Synergies
ECONOMIC CONSULTING

Compensation claims arising in National Electricity Market during Billing Weeks 25 and 26 of 2022
DRAFT DETERMINATION

An independent expert report for AEMO

11 November 2022

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Contents

1 Introduction 6

1.1 Direct and indirect cost claims for billing weeks 25 and 26 6

1.2 Administered pricing period and market suspension event in NEM 7

1.3 Categorisation of compensation claims 7

1.4 Structure of the draft determination 9

Part A – Additional compensation claims in relation to AEMO *directions* during administered pricing period and market suspension event – Clause 3.15.7B of NER 11

Summary of NER compensation provisions 11

2 Compensation claims under clause 3.15.7B of NER 12

2.1 Basis of the *directions* 12

2.2 Clause 3.15.7 of NER 12

2.3 Clause 3.15.7B(a) of NER 13

3 Claims 1A and 1B (Claimant 1) 14

3.1 *Claim 1A – administered pricing period and directions* 14

3.2 *Claim 1B – market suspension event and directions* 15

4 Claimant 1's claims for additional compensation 16

4.1 Additional compensation in respect of Claims 1A and 1B 16

5 Assessment of Claims 1A and 1B 19

5.1 Claim 1A 19

5.2 Start Costs 20

5.3 Claim 1B 21

5.4 Start Costs 22

5.5 Draft determination for Claimant 1's Claims 1A and 1B 23

6 Claims 2A and 23B (Claimant 2) 25

6.1 *Claims 2A and 2B* 25

6.2 Assessment of Claims 2A and 2B 27

6.3 Draft determination 30

Part B – Compensation claims in relation to market suspension period (no *directions*) – Clause 3.14.5B 31

Summary of NER compensation provisions 31

7 Compensation claims under Clause 3.14.5B 32

7.1 Basis of claims in market suspension period 32

7.2 Clause 3.14.5B of NER 33

8 Claimant 1's market suspension compensation claims with no *directions* (Claim 1C) 35

8.1 Additional compensation in respect of Claim 1C 36

8.2 Assessment of Claim 1C 37

8.3 Draft determination 39

9 Claimant 2's market suspension compensation claims with no *directions* (Claim 1C) 41

9.1 Additional compensation for Claim 2C 41

9.2 Assessment regarding Claim 2C 41

9.3 Draft determination 41

10 Summary of draft determinations 42

Figures and Tables

Table 1 Categorisation of compensation provisions of NER 8

Table 2 Categorisation of compensation claims in draft determination 8

Table 3 AEMO's *directions* to Claimant 1 in administered price period 14

Table 4 AEMO's settlement compensation amounts for Claim 1A 15

Table 5 AEMO's *directions* to Claimant 1 in market suspension period (Claim 2) 15

Table 6 Additional compensation in relation to Claim 1A 16

Table 7 Additional compensation Claim 1B 17

Table 8 AEMO's *directions* to the Claimant 25

Table 9 Initial settlement compensation amounts in administered price period (Claims 2A and 2B) 26

Table 10 Additional compensation amounts for Claims 2A and 2B 26

Table 11 Summary of additional compensation Claim 1C estimates 36

Table 12 Compensation amounts in administered price period (Claims A and B) 41

Table 13 Additional compensation claim draft determination 42

1 Introduction

Synergies Economic Consulting (Synergies) has been appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine additional compensation claims arising from market participants in the National Electricity Market (NEM) between 10 June 2022 and 24 June 2022, spot market suspension from 15 June 2022 to 24 June 2022, and multiple AEMO *directions* for reliability within these periods.

AEMO is required by the NER to use reasonable endeavours to complete all obligations, including final settlement, no later than 30 weeks after the end of the billing period. For these claims relating to billing weeks 25 and 26, the Intervention Settlement Timetable requires that a draft independent expert determination be delivered no later than 9 November 2022 and a final determination by 28 December 2022. This will allow AEMO to complete the intervention settlement process by the required deadlines of 12 and 19 January 2023.

In accordance with the Intervention Settlement Timetable, Synergies is issuing this draft determination on 9 November 2022.

1.1 Direct and indirect cost claims for billing weeks 25 and 26

Under 3.14.5B, 3.14.6, and 3.15.7B of the National Electricity Rules (NER), AEMO received several compensation claims from *Directed Participants* and/or *Market Suspension Claimants* in billing weeks 25 and 26 relating to both direct and some indirect costs as follows:

- Fuel costs
- Generation unit start costs
- Variable generation unit operations and maintenance costs
- Loss of revenue

This draft determination relates to compensation claims made by the same two *Directed Participants* and *Market Suspension Claimants* in billing weeks 25 and 26.

1.2 Administered pricing period and market suspension event in NEM[1]

In June 2022, operation of the NEM was affected by a combination of high commodity prices, NEM spot market price caps, planned and unplanned outages of scheduled generating plant, low output from semi-scheduled generation, and high winter demand conditions.

A significant reduction in generation volumes offered to the market on 10 June 2022 resulted in the first lack of reserve (LOR) level 2 conditions in this series of events and necessitated the first of several reliability-related *directions* to be made by AEMO.

On the evening of Sunday 12 June 2022, the cumulative (market spot) price threshold (CPT) was exceeded in the Queensland region, which triggered an administered price cap of $300/megawatt hour (MWh) under the NER. During the evening of Monday 13 June 2022, the CPT was also exceeded for the New South Wales, Victoria and South Australia regions.

Given reductions in the volume of generation offered to the market, AEMO was required to make several *directions* for system reliability and implemented manual processes to manage capacity and energy limitations on generating facilities.

Directed capacity reached close to 5 gigawatts (GW) on 14 and 15 June 2022, and the large number of constraints necessary to manage directions and supply limitations ultimately resulted in AEMO suspending the NEM at 1400 hrs on 15 June 2022, with prices determined according to the published market suspension pricing schedule.

AEMO continued to issue *directions* to generators for reliability purposes during market suspension, with the volumes and number of *directions* that were required progressively declining after 18 June 2022 as some large generating units returned to service, with all *directions* cancelled by 23 June 2022.

Following a staged process, normal market dispatch pricing was resumed from 0400 hours on 23 June 2022, and the suspension was formally lifted at 1400 hours on 24 June 2022.

1.3 Categorisation of compensation claims

The implementation of an administered pricing period and market suspension event as described in the previous section triggers prescribed compensation arrangements for

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1 This section of the draft determination is based on AEMO's report entitled 'NEM market suspension and operational challenges in June 2022', released in August 2022.

market participants under Chapter 3 Market Rules of the NER, which are relevant for this independent expert draft determination.

Table 1 summarises the different NER compensation provisions that applied during the administered pricing period and market suspension event, including whether *directions* were in place or not, which are relevant to this draft determination.

Table 1 Categorisation of compensation provisions of NER

	Administered pricing period and *directions*	Market suspension event and *directions*	Market suspension event without *directions*
Type of claimant	Directed Participant	Market suspension claimant and a Directed Participant	Market suspension claimant but not a Directed Participant
Initial compensation	Initial compensation calculated by AEMO at 90th percentile price for energy generated	Market participant is compensated using prescribed market suspension benchmark methodology under clause 3.14.5A	Market participant is compensated using prescribed market suspension benchmark methodology under clause 3.14.5A
Additional compensation	Additional compensation claims determined under clause 3.15.7B	Additional compensation claim determined under clause 3.15.7B	Additional compensation claim determined under clause 3.14.5B

Source: Relevant Chapter 3 provisions of NER

The relevant provisions of the NER are discussed in more detail in our assessment of each of the Claimant's additional compensation claims.

