Synergies
ECONOMIC CONSULTING

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

FINAL DETERMINATION

An independent expert report for AEMO

28 December 2022

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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 final determination on 28 December 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 final determination relates to compensation claims made by the same two *Directed Participants* and *Market Suspension Claimants* in billing weeks 25 and 26 of 2022.

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 final 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 final 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 that 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 final 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 final determination

In the remainder of this final 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 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 final 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* made in billing weeks 25 and 26 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 final 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 in billing weeks 25 and 26 under clause 3.14.5B and our assessment of and final determination on the claims.
- Section 9 provides details of the compensation claims made by Claimant 2 under clause 3.14.5B in billing weeks 25 and 26 and our assessment of and final determination on the claims.
- Section 10 presents the financial outcomes for the two Claimants arising from our final 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 at 18.10 hours on 13 June and ending at 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 at 14.00 hours on 15 June and ending at 23.06 hours 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	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	130-12	18/06/2022 15:00	23/06/2022 20:00	Reliability
UNIT 8	144-10	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 9	144-11	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 10	144-12	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 11	144-13	17/06/2022 19:40	23/06/2022 04.00	Reliability
UNIT 12	144-14	17/06/2022 19:40	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. Effectively, the additional compensation claim amount is the difference between the Claimant 1's estimated additional direct costs arising from the *directions* and its compensation entitlement arising from the *directions*.

Table 6 Additional compensation in relation to Claim 1A

Directed unit	Event number	*Direction's* start date/time	Initial settlement comp (DCP – RTA)	Fuel cost (1)	Start cost (2)	Wear and tear cost (3)	Cost of Direction (COD) (1+2+3)	Retained Trading Amount (RTA)	Additional comp amount (COD – RTA)	Initial settlement comp – Additional comp amount
UNIT 1	129-2	26/03/2022 15:00	$5,220	$424,262	$38,000	$878	$463,140	$258,222	$204,918	$199,698
UNIT 2	129-3	26/03/2022 15:00	$7,019	$638,702	$76,000	$1,268	$715,970	$373,382	$342,589	$335,570
UNIT 3	129-4	28/03/2022 16:30	$12,768	$711,111	$114,000	$1,388	$826,499	$408,773	$417,725	$404,958
UNIT 4	129-5	29/03/2022 16:30	$8,638	$836,803	$76,000	$1,617	$914,420	$476,321	$438,099	$429,461
UNIT 5	137-1	29/03/2022 16:30	-	$91,787	$28,000	$162	$119,950	$47,021	$72,928	$72,928
UNIT 6	137-2	31/03/2022 16:30	-	$68,124	$28,000	$162	$96,286	$46,986	$49,300	$49,300
TOTAL	**N/A**	**N/A**	**$33,644**	**$2,770,789**	**$360,000**	**$5,475**	**$3,136,265**	**$1,610,707**	**$1,525,559**	**$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 arising from the *directions* and Claimant 1's estimated additional direct costs of the *directions*.

Table 7 Additional compensation Claim 1B

Directed unit	Event number	*Direction's* start date/time	Benchmark CO	Benchmark RE	Benchmark comp (BC) = CO – RE if (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	$2,893,523	-	$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		$1,023,167	$76,000	$2,107	$1,101,274	$579,794
UNIT 2	129-3	14/06/2022 08:00	$3,726,242	$2,460,014	$1,266,228	$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	$1,402,614	$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	$2,881,852

Directed unit	Event number	*Direction's* start date/time	Benchmark CO	Benchmark RE	Benchmark comp (BC) = CO – RE if (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 7	130-12	18/06/2022 15:00	$146,583	$4,540,329	-	$8,322,999	$28,700	$16,887	$4,617,779	$77,450
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
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	$149,570	$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**	**$17,553,505**

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 *directions*.

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.

Following release of our draft determination, the Claimant confirmed 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. The *directed participant* has subsequently been able to fully reconcile the data used in the compensation cost calculation and terminal gate prices.

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 final 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.

Following release of our draft determination, the *directed participant* confirmed 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 subsequently been able to fully reconcile the data used in the compensation cost calculation and terminal gate prices.

