Additional compensation claims arising from AEMO directions on 4 and 16 December 2020 - FINAL DETERMINATION

An independent expert report for AEMO

May 2021

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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 a *referred directed participant* in the National Electricity Market (NEM), (the Claimant) under clause 3.15.7B of the National Electricity Rules (NER).

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 19 April 2021 and a final determination by 18 June 2021. This will allow AEMO to complete the intervention settlement process by the required deadline of 1 July 2021.

Following the publication of our draft determination on 20 April 2021, Synergies received additional information from the Claimant relevant to our evaluation of its compensable costs for gas. We have considered this information in forming our final determination.

In accordance with the Intervention Settlement Timetables for the 4 and 16 December 2020 Directions, Synergies is issuing this final report on 27 May 2021.

1.1 Structure of the report

In the remainder of this report, we set out the basis for our final determination regarding additional compensation resulting from these directions under the NER, as follows:

- Section 2 summarises the circumstances of the directions and sets out 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 determined by AEMO;
- Section 4 provides an overview of the claims made for additional compensation by the Claimant as a result of the *directions*;
- Section 5 provides our analysis of the additional compensation claims in relation to the *directions*; and
- Section 6 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 company that has submitted a claim for additional compensation was a *directed participant* on 4 and 16 December 2020 for the purposes of clause 3.15.7B.

Between 4 and 16 December 2020, AEMO issued *directions* to South Australian Market Participants to maintain power system security – summarised in Table 1. In response, the *Claimant* modified the operations of three of its generating units to respond to AEMO's *directions* and in turn incurred costs.

Table 1 Summary of the relevant South Australia directions on 4 and 16 December

Direction	Directed participant	Issue time	Directed Unit
80688	Direction	11:31 hrs, 04/12/2020	Unit A, Unit B
80928	Cancellation	03:54 hrs, 08/12/2020	Unit A, Unit B
81270	Direction	17:49 hrs, 16/12/2020	Unit C
81506	Cancellation	17:23 hrs, 20/12/2020	Unit C

Source: AEMO.

As such, as a *directed participant*, the Claimant was entitled to compensation under clause 3.15.7, 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.

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:

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

- AEMO identifying fault level shortfalls at critical nodes in the transmission 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.

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:

- 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:

(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

2 For instance, in South Australia, ElectraNet plans to commission the first two of four planned synchronous condensers at the Davenport substation in mid-2020 and a second two at the Robertstown substation by the end of 2020. They will be commissioned by early 2021. See https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

3 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)

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.

The *directed participant* has made a claim for compensation for additional net direct costs pursuant to clause 3.15.7B (a)(1).

3 The *directions* and initial compensation

3.1 4 December 2020 *direction*

The Claimant submitted initial and modified additional compensation claim estimates to AEMO in relation to the 4 December 2020 *direction*. The modified additional compensation claim incorporated a revised gas cost methodology, which was accepted by AEMO.

3.1.1 Details of the *directions*

AEMO issued the following *directions* to the Claimant on 4 December 2020.

Table 2 AEMO's direction on 04 December 2020

Directed unit	Event Number	Issued date/time	Effective datetime	End datetime	Reason
Unit A	1-1	11:00 hrs, 04/12/2020	22:30 hrs, 04/12/2020	04:00 hrs, 08/12/2020	System strength
Unit B	1-1	11:00 hrs, 04/12/2020	01:30 hrs, 05/12/2020	13:30 hrs, 07/12/2020	System strength

Source: AEMO

3.1.2 Initial compensation

In accordance with the above NER provisions, AEMO calculated settlement compensation for the 4 December 2020 direction as summarised in Table 3

Table 3 AEMO's settlement compensation amounts in respect of 4 December 2020 directions

Directed unit	Event number	Billing week	Final billing statement	DCP	Retained trading amounts (RTA)	Settlement compensation (DCP – RTA)
Unit A	1-1	49	04/01/2020	$68,089	-$7,363	$75,452
Unit A	1-1	50	11/01/2020	$142,214	-$73,388	$215,602
Unit B	1-1	49	04/01/2020	$58,876	-$10,417	$69,294
Unit B	1-1	50	11/01/2020	$100,311	-$62,300	$162,611

Source: AEMO

DCP is calculated in accordance with NER Clause 3.15.7(c). The Retained Trading Amount (RTA) is calculated in accordance with NER 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 both units are presented in two parts – one for each relevant billing week.

Provisional Settlement Compensation is determined as the amount of compensation the directed participant is entitled to receive (DCP) minus RTA and included in the Final Billing statement.