In the remainder of the report to protect commercial-in-confidence supporting information we have been given by the two claimants, the following categorisation of the claimants and their claims has been adopted:

Table 2 Categorisation of compensation claims in draft determination

Claimant/Claim	Nature of claim	NER additional compensation clause
Claimant 1		
Claim 1A	Market suspension claimant and a Directed Participant	Clause 3.15.7B
Claim 1B	Market suspension claimant and a Directed Participant	Clause 3.15.7B
Claim 1C	Market suspension claimant but not a Directed Participant	Clause 3.14.5B
Claimant 2		
Claim 2A	Market suspension claimant and a Directed Participant	Clause 3.15.7B

Claimant/Claim	Nature of claim	NER additional compensation clause
Claim 2B	Market suspension claimant and a Directed Participant	Clause 3.15.7B
Claim 2C	Market suspension claimant but not a Directed Participant	Clause 3.14.5B

Source: Synergies based on compensation applications

1.4 Structure of the draft determination

In the remainder of this draft determination, which is split into two parts. we set out our reasons regarding the two claimants' additional compensation claims as follows:

- Part A assesses those claims made under clause 3.15.7B of the NER in relation to AEMO *directions* during each of the administered pricing period and market suspension event; and
- Part B assesses those claims made under clause 3.14.5B of the NER in relation to the market suspension event but where no AEMO *directions* were in place.

The structure of our draft determination is as follows:

1.4.1 Part A

- Section 2 summarises the compensation claim provisions relating to *directions* to be assessed under clause 3.15.7B of NER.
- Section 3 provides details of the *directions* under clause 3.15.7B and, where relevant, initial compensation amounts determined by AEMO.
- Section 4 provides an overview of the additional compensation amounts claimed by the two Claimants under clause 3.15.7B.
- Section 5 provides our analysis of the reasonableness of the compensation amounts claimed and our draft determination on the claims.

1.4.2 Part B

- Section 7 summarises the compensation claim provisions relating to the market suspension period under clause 3.14.5B of the NER.
- Section 8 provides details of the compensation claims made by Claimant 1 under clause 3.14.5B and our assessment of and draft determination on the claims.

- Section 9 provides details of the compensation claims made by Claimant 2 under clause 3.14.5B and our assessment of and draft determination on the claims.
- Section 10 presents the financial outcomes arising from our draft determination

Part A – Additional compensation claims in relation to AEMO *directions* during administered pricing period and market suspension event – Clause 3.15.7B of NER

Summary of NER compensation provisions

Claimants 1 and 2 have made claims in relation to the administered pricing period and market suspension event.

Initial compensation paid to *directed participants* during the administered pricing period, is calculated based on the 90th percentile price for the energy generated. Any additional compensation claims by a *directed participant* must be assessed under clause 3.15.7B.

In contrast, the initial compensation for a *market suspension claimant* that is also a *directed participant*, must be calculated using the market suspension benchmark value method prescribed in clause 3.14.5A of the NER. Any additional compensation claims by such a directed *market suspension claimant* must also be assessed under clause 3.15.7B.

The initial compensation for a *market suspension claimant* that is not a *directed participant*, must be calculated using the market suspension benchmark value method prescribed in clause 3.14.5A. However, any additional compensation claims made by such a *market suspension claimant* is assessed under clause 3.14.5B rather than clause 3.15.7B.

2 Compensation claims under clause 3.15.7B of NER

This section sets out the additional compensation claim provisions of clause 3.15.7B of the NER relevant to the *direction*-related claims in billing weeks 25 and 26 in 2022.

2.1 Basis of the *directions*

Section 116 of the NEL and clause 4.8.9 of the NER establish that AEMO may direct a *Registered Participant* to take relevant actions to maintain or restore the security or reliability of the power system.

During billing weeks 25 and 26 in 2022, AEMO issued several *directions* to *market participants* to maintain reliability of the system. In response, these *market participants* modified the operations of their generating units.

2.2 Clause 3.15.7 of NER

As a result of the operational responses to the *directions*, the *directed participants* incurred costs and are entitled to compensation under clause 3.15.7 of the NER.

Under this clause, AEMO must compensate each *directed participant* for the provision of energy or market ancillary services pursuant to a *direction* to be determined in accordance with the following formula:

$$DCP = AMP * DQ$$

Where:

- DCP is the amount of compensation the *directed participant* is entitled to receive.[2]
- AMP is the price below which are 90% of the spot prices or ancillary service prices (as the case may be) for the relevant service provided by Scheduled Generators, Semi-Scheduled Generators, Scheduled Network Service Providers or Market Customers in the region to which the direction relates, for the 12 months immediately preceding the trading day in which the *direction* was issued.

DQ is either:

(a) the difference between the total adjusted gross energy delivered or consumed by the *directed participant* and the total adjusted gross energy that would have been delivered or consumed by the *directed participant* had the *direction* not been issued; or

2 DCP is calculated in accordance with NER Clause 3.15.7(c).

(b) the amount of the relevant market ancillary service which the *directed participant* has been enabled to provide in response to the *direction*.

In line with the Intervention Settlement Timetable for billing weeks 25 and 26, AEMO calculated *directed participant* initial compensation and notified the *directed participants* of the compensation payable under clause 3.15.7.

2.3 Clause 3.15.7B(a) of NER

A *directed participant* that is entitled to compensation under clause 3.15.7 (and 3.15.7A) of the NER may make a claim for additional compensation under clause 3.15.7B, which confines compensation (under clause 3.15.7B (a)) to:

1. the aggregate of the loss of revenue and additional net direct costs incurred by the *directed participant* in respect of a scheduled generating unit, semi-scheduled generating unit or scheduled network services, as the case may be, as a result of the provision of the service under direction; less
2. the initial compensation amount notified to that *directed participant* pursuant to clause 3.15.7(c) or clause 3.15.7A(f); less
3. the aggregate amount the *directed participant* is entitled to receive in accordance with clause 3.15.6(c) for the provision of a service rendered as a result of the *direction*.

In broad terms, clause 3.15.7B(a) entitles a *directed participant* to claim additional compensation to cover loss of revenue and net direct costs minus *trading amounts* for *energy* and *market ancillary services* minus any initial compensation for directed services that has already been determined by AEMO.

The two *directed participants* in this case have made claims for compensation for additional net direct costs pursuant to clause 3.15.7B(a)(1) arising from their respective responses to *direction*s issued by AEMO during billing weeks 25 and 26.

3 Claims 1A and 1B (Claimant 1)

Claimant 1 has made additional compensation claims in relation to the administered pricing period (Claim 1A) and market suspension event (Claim 1B) when it was generating subject to AEMO *directions*. Each of these claims must be assessed in accordance with clause 3.15.7B of the NER.

