Additional compensation claims arising from AEMO directions during billing weeks 41 to 44, 2023
DRAFT DETERMINATION

An independent expert report for AEMO

22 February 2024

Synergies Economic Consulting Pty Ltd
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1 Introduction

Synergies Economic Consulting (Synergies) was appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine additional compensation claims for two *directed participants* under clause 3.15.7B of the National Electricity Rules (NER) in relation to billing weeks 41 to 44 in 2023.

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 *direction(s)*. For the *directions* relating to billing weeks 41 to 44, the Intervention Settlement Timetable requires that a draft independent expert determination be delivered no later than 22 February 2024 and a final determination by 24 April 2024. This will allow AEMO to complete the intervention settlement process by the required deadlines of 9 May 2024, 16 May 2024, 23 May 2024, and 30 May 2024 for *directions* occurring during billing weeks 41 to 44.

In accordance with the Intervention Settlement Timetable, Synergies is issuing this draft determination on 22 February 2024.[1]

1.1 Structure of the draft determination

In the remainder of this document, we set out the basis of our draft determination regarding additional compensation claims resulting from the *directions* relating to billing weeks 41 to 44 for the two *directed participants* under the NER, as follows:

- Section 2 summarises the circumstances of the *directions* and the additional compensation claim provisions of clause 3.15.7B relevant to the Claims.
- Section 3 provides details of the *directions* made and initial compensation amount determined by AEMO.
- Section 4 provides an overview of the additional compensation amounts claimed by the *directed participants* because of the *directions*.
- Sections 5 presents our analysis of the reasonableness of Claimant 1's additional compensation claim.
- Section 6 presents our analysis of the reasonableness of Claimant 2's additional compensation claim.
- Section 7 provides our draft determination.

[1] All italicised words in this determination are defined terms in the NER (refer Chapter 10 – Glossary).

2 Claims under clause 3.15.7B

This section summarises the circumstances of the *directions* and sets out the additional compensation claim provisions of clause 3.15.7B relevant to the claims.

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 41 to 44 in 2023, AEMO issued several *directions* to two South Australian *market participants* to maintain the system in a secure operating state. In response, the *market participants* modified the operations of their generating units.

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, which sets out compensation based upon:

- the amount of the relevant market service which the *directed participant* has been enabled to provide in response to the *direction*; and
- the 90th percentile price of the relevant market service over the preceding 12 months.

In line with the Intervention Settlement Timetable, AEMO calculated *directed participant* compensation and notified the *directed participant* of the compensation payable under clause 3.15.7.

In addition to the additional compensation claims that we have assessed, several other claims were also made due to the *directions*. However, they were not assessed as part of this determination as any claims under $20,000 are not required to be assessed by an independent expert under clause 3.12.2(l)(2) of the NER.

2.1.1 Managing system strength

Following changes to the NER in 2017[2], the South Australian region's system strength issues (i.e., adequate fault currents) are being and/or will be principally managed by:

- AEMO identifying fault level shortfalls at critical nodes in the network;

[2] AEMC (2017) *National Electricity Amendment (Managing power system fault levels) Rule 2017*, 19 September.

- Transmission Network Service Providers (TNSPs) performing the role of system strength service provider, with responsibility to procure system strength services, including from scheduled generators, to address fault level shortfalls as determined by AEMO; and
- AEMO directing specific scheduled generators to synchronise or remain online where necessary to ensure adequate system strength is maintained.

While these arrangements may in time prove sufficient to ensure system strength requirements are met in the future, the process of TNSPs procuring system strength services remains ongoing[3]. In the meantime, AEMO has been ensuring adequate fault levels are maintained by applying operational procedures regarding permissible combinations of generators. Where the optimal supply solution determined by the NEM dispatch engine (NEMDE) is inconsistent with these permissible combinations, AEMO overrides the solution and directs specific generators to take actions to ensure the permissible combination of generators is operating.