3.2 16 December 2020 direction

The Claimant also submitted initial and modified additional compensation claim estimates to AEMO in relation to the 16 December 2020 direction.

3.2.1 Details of the *directions*

AEMO issued several *directions* on 16 December 2020 requiring the provision of system strength services. Compensation was payable to multiple *Market Participants*. AEMO issued the following direction to the Claimant on 16 December 2020:

Table 4 AEMO's direction on 16 December 2020

Directed unit	Event Number	Issued date/time	Effective datetime	End datetime	Reason
Unit C	1-1	18:00 hrs, 16/12/2020	1:30 hrs, 17/12/2020	17:30 hrs, 20/12/2020	System strength

Source: AEMO

3.2.2 Initial compensation

In accordance with the above NER provisions, AEMO calculated settlement compensation for the 16 December 2020 *direction* as follows:

Table 5 AEMO's settlement compensation amount in respect of 16 December 2020 direction

Directed unit	Event number	Billing week	Final billing statement	DCP	Retained trading amounts (RTA)	Settlement compensation (DCP – RTA)
Unit C	1-1	51	18/01/2021	$188,091	$32,033	$156,058
Unit C	1-1	52	22/01/2021	$46,710	$14,304	$32,406

Source: AEMO

4 The claims for additional compensation

4.1 Additional compensation in respect of 4 December 2020

The Claimant has submitted the following claims for additional compensation for the 4 December 2020 *directions* as a *directed participant*.

Table 6 Claimant's additional compensation claim estimate in respect of *directions* of 4 December 2020

Item	Unit A Cost	Unit B Cost
Gas at a blended cost for the period	$235,003	$186,461
Start cost	$12,017	N/A
Variable and operating maintenance (VOM)	$9,401	$7,279
Contingency raise recovery cost	$747	$706
Cost of Direction (COD)	$257,168	$194,446
Amount of compensation (DCP)	$210,303	$159,187
Additional compensation (COD – DCP)	**$46,865**	**$35,259**

Source: The Claimant.

4.2 Additional compensation in respect of 16 December 2020

The Claimant has submitted the following claims for additional compensation for the 16 December 2020 direction as a *directed participant*.

Table 7 Claimant's additional compensation claim estimate in respect of *direction* of 16 December 2020

Item	Unit C Costs
Gas at a blended cost for the period	$283,449
Start cost	N/A
VOM	$0
Contingency raise recovery cost	$1,167
Cost of Direction (COD)	$284,616
Amount of compensation (DCP)	$234,801
Additional compensation (COD – DCP)	**$49,815**

Source: The Claimant.

4.3 Total additional compensation claimed

Table 8 Summary of total additional compensation claimed

Unit	Direction date	Total additional compensation claimed
Unit A	4 December 2020	$46,865
Unit B	4 December 2020	$35,259
Unit C	16 December 2020	$49,815
TOTAL		**$131,939**

4.4 Additional information from Claimant

Following discussions with the Claimant after the draft determination, a number of additional relevant facts were ascertained.

4.4.1 Whether the gas prices reflected efficient costs

In our draft determination, Synergies observed that it appeared the cost of the gas used to comply with the *directions* could have been lower, had all the required gas been sourced from the Claimant's gas pipeline contract with the lower price (gas supply for the affected generation units is sourced via two different pipelines under two different contracts).

During the period for which they were directed, the three directed units consumed on average slightly less than 80 per cent of their gas from the cheaper of the two contracts. In our draft determination, we noted that it was not clear why any of the gas had been sourced from the more expensive of the contracts.

Continuous supply under both supply contracts

The Claimant advised that it operates the power station maintaining a degree of redundancy in the fuel supply by continually taking gas supply from two pipelines, whenever possible. This is part of the reason why gas is continuously observed to be drawn from both contracts during the *direction* and not solely from under the cheapest of the two contracts.

Practical considerations related to gas trading

The Claimant advised that its gas traders allocate gas (and hence contractual gas costs) to individual delivery points based on portfolio-wide considerations and some broad operational considerations pertinent to individual off-take points.

The gas trading desk is afforded limited visibility of the wholesale electricity market and the operating outlooks facing individual generating units and power stations within the

Claimant's portfolio. The gas traders simply receive a forward estimate of gas requirement based on market conditions – primarily the day-ahead pre-dispatch forecast. The gas requirements to meet a direction are not included in this forecast which limits the time permitted to optimise incremental gas procurement.