3.1 *Claim 1A – administered pricing period and directions*

AEMO issued the following *directions* to Claimant 1 commencing 18.10 hours on 13 June and ending 12.35 hours on 15 June 2022 when an administered pricing period was in place in the NEM (but prior to the commencement of the market suspension event).

Table 3 AEMO's *directions* to Claimant 1 in administered price period

Directed unit	Event Number	Issued date/time	End date/time	Reason
UNIT 1	128-1	13/06/2022 18:10	13/06/2022 20:00	Reliability
UNIT 2	128-2	13/06/2022 18:10	13/06/2022 20:00	Reliability
UNIT 3	128-3	13/06/2022 18:10	13/06/2022 20:00	Reliability
UNIT 1	129-2	14/06/2022 08:00	15/06/2022 14:00	Reliability
UNIT 2	129-3	14/06/2022 08:00	15/06/2022 14:00	Reliability
UNIT 3	129-4	14/06/2022 08:00	15/06/2022 14:00	Reliability
UNIT 4	129-5	14/06/2022 08:00	15/06/2022 14:00	Reliability
UNIT 5	137-1	15/06/2022 12:35	15/06/2022 14:00	Reliability
UNIT 6	137-2	15/06/2022 12:35	15/06/2022 14:00	Reliability

Source: AEMO

3.1.1 Claimant 1's initial settlement compensation

As explained in section 2.2, initial settlement compensation is calculated based on the directed participant's compensation entitlement (DCP) minus its retained trading amount (RTA). Initial settlement compensation is determined as DCP minus RTA and included in the Final Billing statement.

DCP is calculated in accordance with Clause 3.15.7(c) of the NER.

RTA, or revenue earned, is calculated in accordance with Clause 3.15.6(b) for the additional energy produced, which would have been included in the Claimant's settlement amount indicated in its Preliminary Billing statement.

Table 4 presents the initial settlement compensation for Claimant 1's *directions* during the administered pricing period identified above.

Table 4 AEMO's settlement compensation amounts for Claim 1A

Directed unit	Event number	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
UNIT 1	128-1	-	-	-
UNIT 2	128-2	-	-	-
UNIT 3	128-3	-	-	-
UNIT 1	129-2	$263,451	$258,232	$5,220
UNIT 2	129-3	$380,469	$373,451	$7,019
UNIT 3	129-4	$666,862	$654,095	$12,768
UNIT 4	129-5	$485,031	$476,393	$8,638
UNIT 5	137-1	$42,356	$47,026	-$4,670
UNIT 6	137-2	$41,770	$46,982	-$5,212

Source: AEMO

3.2 *Claim 1B – market suspension event and directions*

AEMO issued the following *directions* to Claimant 1 commencing 14.00 on 15 June and ending 23.06 on 23 June 2022 when the market suspension event was in place in the NEM.

Table 5 AEMO's *directions* to Claimant 1 in market suspension period (Claim 2)

Directed unit	Event Number	Issued date/time	End date/time	Reason
UNIT 1	129-2	14/06/2022 8:00	22/06/2022 20:00	Reliability
UNIT 2	129-3	14/06/2022 08:00	23/06/2022 20:00	Reliability
UNIT 3	129-4	14/06/2022 08:00	23/06/2022 20:00	Reliability
UNIT 4	129-5	14/06/2022 08:00	23/06/2022 20:00	
UNIT 5	130-12	18/06/2022 15:00	23/06/2022 20:00	Reliability
UNIT 1	130-27	22/06/2022 04:00	23/06/2022 20:00	Reliability
UNIT 5	137-1	15/06/2022 12:35	15/06/2022 14:00	Reliability
UNIT 6	137-2	15/06/2022 12:35	15/06/2022 14:00	Reliability
UNIT 5	144-8	17/06/2022 17:40	23/06/2022 04.00	Reliability
UNIT 6	144-9	17/06/2022 17:40	23/06/2022 04.00	Reliability
UNIT 7	144-10	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 8	144-11	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 9	144-12	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT10	144-13	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 11	144-14	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 12	144-23	18/06/2022 15:00	23/06/2022 04.00	Reliability
UNIT 13	144-24	18/06/2022 15:00	23/06/2022 04.00	Reliability

Source: AEMO

4 Claimant 1's claims for additional compensation

This section presents Clamant 1's additional compensation Claims 1A and 1B in relation to the *directions* received during billing weeks 25 and 26.

4.1 Additional compensation in respect of Claims 1A and 1B

Table 6 presents Claimant 1's Claim 1A additional compensation amount in relation to the administered pricing period (but not market suspension event), calculated in accordance with clause 3.15.7B of the NER.

Table 6 Additional compensation in relation to Claim 1A

Directed unit	Event number	*Direction's* start date/time	Fuel cost (1)	Start cost (2)	Wear and tear cost (3)	Cost of Direction (COD) (1+2+3)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
UNIT 1	129-2	26/03/2022 15:00	$424,262	$38,000	$878	$463,140	$204,918	$199,697
UNIT 2	129-3	26/03/2022 15:00	$638,702	$76,000	$1,268	$715,970	$342,588	$335,560
UNIT 3	129-4	28/03/2022 16:30	$711,111	$114,000	$1,388	$829,499	$417,725	$404,958
UNIT 4	129-5	29/03/2022 16:30	$836,803	$76,000	$1,617	$914,420	$438,099	$429,461
UNIT 5	137-1	29/03/2022 16:30	$91,787	$28,000	$162	$119,950	$72,938	$77,927
UNIT 6	137-2	31/03/2022 16:30	$68,124	$28,000	$162	$96,286	$49,299	$49,299
TOTAL	**N/A**	**N/A**	**$2,770,789**	**$360,000**	**$5,475**	**$3,136,265**	**$1,525,558**	**$1,491,915**

Source: *Directed participant*

Table 7 presents Claimant 1's Claim 1B additional compensation amount relation to the market suspension event, calculated in accordance with clause 3.15.7B of the NER. Effectively, the additional compensation claim amount is the difference between the NER prescribed benchmark generation cost and Claimant 1's estimated direct costs.