2.2 Clause 3.15.7 of NER

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.[4]
- 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

3 For instance, in South Australia, ElectraNet installed two synchronous condensers at Davenport substation and two at Robertstown substation, all operational from October 2021. See https://www.electranet.com.au/strength-reliability-boost-to-south-australias-electricity-network/

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

delivered or consumed by the *directed participant* had the *direction* not been issued; or

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

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 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 compensation for directed services that has already been determined by AEMO.

The two *directed participants* in this case each have made a claim for compensation for additional net direct costs pursuant to clause 3.15.7B (a)(1) arising from their response to *direction*s issued during billing weeks 41 to 44 in 2023.

3 The directions and initial compensation

This section presents the *directions* and initial settlement compensation made to the two directed *market participants* (Claimants 1 and 2 respectively) seeking additional compensation under clause 3.15.7B (a) of the NER.

3.1 Claimant 1's *directions*

AEMO issued the following *directions* to Claimant 1 between 13 October and 10 November 2023.

Table 1 AEMO's *directions* to Claimant 1

Directed unit	Event Number	Issued date/time	Effective date/time	End date/time	Reason
UNIT 4	395-1	13/10/2023 17:30	13/10/2023 20:00	18/10/2023 17:00	System security
UNIT 2	395-3	13/10/2023 17:30	14/10/2023 07:30	14/10/2023 16:30	System security
UNIT 2	395-4	14/10/2023 16:35	15/10/2023 08:00	16/10/2023 16:00	System security
UNIT 2	395-5	16/10/2023 15:30	17/10/2023 08:00	17/10/2023 16:30	System security
UNIT 2	395-6	17/10/2023 16:00	18/10/2023 08:00	18/10/2023 16:00	System security
UNIT 4	396-2	18/10/2023 17:00	19/10/2023 08:00	19/10/2023 13:00	System security
UNIT 2	397-2	19/10/2023 16:00	20/10/2023 08:00	22/10/2023 15:30	System security
UNIT 2	400-1	23/10/2023 15:00	23/10/2023 21:00	26/10/2023 16:00	System security
UNIT 4	400-3	23/10/2023 14:35	24/10/2023 09:00	24/10/2023 15:30	System security
UNIT 4	402-1	27/10/2023 15:00	28/10/2023 02:00	28/10/2023 17:30	System security
UNIT 4	403-2	28/10/2023 16:00	29/10/2023 07:30	29/10/2023 18:20	System security
UNIT 4	404-1	29/10/2023 16:00	30/10/2023 07:00	31/10/2023 16:00	System security
UNIT 4	405-1	31/10/2023 16:00	01/11/2023 08:00	01/11/2023 17:00	System security
UNIT 4	406-1	01/11/2023 16:00	02/11/2023 07:30	02/11/2023 17:00	System security
UNIT 2	407-1	02/11/2023 14:25	3/11/2023 7:30	06/11/2023 16:00	System security
UNIT 4	407-2	02/11/2023 14:25	03/11/2023 07:00	05/11/2023 16:30	System security
UNIT 2	408-1	06/11/2023 15:30	07/11/2023 08:00	07/11/2023 16:00	System security
UNIT 2	409-1	07/11/2023 15:30	08/11/2023 07:00	08/11/2023 15:30	System security
UNIT 2	410-1	08/11/2023 14:30	09/11/2023 07:30	09/11/2023 14:30	System security
UNIT 3	411-1	09/11/2023 14:30	10/11/2023 07:30	10/11/2023 14:00	System security
UNIT 2	412-1	10/11/2023 16:00	11/11/2023 00:30	11/11/2023 16:30	System security
UNIT 3	412-2	10/11/2023 16:00	11/11/2023 00:30	11/11/2023 18:30	System security

Source: AEMO.

3.1.1 Initial compensation

In accordance with relevant NER provisions noted above, AEMO calculated initial settlement compensation for the above *directions* as summarised in Table 2.

