Additional compensation claims arising from AEMO directions during billing weeks 21 to 24
FINAL DETERMINATION

An independent expert report for AEMO

1 December 2021

Synergies Economic Consulting Pty Ltd
www.synergies.com.au

Disclaimer

Synergies Economic Consulting (Synergies) has prepared this report exclusively for the use of the party or parties specified in the report (the client) for the purposes specified in the report (Purpose). The report must not be used by any person other than the client or a person authorised by the client or for any purpose other than the Purpose for which it was prepared.

The report is supplied in good faith and reflects the knowledge, expertise and experience of the consultants involved at the time of providing the report.

The matters dealt with in this report are limited to those requested by the client and those matters considered by Synergies to be relevant for the Purpose.

The information, data, opinions, evaluations, assessments and analysis referred to in, or relied upon in the preparation of, this report have been obtained from and are based on sources believed by us to be reliable and up to date, but no responsibility will be accepted for any error of fact or opinion.

To the extent permitted by law, the opinions, recommendations, assessments and conclusions contained in this report are expressed without any warranties of any kind, express or implied.

Synergies does not accept liability for any loss or damage including without limitation, compensatory, direct, indirect or consequential damages and claims of third parties, that may be caused directly or indirectly through the use of, reliance upon or interpretation of, the contents of the report.

Brisbane
Level 3, 10 Felix Street
Brisbane QLD 4000
P 61 7 3227 9500
F 61 7 3221 0404

Perth
L12, 172 St Georges Terrace
Perth WA 6000
P 61 407 348 612
F 61 7 3221 0404

Sydney
Suite 518, 377 Kent Street
Sydney NSW 2000
P 61 2 8915 6235
F 61 7 3221 0404

Melbourne
Level 10, 440 Collins Street
Melbourne VIC 3000
P 61 3 8692 7272
F 61 7 3221 0404

Darwin
Level 1, 48-50 Smith St Mall
Darwin NT 0800
P 61 419 412 369
F 61 7 3221 0404

W www.synergies.com.au

Contents

Figures and Tables

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 *directed participants* under clause 3.15.7B of the National Electricity Rules (NER) for billing weeks 21 to 24 during the period between 22 May and 10 June 2021.

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. The intervention timetable requires that a draft independent expert determination be delivered no later than 24 September 2021 and a final determination by 1 December 2021. This will allow AEMO to complete the intervention settlement process by the required deadline of 16 December 2021, 23 December 2021, 30 December 2021, and 6 January2022 for directions occurring during billing weeks 21 to 24.

In accordance with the Intervention Settlement Timetable, Synergies is issuing this final determination on 1 December 2021.

1.1 Structure of the report

In the remainder of this report, we set out the basis for our final determination regarding an additional compensation claim resulting from these directions 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 claim;
- Section 3 provides details of the *directions* made and initial compensation determined;
- Section 4 provides an overview of the additional compensation claimed for Claim 1 and Claim 2 as a result of the *directions*;
- Sections 5 and 6 provides our analysis of the additional compensation claim for Claim 1 and Claim 2 respectively; and
- Section 7 provides our final determination.

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.

The companies that have submitted a claim for additional compensation were *directed participants* on several occasions between 22 May and 10 June 2021 for the purposes of clause 3.15.7B. During billing weeks 21 to 24, AEMO issued *directions* (Table 1) to South Australian *market participants* to maintain the system in a secure operating state. In response, the *market participants* modified the operations of its generating units.

As a result of the above 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.