Table 7 Additional compensation Claim 1B

Directed unit	Event number	*Direction's* start date/time	Benchmark CO	Benchmark RE	Benchmark compensation BC = CO – RE subject to (CO – RE >0)	Claimant's fuel cost (1)	Claimant's start cost (2)	Claimant's wear and tear cost (3)	Claimant's direct cost of *direction* (COD) (1+2+3)	Additional compensation amount (COD – RE – BC)
UNIT 1	129-2	14/06/2022 8:00	$1,725,468	$2,893,522	-	$5,333,044	$418,000	$10,307	$5,761,351	$2,867,828
UNIT 1	130-27	22/06/2022 04:00	$335,932	$521,480	$1,266,278	$1,023,167	$76,000	$2,107	$1,101,274	$579,794
UNIT 2	129-3	14/06/2022 08:00	$3,726,242	$2,460,014	$1,402,614	$4,861,189	$532,000	$8,779	$5,401, 968	$1,675,726
UNIT 3	129-4	14/06/2022 08:00	$4,394,671	$2,992,056	-	$5,891,973	$570,000	$10,738	$6,472,712	$ 2,078,.041
UNIT 4	129-5	14/06/2022 08:00	$1,403,845	$2,333,636	-	$4,161,193	$494,000	$8,468	$4,663,662	$2,330,025
UNIT 5	137-1	15/06/2022 12:35	-	$319,973	-	$684,238	-	$1,208	$685,446	$365,473
UNIT 5	144-8	17/06/2022 17:40	$1,437,983	$2,335,743	-	$4,661,429	$224,000	$9,593	$4,895,021	$2,559,278
UNIT 6	137-2	15/06/2022 12:35	-	$320,420	-	$685,229	-	$1,210	$686,439	$366,019
UNIT 6	144-9	17/06/2022 17:40	$175,027	$2,142,443	-	$4,792,050	$224,000	$8,246	$5,024,295	$77,450
UNIT 7	130-12	18/06/2022 15:00	$146,583	$4,540,329	-	$8,322,999	$28,700	$16,887	$8,368,586	$2,330,025
UNIT 8	144-10	17/06/2022 19:40	$140,690	$236,053	--	$555,703	$7,500	$922	$564,125	$328,072
UNIT 9	144-11	17/06/2022 19:40	$168,695	$267,562	-	$679,527	$10,000	$1,126	$690,653	$423,090
UNIT 10	144-12	17/06/2022 19:40	$119,571	$202,813	-	$497,624	$7,500	$822	$505,945	$303,132

Directed unit	Event number	*Direction's* start date/time	Benchmark CO	Benchmark RE	Benchmark compensation BC = CO – RE subject to (CO – RE >0)	Claimant's fuel cost (1)	Claimant's start cost (2)	Claimant's wear and tear cost (3)	Claimant's direct cost of *direction* (COD) (1+2+3)	Additional compensation amount (COD – RE – BC)
UNIT 11	144-13	17/06/2022 19:40	$147,347	$224,867	-	$530,329	$7,500	$891	$538,721	$313,853
UNIT 12	144-14	17/06/2022 19:40	$149,571	$249,735	-	$642,550	$10,000	$1,056	$653,606	$403,871
TOTAL	**N/A**	**N/A**	**14,071,625**	**$22,040,650**	**$2,668,842**	**$43,322,244**	**$2,609,200**	**$82,360**	**$46,013,803**	**$17,476,505**

Note: Totals may not sum exactly due to rounding

Source: *Directed Participant*

5 Assessment of Claims 1A and 1B

This section analyses the reasonableness of Claimant 1's two claims under clause 3.15.7B in relation to each component of the additional claimed costs.

5.1 Claim 1A

This additional compensation claim of $1,491,915 relates to the administered pricing period and *direction*s.

5.1.1 Fuel cost

The Claimant used a combination of its open cycle gas turbine (OCGT) and diesel (LNG) generation units to meet the *directions* during the administered pricing period.

Gas fuel

The following formula was applied by Claimant 1 to calculate the additional gas fuel cost for each directed gas generation unit:

- Sum of MWh of generation on gas * Gas fuel cost ($GJ) * Heat rate (GJ/MWh)

The sum of MWh of gas generated was based on settlement date five minute dispatch intervals.

The gas fuel cost was based on contract gas supply for which Claimant 1 has provided the relevant invoice.

Converting the directed megawatts to gas gigajoules using an appropriate heat rate for the directed generation unit provides a reasonably accurate estimate of gas consumed. The assumed heat rate is reasonable based on our benchmarking of the rate using publicly available sources.

Diesel fuel

The Claimant used the same formula as for gas fuel to calculate the additional diesel fuel cost for each directed diesel generation unit:

- Sum of MWh of generation on diesel * Diesel fuel cost ($GJ) * Heat rate (GJ/MWh)

The sum of MWh of gas generated was based on settlement date five minute dispatch intervals.

We understand that the diesel fuel cost was based on the Australian terminal gate diesel price that is publicly available on the Australian Institute of Petroleum web site. We have not been able to fully reconcile the data used in the compensation cost calculation and terminal gate prices at this time. However, we have established broad correspondence between the relevant values. We reserve the right to revise these values following the release of our draft determination in consultation with AEMO and the *directed participant*.

Converting the directed megawatts to diesel gigajoules using an appropriate heat rate for the directed generation unit provides a reasonably accurate estimate of gas consumed. The assumed heat rate is reasonable based on our benchmarking of the rate using publicly available sources.

5.2 Start Costs

Start costs were claimed for most of the *directions*.

Claimant 1 estimated its start costs using the following formula:

- assumed $ per start cost
- apply the $ per start cost to the generation unit in a specific 5 minute trading interval if it was not operating in the preceding trading interval.

The need for the *directions* arose from AEMO's consideration of forecasts of plant dispatch based on forecast demand and the prices that generation was being bid in future periods. As per previous similar determinations, Synergies is satisfied that the directed generating units would not have been in operation during the directed periods but for the *directions*.

Synergies accepts as reasonable the start cost estimates in this claim for additional compensation. We note that these additional claimed costs comprise a relatively small proportion of the additional claimed amount (around $360,000).

5.2.1 Wear and tear costs

Claimant 1's method to calculate the wear and tear costs was as follows:

- assumed $ per MWh rate of wear and tear of the relevant generation unit
- apply the $ per MWh rate to the volume of generation at each 5 minute trading interval (in MWh).

We accept that the wear and costs claimed for all generation units have been reasonably substantiated for this draft determination. We note that these additional claimed costs comprise a very small proportion of the additional claimed amount (around $5,000).

5.3 Claim 1B

This additional compensation claim of **$17,495,191** relates to the market suspension event and *direction*s.

Additional compensation claims under clause 3.14.5B during a market suspension event are calculated using a different methodology to claims made under clause 3.15.7B for the administered pricing period that were assessed in the preceding section 5.2.

The key difference is that market suspension claims are based on calculating the difference between a market suspension benchmark compensation claim (using relevant benchmark values derived under the NER) and the additional compensation claim estimated by the *directed participant*.

However, the additional compensation claim itself is estimated in the same way as for claims made under clause 3.15.7B, with direct costs (and loss of revenue) being the source of the additional costs claimed by the *directed participant*.

5.3.1 Fuel cost

Claimant 1 used a combination of its open cycle gas turbine (OCGT), diesel (LNG) and hydro generation units to meet the *directions*.

Gas fuel

The following formula was applied by Claimant 1 to calculate the additional gas fuel cost for each directed gas generation unit:

- Sum of MWh of generation on gas * Gas fuel cost ($GJ) * Heat rate (GJ/MWh)

The sum of MWh of gas generated was based on settlement date five minute dispatch intervals.

The gas fuel cost was based on a combination of contract gas for which the Claimant has provided the relevant invoice) and spot gas supply at different trading intervals during the *directions*. We have verified the use of spot gas prices in relation to the Victorian Declared Wholesale Gas Market.

Converting the directed megawatts to gas gigajoules using an appropriate heat rate for the directed generation unit provides a reasonably accurate estimate of gas consumed. The assumed heat rate is reasonable based on our benchmarking of the rate using publicly available sources.

Diesel fuel

Claimant 1 used the same formula as for gas fuel to calculate the additional diesel fuel cost for each directed diesel generation unit:

- Sum of MWh of generation on diesel * Diesel fuel cost ($GJ) * Heat rate (GJ/MWh)

The sum of MWh of gas generated was based on settlement date five minute dispatch intervals.

