reduce the output of a wind farm, a weather model-based forecast is to be used instead.

The AWEFS uses the SCADA control set-point of the wind farm provided in real-time to AEMO to determine whether a wind farm's actual output has been reduced by a network constraint. Otherwise, AWEFS assumes the output reduction is due to a reduction in the level of wind in the area of the wind farm.

4 Incorrect Implementation of UIGF Design

Prior to the implementing the semi-dispatch arrangements, AEMO established guidelines and information provision requirements for the wind farm energy conversion model. During the consultation to develop these guidelines, AEMO changed the real-time provision of wind farm control set-point information from mandatory to optional.

However, without this real-time information, AWEFS could not distinguish between a reduction in wind farm output due to a network constraint or due to a genuine reduction in wind energy.

5 Impact of the UIGF Error

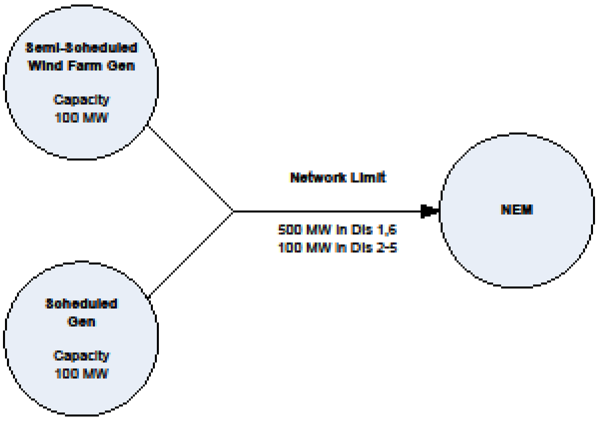
In the dispatch timeframe, AWEFS cannot distinguish between a reduction in wind energy and deliberate action to reduce wind farm output. When a wind farm is constrained off by a network constraint and its output is manually reduced by adjusting the wind farm's control scheme set-point, AWEFS incorrectly assumes that the wind speed must have dropped and produces a lower than expected generation forecast. During a period of network constraint this can progressively reduce the wind farm output to zero and then leave it at zero output.

<u>Example</u>

This example describes a scenario that compares the current, incorrect UIGF outcomes (without the real-time information) with "what-if" UIGF outcomes (where the real-time information is available). The difference between the two indicates how some semi-scheduled wind farms may have been affected by the scheduling error.

Consider a high-priced scheduled generator and a low-priced semi-scheduled wind farm, each physically available for 100 MW and connected to the NEM via a shared transmission line (refer to Figure 1 below).

Figure 1: Example of UIGF Error - Network Model



The scenario assumes the following:

- the semi-scheduled wind farm offer is at a lower price than the alternative scheduled generator offer, and that both generators are offered so that they will be dispatched up to their capacity or the capacity of the network
- ramp rates do not limit the dispatch
- the current wind forecasts (without real-time information) do not use wind speed but rather recent measurements of wind farm output
- the "what-if" wind forecasts, based on wind speed, are correct[5]

Initially, the combined output from the generators is not constrained by the network, with each having a calculated dispatch level of 100 MW for dispatch interval (DI) 1.

A network constraint limits the combined output from the generators to 100 MW in DIs 2 to 5. In DI 6 this network constraint is removed.

Figure 2 and Table 1 below summarise the impact of the incorrect UIGF on dispatch outcomes.

The "what-if" generation based on actual wind energy varies between 100 MW and 25 MW. The correct "what-if" UIGF follows the actual wind energy at the start of the DI, and the incorrect UIGF behaves as described below. The actual generation reflects the generator's compliance with the dispatch instructions based on the current UIGF.