Table 1 Summary of directions

Directed unit	Issue time	Effective date/time	End date/time	Reason
Claim 1				
Unit 1	22/05/2021 16:00	23/05/2021 01:00	23/05/2021 17:00	System strength
Unit 1	23/05/2021 16:00	23/05/2021 21:30	24/05/2021 16:30	System strength
Unit 2	24/05/2021 16:45	24/05/2021 21:00	26/05/2021 12:30	System strength
Unit 2	05/06/2021 17:00	06/06/2021 01:30	06/06/2021 16:45	System strength
Unit 2	06/06/2021 18:00	06/06/2021 21:00	08/06/2021 04:00	System strength
Unit 2	08/06/2021 21:00	08/06/2021 22:00	09/06/2021 15:00	System strength
Claim 2				
Unit 3	06/06/2021 18:30	06/06/2021 21:30	07/06/2021 17:00	System strength
Unit 3	07/06/2021 19:00	07/06/2021 19:30	08/06/2021 04:00	System strength
Unit 3	09/06/2021 18:00	10/06/2021 00:30	10/06/2021 15:30	System strength

Source: AEMO.

In line with the Intervention Settlement Timetable, AEMO calculated *directed participants* compensation and notified the *directed participants* of the compensation payable.

2.1.1 Managing system strength

Following changes to the NER in 2017[1], the South Australian region faces system strength issues (i.e., adequate fault currents) that are being and/or will be principally managed by:

- AEMO identifying fault level shortfalls at critical nodes in the network;
- 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[2]. 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 over-rides the solution and directs specific generators to ensure a permissible combination of generators.

2.2 Clause 3.15.7

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:

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

2 For instance, in South Australia, ElectraNet is in the process of testing and commissioning two synchronous condensers at Davenport substation and two at Robertstown substation (all expected to be in service by the end of August 2021). See https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

- DCP is the amount of compensation the *directed participant* is entitled to receive.[3]
- 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:
  (i) 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
  (ii) 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)

A *directed participant* that is entitled to compensation under clause 3.15.7 and 3.15.7A 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 compensation to cover loss of revenue and net direct costs minus *trading amounts* for *energy* and *market ancillary services* and minus any compensation for directed services that has already been determined.

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

The *directed participants* in this case have made a claim for compensation for additional net direct costs pursuant to clause 3.15.7B (a)(1) arising from their responses to *direction*s issued during billing weeks 21 to 24.

3 The directions and initial compensation

3.1 Claim 1 *directions*

AEMO issued the following *directions* commencing 23 May and ending 9 June 2021.

Table 2 AEMO's *directions* to Claimant 1

Directed unit	Event Number	Issued date/time	Effective date/time	End date/time	Reason
Unit 1	1-1	22/05/2021 16:00	23/05/2021 01:00	23/05/2021 17:00	System strength
Unit 1	2-1	23/05/2021 16:00	23/05/2021 21:30	24/05/2021 16:30	System strength
Unit 2	3-1	24/05/2021 16:45	24/05/2021 21:00	26/05/2021 12:30	System strength
Unit 2	2-1	05/06/2021 17:00	06/06/2021 01:30	06/06/2021 16:45	System strength
Unit 2	3-1	06/06/2021 18:00	06/06/2021 21:00	08/06/2021 04:00	System strength
Unit 2	5-1	08/06/2021 21:00	08/06/2021 22:00	09/06/2021 15:00	System strength

Source: AEMO

3.1.1 Initial compensation

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

Table 3 AEMO's settlement compensation amounts

Directed unit	Event number	Issued date/time	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 1	1-1	22/05/2021 16:00	$42,013	$12,465	$29,549
Unit 1	2-1	23/05/2021 16:00	$49,937	$8,426	$41,512
Unit 2	3-1	24/05/2021 16:45	$104,348	$20,683	$83,665
Unit 2	2-1	05/06/2021 17:00	$43,908	$19,862	$22,324
Unit 2	3-1	06/06/2021 18:00	$85,134	-$6,347	$91,480
Unit 2	5-1	08/06/2021 21:00	$46,163	$14,725	$31,438

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 Preliminary Billing statement. Since invoices are issued weekly and the intervention period spanned two 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 Claim 2 *directions*

AEMO issued the following *directions* commencing 7 June and ending 10 June 2021.