Further, the quantity of gas in question was small compared to the Claimant's wider gas portfolio. It is reasonable to expect that broad optimisation rules would apply where a relatively small tranche of the portfolio is concerned. That such allocation rules may fail to perfectly achieve lowest cost supply under abnormal conditions – such as in the circumstance of a direction – is perhaps also unsurprising.

The information "air-gap" between the gas and electricity business units has the benefit of reducing the potential for conflicts of interest to arise, such as the possibility that higher cost portfolio gas might be over-allocated to a generating unit that was known to be subject to a direction (and hence assured of cost recovery). The downside of this arrangement is that there is limited or no forward planning (from the gas trader's perspective) regarding the procurement of gas to satisfy *directions*. The resulting gas procurement and allocation strategy may, as a consequence, be less than perfectly efficient in terms of minimising the cost of complying with a *direction*.

4.4.2 Opportunity cost of the gas

Synergies noted in its draft determination that one of the two contracts under which gas was supplied, was a take-or-pay contract, raising questions over whether part or all of the gas supplied under it should be treated as a sunk cost.

Not a sunk cost

The Claimant confirmed that it had the flexibility to take receipt of the gas at delivery points besides the generation units in question. The Claimant's gas trading desk allocates gas from its portfolio to a wide range of delivery points throughout the day, having scope, in theory, to allocate gas to its highest value uses (internal to the business) on any given day across multiple regions in the NEM.

Alternative value of the gas

The actual or implied market value of the gas (i.e., its true opportunity cost) has not been established. However, the fact that the quantity of gas in question was small compared to the size of the Claimant's wider gas portfolio and that it was available to be re-allocated to a wide range of alternative delivery points, suggests that the contract prices should be considered a reasonable estimate of this opportunity cost.

5 Synergies' assessment of the claims

This section analyses the reasonableness of the Claimant's additional compensation claim and sets out Synergies' final position on each component of the claim.

5.1 Gas costs

5.1.1 Calculation method

The claimant's method to calculate the additional gas costs is as follows:

- The claimant derived a weighted average gas price by combining gas supplied under two gas contracts according to the total gas taken under each contract and the price set for each contract.
- The claimant then recorded the contribution of the relevant generating unit to the total power station output, based on target outputs[4].
- The generating unit's proportional share of total power station output was multiplied by the power station's total gas consumption for that interval from under each of the two gas pipeline contracts.
- Finally, the generating unit's total allocated quantity of gas was multiplied by the average gas price across both contracts.

In its draft determination, Synergies replicated this analysis but used a slightly different approach of using the separate gas contract prices and calculating generator unit proportional shares of the gas supplied in each contract for each interval. This gives a slightly different result in the case of generating Unit A and Unit C and better reflects the intent of the NER, in our view.

The Claimant's method produces small distortions in the allocation of gas costs between generating units, where the relative share of consumption varies between intervals. Our method avoids this, by calculating the quantities under each contract separately before applying the contract specific price and repeating this for each interval. The differences between the two approaches are modest, as shown in Table 9.

[4] While we are unclear as to why this calculation should use target instead of actual outputs, the choice of input makes limited difference for the final result.

Table 9 Summary of total gas costs claimed versus Synergies' estimate

Unit	Direction date	Total gas cost (as claimed)	Total gas cost (Synergies calculation)	Difference
A	4 December 2020	$235,003	$233,160	-$1,842
B	4 December 2020	$283,449	$280,336	-$3,113
C	16 December 2020	$186,461	$186,461	$0

The Claimant's supporting evidence provides copies of invoices from a gas supplier for each of the two contracts.

5.1.2 Quantity of gas burned

Following further communications with the Claimant by email and telephone, Synergies established that the gas quantities were actual quantities measured at the power station's gas blending station, which mixed gas supplied from the two sources before the blended gas is delivered to the generating units. On this basis, we accept that the Claimant's calculation method accurately reflects the actual quantities of gas burned in the relevant generating units.

5.1.3 Gas drawn from two contracts

Prior to our draft determination, the claimant advised that the gas supply agreements impose different terms of service, in addition to having different gas prices. The more expensive of the two contracts is subject to a minimum daily take-or-pay quantity. For this reason, despite taking most of their gas from under the cheaper supply contract, the generating units were always drawing some amount of gas from the more expensive of the two contracts. Synergies accepts this as a commercially reasonable arrangement and accepts the evidence provided as to the price of gas supplied.

Noting that one of the gas pipeline contracts is subject to minimum daily quantities, Synergies had advised the Claimant that it would need more information before it could allow the costs arising under this contract to be included among the compensable costs. In particular, it was necessary to establish what alternative uses the contracted gas could have been put to, had the Claimant not been directed in the manner it was.