- For DI 1:
  - AWEFS correctly calculates a UIGF of 100 MW for the semi-scheduled generator based on its previous, unrestricted output.
  - Dispatch calculates a dispatch level of 100 MW for the semi-scheduled generator based on this UIGF, and a dispatch target of 100 MW for the scheduled generator up to its physical capacity.
  - There are no binding network constraints affecting the generators, hence the semi-dispatch cap flag for the semi-scheduled generator is set to "False" and the generator is free to operate as the wind allows.
- For DI 2:
  - During DI 1, the wind drops off below forecast and the semi-scheduled generator output reduces to 50 MW. Based on this output, AWEFS correctly calculates a UIGF of 50 MW for DI 2.
  - Dispatch calculates a dispatch level of 50 MW for the semi-scheduled generator based on its UIGF, and a dispatch target of 50 MW for the scheduled generator, the remaining capacity of the network constraint.
  - The network constraint binds at the combined dispatch of 100 MW, and the semi-dispatch cap flag for the semi-scheduled generator is set to "True".
  - Based on this flag, the semi-scheduled generator complies and caps its output at the dispatch level of 50 MW during DI 2.
- For DI 3:
  - Based on previous output AWEFS interprets, absent the control set-point, that the wind has dropped, and incorrectly calculates a UIGF of 50 MW for DI 3.
  - Dispatch calculates a dispatch level of 50 MW for the semi-scheduled generator based on its UIGF, and a dispatch target of 50 MW for the scheduled generator, the remaining capacity of the network constraint.

[5] Note the current UIGF without real-time information uses recent measurements of wind farm output to forecast the wind farm output in the next dispatch interval. The real-time information indicates to AWEFS whether the current output has reduced to below the UIGF level, requiring a wind speed based forecast.

  - The network constraint is still binding and the semi-dispatch cap flag for the semi-scheduled generator is set to "True".
  - Based on this flag, the semi-scheduled generator complies and caps its output at the dispatch level of 50 MW during DI 3.
  - Based on wind energy the correct UIGF should be 75 MW, the dispatch level should only be capped to 75 MW, and hence the semi-scheduled generator has lost 25 MW of output. There is a scheduling error in this DI.
- For DI 4:
  - Based on previous output, AWEFS calculates an incorrect UIGF of 50 MW for DI 4.
  - Dispatch calculates a dispatch level of 50 MW for the semi-scheduled generator based on its UIGF, and a dispatch target of 50 MW for the scheduled generator, the remaining capacity of the network constraint.
  - The network constraint is still binding and the semi-dispatch cap flag is set to "True"
  - Based on this flag, the semi-scheduled generator complies and caps its output at the dispatch level of 50 MW during DI 4.
  - Based on wind energy the correct UIGF should be 85 MW, the dispatch level should only be capped to 85 MW, and hence the semi-scheduled generator has lost 35 MW of output. There is a scheduling error in this DI.
- For DI 5:
  - During DI 4, the wind drops off below forecast and the semi-scheduled generator output reduces to 25 MW. Based on this output, AWEFS correctly calculates a UIGF of 25 MW for DI 5.
  - Dispatch calculates a dispatch level of 25 MW for the semi-scheduled generator based on its UIGF, and a dispatch target of 75 MW for the scheduled generator, the remaining capacity of the network constraint.
  - The network constraint is still binding and the semi-dispatch cap flag is set to "True"
  - Based on this flag, the semi-scheduled generator complies and caps its output at the dispatch level of 25 MW during DI 5.
- For DI 6:
  - During DI 5, the wind picks up above forecast however the semi-scheduled generator output is capped at 25 MW. Based on this output, AWEFS incorrectly calculates a UIGF of 25 MW
  - The network constraint is no longer binding, and Dispatch calculates a dispatch level of 25 MW for the semi-scheduled generator based on its UIGF with its semi-dispatch cap flag set to "False", and a dispatch target of 100 MW for the scheduled generator up to its physical capacity
  - Based on wind energy the correct UIGF should be 90 MW and the dispatch level should be 90 MW. However as its semi-dispatch cap flag is set to "False" the semi-scheduled generator is free to operate as the wind allows and can ignore its 25 MW dispatch level, hence no output is lost.

