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

The Claimants listed in Schedule 1	**(Claimants)**
and	
Australian Energy Market Operator Limited (ABN 94 072 010 327)	**(AEMO)**

A. Introduction

1. The italicised terms used in this submission are defined in the National Electricity Rules (***Rules***).[1]
2. Other terms and acronyms are defined in bold where they are first used in this submission. For convenience, they are also listed in **Schedule 2**.

B. Application

1. The Claimants are and were, at all material times, registered as *Market Generators* for the *generating systems* listed in **Schedule 1** (**Generating Systems**).
2. On 31 October 2015, AEMO declared under clause 3.8.24(a)(2) of the *Rules* that a *scheduling error* had occurred that affected the Generating Systems from the *dispatch interval* ending 1110 hr on 2 May 2014 to the *dispatch interval* ending 1740 hr on 6 June 2014 (**Scheduling Error Period**).
3. Clause 3.16.2(a) of the *Rules* permits any *Market Generator* affected by a *scheduling error* 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 Claimant from the *Participant compensation fund*;[2] and
   (c) the manner and timing of that payment.[3]

C. Rules

4. The version of the *Rules* that applied during the Scheduling Error Period is Version 62.

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

5. The amendments made to the *Rules* since Version 62 do not alter the effect of the provisions cited in this submission in a manner that is material to the matters relevant to the DRP's determination of compensation as a result of the *scheduling error*.

D. AEMO and the National Electricity Market (NEM)

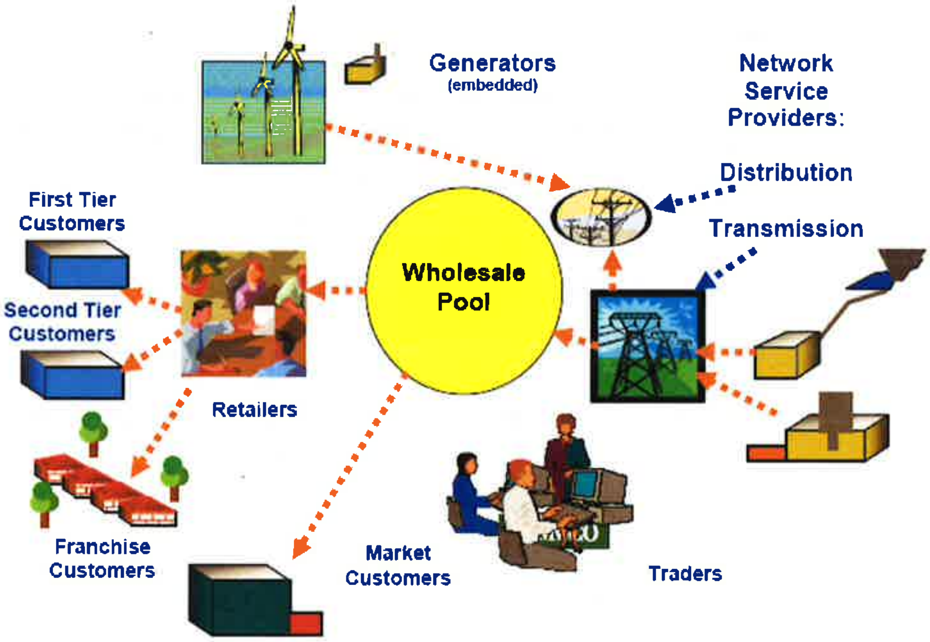
6. Sections D to H set out background information regarding the operation of the *NEM* and how *Scheduled Generators* and *Semi-Scheduled Generators* are *dispatched* in the *NEM*. This is included to provide context to the DRP.

7. 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.

8. Electricity is 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*.

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

Figure 1 – The National Electricity Market



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

11. 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.

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

(a) Queensland;

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

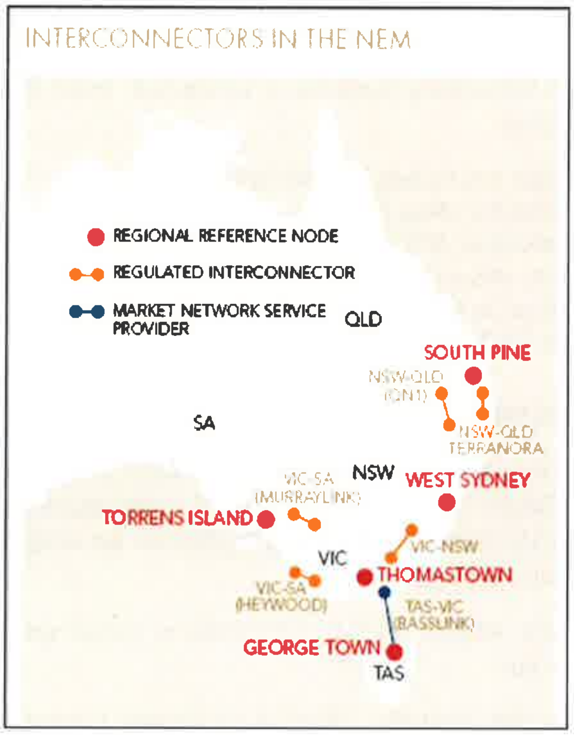
(c) Victoria;

(d) South Australia; and

(e) Tasmania.

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

Figure 2 – Interconnectors in the NEM



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

15. The *Rules* allow 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*.

16. Each of the Generating Systems is scheduled, apart from the following, which are semi-scheduled:

- Hallett 1 & Hallett 2 Wind Farm
- Macarthur Wind Farm
- Musselroe Wind Farm
- North Brown Hill Wind Farm
- Oaklands Hill Wind Farm
- The Bluff Wind Farm

E. The regulatory framework

17. 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.

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

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

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

F. Central dispatch

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

22. *Central dispatch* should aim to maximise the value of *spot market* trading on the basis of *dispatch offers* and *dispatch bids* (that is, the lowest cost *generating units* needed for electricity supply to meet demand are *dispatched*) subject to a number of matters, such as *network constraints* and *power system security* requirements.[4]

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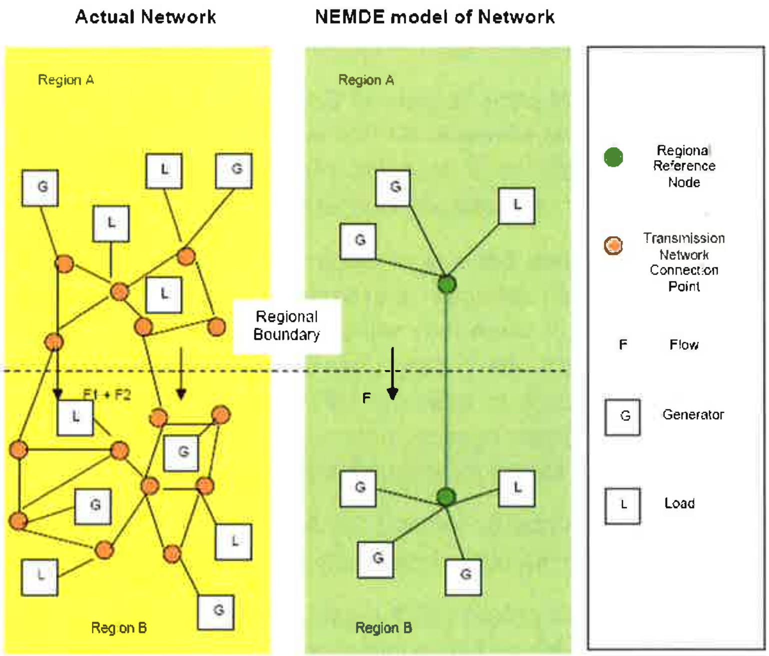
[4] Clause 3.8.1(b).