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 in the period following the end of market suspension. 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 Claim 1C made under clause 3.14.5B. However, adjusting this component of the direct cost claim for our alterative estimation of the fuel component of this Claim 1B reduces the claimed amount by $621,119.

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 final determination. We note that these additional claimed costs comprise a very small proportion of the additional claimed amount (around $82,000).

5.4.2 Initial compensation claim estimate

In making our draft determination, Synergies noted that there may 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 7 of this final determination). The apparent error arose from an assumption that it had already been compensated for this amount in relation to Unit 1 (*Direction* 130-27) and Unit 2 (*Direction* 129-3).

We have subsequently engaged with AEMO to resolve this matter and it has advised us that the Claimant was provided with benchmark compensation in relation to one of its units which generated using a combination of gas and distillate during the market suspension period.

We note that the Claimant's estimate of this benchmark compensation was spread across this Claim 1B (assessed under clause 3.15.7B and Claim 1C (assessed under clause 3.14.5B in Section 8 of this final determination). The Claimant's total estimated benchmark compensation was $4,298,864, which compares to AEMO's higher estimate of $4,335,489, a difference of only $194,375. However, given AEMO's advice that this compensation was provided in relation to a single power station that is not subject to any claims under Claim 1C, we have assumed that the full $4,335,489 benchmark compensation was made in relation to Claim 1B. This has the effect of reducing Claim 1B by $1,666,647 and increasing Claim 1C by $1,861,022 (the initial compensation amount included in the claim).

5.5 Final 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.

Our alterative estimation of the fuel component of this Claim 1B reduces the claimed amount by $621,119. We have also reduced the claim by $1,666,647 to reflect the benchmark compensation paid in relation to relevant units subject to this claim and corrected a small error ($58,314) in the original claim spreadsheet in relation to the trading amount for Unit 1 (Event number 130-27).

Synergies accepts an additional compensation amount of **$15,207,425** compared to the *directed participant's* claimed amount of $17,553,505.

Table 8 summarises our final determination including revised additional compensation amount.

Table 8 Claim 1B final additional compensation amount

Generation unit	Benchmark compensation (BC)	Claimant's direct costs (DC)	Retained Trading amount (RTA)	Additional compensation amount (DC – BC – RTA)
UNIT 1	$1,019,080	$5,761,351	$2,893,523	$1,848,748
UNIT 1	$1,409,056	$1,101,274	$579,794	-$887,576
UNIT 2	-	$5,401,968	$2,460,014	$2,941,954
UNIT 3	$1,907,353	$6,472,712	$2,992,056	$1,573,303
UNIT 4	-	$4,663,662	$2,333,636	$2,330,025
UNIT 5	-	$685,446	$319,973	$365,473
UNIT 5	-	$4,895,021	$2,335,743	$2,559,278
UNIT 6	-	$686,439	$320,420	$366,019
UNIT 6	-	$5,024,295	$2,142,443	$2,881,852
UNIT 7	-	$3,996,660	$4,540,329	-$543,669
UNIT 8	-	$564,125	$236,053	$328,072
UNIT 9	-	$690,653	$267,562	$423,090
UNIT 10	-	$505,945	$202,813	$303,132
UNIT 11	-	$538,721	$224,867	$313,853
UNIT 12	-	$653,606	$249,735	$403,871
TOTAL	**$4,335,489**	**$41,641,877**	**$22,098,963**	**$15,207,425**

Source: Synergies using our and Claimant's data

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 9 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 9 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 10 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 10 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 11 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 11 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.

Draft determination

In our draft determination, we noted that from a conceptual perspective, subject to an important caveat, 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 had 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 was 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, following release of our draft determination, we engaged further with the Claimant who also provided 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 included demonstrating historical patterns of operation of the power station.

Final determination

We have considered the further supporting information provided by the Claimant, including analysing the dispatch profile of the power station in the days prior to 4 and 5 July. This includes AEMO's short term projected assessment of system adequacy (STPASA) forecasts, which on 30 June indicated that winter peak demand in the relevant jurisdiction was expected to be exceeded on 4 and 5 July.