Table 4 AEMO's *directions* to Claimant 2

Directed unit	Event Number	Issued date/time	Effective date/time	End date/time	Reason
Unit 3	3-1	06/06/2021 18:30	06/06/2021 21:30	07/06/2021 17:00	System strength
Unit 3	3-2	07/06/2021 19:00	07/06/2021 19:30	08/06/2021 04:00	System strength
Unit 3	6-1	09/06/2021 18:00	10/06/2021 00:30	10/06/2021 15:30	System strength

Source: AEMO

3.2.1 Initial compensation

In accordance with the above NER provisions, AEMO calculated settlement compensation for the above *directions* as summarised in Table 5.

Table 5 AEMO's settlement compensation amounts

Directed unit	Event number	Issued date/time	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 3	3-1	06/06/2021 18:30	$251,367	-$95,863	$347,230
Unit 3	3-2	07/06/2021 19:00	$110,288	$31,247	$79,041
Unit 3	6-1	09/06/2021 18:00	$193,503	$85,656	$107,847

Source: AEMO

4 Claims for additional compensation

4.1 Additional compensation in respect of Claim 1

Claimant 1 has submitted the following claims for additional compensation for the *directions* received during billing weeks 21 to 24.

Table 6 Summary of additional compensation claim estimates for Claim 1

Directed unit	Event number	Direction date/time	Gas fuel cost (1)	FCAS (2)	Variable operating & maintenance (3)	Cost of Direction (COD) (1+2+3)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
Unit 1	1-1	22/05/2021 16:00	$83,303	$993	$1,941	$86,237	$42,013	$44,224
Unit 1	2-1	23/05/2021 16:00	$100,898	$240	$2,305	$103,442	$49,937	$53,505
Unit 2	3-1	24/05/2021 16:45	$195,000	$1,403	$4,792	$201,194	$104,348	$96,847
Unit 2	2-1	05/06/2021 17:00	$77,762	$392	$1,880	$80,035	$43,908	$36,126
Unit 2	3-1	06/06/2021 18:00	$155,143	$501	$3,761	$159,405	$85,134	$74,271
Unit 2	5-1	08/06/2021 21:00	$83,589	$259	$2,062	$85,910	$46,163	$39,748
Total additional compensation claimed			**$695,696**	**$3,788**	**$16,741**	**$716,224**	**$371,504**	**$344,720**

Note: There may be some small differences due to rounding.

Source: Claimant 1.

4.2 Additional compensation in respect of Claim 2

Claimant 2 has submitted the following claims for additional compensation for the *directions* received during billing weeks 21 to 24.

Table 7 Summary of additional compensation claim estimates for Claim 2

Directed unit	Event number	Direction date/time	Gas fuel cost (1)	Equivalent Operating Hours cost (2)	Transport costs & FCAS (3)	Cost of Direction (COD) (1+2+3)	Compensation entitlement (DCP)	Add. comp amount (COD-DCP)
Unit 3	3-1	06/06/2021 18:30	$239,351	$17,667	$3,168	$260,186	$251,367	$8,819
Unit 3	3-2	07/06/2021 19:00	$124,358	$7,701	$1,679	$133,738	$110,288	$23,450
Unit 3	6-1	09/06/2021 18:00	$203,409	$13,590	$1,076	$218,075	$193,503	$24,572
Total additional compensation claimed			**$567,117**	**$38,958**	**$5,923**	**$611,998**	**$555,158**	**$56,840**

Note: There may be some small differences due to rounding

Source: Claimant 2.

We note that Event 3-1 was not assessed as part of the draft determination as any claims under $20,000 are not required to be assessed by an independent expert under clause 3.15.7B(c)(1) of the NER.

However, the cost estimation approach and findings of our draft determination implicated the costs claim for Event 3-1. Therefore, this claim has been included in our final determination assessment to allow for a consistent assessment across the series of related *direction* events and associated claims.

5 Synergies' assessment regarding Claim 1

This section analyses the reasonableness of the claim and sets out Synergies' final position on each component of claimed cost.