Table 2 AEMO's initial settlement compensation amounts for Claimant 1

Directed unit	Event number	Billing week	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
UNIT 4	395-1	41/42	$861,607	$74,795	$786,812
UNIT 2	395-3	41	$66,428	-$19,185	$85,613
UNIT 2	395-4	42	$235,821	-$5,803	$241,623
UNIT 2	395-5	42	$61,530	$1,069	$60,461
UNIT 2	395-6	42	$57,290	$3,531	$53,758
UNIT 4	396-2	42	$36,099	$2,073	$34,026
UNIT 2	397-2	42/43	$396,400	-$40,755	$437,155
UNIT 2	400-1	43	$482,051	-$48,051	$530,102
UNIT 4	400-3	43	$44,137	-$17,585	$61,722
UNIT 4	402-1	43	$105,856	-$31,071	$136,927
UNIT 4	403-2	44	$77,751	-$51,155	$128,906
UNIT 4	404-1	44	$277,924	-$65,566	$343,490
UNIT 4	405-1	44	$65,324	-$688	$66,012
UNIT 4	406-1	44	$67,749	$6,184	$61,566
UNIT 2	407-1	44/45	$573,551	-$67,290	$640,841
UNIT 4	407-2	44/45	$413,822	-$75,129	$488,951
UNIT 2	408-1	45	$57,182	-$6,048	$63,230
UNIT 2	409-1	45	$61,944	-$5,371	$67,315
UNIT 2	410-1	45	$50,348	$8,260	$42,087
UNIT 3	411-1	45	$40,699	-$7,004	$47,703
UNIT 2	412-1	45	$115,544	-$17,791	$133,335
UNIT 3	412-2	45	$125,542	-$17,439	$142,981

Source: AEMO.

The amount of compensation a *directed participant* is entitled to receive (DCP) is calculated in accordance with Clause 3.15.7(c) of the NER. The Retained Trading Amount (RTA) is calculated in accordance with Clause 3.15.6(b) for the additional energy produced, which would have been included in the settlement amount indicated in the *directed participant's* Preliminary Billing statement. Since invoices are issued weekly and the intervention period spanned four billing weeks, the compensation calculations for all units are presented for each relevant billing week.

Initial settlement compensation is determined as DCP minus RTA and included in the Final Billing statement.

3.2 Claimant 2's *directions*

AEMO issued the following *directions* to Claimant 2 between 18 October and 8 November 2023.

Table 3 AEMO's *directions* to Claimant 2

Directed unit	Event Number	Issued date/time	Effective date/time	End date/time	Reason
UNIT 1	396-1	18/10/2023 17:15	19/10/2023 08:00	19/10/2023 13:00	System security
UNIT 1	397-1	19/10/2023 16:00	20/10/2023 02:00	22/10/2023 15:30	System security
UNIT 1	399-2	22/10/2023 16:10	23/10/2023 08:00	23/10/2023 17:00	System security
UNIT 1	400-2	23/10/2023 15:00	24/10/2023 01:00	24/10/2023 09:00	System security
UNIT 1	400-4	23/10/2023 15:00	24/10/2023 15:30	25/10/2023 21:30	System security
UNIT 1	400-5	25/10/2023 17:30	26/10/2023 07:30	26/10/2023 17:00	System security
UNIT 1	401-2	26/10/2023 17:00	27/10/2023 07:00	27/10/2023 16:30	System security
UNIT 1	402-2	27/10/2023 16:30	28/10/2023 06:00	28/10/2023 17:30	System security
UNIT 1	403-1	28/10/2023 17:00	29/10/2023 07:30	29/10/2023 18:20	System security
UNIT 1	407-3	05/11/2023 16:30	06/11/2023 07:30	06/11/2023 17:00	System security
UNIT 1	408-2	06/11/2023 15:30	07/11/2023 08:00	07/11/2023 16:00	System security
UNIT 1	409-2	07/11/2023 15:30	08/11/2023 07:30	08/11/2023 15:30	System security
UNIT 1	410-2	08/11/2023 14:50	09/11/2023 08:00	09/11/2023 14:30	System security

Source: AEMO.