23. 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.

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

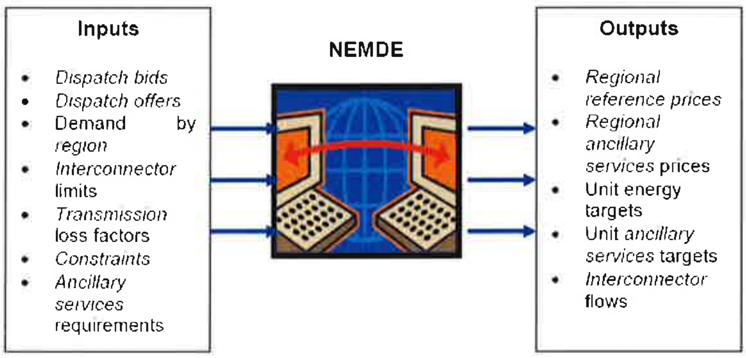
25. NEMDE is based on a constrained optimisation program that uses linear programming techniques that represent the *power system* as reflected in Figure 3:

Figure 3 – How NEMDE Represents the Interconnected Network



26. AEMO forecasts electricity consumption in each *region*, identifies the capability of each *transmission network* to transmit electricity and captures the present state of the *power system* from information provided by *Transmission Network Service Providers* (**TNSPs**). AEMO then determines the *generation* outputs for each *Generator* according to an optimisation process that is specified in the *Rules* and, in practice, performed by NEMDE. This process is repeated for every *dispatch interval*. A simplified form of this optimisation process, as it applies at a general level, is depicted in Figure 4.

Figure 4 – NEMDE Optimisation Process



27. The *central 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.

G. Scheduled Generation and Central dispatch

28. To participate in *central dispatch*, *Scheduled Generators* must submit *dispatch offers* to AEMO to generate electricity[5]. 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 a *trading day* and may make offers for up to ten *price bands* for each *generating unit*.[6] 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*.

29. The highest price *Scheduled Generators* can offer is $14,000 per MWh (*market price cap*) and the lowest is -$1,000 per MWh (*market floor price*).[7] *Scheduled Generators* must specify other technical matters in their *dispatch offers*, such as their rate of change for increasing or decreasing their output in MW/minute (*ramp rate*).

30. AEMO sends *Scheduled Generators* a *pre-dispatch schedule* every 30 minutes. A *pre-dispatch schedule* is essentially a forecast that gives *Scheduled Generators* an indication of when they will be *dispatched*, and for what level of output they will be *dispatched* for the *trading intervals* in the next two days. *Scheduled Generators* have an 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.

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

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

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

34. All of the *Scheduled 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 *Scheduled Generators* whose offers were too expensive and were not needed to meet demand are not *dispatched* and, consequently, do not get paid. In this way, the wholesale exchange encourages competition between *Scheduled Generators*.

H. Semi-Scheduled Generation and Central Dispatch

35. A *Semi-Scheduled Generator* must operate a *semi-scheduled generating unit* in accordance with the *central dispatch* process under Chapter 3 of the *Rules*.[8]

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[5] Clause 3.8.2(a).
[6] Clause 3.8.6(a).
[7] Clauses 3.9.4(b) and 3.9.6(b).
[8] Clause 2.2.7(h).

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

(a) *semi-dispatch intervals*; and

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

37. *Semi-Scheduled Generators* participate in the *central dispatch* process by submitting offers, but effectively operate as though they were *Non-Scheduled Generators* (and need not respond to *dispatch instructions*) 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.

38. In operating the *central dispatch* process under clause 3.8 of the *Rules*, AEMO's obligation in clause 3.8.1(b) to aim to maximise the value of *spot market trading* is subject to a number of matters, including, *non-scheduled load* requirements in each *region*[9] and, in respect of *semi-scheduled generating units*, *constraints* identified by the *unconstrained intermittent generation forecast* (**UIGF**).[10]

39. The requirement for AEMO to develop a UIGF is established in clause 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.*[11]

I. The Scheduling Error

40. Clause 3.8.24(a) of the *Rules* provides that a *scheduling error* is any one of the following circumstances:

(a) the DRP determines under clause 8.2 that AEMO has failed to follow the *central dispatch* process set out in clause 3.8;[12]

(b) AEMO declares that it failed to follow the *central dispatch* process set out in clause 3.8;[13] or

(c) AEMO determines under clause 3.9.2B(d) that a *dispatch interval* contained a manifestly incorrect input.[14]

41. On 31 October, 2015, AEMO declared that it failed to follow the *central dispatch* process when its Energy Management System (**EMS**) did not calculate the *load* for southern Tasmania correctly. This data was then used in constraint equations that were subsequently used in *central dispatch.*

42. AEMO has *published* a Scheduling Error Report titled 'NEM Scheduling Error - Incorrect Tasmanian Southern Area Load' (**Report**). The Report describes the occurrence of the *scheduling error* and a copy is provided in **Schedule 3** .

[9] Clause 3.8.1(b)(3).
[10] Clause 3.8.1(b)(2)(ii).
[11] Clause 3.7B(a)(2).
[12] Clause 3.8.24(a)(1).
[13] Clause 3.8.24(a)(2).
[14] Clause 3.8.24(a)(3).

J. Dispatch Intervals affected by the Scheduling Error

43. In its Report, AEMO confirms that the *scheduling error* affected a number of *dispatch intervals* between 2 May 2014 and 6 Jun 2014 and the output of a number of *Market Generators* with *scheduled generating units* and *semi-scheduled generating units* during those *dispatch intervals*.[15]

K. Calculation of Compensation - Overview

44. Clause 3.16.2 of the *Rules* provides that where a *scheduling error* occurs:

    (a) a *Market Participant* may apply to the DRP for a determination as to compensation;[16] 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*.[17]

45. A *Scheduled Generator* or *Semi-Scheduled Generator* who receives an instruction in respect of a *scheduled generating unit* or *semi-scheduled generating unit* (as applicable) to operate at a lower level than the level at which it would have been instructed to operate had the *scheduling error* not occur is entitled to receive in compensation an amount determined by the DRP.[18]

46. The DRP must, therefore, determine the compensation payable in respect of any *scheduled generating unit* or *semi-scheduled generating unit* that, as a result of the *scheduling error*, was *dispatched* at a lower level than it would have been had the *scheduling error* not occur.[19]

47. To determine the amount of this compensation payable to a *Scheduled Generator*, it is necessary to establish the following values for each affected *dispatch interval*:

    (a) the actual output of each affected *generating system*;

    (b) the *dispatch instruction* that would have been issued by AEMO in the absence of the *scheduling error*;

    (c) the applicable *intra-regional loss factor* for the affected *generating system*; and

    (d) the applicable *spot price*.[20]

48. To determine the amount of this compensation payable to a *Semi-Scheduled Generator*, it is necessary to establish the following values for each affected *semi-dispatch interval*:

    (a) the actual output of each affected wind farm;

    (b) the level at which the wind farm output would have been capped if the *scheduling error* had not occurred;

    (d) the applicable *intra-regional loss factor* for the wind farm; and

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[15] See Table 1 of the Report

[16] Clause 3.16.2(a).