5.1.4 An avoidable cost

Based on the information provided by the Claimant subsequent to publication of our draft determination, Synergies has concluded that the tranche of gas consumed from take-or-pay contract (which is also the more expensive of the two contracts) should be regarded as an avoidable cost.

The Claimant confirmed that it had the flexibility to take receipt of the gas at delivery points besides the power station in question, which is a necessary precondition for considering that the gas costs were avoidable, but for the *direction*.

5.1.5 Regarding the actual opportunity cost of the gas

Synergies has concluded that the contract price of the gas take-or-pay contract provides an acceptable estimate of the actual opportunity of the gas. The Claimant was not able to demonstrate what the value of the gas would have been in its next best alternative use, however, the fact that the quantity of gas in question was small compared to the size of the Claimant's wider gas portfolio and that it was available to be re-allocated to a wide range of alternative delivery points, suggests that the contract prices should be considered a reasonable estimate of this opportunity cost.

5.1.6 Regarding whether the Claimant should have used cheaper gas

Synergies has concluded that the full cost of gas incurred at its power station to comply with the directions should be compensated, notwithstanding that the gas costs allocated to the directed units during the direction may not have been the lowest possible cost.

We note that market participants are not obliged to minimise their costs under the NER in complying with a *direction*. However, we consider that the claim for additional compensation must be evaluated in the expectation that costs which appear to be higher than might have been expected should be supported by a reasonable explanation.

In the case of allocated costs, we are mindful of the risk, actual or perceived, that a *directed participant* might present to AEMO a statement of its costs that allocates to the directed plant its highest cost procurement options, so as to maximise its claim for additional compensation. That the Claimant derived a portion of the gas needed to comply with the direction from a more expensive gas contract, was an observation that warranted investigation for that reason.

We accept that, in the face of contractual constraints, it may be a reasonable gas trading strategy to continuously use some portion of more expensive gas in one's fuel mix, where the gas is supplied under a take-or-pay arrangement. In theory, and depending on the terms of the contract in its totality, one may be able to reduce overall fuel costs by delaying the consumption of take-or-pay gas while the cost of alternatives is low. This approach will depend on having a reasonably accurate forecast of gas demand and prices.

Based on the additional information summarised in section 4.4, Synergies accepts that the Claimant's gas supply strategy during the directions was subject to information constraints that reduced its ability to source gas at lowest theoretical cost. In view of the Claimant's gas demand information constraints, we think it reasonable to assume that the gas allocated to the directed units during the direction was allocated in good faith.

Further, we accept that it is desirable that the Claimant maintain redundancy in the gas supply to the power station at which the directed units operate. To the extent that this may slightly increase the fuel costs of complying with *directions*, we think it is a cost that the market should reasonably bear given the considerable benefit for system security that derives from ensuring that generating plant providing system strength services face a very low probability of fuel supply interruptions.

In conclusion, Synergies has decided to recognise as compensable the full cost of gas burned at the facility during the *direction*s of 4 December and 16 December 2020, noting that we have adjusted the value of this gas, by applying our preferred calculation method.

5.2 Start costs

The Claimant's method to calculating the start costs was as follows:

- The claimant identified the type of start as being a cold start following a period offline of duration greater than 90 hours.
- 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 fuel to heat the generator (priced at the same weighted average price used for the gas costs).

The costs were supported by a confidential report provided by the Claimant.

In this final determination, Synergies confirms it accepts the start cost estimates, calculated using the blended gas price method used by the Claimant in its claim for additional compensation.

5.3 Variable operating and maintenance (VOM) costs

The claimant's method to calculate the VOM costs is as follows:

- A per interval VOM cost was calculated based on a historical estimate and 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 the Claimant.

The Claimant revised its claim in respect of Unit A and Unit B and in this updated claim for these two units the VOM cost item is set out, although it had been absent from the initial claim. The claim for Unit C was not updated further following the re-submitted claim for Unit A and Unit B. Thus, for Unit C, the claim makes no mention of VOM costs. This appears to have been an oversight.

The VOM costs identified by the Claimant 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 as a result of the *directions*) if there is clear evidence that the generating units would have been off-line but for the *directions*. The need for the direction 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. AEMO advises that it is reasonable to conclude that Unit A, Unit B and Unit C would not have been operating during the period in which they were subject to the *directions*, but for those *directions*.

On the basis of the above, we confirm that we agree with the inclusion of VOM costs for Unit A and Unit B and consider that VOM costs should also be included for Unit C.