3.2.1 Initial compensation

In accordance with the above NER provisions, AEMO calculated initial settlement compensation for the *directions* in Table 3, which are summarised in Table 24.

Table 4 AEMO's initial settlement compensation amounts for Claimant 2

Directed unit	Event number	Billing week	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
UNIT 1	396-1	42	$26,647	$1,306	$25,340
UNIT 1	397-1	42	$260,211	-$7,348	$267,559
UNIT 1	399-2	43	$50,942	-$3,243	$54,185
UNIT 1	400-2	43	$45,104	-$14,056	$59,160
UNIT 1	400-4	43	$169,526	-$5,197	$174,723
UNIT 1	400-5	43	$53,796	-$10,948	$64,745
UNIT 1	401-2	43	$53,680	-$11,103	$64,782
UNIT 1	402-2	43	$64,942	-$22,872	$87,814
UNIT 1	403-1	43/44	$61,309	-$39,473	$100,782
UNIT 1	407-3	45	$53,229	-$10,556	$63,785
UNIT 1	408-2	45	$44,806	-$4,625	$49,431
UNIT 1	409-2	45	$44,841	-$4,099	$48,940
UNIT 1	410-2	45	$36,324	$4,969	$31,355

Source: AEMO.

As for Claimant 1, initial settlement compensation is determined as DCP minus RTA and included in the Final Billing statement.

4 Claims for additional compensation

This section presents the *directed participant's* claims for additional compensation in relation to the *directions* received during billing weeks 41 to 44.

4.1 Additional compensation in respect of Claim 1

Table 5 presents the *directed participant's* claimed costs.

Table 5 Summary of additional compensation claim estimates for Claim 1

Directed unit	Event number	Effective date/time	Gas fuel cost	Start cost	Variable operating & maintenance	FCAS	Cost of Direction (COD)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
UNIT 4	395-1	13/10/2023; 20:00	$978,997	$0	$14,130	$762	$993,889	$861,606	$132,283
UNIT 2	395-3	14/10/2023; 07:30	$73,331	$12,729	$1,087	$9	$87,157	$66,428	$20,729
UNIT 2	395-4	15/10/2023; 08:00	$261,307	$12,864	$3,865	$214	$278,250	$235,821	$42,429
UNIT 2	395-5	17/10/2023; 08:00	$70,027	$13,053	$1,027	$13	$84,119	$61,530	$22,589
UNIT 2	395-6	18/10/2023; 08:00	$68,023	$13,032	$966	$8	$82,030	$57,290	$24,740
UNIT 4	396-2	19/10/2023; 08:00	$55,683	$0	$604	$12	$56,299	$36,099	$20,200
UNIT 2	397-2	20/10/2023; 08:00	$477,234	$22,571	$6,703	$459	$506,967	$396,400	$110,568
UNIT 2	400-1	23/10/2023; 21:00	$576,529	$0	$8,092	$526	$585,147	$482,051	$103,096
UNIT 4	400-3	24/10/2023; 09:00	$52,087	$20,659	$785	$6	$73,537	$44,137	$29,400
UNIT 4	402-1	28/10/2023; 02:00	$148,840	$25,290	$1,872	$55	$176,057	$105,856	$70,201
UNIT 4	403-2	29/10/2023; 07:30	$102,466	$0	$1,308	$254	$104,029	$77,751	$26,278
UNIT 4	404-1	30/10/2023; 07:00	$326,419	$0	$3,985	$997	$331,401	$277,924	$53,478
UNIT 4	405-1	01/11/2023; 08:00	$91,980	$0	$1,087	$113	$93,179	$65,324	$27,855
UNIT 4	406-1	02/11/2023; 07:30	$95,333	$0	$1,147	$156	$96,636	$67,749	$28,887
UNIT 2	407-1	03/11/2023; 07:30	$713,065	$33,354	$9,722	$695	$756,837	$573,551	$183,286