We understand that the diesel fuel cost was based on the Australian terminal gate diesel price that is publicly available on the Australian Institute of Petroleum web site. We have not been able to fully reconcile the data used in the compensation cost calculation and terminal gate prices at this time. However, we have established broad correspondence between the relevant values. We reserve the right to revise these values following the release of our draft determination in consultation with AEMO and the *directed participant*.

Hydro fuel

The following method was applied by the Claimant to calculate the additional hydro fuel costs for each of the *directions*:

- Sum of MWh of generation on diesel * Direct cost ($/MWh)

The direct cost value used in the formula assumes that the electricity generated by the Claimant's three hydro units during the market suspension period (138,000 MW produced) cost them a fixed $/MWh, which is based on some of the highest cost of gas the Claimant used at its gas generation units during this period. The reasons for Synergies not accepting this cost method are discussed in more detail in Section 8 of this draft determination as it has a very large effect on the size of Claimant 1's Claim1C made under clause 3.14.5B. However, removing this component of the direct cost claim for this Claim 1B only reduces the claimed amount by around $78,000.

Based on the evidence provided and the method applied, Synergies accepts the fuel cost claimed due to the *directions* in this draft determination except for the hydro fuel cost, which we consider has been inappropriately calculated using gas fuel cost.

5.4 Start Costs

Start costs were claimed for most of the *directions*.

The Claimant estimated its start costs using the following formula:

- assumed $ per start cost

- apply the $ per start cost to the generation unit in a specific 5 minute trading interval if it was not operating in the preceding trading interval.

The need for the *directions* arose from AEMO's consideration of forecasts of plant dispatch based on forecast demand and the prices that generation was being bid in future periods. As per previous similar determinations, Synergies is satisfied that the directed generating units would not have been in operation during the directed periods but for the *directions*.

Synergies accepts as reasonable the start cost estimates in this claim for additional compensation. We note that these additional claimed costs comprise a relatively small proportion of the additional claimed amount (around $2.6 million).

5.4.1 Wear and tear costs

The Claimant's method to calculate the wear and tear costs was as follows:

- assumed $ per MWh rate of wear and tear of the generation unit
- apply the $ per MWh rate to the volume of generation at each 5 minute trading interval (in MWh).

We accept that the wear and costs claimed for all generation units have been reasonably substantiated for this draft determination. We note that these additional claimed costs comprise a very small proportion of the additional claimed amount (around $82,000).

5.5 Draft determination for Claimant 1's Claims 1A and 1B

5.5.1 Claim 1A

Based on our review, Synergies is satisfied with the Claimant's cost estimation methodologies used to calculate the additional direct costs that it incurred to comply with the *directions* in billing weeks 25 and 26.

Synergies accepts the claimed amount of **$1,491,915**.

5.5.2 Claim 1B

Based on our review, Synergies is not fully satisfied with the Claimant's cost estimation methodologies used to calculate the additional direct costs that it incurred to comply with the *directions* in billing weeks 25 and 26.

Synergies accepts an additional compensation amount of **$17,476,055** compared to the directed participant's claimed amount of $17,495,191.

In accepting this additional compensation amount, Synergies notes that there may also be an error in the *directed participant's* calculation of its claimed amount to the value of $2,668,842 (refer to column BC = CO – RE in Table 6 of this draft determination). The apparent error arises from an assumption that it has already been compensated for this amount in relation to Unit 1 (*Direction* 130-27) and Unit 2 (*Direction* 129-3). However, our understanding from AEMO is that this is not the case. We propose to resolve this matter with the Claimant and AEMO in the development of our final determination.

6 Claims 2A and 23B (Claimant 2)

Claimant 2 has made additional compensation claims in relation to the administered pricing period (Claim 2A - $4,545,696) and market suspension event (Claim 2B - $10,041,235). Each of these claims must be assessed in accordance with clause 3.15.7B of the NER.

6.1 *Claims 2A and 2B*

Table 8 shows the *directions* made to generation units of Claimant 2 between 13 June and 21 June 2022.

Claim 2A relates to the administered pricing period and a single direction affecting a single generating unit. Claim 2B relates to two generation units directed several times during the market suspension period.

Table 8 AEMO's *directions* to the Claimant

Directed unit	Event Number	Issued date/time	End date/time	Reason
CLAIM A				
UNIT 1	127-13	13/06/2022	15/06/2022	Reliability
CLAIM B				
UNIT 2	137-4	15/06/2022 13:20	15/06/2022 13:20	Reliability
UNIT 3	137-8	16/06/2022 8:00	16/06/2022 8:00	Reliability
UNIT 3	144-21	18/06/2022 14.45	18/06/2022 14:45	Reliability
UNIT 2	144-22	18/06/2022 14:45	18/06/2022 14:45	Reliability
UNIT 3	144-27	21/06/2022 19:00	21/06/2022 19:00	Reliability

Source: AEMO

6.1.1 Claim 2A initial compensation (administered pricing period)

As explained in section 2.2, initial settlement compensation is calculated based on the directed participant's compensation entitlement (DCP) minus its retained trading amount (RTA). Initial settlement compensation is determined as DCP minus RTA and included in the Final Billing statement.

DCP is calculated in accordance with Clause 3.15.7(c) of the NER.

RTA, or revenue earned, is calculated in accordance with Clause 3.15.6(b) for the additional energy produced, which would have been included in the Claimant's settlement amount indicated in its Preliminary Billing statement.

6.1.2 Claim 2B market suspension benchmark compensation

As previously noted, additional compensation claims under clause 3.14.5B during a market suspension event are calculated using a different methodology to claims made under clause 3.15.7B for the administered pricing period

The key difference is that market suspension claims are based on calculating the difference between a market suspension benchmark compensation amount (using relevant benchmark values derived under the NER) and the additional compensation amount based on its incurred costs that is estimated by the *directed participant*.

6.1.3 Initial compensation for Claims 2A and 2B

Table 9 presents the initial settlement compensation for Claimant 1's *directions* during the administered pricing period identified above. No initial benchmark compensation has been made in relation to the market suspension *directions*.

Table 9 Initial settlement compensation amounts in administered price period (Claims 2A and 2B)

Directed unit	Event number	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Claim 2A				
UNIT 1	127-13	$118,515	$107,076	$11,439
Claim 2B				
UNIT 2	137-3	-	-	-
UNIT 3	137-4	-	-	-

Source: AEMO

6.1.4 Additional compensation claims in relation to Claims 2A and 2B

Table 10 presents the additional compensation claims for Claims 2A and 2B, which both relate to forecast loss of revenue arising from the *directions* to relevant generation units during the administered pricing period and/or market suspension event.

Table 10 Additional compensation amounts for Claims 2A and 2B

Directed unit	Event Number	Cost of direction (COD) (Loss of revenue)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
Claim 2A				
UNIT 1	127-13	$4,545,696	$118,515	$4,427,181
Claim 2B				
UNIT 2	137-4	$6,919,383	-	$6,919,383
UNIT 2	144-22	$1,524,823	-	$1,524,823

Directed unit	Event Number	Cost of direction (COD) (Loss of revenue)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
UNIT 3	137-8	$1,141,172	-	$1,141,172
UNIT 3	144-21	$37,782	-	$37,782
UNIT 3	144-27	$418,074	-	$418,074

6.2 Assessment of Claims 2A and 2B

This section analyses the reasonableness of Claimant B's two claims under clause 3.15.7B based on estimates of loss of revenue for each claim.