Table 1: Example of UIGF Error – Dispatch Summary Table

Physical Capacities

Limits	DI 1	DI 2	DI 3	DI 4	DI 5	DI 6
Network Limit	500 unrestricted	100 binding	100 binding	100 binding	100 binding	500 unrestricted
Scheduled Gen	100	100	100	100	100	100
Semi-Scheduled Gen as limited by actual wind energy	100	50	75	85	25	90

Current Dispatch Outcomes (using incorrect UIGF)

Outcomes			DI 1	DI 2	DI 3	DI 4	DI 5	DI 6
AWEFS	Semi-Scheduled Gen	UIGF	100	50	50	50	25	25
		Based on…	Actual Gen	Actual Gen	Actual Gen	Actual Gen	Actual Gen	Actual Gen
DISPATCH	Semi-Scheduled Gen	Semi-Dispatch Cap Flag	False	True	True	True	True	False
		Must Cap Output at Dispatch Level?	No	Yes	Yes	Yes	Yes	No
		Dispatch Level	100	50	50	50	25	25
	Scheduled Gen	Dispatch Target	100	50	50	50	75	100

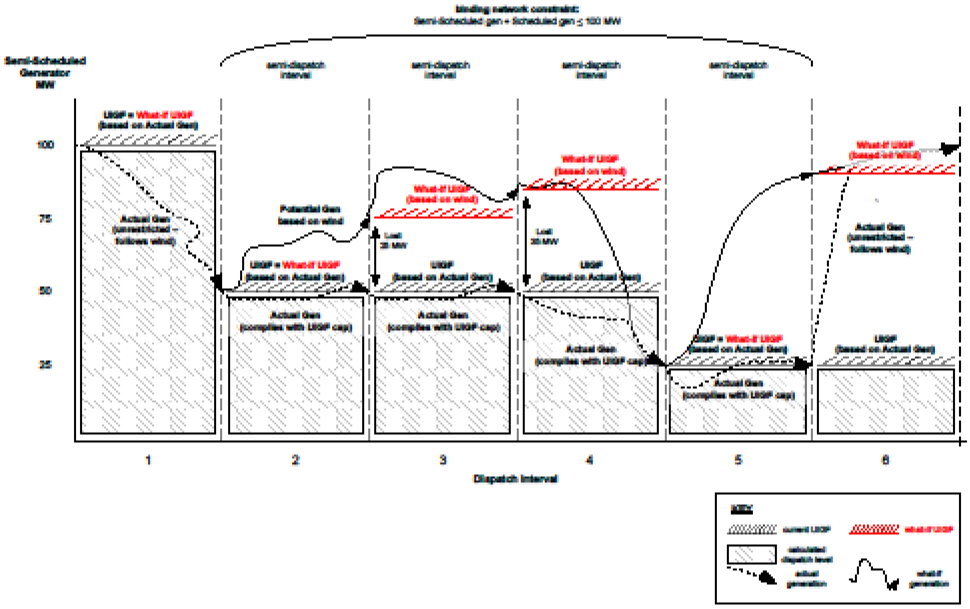
What-If Dispatch Outcomes (assuming correct UIGF)

Outcomes			DI 1	DI 2	DI 3	DI 4	DI 5	DI 6
AWEFS	Semi-Scheduled Gen	UIGF	100	50	75	85	25	90
		Based on…	Actual Gen	Actual Gen	Wind Energy	Wind Energy	Wind Energy[6]	Wind Energy
DISPATCH	Semi-Scheduled Gen	Semi-Dispatch Cap Flag	False	True	True	True	True	False
		Must Cap Output at Dispatch Level?	No	Yes	Yes	Yes	Yes	No
		Dispatch Level	100	50	75	85	25	90
	Scheduled Gen	Dispatch Target	100	50	25	15	75	100

Outcome	DI 1	DI 2	DI 3	DI 4	DI 5	DI 6
Scheduling Error?	NO	NO	YES	YES	NO	NO
Semi-Scheduled Gen MW Lost (What-If minus Current Dispatch Level, for DIs where must cap output)	0	0	25	35	0	0

[6] In this case, actual generation reflects actual wind energy

Figure 2: Example of UIGF Error – Dispatch Summary Graph



6 Scheduling Error Declaration

Under NER clause 3.8.24 (a)(2), a scheduling error occurs when AEMO determines that it has failed to follow the central dispatch process set out in rule 3.8.