The power station's dispatch profile indicates that notwithstanding good forecast knowledge of the anticipated high value events on 4 and 5 July provided in the STPASA, the Claimant continued to generate on 30 June and 1 July using 12,339 GJ of gas.

It appears the Claimant made the decision to partially reduce dispatch on 1 July and to not dispatch on 2 and 3 July to conserve gas for the expected high demand/price days of 4 and 5 July. It also appears that the reduced dispatch on 1 July may have related to line pack (gas storage) in the gas pipeline serving the power station reaching its 'soft' target level previously determined by the responsible gas producer.

Hence, given the pattern of the Claimant's generation in the leadup to 4 and 5 July, we find it implausible that had it not been subject to the *directions* that all the gas that it consumed in complying with the *directions* would have been available for 4 and 5 July as it asserts. Based on the reduction in line pack available to the Claimant in the period to 1 July, it is more likely that if more line pack had been available, the Claimant would have used gas for generation on 2 and 3 July as it had on the previous 5 days. The generation data indicates that the power station was generating into the evening peaks on each of the previous 5 days despite the STPSA indicating that 4 and 5 July would likely be peak demand days.

Supporting information provided by the Claimant after the release of our draft determination indicates that the actual revenue it earned from generating on 4 and 5 July was $5,730,058 based on generation volume of 2636 MWh and gas consumption of 32,635GJ. This implies an average price received for this generation of $2,174/MWh. In contrast, the counterfactual revenue the Claimant assumes it would have earned had gas been available in the absence of the *directions* and administered price cap event is $13,079,732 using 22,135 GJ of gas to generate 1,786MWh. This implies a notional average price for this generation of $7,322/MWh, around three times greater than the actual average price paid for its generation on 4 and 5 July. It is implausible that prices for the gas burned by the Claimant would achieve several orders of magnitude above those it actually achieved as it is reasonable to expect that the Claimant burned any gas available to it when it perceived it was most valuable to do so.

We consider the actual average price the Claimant earned for its generation on 4 and 5 July provides a reasonable guide to the way it operated the generation unit on these days. While it may have run the unit somewhat differently with more gas if it had been available and it may also have been able to target more peak price intervals to generate during these days with more gas, the difference in the actual and notional average prices of generation noted above is implausible.

As the Claimant's supporting information acknowledges, it does not have perfect foresight and must make bidding decisions in an environment of uncertainty about spot market prices. This suggests that its ability to target the absolute highest price intervals on 4 and 5 July, as it appears to assume it would have done, is highly unlikely given actual revenue that was earned on the day, the latter reflecting the Claimant's trading actions.

We recognise that any assumed profile of how the *directions*-related gas would have been used across the early days of July 2022 is highly uncertain and to an extent speculative other than that expected peak price intervals on any of those days would likely be targeted for generation given the revealed operating profile of the generation unit.

In light of this, we have developed an alternative compensation amount that is less reliant on perfect foresight of peak price intervals and rather pays closer regard to prices achieved by the Claimant for its generation on 4 and 5 July. This means assuming the gas used for generation due to the *directions* is 13,724GJ (based on the Claimant's supporting information) and that it would have been fully used for generation on 4 and 5 July. We have applied the revealed average spot price of $2,174/MWh for these two days to this assumed gas volume converted into 1,108 MWh (based on the Claimant's supporting information).

In making these assumptions, we note that it is not certain that all this gas would have been used on 4 and 5 July given the operation of the generation unit preceding these days in late June and early July. However, we have provided the benefit of the doubt to the Claimant on this matter recognising the importance of preserving incentives for generation units to run when directed.

Applying our assumptions, we calculate an additional compensation claim amount reflecting the Claimant's loss of revenue due to the relevant *directions* as follows:

- Claimant's loss of revenue due to the *directions* = ($2,174/MWh * 1,108 MWh) = $2,408,537
- Initial AEMO compensation (already paid to the Claimant) = $118,515
- Final additional compensation amount = $2,290,022.