5.1 Gas fuel 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 electrical production by that unit (supported by dispatch data) and applying the relevant heat rate[4] to convert to gigajoules per hour;
  - this provides the gas consumed by the directed unit per hour (divided by two to derive per trading interval consumption).
- The gas used was sourced from two gas supply contracts each with different terms and conditions, including prices, with gas under each contract transported using two different pipelines (Moomba to Adelaide Pipeline System and SEA Gas Pipeline).[5]
- To allocate the total gas consumed by the directed unit to the two gas supply contracts, the proportion of the gas taken from each pipeline for a given trading interval for *all* the generation that occurred across the units was derived.
- The calculated proportion was then applied to the gas consumed by the directed unit to allocate the gas volumes to the relevant gas pipeline contract at each trading interval.

The gas supply contract prices were supported by copies of confidential invoices.

Converting the directed megawatts to gas gigajoules using an appropriate relevant heat rate for the direct unit provides an accurate calculation of gas consumed. Further, allocating the gas consumed to the two gas supply contracts using the total gas sourced proportion provides a reasonable method of allocating the directed unit's gas used to the two different contract prices rather than using a simple average gas supply contract price.

[4] 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.

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

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

5.2 Variable operating and maintenance (VOM) costs

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

- A per 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 2.5%.
- The VOM rate was applied to every interval that each unit was operating under AEMO's *direction*.
- Then, the half hourly VOM costs were summed across the period for which each generating unit was operating under *direction*.

The unit VOM values were supported by a confidential report provided by Claimant 1.

The VOM costs identified by Claimant 1 relate to the operating and maintenance 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 final determination, including with supporting documentation.

5.3 Frequency Control Ancillary Services (FCAS)

Claimant 1'*s* method to calculate the additional costs incurred due to its increased Frequency Control Ancillary Service (FCAS) Raise liabilities[6] is as follows:

- Claimant 1 first determined the total liability of the power station in respect of contingency FCAS Raise services for the relevant time 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.

6 The costs recovered from Claimant 1 in respect of contingency raise costs, allocated in accordance with the FCAS causer pays formulation.

- 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.

Claimant 1's supporting evidence shows 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, allows the FCAS costs claimed for this final determination.

5.4 Claim 1 results

Claimant 1's costs to comply with the *directions* are as claimed in the additional compensation claim and, on this basis, Claimant 1 is entitled to additional compensation of **$344,720**.

6 Synergies' assessment regarding Claim 2

This section analyses the reasonableness of the claim and sets out Synergies' final position on each component of claimed cost.

6.1 Gas fuel cost

The following method was applied by Claimant 2 to calculate the additional gas fuel cost for each of the *directions*:

- The Claimant draws from multiple long term gas supply agreements and 'as needs' gas supply agreements[7] for its operations. Each day, long term gas supply agreements are utilised for the foreseeable gas requirements of the next day's operations (quantities nominated are to meet typical peak requirements). Each long term gas supply agreement, which is nominated on the day before gas is supplied, has Maximum Daily Quantities (MDQs) with associated fixed prices.

- When a *direction* is received, a supply agreement that has been nominated the previous day for 'business as usual' operations cannot be re-nominated to accommodate the gas requirements of the *direction*. As such, the gas used for the *direction* is drawn from the next available gas supply agreement at the time of the *direction*.

- The Claimant uses a 'stacked' approach to estimate the gas fuel costs it incurs to comply with a *direction*. The underlying principle regarding this approach is that the company uses the gas it requires to profitably optimise its operations, that is, the least expensive gas being used first followed progressively by the more expensive gas.

- As such, the *direction* gas is assigned to the next available gas supply agreement after all other commercial uses of the gas are exhausted with it being the most expensive gas used on that day.

- The proportion of gas used for the *direction* is calculated by determining the proportion of electricity (MWh) generated for the purpose of meeting the *direction* relative to the total generation volume (MWh) for that day. This proportion is then multiplied by the total gas purchase volume to meet the *direction*.