AEMO has determined that it failed to follow the central dispatch process in that the UIGFs used in 5-minute dispatch do not assume there are no network constraints otherwise affecting its generation, and hence AEMO declares that a scheduling error has occurred.

The scheduling error occurred for a semi-scheduled generating unit during semi-dispatch intervals within the affected period where:

- the semi-scheduled generating unit's dispatch level was capped by its UIGF and was less than its available capacity, and
- the interval followed a semi-dispatch interval where the wind farm was involved in a binding or violated network constraint.

The affected period for each wind farm, noted in Table 2 below, is from its classification as a semi-scheduled generating unit until the necessary real-time information is provided and used by AWEFS to produce the correct UIGF.

Note that under NER clause 3.16.2 (a), Market Participants affected by a scheduling error may apply to the dispute resolution panel established under NER clause 8.2.6A for a determination as to compensation.

Table 2: Affected Period for Semi-Scheduled Wind Farms

Wind Farm	Semi-Scheduled from	SCADA Control Set-Point in AWEFS
Bluff	05/07/2011	08/03/2012
Clements Gap	17/04/2009	In progress
Gunning	25/03/2011	In progress
Hallett 1	09/04/2009	20/03/2012
Hallett 2	11/05/2009	08/03/2012
Lake Bonney 2	09/09/2010	19/03/2012
Lake Bonney 3	02/07/2010	Being tested
North Brown Hill	19/07/2010	08/03/2012
Oaklands	05/08/2011	14/04/2012
Snowtown	26/07/2010	In progress
Waterloo	20/08/2010	20/03/2012
Woodlawn	03/05/2011	In progress

7 Resolution and Further Actions

The UIGF error can be resolved by Semi-Scheduled Generators providing the control set-points for their semi-scheduled wind farms via SCADA, and AEMO feeding this into AWEFS. The AWEFS design uses the control set-point to indicate the reduced output is an operator action rather than due to a reduction in the wind speed.

AWEFS checks if the wind farm's output is at or close to (or above) the control set-point. If this is the case, AWEFS sets the wind farm output "down-regulation detected" flag and uses the current wind speed from SCADA to calculate the UIGF, provided it is of good quality.

This then results in a UIGF that correctly assumes the wind farm was not network constrained.

In December 2011 AEMO formally contacted all affected Semi-Scheduled Generators and requested them to voluntarily provide, via SCADA, the control set-point information for each wind farm so that their UIGF can be correctly calculated and to ensure the wind farm is not dispatched down unnecessarily.

AEMO requested a response by 31 January 2012, but placed no particular deadline on the provision of the information itself. At the time of writing this process is largely complete and all Semi-Scheduled Generators are either providing, are in the process of providing, or have agreed to provide, the control set-points for their semi-scheduled wind farms.

AEMO will also request future Semi-Scheduled Generators to voluntarily provide this information.

Before September 2012, AEMO intends to consult with Semi-Scheduled Generators and Transmission Network Service Providers (TNSPs) on changes to the Wind Energy Conversion Model guidelines to make the provision of real-time control set-point information via SCADA as mandatory provision for all existing and future Semi-Scheduled Generators.

SCHEDULE 2

AFFECTED GENERATORS AND WIND FARMS

Affected Generator	Wind Farm	Region	MW	Semi-Scheduled from
AGL Hydro	Bluff	SA	53	5 July 2011
	Hallett 1	SA	95	9 April 2009
	Hallett 2	SA	71	11 May 2009
	North Brown Hill	SA	132	19 July 2010
	Oaklands Hill	VIC	63	5 August 2011
EA	Waterloo	SA	111	20 August 2010
Infigen	Lake Bonney 2	SA	159	9 September 2010
	Lake Bonney 3	SA	39	2 July 2010
	Woodlawn	NSW	48	3 May 2011
Pacific Hydro	Clements Gap	SA	57	17 April 2009
Trustpower	Snowtown	SA	99	26 July 2010

Schedule 4

INFIGEN *ADVISER REFERRAL NOTICE*

NEM
Dispute Resolution
preserving relationships

Form 2:
Please note: The Adviser may forward a copy of this referral to a dispute resolution panel should one be constituted in accordance with the Rules. The Adviser may also include the Notice or a summary in her quarterly report to the market. It will also be placed on the dispute resolution portion of the AER website for precedent purposes.