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 Final determination

6.3.1 Claim 2A

Based on our review of additional supporting information provided by the Claimant, including the dispatch profile of its power station in the days preceding 4 and 5 July, we have estimated an alternative compensation claim amount of **$2,290,022**, reflecting its loss of revenue arising from complying with *directions* in billing weeks 25 and 26**.**

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).

[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 final 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 12 presents Claimant 1's claimed costs during the market suspension event with no *directions* in place.

Table 12 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 6	$85,541	$1,081,380	-	$2,556,897	$84,000	$4,572	$2,645,512	$1,564,132
UNIT 7	-	$287,083	-	$860,878	$5,000	$1,254	$867,132	$580,049
UNIT 8	$44,941	$161,218	-	$464,269	$12,500	$717	$477,486	$316,267
UNIT 9	$40,249	$64,570	-	$143,119	$2,500	$243	$145,863	$81,293
UNIT 10	$74,146	$110,699	-	$260,051	$7,500	$448	$267,999	$157,300

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 11	$6,002	$176,609	-	$519,559	$10,000	$763	$530,321	$353,712
UNIT 12	$792,708	$431,870	$360,838	$831,811	-	$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	$1,594,988	$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	$12,768	$6,858,712	$3,414,496
UNIT 17	$618,688	$17,464,692	-	$38,204,697	$209,300	$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 final 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 in the period immediately after the market suspension event ended.

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 actual cost of operating its gas and diesel generation peaking units in the month following the market suspension event. It argues that this is consistent with recognition of direct costs to supply energy as set out in clause 3.14.5B and paragraph 3.14.5B(d) of the NER. Specifically, these are direct costs that it reasonably incurred in connection with the relevant (hydro) generating unit, where such costs were subsequently incurred to enable the hydro unit to have supplied energy during the market suspension event.

The Claimant further argues that operating its gas and diesel units was the most economic option available for it to replace the hydro generation that would have been utilised in the period following market suspension to hedge its swap and cap contracts, but it could not as the water had been utilised for generation during the market suspension event.

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 actual fuel costs of substitutable generation plant (in this case gas and diesel).

Based on the initial evidence provided by Claimant 1 and the estimation methodology applied, for our draft determination, Synergies accepted the fuel costs claimed for its gas and diesel generation units but not the hydro generation units.

We have subsequently engaged further with the Claimant in relation to its claim, which resulted in further supporting information being provided for our consideration. Having reviewed the additional information, we accept that the Claimant is resource-constrained due to its water licence and that it had to effectively 'borrow' water from a future period to generate during the market suspension event. Consequently, this water resource constraint has required it to incur 'other' direct costs associated with its gas and diesel peaking units to generate in the period after the market suspension event ended given its need to limit hydro generation output to manage water licence release limits.

The Claimant is seeking compensation for 120,450 MWh of hydro generation output during the market suspension event.[4] It supports this claim with evidence that it consistently offered this capacity into the market in very high prices (above $10,000/MWh price bands). However, we do not believe this evidence to be compelling. Market offers during the market suspension are clearly influenced by the existence and knowledge of the suspension.

Instead, we can be guided by the hydro generation by the Claimant in the weeks that followed the end of market suspension. Applying this average to the market suspension period, the Claimant would have produced 11,230 MWh. We therefore consider that the Claimant's fuel compensation should be based on a lower 109,220 MWh[5].

The Claimant is seeking to be compensated at a calculated fuel cost rate of $536/MWh (representing the actual cost of gas and diesel peaking generation units). We consider this to be the upper limit, being a direct cost calculation associated with the Claimant's own gas and diesel generation units.

An alternative approach would be to use the lower of this calculated direct cost and the spot market price for the same period, on the grounds that it would be more efficient for

4 While the Claimant generated 138GWh of output during the market suspension event, 16,877 MWh relate to *directions* applying to one of its generation units, which are subject to a separate additional compensation claim.

5 120,450 MWh minus 11,230 MWh of hydro generation.

the Claimant to have bought from the spot market in periods where the market price was lower than the calculated direct cost. We concur with this view, while acknowledging the potential for entities with large generation portfolios to alter market price outcomes due to their bidding behaviour.