[7] Synergies refers to gas supply agreements used for meeting *directions* (e.g., not business as usual operation) as 'as needs' gas supply agreements as these are negotiated as a result of the *direction*, rather than negotiated for a long term supply agreement and planned use.

- The total quantity of gas used for the purpose of meeting the *direction* is then multiplied by the relevant gas supply price generally reflecting gas purchased under 'as needs' contracts (recognising that the long term gas supply agreements have been used for other commercial purposes) to calculate the total cost of gas used in the *direction*.

The Claimant also used line pack gas to meet the requirements of the *direction*. "Line pack" refers to the volume of gas that can be stored in a gas pipeline in order to meet a peak demand of short duration.[8] The line pack gas costs are calculated as a volume weighted average price across all gas supply contracts for the relevant month.

The Claimant provided confidential data and invoices supporting the gas quantities and cost calculations.

6.1.1 Synergies' view

The Claimant has advised that gas required for its whole portfolio of commercial uses is purchased centrally with no internal transfer pricing applied in allocating purchased gas across each commercial use and to meet *directions*.

Use of 'stacked' gas supply agreement approach

In broad terms, the Claimant's gas supply agreements in its 'stacked' gas fuel estimation approach can be grouped into four categories as follows:

1. Several long term gas supply agreements with MDQs and associated fixed prices.
2. A single long term gas supply agreement with a related gas market participant that provides access to gas purchased by the related party through the Declared Wholesale Gas Market (DWGM).[9]
3. Several gas supply agreements that can be negotiated with gas producers on an 'as needs' basis in the context of each *direction*.
4. Line pack gas accessed as necessary in accordance with the Claimant's two gas transportation contracts.

8 The operational implications of line pack mean that the volume of gas injected into a pipeline (at the inlet), can be greater than the volume of gas withdrawn from the pipeline (at the outlet). This frequently occurs due to the unpredictable nature of end-user operations and hence, their gas demand.

9 The DGWM is a wholesale gas market that enables dynamic trading of gas injections and withdrawals from the Declared Transmission System (DTS) both of which are operated by AEMO.

Synergies considers the last three categories described above to be accessed on an 'as needs' basis, such as in the case of a *direction*.

The stacking of the gas supply agreements occurs from low to high prices with fixed prices under the long term gas supply agreements being the lowest, with prices in the stack increasing and becoming variable as gas is purchased on a short term basis, including spot and line pack prices.

An underlying assumption of the stacked estimation approach is that as the Claimant's use of gas becomes less foreseeable, more expensive sources of gas will be used, hence the *direction* is assumed to use the most expensive gas.

To this end, on the day of each *direction*, the Claimant advises that it was operating as commercially intended. At the time of the *direction*, the Claimant had intended to power off, given the prevailing NEM spot market price, however, it was directed to remain online. It was at this point the Claimant was required to source gas from available 'as needs' supply sources (these are described as category 2, 3, and 4 above).

We consider it reasonable that the gas used to meet the *directions* would not have been taken from the existing long term gas supply agreements that are pre-committed to other commercial uses but rather some combination of the 'as needs' gas supply sources.

However, we consider that the Claimant's stacked estimation approach inappropriately assumes that multiple *directions* on the same day will use sequentially more expensive gas under the 'as needs' gas supply agreements that are used to meet all the *directions*. Given the Claimant argues that there is no visibility regarding the source of gas used for each *direction*, we consider that a volume weighted average price across all 'as needs' gas supply agreements used on the day of the *direction* is a more appropriate approach where multiple *directions* occur on the same day.[10]

The use of a weighted average price of all 'as needs' gas supply agreements (including line pack gas) is more likely to provide an incentive for the Claimant to minimise the gas fuel cost of all *directions* on the same day rather than just the first direction of that day.

Gas line pack cost estimate

Regarding the estimated line pack gas price, Synergies notes there is more than one method to calculate the price per gigajoule, in addition to the Claimant's use of a volume weighted average price across all gas supply contracts for the relevant month. This includes:

---

[10] We note where there is only one *direction* occurring on the day, there is no difference in the value derived using a volume weight average approach and the Claimant's stacked model approach.