Send to:
Shirli Kirschner
National Electricity Market
Resolution Adviser
M | 0411 380 380
F | 61 2 9380 5687
E | shirli@resolveadvisors.com.au

Adviser Referral Notice Clause 8.2.5 (a) - Referral - Form 2

From organisation: Lake Bonney Wind Power Pty Limited ABN 48 104 654 837 and Woodlawn Wind Pty Limited ABN 38 139 165 610

DMS contact name: Rob McDwyer, Senior Legal Counsel, Infigen Energy

Phone: 02 8031 9970

Mobile: 0499 772 387

Email: Rob.McDwyer@infigenenergy.com

Date: 1 November 2012

1. This is a referral under Clause 8.2.5(a) of the Rules.

Type of referral *(check the applicable box)*:

☐ Application of interpretation of the Rules.

☐ The failure of any Registered participants to agree to reach agreement on a matter where the rules require agreement or requires the registered participants to negotiate in good faith with a view to reaching agreement.

☐ The proposed access arrangements or connection agreements of a participant or a connection applicant.

☐ The payment of moneys under or concerning any obligation under the Rules.

☐ Any other matter relating to, or arising out of, the Rules to which a contract between two or more registered participants have agreed in writing that this clause 8.2 should apply.

☐ Any other matter relating to or arising out of the Rules to which two or more registered participants have agreed in writing that this clause 8.2 should apply.

☒ *Any other matter that the Rules provide may or must be dealt with under Rule 8.2 (specify) (e.g. Scheduling errors).*
Scheduling error compensation

072010

NEM Dispute Resolution
preserving relationships

2. Outline of dispute/compensation claim:

A brief history of the dispute/compensation claim and the circumstances giving rise to it:

Application for compensation under Rule 3.16.2 of the National Electricity Rules in respect of the scheduling error outlined in the dispute notice attached (AGL Notice). The approach to compensation for spot market losses in respect of the scheduling error has been agreed. The referring parties also claim compensation for renewable energy certificate losses in respect of the scheduling error.

Please continue on a separate sheet of paper if necessary.

Correspondence attached: Yes/~~No~~

AGL dispute notice.

3. Date of disputed decision or the occurrence of disputed conduct or when it became known *(see clause 8.2.4(b)* : *(for compensation claims please provide the date of the incident and whether AEMO has declared that it failed to follow the central dispatch processes set out in rule 3.8 or that a dispatch interval contains a manifestly incorrect input (3.8.24(2),(3)*.

Scheduling error declared by the Australian Energy Market Operator in a scheduling error report dated 7 June 2012. The periods during which the scheduling error occurred are set out in section 6 of that report.

4. Date of last service of a DMS referral Notice *(please attach a copy of the notice)*: ***(not required for compensation claims).***

Not applicable.

5. A statement of your organisation's issues in relation to the dispute:

The heads of damages and the relevant trading intervals for compensation claims.

Compensation for renewable energy certificate losses in respect of the scheduling error described in the AGL Notice (in addition to the amounts claimed for spot market losses).

Please continue on a separate sheet of paper if necessary.

Name and firm of external legal adviser if applicable:

Mitzi Gilligan, Minter Ellison

072010

6. Names of other parties which the applicant considers parties to the dispute *(attach pages for multi-party dispute)***:** Australian Energy Market Operator

Note*: at this time I expect there have been a number of DMS meetings. Considering the identity of who should be a party to this dispute is important. Being a party give a participant the right to access information and to participate in the process.*

It is also necessary to consider who will be bound by any determination. In general terms if you need a participant to be bound by the determination they will need to be a party. This may affect your view of who should be a party.

If there is a difference of view between the participants about who is a party/effected please indicate below, or by cover email. We can then have a dialogue about this matter as a preliminary issue before progressing further.

For compensation claims please outline if you think there are any other participants who have an interest in the matter.