Recognising that the Claimant was willing to generate in the period following the end of market suspension and to be recompensed at the prevailing spot market prices, we consider that its additional compensation amount should be based on a weighted average market price of $496/MWh based on NSW and Victoria regional reference prices reported in the month following the end of market suspension (24 June to 26 July). In using this figure, we note that it captures spot market prices that were generally below $536/MWh, but for many other days was significantly more than $536/MWh. This approach delivers a better financial outcome for the Claimant than if we had used the lower of the reported average market price and $536/MWh. Our preferred approach recognises the importance of maintaining incentives for generators to continue to supply to the market over time, which we consider is in the long term interest of electricity consumers.

In developing our alternative fuel compensation amount, we have used the $496/MWh estimate in place of the Claimant's $536/MWh direct fuel cost estimate and applied it to 109,220 MWh of hydro generation, which results in a revised fuel cost compensation amount for the hydro units of $54,173,353 compared to the Claimant's $64,561,452 amount (based on its unadjusted generation volume assumption of 120,450 MWh).

Our alternative fuel cost estimate reduces the Claimant's total direct cost claim (fuel plus start plus wear and tear costs) for all generation units from $75,442,520 to $64,393,269 as shown in Table 12 below. No adjustments have been made to the direct cost claims for any of the Claimant's non-hydro units as per our draft determination.

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 final determination. We note that these additional claimed costs comprise a very small proportion of the additional claimed amount (around $142,000).

8.3 Final determination

In this final 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 **$28,958,037.**

Table 13 summarises our final determination including revised additional compensation amount.

Table 13 Claim 1C final additional compensation amount

Generation unit	Claimant's direct costs (DC)	Retained Trading amount (RTA)	Additional compensation amount (DC – RTA)
Unit 1	-	-	-
Unit 2	-	-	-
Unit 3	-	-	-
Unit 4	-	-	-
Unit 5	$2,170,118	$1,058,207	$1,111,911
Unit 6	$2,645,512	$1,081,380	$1,564,132
Unit 7	$867,132	$287,083	$580,049
Unit 8	$477,486	$161,218	$316,267
Unit 9	$145,863	$64,570	$81,293
Unit 10	$267,999	$110,699	$157,300
Unit 11	$530,321	$176,609	$353,712
Unit 12	$833,454	$431,870	$401,584
Unit 13	$1,603,841	$853,961	$749,881
Unit 14	$1,537,690	$827,383	$710,307
Unit 15	$16,479,976	$9,473,345	$7,006,631
Unit 16	$4,495,833	$3,444,216	$1,051,617
Unit 17	$32,338,043	$17,464,692	$14,873,352
TOTAL	$64,393,269	$35,435,232	**$28,958,037**

Source: Synergies using our and Claimant's data

As discussed in section 5.4.2 of this final determination, we have adjusted the initial compensation amount in Table 12 based on advice received from AEMO following the release of our draft determination. Consequently, an amount of $1,861,022, has been added back into the additional compensation amounts for Units 12, 13 and 14 for this Claim 1C.

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

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

Table 14 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 Final determination

In this final 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 final determinations

Table 15 summarises the financial outcomes of our final determination in relation to each of the additional compensation claims that we have assessed.

Table 15 Additional compensation claim final determination

	Claimed amount	Final Determination	Difference
Claimant 1			
Claim 1A	$1,491,915	$1,491,915	-
Claim 1B	$17,553,505	$15,207,425	-$2,346,080
Claim 1C	$37,485,114	$28,958,037	-$8,527,077
Total	***$56,530,534***	***$45,657,377***	***-$10,873,157***
Claimant 2			
Claim 2A	$4,545,696	$2,290,022	-$2,255,674
Claim 2B	$10,041,235	$10,041,235	-
Claim 2C	$1,643,626	$1,643,626	-
Total	***$16,230,557***	***$13,974,883***	***-$2,255,674***

Source: Synergies based on data provided by Claimants