[17] Clause 3.16.2(b).

[18] Clause 3.16.2(d).

[19] Clause 3.16.2(d)

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

(e) the applicable *spot price*.[21]

L. Calculation of compensation – Principles for Determining Inputs

49. The following compensation principles have been agreed by the parties for the purposes of quantifying each Claimant's *spot market* losses during affected *dispatch intervals* or *semi-dispatch intervals* (as applicable) for this *scheduling error*:

(a) Calculate the difference (in MWh) between the actual output of a *generating unit* and the output that would have occurred in the absence of the *scheduling error*;

(b) Multiply the quantity calculated under paragraph (a) by the *intra-regional loss factor* to give the compensable quantity (in MWh).

(c) The *spot market* loss is the compensable quantity calculated under paragraph (b) multiplied by the applicable *spot price*.

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

M. Compensation amounts

50. AEMO has calculated the amount of compensation that would be payable to each Claimant, based on the principles in Part K.

51. The calculations are agreed by each Claimant. The total compensation due to each Claimant are set out below:

Claimant	Compensation
Hydro-Electric Corporation (trading as Hydro Tasmania)	
AGL Loy Yang Marketing Pty Ltd	
CS Energy Limited	
AGL Hydro Partnership	
Origin Energy Electricity Limited	
AGL Macquarie Pty Limited	
Callide Power Trading Pty Limited	
AGL SA Generation Pty Limited	
Delta Electricity	
Snowy Hydro Limited	
Stanwell Corporation Limited	
Hazelwood Power	
EnergyAustralia Pty Ltd	
Aurora Energy (Tamar Valley) Pty Ltd (trading as AETV Power)	
Flinders Operating Services Pty Ltd	
EnergyAustralia Yallourn Pty Ltd	
IPM Australia Limited	
Braemar Power Project Pty Ltd	
Origin Energy Uranquinty Power Pty Ltd	

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

Claimant	Compensation
Pelican Point Power Limited	$753.86

N. Participant Compensation Fund

52. AEMO is required by clause 3.16.1 of the *Rules* to 'maintain, in the books of the corporation, a fund called the *Participant compensation fund* for the purpose of paying compensation ... as determined by the *dispute resolution panel* for *scheduling errors*...'.

53. 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*.[22]

54. Any interest paid on money held in the *Participant compensation fund* also accrues to and forms part of the *Participant compensation fund*.[23]

Participant Fee Determination

55. AEMO must prepare and *publish* before the beginning of each *financial year* a budget of the revenue requirements for AEMO for that *financial year*.[24] 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 clause 3.16.[25] 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*.[26]

56. AEMO must also develop, review and *publish* the structure (including the introduction and determination) of *Participant fees* for such periods as AEMO considers appropriate.[27] The *Participant fees* should recover the budgeted revenue requirements for AEMO determined under clause 2.11.3.[28]

57. AEMO has determined the structure of *Participant fees* for the period 1 July 2016 to 30 June 2021.[29] AEMO determined that the budgeted revenue requirements in respect of the *Participant compensation fund* will be allocated to *Scheduled Generators, Semi-Scheduled Generators* and *Scheduled Network Service Providers* and levied using a combination of historical capacity and historical energy scheduled, where:

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

[22] See clause 3.16.1(c).
[23] Clause 3.16.1(e).
[24] Clause 2.11.3(a).
[25] Clause 2.11.3(b)(8).
[26] Clause 2.11.3(b)(8).
[27] Clause 2.11.1(a).
[28] Clause 2.11.1(b)(2).
[29] See http://www.aemo.com.au/Datasource/Archives/Archive595.

(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.

58. 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.[30] In the case of *Market Participants*, AEMO may, alternatively, include the relevant amount in the *final statements* described in clause 3.15.15.[31] A *Registered Participant* must pay to AEMO the net amount stated in the relevant statement by the date specified by AEMO.[32]

Matters to be taken into account by DRP

59. 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 clause 3.9;[33]

(c) take into account the current balance of the *Participant compensation fund* and the potential for further liabilities to arise during the year;[34] 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.[35]

60. 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 clause 3.16.2(h)(4) is a reference to actual liabilities that will have created a clear balance in the *Participant compensation fund*.[36] The DRP also accepted that the reference to 'year' in clause 3.16.2(h) is a reference to a *financial year*.[37]

61. The *Participant compensation fund* balance as at 27 September 2016 is $5,336,741.30.

62. As a consequence, the funding requirement for the *Participant compensation fund* is nil until 30 June 2017.

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

Market Participant	Date of Scheduling Error	Compensation
Snowy Hydro Limited	31 October 2005	$438,892.00
Macquarie Generation	22 October 2007	$4,544,638.00
AGL Hydro Partnership	19 & 20 November 2009	$571,935.06

[30] Clause 2.11.2(a).
[31] Clause 2.11.2(b).
[32] Clause 2.11.2(c).
[33] Clause 3.16.2(h)(3)
[34] Clause 3.16.2(h)(4).
[35] Clause 3.16.2(h)(5).
[36] See paragraph 24 of the decision.
[37] See paragraph 15 of the decision.

Market Participant	Date of Scheduling Error	Compensation
Synergen Power Pty Ltd	19 May 2009 - 14 January 2010	$246,858.78
AGL Hydro Partnership	Various	$78,585.00
Infigen		$1,178,290.00
Trustpower		$12,031.00
Pacific Hydro		$29,999.00
EnergyAustralia		$11,891.00

64. Since the last payment, a *scheduling error* under clause 3.8.24(a)(2) or (3) has occurred on seven other occasions (four of which appear to have resulted in minor impacts on *generation* output), but no claims for compensation have been made other than this one.

65. Nevertheless, AEMO is aware that claims for compensation may be made in respect of two *scheduling errors*:

(a) Declared by AEMO as a result of incorrect UIGFs that affected a number of *semi-dispatch intervals* between 2012 and 2016. AEMO is still working on an agreement with Affected *Generators* as to the calculation methodology. The Adviser will provide the DRP and the parties with correspondence in relation to this claim and this claim will be made, with amounts in the order of $5 million for the total number of participants. There is likely to be a number of issues which will need to be decided by the DRP.

(b) The second was declared by AEMO as a result of incorrect line ratings applied to 66kv lines in Victoria between 1 December 2014 and 13 January 2015. One Affected *Generator* has inquired of AEMO as to the size of its potential compensation claim but has not indicated whether it would make a claim. If all potential claimants were to seek compensation, AEMO estimates the total amount to be in the order of $5.6 million. There is no notification to the Adviser of a claim as of 6 October 2016. The Adviser will provide the DRP and the parties with correspondence in relation to this claim

66. It is submitted that no reduction be made to the compensation awarded to Affected *Generators* as other potential claimants' entitlements would ordinarily be paid out of any balance in the *Participant compensation fund* up to $5 million. Any windfall gain, such as accumulated interest over the maximum of $5 million, should not be subject to apportionment but dealt with on a first-comer's basis.

Progress of Current Claim

67. A claim notice was received from Hydro Tasmania on 29 June 2016.

68. The *Adviser requested a list from AEMO of each generator who was affected by the error for an amount in excess of $1000. A copy of that list will be provided to the DRP.* The *Adviser* contacted each other Affected *Generator* from 24 August 2016 to ensure that they were aware of the claim and invited them to claim against the *Participant compensation fund* in respect of this *scheduling error*.