Directed unit	Event number	Effective date/time	Gas fuel cost	Start cost	Variable operating & maintenance	FCAS	Cost of Direction (COD)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
UNIT 4	407-2	03/11/2023; 07:00	$506,075	$0	$6,944	$418	$513,437	$413,822	$99,616
UNIT 2	408-1	07/11/2023; 08:00	$83,025	$0	$966	$19	$84,010	$57,182	$26,828
UNIT 2	409-1	08/11/2023; 07:00	$88,517	$0	$1,027	$23	$89,567	$61,944	$27,623
UNIT 2	410-1	09/11/2023; 07:30	$74,842	$0	$845	$16	$75,703	$50,348	$25,356
UNIT 3	411-1	10/11/2023; 07:30	$52,550	$34,570	$785	$14	$87,919	$40,699	$47,220
UNIT 2	412-1	11/11/2023; 00:30	$147,739	$0	$1,932	$51	$149,722	$115,544	$34,178
UNIT 3	412-2	11/11/2023; 00:30	$160,641	$0	$2,174	$57	$162,872	$125,542	$37,330
Total	**N/A**	**N/A**	**$5,204,712**	**$188,123**	**$71,054**	**$4,877**	**$5,468,766**	**$4,274,596**	**$1,194,170**

Source: Claimant 1.

4.1 Additional compensation in respect of Claim 2

Claimant 2 has submitted the following claims for additional compensation for the directions as a *directed participant*.

Table 6 Summary of additional compensation claim estimates in respect to Claim 2

Directed unit	Event number	Effective date/time	Gas fuel cost	Gas transport cost	Start cost	Variable operating & maintenance	FCAS	Cost of Direction (COD)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
UNIT 1	396-1	19/10/2023 08:00	$29,228	$2,757	$26,586	$15,392	$6	$73,968	$26,647	$47,321
UNIT 1	397-1	20/10/2023 02:00	$398,104	$36,079	$0	$190,902	$283	$625,368	$347,967	$277,401
UNIT 1	399-2	23/10/2023 08:00	$63,019	$5,352	$26,586	$27,952	$1,013	$123,922	$50,942	$72,981
UNIT 1	400-2	24/10/2023 01:00	$55,380	$4,775	$26,586	$24,849	$1,142	$112,732	$45,104	$67,628
UNIT 1	400-4	24/10/2023 15:30	$199,606	$17,388	$26,586	$93,054	$251	$336,885	$169,526	$167,359
UNIT 1	400-5	26/10/2023 07:30	$69,383	$5,705	$26,586	$29,494	$31	$131,199	$53,796	$77,403
UNIT 1	401-2	27/10/2023 07:00	$70,320	$5,637	$26,586	$29,493	$1	$132,037	$53,680	$78,357
UNIT 1	402-2	28/10/2023 06:00	$86,554	$6,760	$26,586	$35,698	$21	$155,619	$64,942	$90,677
UNIT 1	403-1	29/10/2023 07:30	$79,155	$6,400	$26,586	$33,639	$30	$145,810	$61,309	$84,501
UNIT 1	407-3	06/11/2023 07:30	$75,469	$5,614	$26,586	$29,458	$0	$137,127	$53,229	$83,898
UNIT 1	408-2	07/11/2023 08:00	$63,258	$4,744	$26,586	$24,816	$0	$119,405	$44,806	$74,599
UNIT 1	409-2	08/11/2023 07:30	$64,973	$4,721	$26,586	$24,831	$5	$121,115	$44,841	$76,275
UNIT 1	410-2	09/11/2023 08:00	$52,912	$3,861	$26,586	$20,159	$6	$103,524	$36,324	$67,200
Total	**N/A**	**N/A**	**$1,307,360**	**$109,794**	**$319,030**	**$579,738**	**$2,788**	**$2,318,710**	**$1,053,112**	**$1,265,598**

Source: Claimant 2.