- applying a price that reflects the actual cost of injecting the gas back into the pipeline (replacement cost approach);
- applying a trailing average actual cost based on gas taken out and put back into the pipeline over the relevant month (trailing average approach); or
- estimating the opportunity cost of the next best alternative use of the gas taken from the line pack (opportunity cost approach).

The use of the volume weighted average price across all supply contract prices is the simplest of these approaches and is likely to provide a reasonable estimate of the line pack cost, on average, over time. Hence, in practice, there will be times when the other approaches will result in a higher or lower cost estimate primarily dependent on the spot gas prices applying when gas is re-injected into the pipeline. However, we consider the additional administrative costs associated with estimating the alternative approaches is likely to outweigh the benefits of potentially more precise estimates in the context of assessing additional compensation claims. On these grounds, we accept the Claimant's line pack cost, which has been substantiated with documentation from the Claimant's accounting system.

Revised gas fuel cost estimate

Based on our assessment of the Claimant's gas fuel estimation approach, we find that using a volume weighted price of the 'as needs' gas supply agreements assumed to be required for the *direction* is a better approach to account for the uncertainty of exactly which gas supply source is used to meet multiple *directions* occurring on the same day.

Our amendment to the 'stacked' estimation approach preserves the Claimant's view that additional gas fuel costs are incurred due to *directions* and that must be met through accessing gas under some least cost combination of 'as needs' gas supply agreements that are available to it.

Our revised gas fuel costs are shown in the table below.

Table 8 Summary of additional compensation claim estimates for Claim 2

Directed unit	Event number	Direction date/time	Gas fuel cost (Claimed)	Gas fuel cost (Synergies)	Difference
Unit 3	3-1	06/06/2021 18:30	$239,351	$246,655	$7,304
Unit 3	3-2	07/06/2021 19:00	$124,358	$111,655	-$12,702
Unit 3	6-1	09/06/2021 18:00	$203,409	$199,863	-$3,545
Total			**$567,117**	**$558,173**	**-$8,944**

Note: There may be some small differences due to rounding.
Source: Synergies.

6.2 Transportation cost

The following method was applied by Claimant 2 to calculate the additional transport costs for the *directions*:

- Transport costs were claimed for *directions* occurring on 6 and 7 June 2021 (but not on 9 June 2021) with the gas taken from the pipeline classified as 'authorised overrun service' for 6 June *direction* and 'unauthorised overrun' for 7 June *direction*. The volumes and costs are supported by a confidential invoice.
- To find the transport costs relevant to the *direction*, the total gas volume transported and charged for that day was multiplied by the proportion of generation (and therefore gas required) attributable to the *direction* relative to total generation for that day (as calculated for gas fuel costs above).
- The unauthorised overrun service tariff is the rate that is charged when a user takes gas from the pipeline without pre-planning or authorisation from the pipeline operator. The authorised overrun service tariff is the rate that is charged when a user requests to take gas from the pipeline and receives authorisation from the pipeline operator to do so.
- Gas is assumed to be taken from the pipeline on an 'unauthorised overrun' basis where gas volumes under the firm MDQ (pre-purchased transport) contractual arrangement have already been allocated to other commercial uses and authorisation from the pipeline operator is not received. As such, to meet the requirements of the *direction*, gas is taken notwithstanding the relatively high unauthorised overrun tariff.
- On 7 June 2021, the *direction* required generation (and therefore gas supply) over and above the commercial operation on the day, and as a result required 'overrun' gas taken from the pipeline which was in this case authorised. Noting that gas is at times accessed on an 'authorised overrun' basis for commercial operations, the authorised overrun transport costs were apportioned accordingly to the proportion of gas volume used for the *direction and for commercial operations*.
- Further, in alignment with minimising transportation costs, the Claimant assumes the gas is taken from the pipeline which provides more flexibility and has the lowest overrun cost. The price per gigajoule is supported by a confidential invoice.