69. The Adviser will provide a notice to all DMS contacts about the referral of the matter to the DRP when the matter is formally referred to a DRP.

Balance of Participant Compensation Fund

70. If an order was made for compensation to be paid in full amount in respect of all claims by the Affected *Generators* ($296,661.14), the balance in the *Participant compensation fund* would be $5,040,080.16.

O. Costs

71. For the purposes of this claim, AEMO and Hydro Tasmania 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 18 October 2016. Each party will bear its own legal costs.

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

DATED: 18 October 2016

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EVY PAPADOPOULOS
Principal Corporate Lawyer
Australian Energy Market Operator Ltd

Schedule 1 - CLAIMANTS

Affected Generator	ABN	Affected Generating System	DUID
AGL Hydro Partnership	86 076 691 481	Somerton Power Station	AGLSOM
		The Bluff Wind Farm	BLUFF1
		Dartmouth Power Station	DARTM1
		Eildon Power Station	EILDON2
		Hallett 1 Wind Farm	HALLWF1
		Hallett 2 Wind Farm	HALLWF2
		Macarthur Wing Farm	MACARTH1
		Bogong/Mckay Power Station	MCKAY1
		North Brown Hill Wind Farm	NBHWF1
		Oaklands Hill Wind Farm	OAKLAND1
		West Kiewa Power Station	WKIEWA1 & WKIEWA2
		Townsville Gas Turbine	YABULU & YABULU2
AGL Loy Yang Marketing Pty Ltd	19 105 758 316	Loy Yang A Power Station	LYA1, LYA2, LYA3 & LYA4
AGL Macquarie Pty Ltd	18 167 859 494	Bayswater Power Station	BW01, BW02, BW03 & BW04
		Hunter Valley Gas Turbine	HVGTS
		Liddell Power Station	LD03 & LD04
AGL SA Generation Pty Ltd	84 081 074 204	Torrens Island Power Station "A"	TORRA1, TORRA2, TORRA3 & TORRA4
		Torrens Island Power Station "B"	TORRB1 & TORRB2
Aurora Energy (Tamar Valley) Pty Ltd (Trading as AETV Power)	29 123 391 613	Bairnsdale Power Station	BDL02
		Tamar Valley Combined Cycle Power Station	TVCC201
		Tamar Valley Peaking Power Station	TVPP104
Braemar Power Project Pty Ltd	54 113 386 600	Braemar Power Station	BRAEMAR1, BRAEMAR2 & BRAEMAR3
Callide Power Trading Pty Limited	80 082 468 719	Callide Power Plant	CPP_4
CS Energy Limited	54 078 848 745	Callide B Power Station	CALL_B_1 & CALL_B_2
		Gladstone Power Station	GSTONE1, GSTONE2, GSTONE3, GSTONE4 GSTONE5, GSTONE6
		Kogan Creek Power Station	KPP_1
Delta Electricity	75 162 696 335	Vales Point "B" Power Station	VP5 & VP6
EnergyAustralia Pty Ltd	99 086 014 968	Mt Piper Power Station	MP1 & MP2
		Tallawarra Power Station	TALWA1
EnergyAustralia Yallourn Pty Ltd	47 065 325 224	Yallourn Power Station	YWPS1 & YWPS4
Flinders Operating Services Pty Ltd	36 094 130 837	Northern Power Station	NPS1 & NPS2
Hazelwood Power	40 924 759 557	Hazelwood Power Station	HWPS1, HWPS3, HWPS4, HWPS5 HWPS6, HWPS7 & HWPS8
Hydro-Electric Corporation (Trading as Hydro Tasmania)	48 072 377 158	Bastyan Power Station	BASTYAN
		Catagunya/Liapootah/Wayatinah Power Station	LI_WY_CA
		Cethana Power Station	CETHANA
		Devil's Gate Power Station	DEVILS_G

Affected Generator	ABN	Affected Generating System	DUID
		Lake Echo Power Station	LK_ECHO
		Fisher Power Station	FISHER
		Gordon Power Station	GORDON
		John Butters Power Station	JBUTTERS
		Lemonthyme/Wilmot Power Station	LEM_WIL
		Mackintosh Power Station	MACKNTSH
		Meadowbank Power Station	MEADOWBK
		Musselroe Wind Farm	MUSSELR1
		Poatina Power Station	POAT110 & POAT220
		Reece Power Station	REECE1 & REECE2
		Tarraleah Power Station	TARRALEA
		Trevallyn Power Station	TREVALLN
		Tribute Power Station	TRIBUTE
		Tungatina Power Station	TUNGATIN
IPM Australia Limited	87 055 563 785	Loy Yang B Power Station	LOYYB1 & LOYYB2
Origin Energy Electricity Limited	33 071 052 287	Eraring Power Station	ER01, ER02 & ER04
		Darling Downs Power Station	DDPS1
		Ladbroke Grove Power Station	LADBROK1 & LADBROK2
		Mortlake Power Station Units	MORTLK11 & MORTLK12
		Mt Stuart Power Station	MSTUART1
		Osborne Power Station	OSB-AG
		Quarantine Power Station	QPS1, QPS2, QPS3 & QPS4
		Bendeela/Kangaroo Valley Power Station	SHGEN
		Roma Gas Turbine Station	ROMA_7 & ROMA_8
Origin Energy Uranquinty Power Pty Ltd	26 120 384 938	Uranquinty Power Station	URANQ11, URANQ12, URANQ13 & URANQ14
Pelican Point Power Limited	11 086 411 814	Pelican Point Power Station	PPCCGT
Snowy Hydro Limited	17 090 574 431	Colongra Power Station	CG4
		Blowering Power Station	BLOWERNG
		Guthega Power Station	GUTHEGA
		Laverton North Power Station	LAVNORTH
		Tumut 1 & 2 Power Station	UPPTUMUT
		Tumut 3 Power Station	TUMUT3
		Murray 1 & Murray 2 Power Station	MURRAY
Stanwell Corporation Limited	37 078 848 674	Kareeya Power Station	KAREEYA1, KAREEYA2, KAREEYA3 & KAREEYA4
		Barron Gorge Power Station	BARRON-1 & BARRON-2
		Mackay Gas Turbine	MACKAYGT
		Stanwell Power Station	STAN-1, STAN-2, STAN-3 & STAN-4
		Swanbank E Gas Turbine	SWAN_E
		Tarong North Power Station	TNPS1
		Tarong Power Station	TARONG#1 & TARONG#3

Schedule 2 - GLOSSARY

TERM	MEANING
Affected Generator	Any *Market Generator* impacted by the *scheduling error* and whose estimated losses are greater than $1,000.
DRP	*dispute resolution panel*
DUID	Dispatchable unit ID
EMS	AEMO's Energy Management System
EST	*Eastern Standard Time*
MW / MWh	megawatt / megawatt hour
NEL	National Electricity Law
NEMDE	*NEM* dispatch engine
NSP	*Network Service Provider*
Scheduling Error Period	The period commencing at the *dispatch interval* ending 1110 hr on 2 May 2014 and ending at the *dispatch interval* ending 1740 hr on 6 June 2014.
TNSP	*Transmission Network Service Provider*
UIGF	*unconstrained intermittent generation forecast*

Schedule 3 - SCHEDULING ERROR REPORT

NEM SCHEDULING ERROR

INCORRECT TASMANIAN SOUTHERN AREA LOAD

Published: **November 2015**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this report to advise of its consideration and determination of an incident using information available as at 30 October 2015, unless otherwise specified.