5 Synergies' assessment regarding Claimant 1's additional compensation claim

This section analyses the reasonableness of Claim 1 and sets out Synergies' draft position on each component of claimed costs.

5.1 Gas cost

The following method was applied by Claimant 1 to calculate the additional gas fuel costs for each of the *directions*:

- The volume of gas used by the directed unit during the *direction* was calculated by taking the directed megawatts of electricity produced by that unit (supported by dispatch data) and applying the relevant heat rate[5] to convert to gigajoules per hour;
  - this provides the gas consumed by the directed unit per hour (divided by twelve to derive per 5-minute trading interval consumption).
- The gas used was sourced from one gas supply contract with the associated price applied to gas transported through two different pipelines (Moomba to Adelaide Pipeline System and SEA Gas Pipeline).[6]
  - Explanation for the approach taken to sourcing gas to meet these *directions* was provided by the Claimant and as such, has been accepted.
  - The gas supply contract price was supported by a copy of the confidential invoice from the relevant gas producer.

Converting the directed megawatts to gas gigajoules using an appropriate relevant heat rate for the directed unit provides an accurate calculation of gas consumed.

Based on the evidence provided and the method applied, Synergies accepts the gas fuel cost claimed due to the *directions* in this draft determination.

5.2 Transportation cost

Claimant 1 did not claim any transport cost relating to daily variations in its forward haul service due to a *direction*.

[5] Heat rate is one measure of the efficiency of electrical generators/powers that convert a fuel into heat and into electricity. The heat rate is the amount of energy used by an electrical generator/power plant to generate one kilowatt hour (kWh) of electricity.

[6] *The Claimant is not claiming additional gas transportation costs in relation to these directions.*

5.3 Variable operating and maintenance (VOM) costs

Claimant 1's method to calculate the VOM costs was as follows:

- A per 5-minute interval VOM cost was calculated based on a historical VOM cost estimate, which was then adjusted for inflation by using an annual inflation rate of 2.50%.
- The VOM rate was applied to every interval that each generating unit was operating under AEMO's *direction*.
- Then, the 5-minute interval VOM costs were summed across the period for which each generating unit was operating under *direction*.

The VOM costs identified by the Claimant relate to the costs driven by the hours of operation of the plant. VOM costs can only be considered avoidable costs (i.e., costs incurred due to the *directions*) if there is clear evidence that the generating units would have been off-line but for the *directions*.

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*.

We accept the VOM costs claimed for all units have been reasonably substantiated for this draft determination, including with supporting documentation.

5.4 Start Costs

Start costs were claimed for most of the *directions* in this claim. The Claimant's method for calculating the start costs is as follows:

- The Claimant identified the start as following a period off-line of 36 hours duration.
- The Claimant then took a historical estimate of the cost of a 'cold' start and adjusted the estimate for inflation by using an approximate annual inflation rate of 2.5%.
- To derive the final start cost, the cost of electricity for internal loads (priced at the average market price over the start-up period) was added to the cost of gas fuel to heat the generator (using the same $/GJ price as that which was claimed for the gas fuel costs).

The costs were supported by confidential data provided by the Claimant. Synergies accepts the start cost estimates in this claim for additional compensation.

5.5 Frequency Control Ancillary Services (FCAS)

The Claimant's method to calculate the additional costs incurred due to its increased Frequency Control Ancillary Service (FCAS) Raise liabilities[7] is as follows:

- The Claimant first determined the total liability of the power station in respect of contingency FCAS Raise services for the relevant period during the gas day of the *direction*.
- The Claimant then determined the contribution of the directed units to the total power station output during the relevant period.
- Next, the generating unit's proportional share of power station output was multiplied by the power station's total FCAS Raise liability for each relevant interval on the gas day.
- Finally, this value was summed for the period.

The Claimant has previously shown workings and detailed FCAS cost assumptions for the power station provided by AEMO. Synergies has verified this data by reviewing the calculations and FCAS Raise unit costs provided by AEMO and as such, accepts the FCAS costs claimed for this draft determination, which we note are immaterial ($4,877).