6.2.1 Assessment of Claim 2A

Claimant 2's additional compensation claim is based on calculating a loss of future revenue estimate arising from *directions* to one of its gas generation units during the administered price period and market suspension event.

Claimant B notes that the primary role of the relevant gas generation unit is to monetize and manage the gas transmission pipeline line pack (volume of gas that can be stored in a gas pipeline) after the withdrawal of gas by several industrial customers. There is no access to other markets for this gas, which is served by a single transmission pipeline from gas producer to power station (with laterals for the industrial customers). The generation unit is constrained by its role managing the pipeline.

Claimant 2's methodology to calculate its additional compensation claim is as follows:

- calculate counterfactual revenue that could have been earned if the gas used for generation during the *direction*s was used to generate on 4 and 5 July after the market suspension was lifted, which are the first two subsequent peak days in terms of the electricity spot market price;
- subtract actual revenue earned from generating on 4 and 5 July from the counterfactual revenue to determine the compensation amount; and
- subtract the initial compensation arising from the *directions* from the compensation amount to determine the additional compensation amount.

From a conceptual perspective, subject to an important caveat, we consider that the methodology proposed by the Claimant is reasonable in terms of estimating a potential future loss of revenue arising from the *directions*. However, given the operational constrained characteristics of the pipeline, including gas production constraints and the associated role of the power station in daily managing the gas pipeline flows, we have concerns about the assumption that the loss of revenue estimate should relate solely to the first two peak spot price days of 4 and 5 July 2022 following the lifting of market suspension. This ex-post calculation assumes the Claimant had perfect foresight in having equivalent gas that was used in the *directions* being available for generation on these two peak days in July.

It is not clear to us that this would be a reasonably likely outcome. This is important because the Claimant's gas availability assumption maximises the size of the loss of revenue amount it has claimed. While estimates of forward-looking revenue losses will always have an element of doubt given the future is uncertain, we need the Claimant to provide further substantiation of the likelihood of this favourable outcome for it as opposed to other less favourable potential outcomes resulting in smaller foregone revenue. This could be done by demonstrating historical patterns of operation that would support its contended use of the power station.

Further, in reviewing the supporting information and associated Excel spreadsheet provided by the Claimant, we have a concern that the assumed volume of gas that would have been available for potential future generation (and associated future revenue) if not for the *directions* is an over-estimate.

For these reasons, we do not accept the claimed loss of revenue amount for this draft determination. However, we remain open to revising this assessment if compelling information can be adduced by the Claimant to support its claim.

6.2.2 Assessment of Claim 2B

Claimant 2's additional compensation claim is based on calculating a loss of future revenue arising from *directions* to two of its generation units that are water resource constrained. In other words, its affected generation units were required to run at a time when they would have chosen not to, given the prevailing administered spot market price and given a constrained resource. Rather, the generation units would have run at some future point in time when the spot market price was higher.

In this regard, Claimant 2 notes that its generation units are used as peaking generators that generally run at times of high spot market prices. We accept this characterisation of these units recognising the constrained nature of the generation fuel. Given this characterisation, Claimant 2 has proposed the following alternative ways of estimating its loss of revenue:

- Option 1. Loss of peak cap contract sales
- Option 2. Loss of spot sales at the forward market price
- Option 3. Loss of spot sales at the market price cap.

Of the three options proposed, we consider that either of Options 1 and 2 are reasonable but Option 3 is not less so recognising that the level of the market price cap is such that these units would not have run in the absence of the *directions*.

The Claimant has explained the methodology it has used for each of Options 1 and 2 as follows:

Option 1 methodology

Calculating loss of future revenue based on assumed forward peak cap contracts involves the following steps.

- Calculate the MWh dispatched under direction during the identified events (i.e. the MWh worth of water that the Claimant does not have available to defend sold caps).
- Estimate the number of hours with prices greater than $300 that will occur in Quarter 3 2022 (Q3), based on the maximum of previous corresponding periods in historical data.
- Calculate the number of cap contracts that could not be sold or could not be defended based on the MWh dispatched under direction and the number of hours in which contract capacity would be required.
- Estimate gross revenue associated with these cap contracts, comprising:
  - Contract sale revenue: the Q3 cap price at 23 June 2022 ($38) multiplied by the MW of contracts sold multiplied by hours in quarter; and
  - Under-cap spot revenue: the number of hours of cap cover required multiplied by $300/MWh.

Option 2 methodology

Calculating loss of future revenue based on assumed forward spot market sales involves the following steps:

- Identify the relevant high-priced half hours over Q3 2022 that its two generation units would have otherwise run; and
- Calculate the total cost associated with these half hours.

Loss of revenue is then calculated with reference to the following factors:

- develop projected prices for Q3 2022 by scaling Q3 2021 prices by the Q3 2022 base swap price at 23 June 2022 ($260) less a contract premium (5 per cent).

- determine the volume of generation that the two generation units would have run in Q3 if the water used in *directions* had still been available to the Claimant. This was done by assuming that the two generation units use the MWh dispatch under direction under suspension (adjusted for MWh under the Claimant's control);
- this generation volume is then assumed to capture the forecast projected prices from highest to lowest.[3]

Claimant 2 argues this same methodology has been used to forecast spot prices for the purpose of determining the annual Victorian Default (Electricity) Market Offer for the Essential Services Commission of Victoria. Claimant B also provided Excel spreadsheets in support of its quantification of Options 1 and 2, which we have verified.

Of the two options quantified, Claimant B has proposed Option 2 (forward spot market revenue loss) as the basis of its additional compensation claim. We have no reason to favour Option 1 ahead of Option 2 considering both approaches to be capable of meeting the relevant compensation criteria, with the Option 2 methodology having the desirable attribute of having been accepted in a broadly comparable regulatory setting. On these grounds, we accept the additional compensation claimed amount based on the Option 2 loss of revenue methodology.

6.3 Draft determination

6.3.1 Claim 2A

Based on our review, Synergies requires further substantiation of the operation of Claimant 2's generation unit to accept the methodology it has used to estimate its loss of revenue claim to comply with the *directions* in billing weeks 25 and 26. We will work with the Claimant in finalising our final determination to satisfy ourselves on this issue.

6.3.2 Claim 2B

Based on our review, Synergies is satisfied with Claimant 2's methodology used to calculate the loss of revenue it has claimed it incurred to comply with the *directions* in billing weeks 25 and 26.

Synergies accepts the total claimed amount of **$10,041,235** ($8,444,203 in relation to Unit 2 and $1,597,029 in relation to Unit 3).

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3 Option 3 would be calculated as per Option 2 but instead of using the forward contract prices to assess lost market revenue, the market price cap would be used instead.

Part B – Compensation claims in relation to market suspension period (no *directions*) – Clause 3.14.5B

Summary of NER compensation provisions

Claimant 1 and Claimant 2 have each made claims in relation to the market suspension period when no *directions* were in place.