Disclaimer

AEMO has made every effort to ensure the quality of the information in this report but cannot guarantee its accuracy or completeness. Any views expressed in this report are those of AEMO unless otherwise stated, and may be based on information given to AEMO by other persons.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this report:

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CONTENTS

1. SUMMARY

AEMO has determined that a scheduling error has occurred where the calculation in AEMO's Energy Management System (EMS) for the Tasmanian southern area load was incorrect between 2 May 2014 and 6 June 2014. The error arose as the EMS calculation of the term did not reflect the recent commissioning of some new lines in Tasmania.

The term is an input to the right-hand-side (RHS) of several constraint equations used in central dispatch, and a number of these constraint equations bound or violated during the period of the error. Most Tasmanian generators are represented in these constraint equations.

AEMO has investigated the incident and declares that it had made a scheduling error by failing to follow the central dispatch process set out in rule 3.8 of the National Electricity Rules (NER).

2. THIS REPORT

AEMO has prepared this report to declare a scheduling error under NER clause 3.8.24(a)(2).

Data from AEMO's EMS and EMMS has been used in analysing the event. Hydro Tasmania were consulted in the preparation of this report.

All references to time in this report are to Australian Eastern Standard Time.

3. BACKGROUND

Tasmanian southern area load is automatically calculated in AEMO's EMS. The calculation consists of all the loads in the southern end of the Tasmanian region, as shown in Figure 1.

The calculated EMS analogue is passed to AEMO's Electricity Market Management System (EMMS) as term 'TRLOAD_S'.

The TRLOAD_S term is an input into the RHS of a number of Tasmanian constraint equations used in central dispatch, including:

- T>T_NIL_BL_3C – manages the post-contingent flow on a Hadspen to Palmerston 220 kV line for trip of the parallel line.
- T>T_NIL_BL_5C – manages the post-contingent flow on a Hadspen to George Town 220 kV for trip of the parallel line.
- T>>T_NIL_BL_EXP_5F – manages the post-contingent flow on a Hadspen to George Town 220 kV line for trip of the parallel line.

The left-hand-side (LHS) and RHS terms of all three constraint equations are available from Appendix A.

If any of these constraint equations bind, the a number of Tasmanian generating units may be constrained (other than gas turbine power stations).

Figure 1: Tasmanian Southern Area Load

4. EVENT DETAILS

Between DI ending 1110 hrs on 2 May 2014 and DI ending 1740 hrs on 6 June 2014, the EMS calculation of the TRLOAD_S term did not include the line flows of two recently commissioned transmission lines in Tasmania:

- Tungatinah to New Norfolk No.1 110 kV line, commissioned on 2 May 2014
- Creek Rd to Risdon No.1 110 kV line, commissioned on 23 May 2014

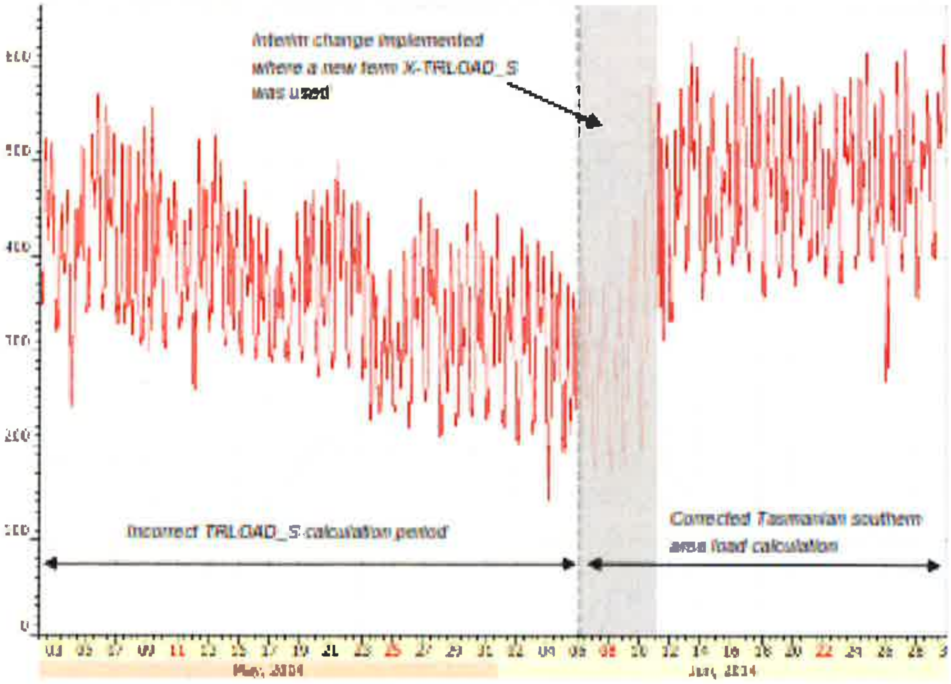
AEMO was aware of these network augmentations and had already updated its EMS to include the metering for each of the new lines. However, AEMO failed to update the Tasmanian southern area load calculation to include the metered line flows on the new lines. An augmentation checklist that AEMO follows did not include checking of the various area load calculations.

Hydro Tasmania notified AEMO of the error on 6 June 2014.

Upon notification, AEMO made immediate changes to correct the calculation of the Tasmanian southern area load. This change involved creating a temporary term, X-TRLOAD_S, that calculates the southern area load inclusive of the loads from the new transmission lines. This interim change was in place until the next available EMS production release. The TRLOAD_S term was permanently corrected on 11 June 2014.

Figure 2 shows the value of the TRLOAD_S term during the error and after it was corrected.

Figure 2: Tasmanian Southern Area Load TRLOAD_S



5. 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 because it did not update the EMS calculation for the Tasmanian southern area load in a timely manner to include recent network changes, resulting in an incorrectly low values input to central dispatch.

Hence, AEMO declares that a scheduling error has occurred between DI ending 1110 hrs on 2 May 2014 and DI ending 1740 hrs on 6 June 2014, a total of 10,159 DIs.

As noted in section 6, the scheduling error resulted in the a number of Tasmanian generators being constrained down for a total of 126 dispatch intervals (DIs) when relevant network constraints were binding or violated.

6. MARKET IMPACT OF SCHEDULING ERROR

During the scheduling error, the TRLOAD_S term was input to the RHS of the following binding or violated constraint equations:

- T>T_NIL_BL_3C
- T>T_NIL_BL_5C
- T>>T_NIL_BL_EXP_5F

These constraint equations, formulated to manage the Network Control System Protection Scheme (NCSPS), bound for a total of 126 DIs.

Table 1 summarises the date and number of DIs that these constraint equations bound or violated.

Table 1: Constraint impact of Scheduling Error

Date	DIs Affected
24/05/2014	3
25/05/2014	14
02/06/2014	4
03/06/2014	6
04/06/2014	27
05/06/2014	37
06/06/2014	35

Energy and FCAS prices in Tasmania were below the reporting threshold during the period when the EMS calculation was incorrect, other than on two occasions[1]:

- 3 May 2014 – Tasmanian energy spot price was -$142.31/MWh for trading interval ending 0000 hrs when there was a brief loss of SCADA communications between Hydro Tasmania and AEMO.
- 4 June 2014 – Tasmanian energy spot price was $2,235.23/MWh for trading interval ending 0230 hrs when constraint equation T>>T_NIL_BL_EXP_5F violated in dispatch and reduced the generation from a number of units in Tasmania.