5.6 Claimant 1 draft determination

Our draft determination in relation to Claimant 1's additional compensation claim is summarised in Table 87. Synergies has accepted all additional compensation claimed.

Table 7 Claimant 1's final compensation amount

Item	Costs claimed	Synergies' draft determination
Gas cost	$5,204,712	$5,204,712
Start costs	$188,123	$188,123
Variable operating and maintenance costs (VOM)	$71,054	$71,054
FCAS costs	$4,877	$4,877
Cost of direction (COD)	**$5,468,766**	**$5,468,766**
Compensation entitlement (DCP)	$4,274,596	$4,274,596
Additional compensation amount (COD - DCP)	**$1,194,170**	**$1,194,170**

Source: Claimant 1, Synergies.

[7] The costs recovered from the Claimant in respect of contingency raise costs, allocated in accordance with the FCAS causer pays formulation.

6 Synergies' assessment regarding Claimant 2's additional compensation claim

This section analyses the reasonableness of Claim 2 and sets out Synergies' draft position on each component of claimed cost.

6.1 Gas fuel cost

The Claimant incurred its gas costs under a gas sales and transportation agreement it has with its related party. The Claimant's method to calculate the additional gas costs was based on the price at which gas was supplied during the *direction* period multiplied by the amount of gas used during that period. The details of the transaction relevant to the *direction* period were contained in a monthly invoice provided by the Claimant.

This monthly invoice contained a break-down of the gas supplied for each day. On several of the days in which a *direction* was made, the Claimant's plant generated electricity both for the *direction* and outside of the *direction*. The invoice did not distinguish between these two uses.

To determine what percentage of the supplied gas was used for each *direction*, the Claimant summed the total number of MWh's generated in the given *direction* period and divided it by the quantity generated by the relevant generating unit for the whole of the day of the direction (this was obtained from AEMO data). This percentage was then multiplied by the total quantity of gas supplied to the generating unit to calculate the amount of gas used for the purpose of the *direction*.

Based on the gas invoice from the gas supplier that was provided by the Claimant, Synergies accept the quantity of gas burned by the Claimant's plant during the *direction*s and the prices at which gas was purchased from the suppliers.

6.2 Transportation cost

The Claimant incurred costs under its gas sales and transportation agreement with its related party noted above. The details of its transportation costs were separately recorded on the invoice provided by the Claimant. These included a cost per unit charge for gas delivery which was multiplied by the amount of gas supplied.

As described in the calculation of gas fuel costs, for several *directions* it was the case that some of the gas delivered on the day of a *direction* was used separately to the *direction*. As such, the same method was used to calculate the gas transport cost for the *direction*. The quantity of gas units transported on a given direction day was multiplied by the percentage of electricity generated for the *direction*.

Synergies accepts both the calculation method and the quantities claimed.

6.3 Frequency Control Ancillary Services (FCAS)

The Claimant incurred FCAS costs as result of the *direction* and calculated these by summing each contingency Raise service that it provided during each of the *directions*. The Claimant's supporting evidence shows FCAS Raise unit costs for the power station incurred during a *direction*, which we have accepted as being reasonable and note are immaterial ($2,788).

6.4 Variable operating and maintenance (VOM) costs

The Claimant incurred variable operating and maintenance (VOM) costs because of the *direction*. The VOM costs comprise fixed dollar per hour of operation and dollar per megawatt generated components. These are assessed in the sections below.

6.4.1 VOM costs ($/hour)

The Claimant's generating units incur wear-and-tear during use that requires it to undertake prescribed maintenance activities after a certain number of hours of operation[8]. The maintenance costs associated with a given maintenance procedure are divided by the number of hours for which the generating unit operates before needing that maintenance procedure. This then is taken to be the maintenance unit cost per hour of operation, expressed in fixed dollar per hour terms.[9]

The Claimant advises that its equivalent operating hours assumption is based on initial manufacturer's recommendation, adjusted to account for the Claimant's maintenance regime informed by:

- the age of the generating unit; and
- actual unit maintenance costs.