Other parties Effected – for *each* provide:

Organisation: As set out in the AGL Notice

DMS contact name:

Email:

Mobile:

7. Process Election:

We agree/~~do not agree~~ *(strike out whichever does not apply)* **to the Adviser attempting to resolve the dispute by any means she considers appropriate (see clause 8.2.5(c) (1) of the Rules).**

For claims from the participant compensation fund the scope of the adviser process under this election is restricted as the determination of an error under 3.8.24 or the award of compensation must be made by a DRP.

Note re Adviser process:

The Rules provide fairly tight time frames for the establishment of the DRP as an alternative to the Adviser process. Agreeing to me resolving the dispute can take a number of forms. It may be agreement to resolve it generally, appoint a mediator or some other process. A number of disputes have been resolved this way.

It may also be more limited including meeting to agree to a time frame and a process for bringing the dispute into a sharper focus. This can include having the parties exchange issues statements and clarify the exact scope of the dispute. The DRP process provides for the selection of 1-3 panel members and there are a range of skills. Having a process to clarify the dispute is useful to ensure that the DRP when selected has the right skill mix, that a timeframe is properly estimated allowing the consultants on the DRP to ensure that they are available to meet the commitment. It ensures a tighter process which in turn impacts on costs.

Often parties are uncomfortable to tick the box and give me an unfettered discretion. In other disputes this has been dealt with by referring it, with my agreement and that of the parties, for a specified time period with agreed steps.

Continued overleaf.

Generally once referred I will contact the other parties to the dispute and then meet by phone or in person to agree next steps.

In the event that my process cannot resolve the dispute what occurs next is a referral to the DRP. Prior to the referral I have a meeting with the parties to discuss:

- *The constitution of the DRP; and*
- *the exchange of information prior to submitting the matter to a DRP.*

In the usual course the information exchange will include:

- *Confirmation of all the parties to the dispute.*
- *The Applicant providing a full statement of issues facts and contentions in dispute. (Around 5 days.)*
- *The Respondent(s) providing a reply statement of issues facts and contentions in dispute. (Around 7-10 days.)*
- *The parties, if possible agreeing on a list of documents. (At the same time.)*
- *The parties providing an estimate of the number and type of witnesses.*

This allows for an estimate of hearing dates and when the hearing is likely to occur. This is useful in choosing a DRP. The information can then be submitted to a DRP.

8. Consultation on a DRP:

Names of persons we would like you to consider in constituting any dispute resolution panel. Please provide contact details if they are not on the pool as published on the net.

Numbers of members and the types of skills they have would be a useful guide.

Name:

Technical expertise:

Contact details:

Referee *(if possible)*:

Adviser checklist:

Date received:

Clause 8.2 applies: Yes/No

Notification sent to parties:

Notes on resolution options sent:

Schedule 5

Clause 3.16.2 under version 1 and version 52 of the National Electricity Rules

Description	Version 1 reference	Version 52 equivalent
DRP to determine compensation	3.16.2(a)	3.16.2(b)
Determination must be consistent with clause 3.16.2	3.16.2(b)	3.16.2(c)
Scheduled Generator entitlement to compensation	3.16.2(c)	3.16.2(d)
Scheduled Network Service Provider entitlement to compensation	3.16.2(c1)	3.16.2(e)
Spot price as determined under rule 3.9 to be used in determining level of compensation	3.16.2(d)	3.16.2(h)(3)
DRP to take into account current balance of fund and potential for further liabilities during year	3.16.2(e)	3.16.2(h)(4)
Aggregate liability cannot exceed balance of fund that would have been available at end of year if no payments	3.16.2(f)	3.16.2(h)(5)
DRP to determine manner and timing of payments	3.16.2(g)	3.16.2(i)
NEMMCO not liable in respect of *scheduling error* except out of fund, to maximum extent permitted by law	3.16.2(h)	3.16.2(j)

Note:

Clauses 3.16.2(f), 3.16.2(g), 3.16.2(h)(1) and 3.16.2(h)(2) of version 52 of the National Electricity Rules do not have any equivalent in version 1 of the National Electricity Rules.

Those provisions are not relevant to the matters to be determined by the *DRP* in respect of this *scheduling error*.