Only the second event on 4 June 2014 was impacted by the incorrect EMS calculation of TRLOAD_S.

To assess the market impact due to the scheduling error, AEMO carried out NEMDE simulated re-runs of NEMDE dispatch files between DI ending 1110 hrs on 2 May 2014 and DI ending 1740 hrs on 6 June 2014, replacing the incorrect load calculation with the correct amount based on data available in AEMO's EMS. Based on the simulated re-runs, a total of 2,961 MWh of generation was constrained-off across all regions in the NEM due to the scheduling error. The trading interval ending 0230 hrs on 4 June 2014 in Tasmania had the highest market impact.

Appendix B lists the amount of generation constrained-off for each unit.

Scheduled and semi-scheduled generating units in the NEM that were constrained-off are included in Appendix B. The constrained-off amount is the difference between targets in the simulated "no error" run and the actual loading for each of the generating units. In accordance with NER clause 3.16.2(d), only generating units that would have been dispatched higher in the simulated run for each trading interval of the scheduling error period have been considered in determining the constrained-off MWh.

[1] AEMO. 2014. *Pricing Event Reports*. Available: http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports

7. FURTHER ACTIONS

AEMO has updated the augmentation checklist for Tasmania to include an extra step of updating the load/ demand calculation in the EMS for future network augmentations.

AEMO will review relevant constraint equations with each augmentation notice to ensure that all the terms in the constraint equation are up-to-date.

APPENDIX A. CONSTRAINT EQUATION FORMULATION FOR BINDING CONSTRAINT EQUATIONS

A.1 Constraint Equation T>T_NIL_BL_3C

Constraint type: LHS<=RHS
Effective date: 21/08/2013
Version No: 1
Weight: 30
Constraint active in: Dispatch and DS PASA, Predispatch and PD PASA
5 Min Predispatch RHS: Dispatch

Constraint description: Out = Nil, avoid O/L a Hadspen to Palmerston 220 kV line (flow to Hadspen) for trip of the other Hadspen to Palmerston 220 kV line considering NCSPS action, ensure sufficient NCSPS generation dispatched.
Impact: Tasmanian Generation
Source: Transend
Limit type: Thermal
Reason: Avoid overload of a Hadspen to Palmerston 220 kV line for trip of the other Hadspen to Palmerston 220 kV line
Modifications: Add Musselroe Wind Farm
Additional Notes: NCSPS Type 2 constraint - NCSPS IDs 31, 32. Swamped if NCSPS scheme disabled or Basslink not exporting > 280 MW or lines set to firm rating or NCSPS IDs not enabled. Transend limit advice 3/1/2013. CCR 567

LHS=

0.2823 x Cethana hydro (ENERGY)
0.0923 x Musselroe wind farm (ENERGY)
0.2823 x Devils Gate hydro (ENERGY)
0.2823 x Bastyan hydro (ENERGY)
0.2823 x Fisher hydro (ENERGY)
0.9343 x Gordon hydro (3 aggregated units) (ENERGY)
0.2823 x John Butters hydro (ENERGY)
0.798 x Lake Echo hydro (ENERGY)
0.9816 x Liapootah, Catagunya and Wayatinah aggregated hydro (ENERGY)
0.2823 x Mackintosh hydro (ENERGY)
0.8881 x Meadowbank hydro (ENERGY)
+ Poatina hydro (units 3, 4, 5 & 6 aggregated) (ENERGY)
0.5262 x Poatina hydro (units 1 & 2 aggregated) (ENERGY)
0.2823 x Reece hydro unit 1 (ENERGY)
0.2823 x Reece hydro unit 2 (ENERGY)
0.2823 x Lemonthyme and Wilmot hydro (aggregated) (ENERGY)
0.8211 x Tarraleah hydro (6 aggregated units) (ENERGY)
0.2823 x Tribute hydro (ENERGY)
0.0923 x Trevallyn hydro (4 aggregated units) (ENERGY)
0.8207 x Tungatinah hydro (5 aggregated units) (ENERGY)

RHS

Default RHS value= 1000

Dispatch RHS=
1.0975 x (0.09 x (Min
[
Tasmania: Palmerston - Hadspen #2 220KV Line Continuous Rating,
Tasmania: Palmerston - Hadspen #1 220KV Line Continuous Rating
])
- 0.9 (Intercept)
- 0.4835 x [Butlers Gorge PS]
- 0.362 x [Cluny PS]
- 0.1663 x [Paloona PS (SCADA)]
- 0.362 x [Repulse PS]
- 0.1663 x [Rowallan PS (SCADA)]
- 0.1663 x [Total SCADA MW for Woolnorth Windfarm - Combined output of Bluff Point & Studland Bay wind farms]
+ 0.0969 x [Northern MW load supplied from Palmerston & Hadspen (Palmerston, Trevallyn, Mowbray, Aurora, Derby, Scottsdale, Norwood, Avoca, St Marys, Arthurs Pump) Native load]

+ 0.173 x [North West MW load normally radial from Sheffield (Hampshire, Burnie, Port Latta, Smithton, Emu Bay, Ulverstone Devonport, Wesley Vale, Railton). Native Load]
+ 0.5598 x [Southern TAS MW load. All load south of Palmerston, including industrial loads. Native Load. Sum of South East, SouthernX and Hobart area loads]
+ 0.173 x [West Coast MW load normally radial from Farrell (Rosebery, Queenstown, Newton, Que, Savage River). Native Load]
+ 0.5891 x [Min MW operating limit for Poatina unit 4. MW guaranteed available for NCSPS tripping. Transend limit advice 8-2-07.]
+ 0.5665 x [Min MW operating limit for Catagunya Unit 1. MW guaranteed available for NCSPS tripping. Transend limit advice 8-2-07.]
+ 0.5504 x [Min MW operating limit for Gordon unit 2. MW guaranteed available for NCSPS tripping. Transend limit advice 8-2-07.]
+ 0.5891 x [Min MW operating limit for Poatina unit 5. MW guaranteed available for NCSPS tripping. Transend limit advice 8-2-07.]
+ 0.5665 x [Min MW operating limit for Catagunya Unit 2. MW guaranteed available for NCSPS tripping. Transend limit advice 8-2-07.]
+ 0.5504 x [Min MW operating limit for Gordon unit 3. MW guaranteed available for NCSPS tripping. Transend limit advice 8-2-07.])