Hypothetically, if the plant required a $300,000 maintenance procedure after every 1,000 hours of use and a $1,000,000 procedure after 5,000 hours of use, the equivalent operating hours would be equal to $300,000/1,000 plus $1,000,000/5,000, equalling $500 per hour.

8 The main source of wear-and-tear incurred by a gas generator is the fracturing of the turbine fins caused by the expansion of metal due to changes in temperature. This metal fatigue develops due to frequency of starts and operations and develops more rapidly where the rate of temperature change is faster. Thus, the wear caused by steady operation is less than that associated with starting, stopping, and rapidly accelerating or decelerating.

9 For some maintenance procedures, the trigger may be the production of some cumulative amount of energy and the associated unit cost is derived by the same procedure (cost of procedure/MWh produced between procedures).

The Claimant provided Confidential information on the maintenance cost per hour of operation for Synergies' review.

This supporting information indicates that the Claimant's dollar per operating hour maintenance cost is driven by the major refurbishment cost of the generating unit in 2022/23, divided by the operating hours of the generating unit between 2011 and 2022. We accept the basis of this calculation.

Further, based on information provided by the Claimant, we accept that this hourly maintenance cost is different to the annual maintenance costs associated with the daily operations of the generating unit, which are reflected in the $/MWh VOM cost (discussed in section 6.4.2 below).

Based on our review of the Claimant's supporting evidence, Synergies accepts the claimed $/hour VOM costs.

6.4.2 VOM costs ($/MWh)

The second component of the VOM is calculated on a per megawatt basis. This is determined by the Claimant by dividing the annual maintenance cost that is incurred operating the generation unit (i.e., those maintenance items driven by energy produced), by the annual output of the generation unit. The resulting MWh-based unit cost is then multiplied by the energy produced by the generating unit during each of the *directions*.

Synergies has reviewed the Claimant's supporting evidence and accepts the claimed $/MWh VOM costs.

6.5 Start cost

Each time the generating unit starts, it is assumed that this imposes wear and tear on the unit equivalent to a fixed number of hours of operation.

The Claimant estimates this cost by first using the refurbishment cost estimate from 2022/23 noted in section 6.4.1, which it argues reflects the cost of the hot path components of the generating unit, which are primarily subject to wear and tear (thermal stresses) arising from generating unit starts.

This refurbishment cost estimate is then divided by the original equipment manufacturer-recommended number of equivalent operating hours attributable to start-up of the generating unit.

The Claimant provided confidential information on the start cost calculation for Synergies' review.

Based on the Claimant's supporting evidence, Synergies accepts the claimed start costs.

6.6 Claimant 2 draft determination

Our draft determination in relation to Claimant 2's additional compensation claim is summarised in Table 8. Synergies has accepted all additional compensation claimed.

Table 8 Claim 2 final compensation amount

Item	Additional costs claimed	Synergies' draft determination
Gas cost	$1,307,360	$1,307,360
Gas transport costs	$109,794	$109,794
Start costs	$319,030	$319,030
Variable operating and maintenance costs (VOM)	$579,738	$579,738
FCAS costs	$2,788	$2,788
Cost of direction (COD)	**$2,318,710**	**$2,318,710**
Compensation entitlement (DCP)	$1,053,112	$1,053,112
Additional compensation amount (COD - DCP)	**$1,265,598**	**$1,265,598**

Source: Claimant 2, Synergies.

7 Conclusion

In this draft determination, Claimant 1's additional costs to comply with the *directions* have been accepted as claimed and it is entitled to additional compensation of **$1,194,170**.

Claimant 2's additional costs to comply with the *directions* have also been accepted as claimed and it is entitled to additional compensation of **$1,265,598**.

The *directed participants* have been informed of the draft determination outcome, our reasons, and the amount of additional compensation accepted.