For any such claims, the NER requires that compensation for a *market suspension claimant* is based on the market suspension benchmark value methodology prescribed in the NER, with any additional compensation claims assessed under clause 3.14.5B.

7 Compensation claims under Clause 3.14.5B

This section sets out the additional compensation claim provisions of clause 3.14.5B of the NER relevant to the market suspension period claims in billing weeks 25 and 26.

7.1 Basis of claims in market suspension period

Clause 3.14.5A establishes the basis for payment of compensation to *market participants* arising from market suspension pricing schedule periods.

Clause 3.14.5A(d) provides that the compensation payable to each *Market Suspension Compensation Claimant* is to be determined in accordance with the formula set out below:

C = CO - RE

where:

C = the amount of compensation the Market Suspension Compensation Claimant is entitled to receive.

CO = the costs the Market Suspension Compensation Claimant is deemed to have incurred during the market suspension pricing schedule period, to be determined in accordance with the formula set out below:

CO = (SOG x BVG) + (MWE x BVAS) + (MWDR x BVDR)

where:

SOG = the sum of the Market Suspension Compensation Claimant's sent out generation (in MWh) during the market suspension pricing schedule period.

BVG = the amount (in $/MWh) calculated in accordance with paragraph (e) below.

MWE = the sum of the relevant market ancillary services (in MW) which the Market Suspension Compensation Claimant's ancillary service generating unit has been enabled to provide during the market suspension pricing schedule period.

BVAS = the amount (in $/MWh) calculated in accordance with paragraph (f) below.

MWDR = the sum of the wholesale demand response settlement quantities of the Market Suspension Compensation Claimant (in MWh) during the market suspension pricing schedule period.

BVDR = the amount (in $/MWh) calculated in accordance with paragraph (f1) below.

RE = the sum of the trading amounts determined pursuant to clauses 3.15.6 and 3.15.6A payable to the Market Suspension Compensation Claimant during the market suspension pricing schedule period,

The benchmark value for generation (BVG) at paragraph (d) is to be determined in accordance with the formula set out below and the market suspension compensation methodology developed under paragraph (h):

BVG = BC(av) x 1.15

where:

BC (av) = the capacity-weighted average of the benchmark costs (BC) (in $/MWh) of all Scheduled Generators in the same class of Generator and same region as the Market Suspension Compensation Claimant, with each benchmark cost to be determined in accordance with the formula below:

BC = (FC x E) + VOC

where:

FC = the fuel cost (in $/GJ) for the relevant Generator.

E = the efficiency (in GJ/MWh) for the relevant Generator.

VOC = the variable operating cost (in $/MWh) for the relevant Generator.

Where C is a negative number, it will be deemed to be zero.

The above compensation formula is subject to the additional compensation claim provisions of clause 3.14.5B.

7.2 Clause 3.14.5B of NER

Clause 3.14.5B provides that a market participant may claim an amount equal to the amount by which its direct costs of supplying energy, market ancillary services or wholesale demand response during the market suspension pricing schedule period exceed the sum of:

- any compensation payable to the Market Suspension Compensation Claimant under clause 3.14.5A (as discussed in the preceding section) with respect to that market suspension pricing schedule period;
- the Market Suspension Compensation Claimant's "RE" as calculated under clause 3.14.5A(d); and

- any other compensation which the Market Suspension Compensation Claimant has received or is entitled to receive in connection with the relevant generating unit supplying energy or market ancillary services or the relevant wholesale demand response unit supplying wholesale demand response during that market suspension pricing schedule period.

Where a Market Suspension Compensation Claimant is a *Directed Participant* with respect to any trading interval during a market suspension pricing schedule period, such Market Suspension Compensation Claimant:

- is entitled to make a claim under clause 3.15.7B(a) regarding *direction*s-related additional compensation claims (refer to section 2.3 of Part A of this draft determination); and
- is not entitled to make a claim under this clause 3.14.5B.

8 Claimant 1's market suspension compensation claims with no *directions* (Claim 1C)

Claimant 1 has made 17 additional individual compensation claims in relation to its various generation units running during the market suspension event (Claim 1C).

Table 9 over page presents the claims and additional compensation claim amount of $37,485,114 that comprise Claim 1C.

8.1 Additional compensation in respect of Claim 1C

Table 11 presents Claimant 1's claimed costs during the market suspension event with no *directions* in place.

Table 11 Summary of additional compensation Claim 1C estimates

Directed unit	Benchmark CO	Benchmark RE	Benchmark compensation BC = CO – RE subject to (CO – RE >0)	Claimant's fuel cost (1)	Claimant's start cost (2)	Claimant's wear and tear cost (3)	Claimant's direct cost (DC) (1+2+3)	Additional compensation amount (DC – RE – BC)
UNIT 1	-	-	-	-	-	-	-	
UNIT 2	-	-	-	-	-	-	-	-
UNIT 3	-	-	-	-	-	-	-	
UNIT 4	-	-	-	-	-	-	-	
UNIT 5	$751,772	$1,058,207	-	$2,109,546	$56,000	$4,572	$2,170,118	$1,111,911
UNIT 5	$85,541	$1,081,380	-	$2,556,897	$84,000	$4,572	$2,645,512	$1,564,132
UNIT 8	-	$287,082	-	$860,878	$5,000	$1,254	$867,132	$580,049
UNIT 9	$44,941	$161,218	-	$464,269	$12,500	$717	$477,486	$316,267
UNIT 10	$40,249	$64,560	-	$143,119	$2,500	$243	$145,863	$81,293
UNIT 11	$74,146	$110,699	-	$260,050	$7,500	$448	$267,999	$157,300
UNIT 11	$6,002	$176,609	-	$519,559	$10,000	$763	$530,321	$353,712
UNIT 12	$792,708	$431,870	$360,838	831811	-	$1,643	$833,454	$40,746
UNIT 13	$1,586,540	$853,961	$732,579	1,600,553	-	$3,288	$1,603,841	$17,302
UNIT 14	$1,594,987	$827,383	$767,605	1,534,384	-	$3,306	$1,537,690	`````-$57,298
UNIT15	$315,999	$9,473,345	-	19,513,310	$70,000	$36,405	$19,619,716	$10,146,371
UNIT 16	$110,823	$3,444,216	-	6,843,444	$25,200	$12,767	$5,596,960	$2,152,744
UNIT 17	$618,688	$17,464,692	-	38,204,987	$209,000	$71,277	$38,485,275	$21,020,583
TOTAL	**$6,022,398**	**35,435,232**	**$1,861,022**	**$75,442,520**	**$482,000**	**$141,256**	**$74,781,367**	**$37,485,114**

8.2 Assessment of Claim 1C

8.2.1 Fuel cost

The Claimant used a combination of its open cycle gas turbine (OCGT), diesel (LNG) and hydro generation units during the market suspension event.

Gas fuel

The following formula was applied by the Claimant to calculate the additional gas fuel cost for each gas generation unit running during the market suspension event:

- Sum of MWh of generation on gas * Gas fuel cost ($GJ) * Heat rate (GJ/MWh)

The sum of MWh of gas generated was based on settlement date five minute dispatch interval.

The gas fuel cost was based on a combination of contract gas for which the Claimant has provided the relevant invoice) and spot gas supply at different trading intervals during the market suspension. We have verified the use of spot gas prices in relation to the Victorian Declared Wholesale Gas Market.