+ **if**
 1 {Swamping_Offset}
 + 2 x [Firm flow enablement status for PMHA No.1 line]
 + 2 x [Firm flow enablement status for PMHA No.2 line]
 + 2 x [Generic Equation: PM_HA12_NCSPS_DISAB]
 - NCSPS enablement status for PMHA No.1 on trip of PMHA No.2 trip
 - NCSPS enablement status for PMHA No.2 on trip of PMHA No.1 trip **<= 0**

then
 0
else
 10000

Equation: PM_HA12_NCSPS_DISAB

if
 Absolute(**if**
  MW flow north on the Basslink DC Interconnector
  - 280 {Export_offset} **<= 0**
 then
  0
 else
  1
 + Georgetown Basslink frequency controller operational enablement status
 + On status of the Tas Network SPS
 - 3 {Offset}) **<= 0**

then
 0
else
 1

A.2 Constraint Equation T>T_NIL_BL_5C

Constraint type: LHS<=RHS
Effective date: 30/09/2013
Version No: 1
Weight: 30
Constraint active in: Dispatch and DS PASA, Predispatch and PD PASA
5 Min Predispatch RHS: Predispatch

Constraint description: Out = Nil, avoid O/L a Hadspen to George Town 220 kV line (flow to George Town) for trip of the other Hadspen to George Town 220 kV line considering NCSPS action, ensure sufficient NCSPS generation dispatched.
Impact: Tasmanian Generation
Source: Transend
Limit type: Thermal
Reason: Avoid overload of a Hadspen to George Town 220 kV line for trip of the other Hadspen to George Town 220 kV line
Modifications: Recalculated. Now derived directly from corresponding Type 4 constraint formulation.
Additional Notes: NCSPS Type 2 constraint - NCSPS IDs 71, 72. Swamped if NCSPS disabled or Basslink export below 280 MW or lines set to firm rating or NCSPS IDs not enabled. Transend limit advice 3/1/2013.

LHS=

0.2566 x Cethana hydro (ENERGY)
+ Musselroe wind farm (ENERGY)
0.2566 x Devils Gate hydro (ENERGY)
0.2566 x Bastyan hydro (ENERGY)
0.2566 x Fisher hydro (ENERGY)
0.9167 x Gordon hydro (3 aggregated units) (ENERGY)
0.2566 x John Butters hydro (ENERGY)
0.9305 x Lake Echo hydro (ENERGY)
0.9138 x Liapootah, Catagunya and Wayatinah aggregated hydro (ENERGY)
0.2566 x Mackintosh hydro (ENERGY)
0.9239 x Meadowbank hydro (ENERGY)
0.9097 x Poatina hydro (units 3, 4, 5 & 6 aggregated) (ENERGY)
0.2566 x Reece hydro unit 1 (ENERGY)
0.2566 x Reece hydro unit 2 (ENERGY)
0.2566 x Lemonthyme and Wilmot hydro (aggregated) (ENERGY)
0.9261 x Tarraleah hydro (6 aggregated units) (ENERGY)
0.2566 x Tribute hydro (ENERGY)
+ Trevallyn hydro (4 aggregated units) (ENERGY)
0.9261 x Tungatinah hydro (5 aggregated units) (ENERGY)

RHS

Default RHS value= 1000

Dispatch RHS=
1.417 x (0.98 x (Min
[
Tasmania: Hadspen - Georgetown #2 220kV Line Continuous Rating,
Tasmania: Hadspen - Georgetown # 1 220kV Line Continuous Rating
])
+ 0.6801 x [Southern TAS MW load. All load south of Palmerston, including industrial loads. Native Load. Sum of South East, SouthernX and Hobart area loads]
+ 0.7197 x [MW load supplied from Hadspen (Hadspen, Trevallyn, Mowbray, St Leonards, Norwood, Scottsdale, Derby) Native load]
+ 0.1749 x [All TAS North West and West Coast MW load supplied from Sheffield and Farrell. Sum of existing West Coast and North West load terms. Native load.]
+ 0.7166 x [MW load supplied from Palmerston (Palmerston, Avoca, St Marys, Arthurs). Native load]
- 3.012 [Constant])
- 0.9261 x [Butlers Gorge PS]
- 0.9140 x [Cluny PS]
- 0.2566 x [Paloona PS (SCADA)]
- 0.9140 x [Repulse PS]
- 0.2566 x [Rowallan PS (SCADA)]
- 0.2566 x [Total SCADA MW for Woolnorth Windfarm - Combined output of Bluff Point & Studland Bay wind farms]
+ 0.9167 x [Min MW operating limit for Gordon unit 2. MW guaranteed available for NCSPS tripping. Transend limit advice 6-2-07.]
+ 0.9167 x [Min MW operating limit for Gordon unit 3. MW guaranteed available for NCSPS tripping. Transend limit advice 6-2-07.]
+ 0.9138 x [Min MW operating limit for Catagunya Unit 1. MW guaranteed available for NCSPS tripping. Transend limit advice 6-2-07.]
+ 0.9138 x [Min MW operating limit for Catagunya Unit 2. MW guaranteed available for NCSPS tripping. Transend limit advice 6-2-07.]
+ 0.9097 x [Min MW operating limit for Poatina unit 4. MW guaranteed available for NCSPS tripping. Transend limit advice 6-2-07.]
+ 0.9097 x [Min MW operating limit for Poatina unit 5. MW guaranteed available for NCSPS tripping. Transend limit advice 6-2-07.]
+ If
1 (Swamping_Offset)
+ 2 x [Firm flow enablement status for HAGT No.1 line]
+ 2 x [Firm flow enablement status for HAGT No.2 line]
+ 2 x [*Generic Equation:* HA_GT_NCSPS_DISAB]
- NCSPS enablement status for HAGT No.1 on trip of HAGT No.2 trip
- NCSPS enablement status for HAGT No.2 on trip of HAGT No.1 trip <= 0
then
0
else
10000

Equation: HA_GT_NCSPS_DISAB

```
If
 Absolute( if
  MW flow north on the Basslink DC Interconnector
  - 280 (Export_offset) <= 0
 then
  0
 else
  1
 + Georgetown Basslink frequency controller operational enablement status
 + On status of the Tas Network SPS
 - 3 (Offset)) <= 0
then
 0
else
 1
```

A.3 Constraint Equation T>>T_NIL_BL_EXP_5F

Constraint type: LHS<=RHS
Effective date: 30/09/2013
Version No: 1
Weight: 30
Constraint active in: Dispatch and DS PASA, Predispatch and PD PASA
5 Min Predispatch RHS: Predispatch

Constraint description: Out = Nil, avoid O/L a Hadspen to George Town 220 kV line (flow to George Town) for trip of the other Hadspen to George Town 220 kV line considering NCSPS action, ensure Basslink can fully compensate NCSPS action.
Impact: Tasmanian Generation + Interconnectors
Source: Transend
Limit type: Thermal
Reason: Avoid overload of a Hadspen to George Town 220 kV line for trip of the other Hadspen to George Town 220 kV line
Modifications: Recalculated. Now derived directly from corresponding Type 4 constraint formulation.
Additional Notes: NCSPS Type 3 constraint - NCSPS IDs 71, 72. Swamped if NCSPS disabled or Basslink export below 280 MW or lines set to firm rating or NCSPS IDs not enabled or no overload will occur on monitored ccts. Transend limit advice 3/1/2013.