In this final determination, Synergies accepts the claimed pipeline transport costs on the grounds that it is reasonable to assume, absent the *direction*, gas would not have been required, which triggered the need to access gas under the unauthorised and authorised overrun tariffs charged by the pipeline operator.

6.3 Frequency Control Ancillary Services (FCAS)

Claimant 2's method to calculate the additional costs incurred due to its increased Frequency Control Ancillary Service (FCAS) Raise liabilities[11] is as follows:

- FCAS Charges means the share of FCAS contingency raise charges allocated to the Claimant in accordance with AEMO's procedures for recovering ancillary service costs and as set out in AEMO's Settlement Report for billing week 24 (FCAS Charges).
- The amount of these charges for each gas day has been calculated by AEMO and provided to the Claimant.
- The Claimant summed the FCAS provided for each gas day relevant to the *direction*. Where more than one *direction* occurred on the same gas day, the Claimant applied the relevant portion of directed volume for the two directions to the total FCAS for that gas day.

In this final determination, Synergies accepts this calculation method and the resulting costs claimed.

6.4 Equivalent operating hours (EOH)

Incremental maintenance costs in connection with the generating units are explicitly recognised as a head of compensation under clause 3.15.7B(a3)(2). These are measured in equivalent operating hours (EOH).

The Claimant incurred such costs valued at a cost per EOH, based on whole-of-life major inspection costs to 2033 in $2021. The assumptions underlying these figures include costs for parts from contractual documentation, outage costs, and costs based on historical estimates. The cost per EOH is then multiplied by operating hours attributable to the *direction*, which is supported by dispatch data.

Based on the evidence provided, Synergies accepts the costs claimed for EOH.

6.5 Claim 2 results

Based on our above assessment, the revised additional compensation claim for Claim 2 is as follows.

---

11 The costs recovered from Claimant 2 in respect of contingency raise costs, allocated in accordance with the FCAS causer pays formulation.

Table 9 Unit 3 (6 June 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$239,351	$246,655	$7,304
Equivalent Operating Hours (EOH) cost	$17,667	$17,667	$0
Other costs (transportation costs & FCAS)	$3,168	$3,168	$0
Cost of Direction (COD)	$260,186	$267,489	$7,304
Compensation entitlement (DCP)	$251,367	$251,367	$0
Additional compensation amount (COD-DCP)	**$8,819**	**$16,123**	**$7,304**

Source: Claimant 2, Synergies.

Table 10 Unit 3 (7 June 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$124,358	$111,655	-$12,702
Equivalent Operating Hours (EOH) cost	$7,701	$7,701	$0
Other costs (transportation costs & FCAS)	$1,679	$1,679	$0
Cost of Direction (COD)	$133,738	$121,036	-$12,702
Compensation entitlement (DCP)	$110,288	$110,288	$0
Additional compensation amount (COD-DCP)	**$23,450**	**$10,748**	**-$12,702**

Source: Claimant 2, Synergies.

Table 11 Unit 3 (9 June 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$203,409	$199,863	-$3,545
Equivalent Operating Hours (EOH) cost	$13,590	$13,590	$0
Other costs (transportation costs & FCAS)	$1,076	$1,076	$0
Cost of Direction (COD)	$218,075	$214,530	-$3,545
Compensation entitlement (DCP)	$193,503	$193,503	$0
Additional compensation amount (COD-DCP)	**$24,572**	**$21,026**	**-$3,545**

Source: Claimant 2, Synergies.

In total, Claimant 2 is entitled to additional compensation of **$47,896**.

7 Conclusion

In this final determination, Synergies concludes:

- Claimant 1's costs to comply with the *directions* are as claimed in its additional compensation claim and, on this basis, Claimant 1 is entitled to additional compensation of **$344,720**.
- Claimant 2 has incurred costs as a result of the directions and based on our different approach to calculating its gas fuel costs, we determine Claimant 2 is entitled to additional compensation of **$47,896.**

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