We calculated the VOM costs for Unit C by assuming the same per interval cost demonstrated by the Claimant in its claim for Unit A and Unit B and multiplying this by the number of intervals that Unit C was operating under AEMO's *direction*s.

5.4 Contingency raise costs

The Claimant's method to calculate the additional costs incurred as a result of its increased Frequency Control Ancillary Service (FCAS) raise liabilities (i.e., the costs recovered from the Claimant in respect of contingency raise costs, allocated in accordance with the FCAS causer pays formulation) is as follows:

- The Claimant first determined the total liability of the power station in respect of contingency FCAS Raise services (i.e., to pay for 6-second, 60-second and 5-minute FCAS raise services).

- The Claimant then determined the total contribution of the units to the total power station output during the relevant period, based on target outputs[5].
- Next, the generating unit's proportional share of power station output was multiplied by the power station's total FCAS raise liability for that interval.
- Finally, this value was summed for the period.

The Claimant's supporting evidence shows workings and detailed FCAS cost assumptions for the power station. Synergies has not verified these data by collecting FCAS raise unit costs from the market independently, since the values are small.

In our draft determination, we found this methodology appeared reasonable, subject to the figures reflecting a correct interpretation of the FCAS cost allocation rules (which we have not assessed because the FCAS costs constitute a very minor component of the total costs). We remain of this view and therefore, for our final determination, Synergies has decided to allow this element of the compensation claim.

5.5 Results

Our assessment of the Claimant's total claimed costs is summarised in Table 10.

Our modifications to the calculation approach for gas (in the case of Unit A and Unit C) and VOM (adding this cost for Unit C) produces a small reduction in the value of the relevant costs in the case of Unit A, a small increase in the case of Unit C and no change in the relevant costs for Unit B compared to those claimed. We note that overall, these reductions are minor and amount to less than one percent of the Claimant's estimated total costs. Our addition of an allowance for VOM costs for Unit C more than offsets the reductions due to our recalculation of gas costs.

Table 10 Summary of compensable costs as re-calculated and determined by Synergies

Component	Unit A	Unit B	Unit C
Directions period	4/12/2020	4/12/2020	16/12/2020
Total costs presented by Claimant	$257,168	$194,446	$284,616
Costs calculated by Synergies			
Gas costs **(a)**			
Contract 1 (variable)	$171,549	$141,659	$166,473
Contract 2 (take or pay)	$61,611	$44,802	$113,862
Total	$233,160	$186,461	$280,336

5 While we are unclear as to why this calculation should use target instead of actual outputs, the choice of input makes little difference for the final result.

Component	Unit A	Unit B	Unit C
FCAS costs	$747	$706	$1,167
Start costs	$12,017	$0	$0
VOM costs	$9,401	$7,279	$10,675
Total compensable costs recognised by Synergies	$255,325	$194,446	$292,178
Change relative to claim	-$1,842	$0	$7,562
DCP (all billing periods)	$210,303	$159,187	$234,801
Additional compensation	$45,022	$35,258	$57,377
Total determined additional compensation			**$137,658**

(a) Gas costs are as recalculated by Synergies (see Section 5.1).

Source: Synergies analysis

In our draft determination, we had assumed that the gas consumed under the take-or-pay contract was a sunk cost that could not otherwise be offset by the Claimant. As discussed above, for our final determination we conclude that the gas consumed under the take-or-pay contract was not a sunk cost, but instead an avoidable cost and that the opportunity cost of using the gas to comply with the *directions* can reasonably be assumed to be equal to its contract value.

Therefore, we have determined to allow all of the gas costs claimed, subject to our recalculations. This has raised the Claimant's total compensable costs above the DCP amounts for all three units resulting in a compensation shortfall of **$137,658**. This amount is around $6,000 greater than the amount claimed – being the balance of reductions in compensable costs due to the modified method for calculating gas costs and an increase in compensable costs for Unit C, due to Synergies' inclusion of an amount for VOM costs.

6 Conclusion

In the draft determination, Synergies formed the preliminary view that no additional compensation was payable. In forming this view, we allowed that the Claimant may be able to provide additional information to satisfy us that certain disallowed fuel costs were avoidable and could be attributable to the *directions*.

Following the draft determination, the Claimant provided additional information that permitted Synergies a more detailed understanding of the nature of the Claimant's fuel costs during the *directions*. Based on this additional information and our further consideration of the facts of the *directions*, our final determination is that additional compensation of $137,658 is payable.

The *directed participant* has been informed of these final determinations, the reasons for them, and the amount of compensation.