LHS=

0.2568 x Cethana hydro (ENERGY)
+ Musselroe wind farm (ENERGY)
0.2568 x Devils Gate hydro (ENERGY)
0.2568 x Bastyan hydro (ENERGY)
0.2568 x Fisher hydro (ENERGY)
0.9167 x Gordon hydro (3 aggregated units) (ENERGY)
0.2568 x John Butters hydro (ENERGY)
0.9305 x Lake Echo hydro (ENERGY)
0.9138 x Liapootah, Catagunya and Wayatinah aggregated hydro (ENERGY)
0.2568 x Mackintosh hydro (ENERGY)
0.9239 x Meadowbank hydro (ENERGY)
0.9097 x Poatina hydro (units 3, 4, 5 & 6 aggregated) (ENERGY)
0.9565 x Poatina hydro (units 1 & 2 aggregated) (ENERGY)
0.2568 x Reece hydro unit 1 (ENERGY)
0.2568 x Reece hydro unit 2 (ENERGY)
0.2568 x Lemonthyme and Wilmot hydro (aggregated) (ENERGY)
0.9261 x Tarraleah hydro (6 aggregated units) (ENERGY)
0.2568 x Tribute hydro (ENERGY)
+ Trevallyn hydro (4 aggregated units) (ENERGY)
0.9261 x Tungatinah hydro (5 aggregated units) (ENERGY)
-0.9097 x MW flow north on the Basslink DC Interconnector

RHS

Default RHS value= 750

Dispatch RHS=
1.417 x (0.89 x (Min

AEMO

[
Tasmania: Hadspen - Georgetown # 1 220kV Line Continuous Rating,
Tasmania: Hadspen - Georgetown # 1 220kV Line Continuous Rating
)]
+ 0.6601 x [Southern TAS MW load. All load south of Palmerston, including industrial loads. Native Load. Sum of South East, SouthernX and Hobart area loads]
+ 0.7197 x [MW load supplied from Hadspen (Hadspen, Trevallyn, Mowbray, St Leonards, Norwood, Scottsdale, Derby) Native load]
+ 0.1749 x [All TAS North West and West Coast MW load supplied from Sheffield and Farrell. Sum of existing West Coast and North West load terms. Native load.]
+ 0.7166 x [MW load supplied from Palmerston (Palmerston, Avoca, St Marys, Arthurs). Native load]
- 3.012 (Constant)
+ 0.642 x (-50 (Min_Export_offset)
- 144 (Max_Overtripping)))
- 0.9281 x [Butlers Gorge PS]
- 0.9146 x [Cluny PS]
- 0.2568 x [Paloona PS (SCADA)]
- 0.9146 x [Repulse PS]
- 0.2568 x [Rowallan PS (SCADA)]
- 0.2568 x [Total SCADA MW for Woolnorth Windfarm - Combined output of Bluff Point & Studland Bay wind farms]
+ If
1 (Swamping_Offset)
+ 2 x [Firm flow enablement status for HAGT No.1 line]
+ 2 x [Firm flow enablement status for HAGT No.2 line]
+ 2 x [Generic Equation: HA_GT_NCSPS_DISAB]
- NCSPS enablement status for HAGT No.1 on trip of HAGT No.2 trip
- NCSPS enablement status for HAGT No.2 on trip of HAGT No.1 trip <= 0
then
0
else
10000
+ 10000 x [Generic Equation: NCSPS3_71_72_SWMP_DS]

Equation: HA_GT_NCSPS_DISAB

If
Absolute(**If**
MW flow north on the Basslink DC Interconnector
- 250 (Export_offset) <= 0
then
0
else
1
+ Georgetown Basslink frequency controller operational enablement status
+ On status of the Tas Network SPS
- 3 (Offset)) <= 0
then
0
else
1

Equation: NCSPS3_71_72_SWMP_DS

If
Min
(
0.95 x [Tasmania: Hadspen - Georgetown #2 220kV Line 15 min Rating]
- MVA flow on #2 Hadspen to George Town 220kV line at Hadspen, Line end switched MVA
- 0.7247 x [MVA flow on #1 Hadspen to George Town 220kV line at Hadspen, Line end swiched MVA],
0.95 x [Tasmania: Hadspen - Georgetown #1 220kV Line 15 min Rating]
- MVA flow on #1 Hadspen to George Town 220kV line at Hadspen, Line end switched MVA
- 0.7247 x [MVA flow on #2 Hadspen to George Town 220kV line at Hadspen, Line end swiched MVA]
) <= 0
then
0
else
1

APPENDIX B. GENERATING UNITS CONSTRAINED-OFF

B.1 New South Wales

DUID	Constrained-off MWh
[redacted]	90
[redacted]	63
[redacted]	54
[redacted]	38
TARALGA1	27
[redacted]	25
[redacted]	24
[redacted]	24
TALWA1	21
[redacted]	20
ER01	14
MP1	13
URANQ11	7
[redacted]	7
[redacted]	7
URANQ14	5
URANQ13	5
[redacted]	4
WOODLWN1	4
HUMENSW	4
[redacted]	3
URANQ12	3
[redacted]	2
[redacted]	1
[redacted]	1
HVGTS	1

B.2 Queensland

DUID	Constrained-off MWh
CPP_3	[illegible]
GSTONE3	42
[redacted]	41

[redacted]	40
OSTONE1	37
KAREEYA4	30
OSTONE3	34
[redacted]	20
SWAN_E	18
MPP_2	15
YABULU2	15
MPP_1	13
YARWUN_1	12
BRAEMAR7	12
STAN-2	12
ROMA_7	12
CALL_B_1	9
BRAEMAR2	9
MSTUART1	9
CPP_4	8
BRAEMAR3	7
KAREEYA2	4
BRAEMAR1	4
KAREEYA1	4
KAREEYA3	4
CALL_B_2	4
STAN-3	4
KPP_1	3
[redacted]	3
DDPS1	2
BRAEMAR5	2
ROMA_8	1
TNPS1	1
CPSA	1
TARONGN3	1
TARONGN1	1
MACKAYGT	1

B.3 South Australia

DUID	Constrained-off MWh
NBHWF1	43
TORRA4	39
TORRB2	31
NPS2	18
TORRA2	16
TORRA3	15
SNOWNTH1	12
PPCCGT	11
TORRA1	6
[redacted]	6
[redacted]	6
LADBROK1	5
QPS3	5
QPS4	5
TORRB1	5
OSB-AG	4
WATERLWF	4
QPS2	3
LKBONNY2	3
SNOWSTH1	3
BLUFF1	3
SNOWTWN1	2
QPS5	1
HALLWF2	1

B.4 Tasmania

DUID	Constrained-off MWh
POAT220	547
POAT110	287
MACKNTSH	65
FISHER	56
GORDON	44
MUSSELR1	40
TARRALEA	32
TUNGATIN	26

[illegible]	17
LI_WY_CA	12
LK_ECHO	6
LEM_WIL	6
[illegible]	5
TVPP104	5
[illegible]	3
MEADOWBK	3
[illegible]	1
[illegible]	1

B.5 Victoria

DUID	Constrained-off MWh
[illegible]	124
[illegible]	115
[illegible]	61
HWPS7	50
[illegible]	49
[illegible]	38
[illegible]	32
[illegible]	15
[illegible]	14
[illegible]	13
[illegible]	12
[illegible]	11
[illegible]	10
[illegible]	10
[illegible]	8
[illegible]	8
[illegible]	7
[illegible]	7
[illegible]	7
[illegible]	7
[illegible]	6
[illegible]	5
[illegible]	2
[illegible]	2

OAKLAND1	1
MCKAY1	1

GLOSSARY

Abbreviations	Term
AEMO	Australian Energy Market Operator Ltd
DI	Dispatch Interval
EMMS	Electricity Market Management System
EMS	Energy Management System
LHS	Left-Hand-Side
NCSPS	Network Control System Protection Scheme
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NER	National Electricity Rules
RHS	Right-Hand-Side
SCADA	Supervisory Control and Data Acquisition
TI	Trading Interval