Converting the directed megawatts to gas gigajoules using an appropriate heat rate for the generation unit provides a reasonably accurate estimate of gas consumed. The assumed heat rate is reasonable based on our benchmarking of the rate using publicly available sources.

Diesel fuel

The Claimant used the same formula as for gas fuel to calculate the additional diesel fuel cost for each diesel generation unit running during the market suspension event:

- Sum of MWh of generation on diesel * Diesel fuel cost ($GJ) * Heat rate (GJ/MWh)

The sum of MWh of gas generated was based on settlement date five minute dispatch interval.

We understand that the diesel fuel cost was based on the Australian terminal gate diesel price that is publicly available on the Australian Institute of Petroleum web site. We have not been able to fully reconcile the data used in the compensation cost calculation and terminal gate prices at this time. However, we have established broad correspondence between the relevant values. We reserve the right to revise these values following the release of our draft determination in consultation with AEMO and the *directed participant*.

Converting the directed megawatts to diesel gigajoules using an appropriate heat rate for the generation unit provides a reasonably accurate estimate of diesel consumed. The assumed heat rate is reasonable based on our benchmarking of the rate using publicly available sources

Hydro fuel

The following method was applied by Claimant 1 to calculate the additional hydro fuel costs for each of its hydro units running during the market suspension:

- Sum of MWh of generation on diesel * Direct cost ($/MWh)

The direct cost value used in the formula assumes that the electricity generated by the Claimant's three hydro units during the market suspension event (138,000 MW produced) cost them a fixed $/MWh, which is based on an amalgam of gas prices incurred by the Claimant at its gas generation units during this period.

In choosing to run the hydro generation units during the market suspension event, there are specific provisions in the NER (clause 3.14.5B) about how the Claimant would subsequently be compensated if its direct resource costs exceeded:

- any compensation payable to the *market suspension compensation claimant* under clause 3.14.5A plus
- the revenues it earned from running the hydro units.

In essence, the Claimant has sought to be compensated for the operation of its hydro generation units based on the modelled cost of operating a gas generation unit at that time.

In principle, it is possible that the opportunity cost to a *directed participant* from the directed operation of a hydro resource could be reflected in the fuel costs of substitutable plant. However, on this occasion, the market participant acting without *directions* has sought compensation on the basis that the remuneration it received was insufficient and that it ought to be remunerated for the operation of the hydro plant as if the opportunity cost of doing so was proxied by the modelled fuel costs of substitutable generation plant (in this case gas). In so doing, the *market participant* has not substantiated the basis of its claim for its hydro operations to our satisfaction having regard to all the factors which would have influenced its operational decisions at the time.

Based on the evidence provided by Claimant 1 and the estimation methodology applied, Synergies accepts the fuel costs claimed in this draft determination for its gas and diesel generation units but not the hydro generation units, the latter which we consider has been inappropriately calculated using gas fuel cost.

8.2.2 Start Costs

Start costs were claimed for most of the *directions*.

The Claimant estimated its start costs using the following formula:

- assumed $ per start cost
- apply the $ per start cost to the generation unit in a specific 5 minute trading interval if it was not operating in the preceding trading interval.

Synergies accepts the start cost estimates in this claim for additional compensation. We note that these additional claimed costs comprise a small proportion of the additional claimed amount (around $482,000).

8.2.3 Wear and tear costs

The Claimant's method to calculate the wear and tear costs was as follows:

- assumed $ per MWh rate of wear and tear of the generation unit
- apply the $ per MWh rate to the volume of generation at each 5 minute trading interval (in MWh).

We accept that the wear and costs claimed for all generation units have been reasonably substantiated for this draft determination. We note that these additional claimed costs comprise a very small proportion of the additional claimed amount (around $142,000).

8.3 Draft determination

In this draft determination, the Claimant's additional costs incurred during the market suspension event have not been accepted as claimed and it is entitled to additional compensation of **$4,165,416.**

In not accepting the fuel cost claim in relation to Claimant 1's hydro generation units, we are open to the Claimant providing further support for its calculation methodology having regard to relevant NER requirements.

The Claimant has been informed of the draft determination outcome, our reasons, and the amount of additional compensation accepted.

In accepting this additional compensation amount, Synergies notes that there may also be an error in the *directed participant's* calculation of its claimed amount to the value of $1,861,122 (refer to column BC = CO – RE in Table 11 of this draft determination). The apparent error arises from an assumption that it has already been compensated for this amount in relation to Unit 12, Unit 13 and Unit 14. However, our understanding from AEMO is that this is not the case. We propose to resolve this matter with the Claimant and AEMO in the development of our final determination

9 Claimant 2's market suspension compensation claims with no *directions* (Claim 1C)

This section summarises the circumstances and sets out Claimant 2's compensation claim of $1,643,626 for one of its generation units in relation to the market suspension event made under clause 3.14.5B of the NER (Claim 2C).

9.1 Additional compensation for Claim 2C

Table 12 presents Claimant 2's claimed costs during the market suspension event with no *directions* in place.

Table 12 Compensation amounts in administered price period (Claims A and B)

Directed unit	Benchmark CO	Benchmark RE	Direct cost of fuel (DC)	Retained trading amount (RTA)	Additional compensation (DC – RTA)
UNIT 1	$991,739.02	$1,480,582.16	$3,124,208	$1,480,582	$1,643,626

Claimant 2 argues that the affected gas generation unit draws gas from the Declared Wholesale Gas Market (DWGM) and does not have any fuel storage on site. The cost of gas purchased from the DWGM during the suspension period when converted into electricity exceeded the market suspension price of electricity in the NEM creating the direct cost additional compensation claim under clause 3.14.5B.

9.2 Assessment regarding Claim 2C

Synergies considers that the basis of Claim 3C accords with relevant NER requirements, specifically Clauses 3.14.5A regarding payment of compensation due to the market suspension pricing schedule and 3.14.5B regarding claims for additional compensation for such pricing periods.

Claimant 2 provided Excel spreadsheets in support of its quantification of the additional compensation claim. Synergies has verified these calculations. The average cost of gas implied by the Claimant's calculations is consistent with that prevailing in the DWGM in the relevant period when the gas generation unit was running.

9.3 Draft determination

In this draft determination, the Claimant's additional costs incurred during the market suspension event have been accepted as claimed and it is entitled to additional compensation of **$1,643,626.**

10 Summary of draft determinations

Table 13 summarises the financial outcomes of our draft determination in relation to each of the additional compensation claims that we have assessed.

Table 13 Additional compensation claim draft determination

	Claimed amount	Draft Determination	Difference
Claimant 1			
Claim 1A	$1,491,915	$1,491,915	-
Claim 1B	$17,495,191	$17,476,055	-$19,126
Claim 1C	$37,485,114	$4,165,416	-$33,319,698
Total	***$56,472,220***	***$23,133,386***	***-$33,338,824***
Claimant 2			
Claim 2A	$4,545,696	-	-$4,545,696
Claim 2B	$10,041,235	$10,041,235	-
Claim 2C	$1,643,626	$1,643,626	-
Total	***$16,230,557***	***$11,684,861***	***-$4,545,696***

Source: Synergies based on data provided by Claimants