NEM EVENT - DIRECTION TO SOUTH AUSTRALIA GENERATOR - 9 FEBRUARY 2017

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IMPORTANT NOTICE

Purpose

AEMO has prepared this report in accordance with clause 3.13.6A(a) of the National Electricity Rules (NER), using information available as at 30 June 2017, unless otherwise specified.

This report uses several terms that have defined meanings in the NER. They have the same meanings in this report.

All references to time in this report are based on Australian Eastern Standard Time (AEST).

Disclaimer

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1. PURPOSE

As described in clause 4.8.9 of the National Electricity Rules (NER), AEMO is permitted to intervene in the market and issue ‘directions’ and ‘clause 4.8.9 instructions’ to Registered Participants, if satisfied it is necessary:

- To maintain or re-establish the power system to a secure, satisfactory or reliable operating state.
- For reasons of public safety or otherwise for the security of the power system.

Where AEMO intervenes in the market through the issue of directions, AEMO must, in accordance with NER clause 4.8.9(f) and 3.13.6A (a), publish a report on the circumstances of the direction, the processes followed and its impact on dispatch outcomes.

This report meets those NER obligations.

2. SUMMARY

At 1505 hours on 9 February 2017, AEMO issued a direction to Pelican Point Power Pty Ltd (ENGIE) to synchronise and dispatch Pelican Point unit GT12 to minimum load (Direction). The Direction was issued under clause 4.8.9 of the NER to maintain the power system in a reliable operating state in South Australia (SA).

A Forecast Lack of Reserve level 2 (LOR2) condition had been declared in the SA region for trading intervals between 1600 hours and 1800 hours. A sufficient market response was not received by the latest time to intervene, at 1500 hours.

The Direction was cancelled at 1900 hours, when the LOR2 condition no longer existed and the minimum run time for GT12 was completed.

3. BACKGROUND

On 9 February 2017, the temperature in Adelaide reached a peak of 39.4˚C at 1700 hours. SA demand reached a peak of 3,041 MW at 1830 hours. Wind generation in SA was low, ranging between 182 MW and 385 MW between 1600 hours and 1900 hours.

All Pre-dispatch Projected Assessment of System Adequacy (PDPASA) runs from 2130 hours on 8 February until the Direction at 1505 hours on 9 February forecast LOR2 conditions in SA between 1700 hours and 1830 hours on 9 February.

AEMO issued a number of market notices on 8 and 9 February advising the market of the forecast LOR2 conditions and requesting a market response.

Given the forecast tight supply-demand situation on 9 February, AEMO contacted all Scheduled Generators with thermal generating units in SA on 8 February to confirm their availabilities in PDPASA for the next day, and to ask whether any additional capacity was available for direction (with associated start-up and minimum run times).

The 1500 hours PDPASA run (produced at 1430 hours) on 9 February forecast an LOR2 condition in SA between 1600 hours and 1800 hours. AEMO determined the latest time for intervention was 1500 hours, in the absence of sufficient market response.

At 1505 hours, AEMO issued the Direction to ENGIE to synchronise and dispatch GT12 at Pelican Point power station to its minimum load (of 160 MW). Pelican Point power station consists of two combined cycle gas turbines, GT11 and GT12, and a steam turbine (ST18). Prior to the Direction, GT12 was offline and the combined output from GT11 and ST18 was 214 MW.

The Direction was implemented as follows:

I. Dispatch intervals (DIs) ending between1510 hours and 1545 hours:
   - GT12 was in the process of synchronising.
   - GT11 and ST18 continued to generate at a combined output of less than or equal to 214 MW.

II. DIs ending between 1550 hours and 1610 hours:
   - GT12, after synchronisation, increased generation to 54 MW.
   - Combined output from GT11 and ST18 reduced from 214 MW to minimum load of 160 MW. This was due to a counter-action instruction issued by AEMO to GT11.

   The Direction was implemented in this way so that the combined output from the power station (summated output of GT11, GT12 and ST18) would equal 214 MW during this period.

III. DIs ending between 1615 hours and 1900 hours:
   - GT12 increased generation from 54 MW to minimum load of 160 MW.
   - Combined output from GT11 and ST18 continued at minimum load of 160 MW.

The Direction was implemented as above during this period so that the combined output from the power station (summated output of three units) would equal 320 MW during this period[1].

AEMO also issued counter-action instructions to two other SA Generators. Mintaro gas turbine output was reduced from 69 MW to its minimum load of 30 MW and two Dry Creek generating units were reduced from a combined output of 75 MW to their combined minimum load of 10 MW.

The counter-action instructions aimed to minimise the market impact of the Direction, as required by clauses 3.8.1(b)(11) and 4.8.9(h)(3) of the NER. The reduction in generation due to the counter-action amounted to 158 MW[2], similar to the directed amount of generation of 160 MW[3].

Although the reduction in generation due to counter-action was similar to the increased generation due to the Direction, it had the advantage of ensuring generation availability from five generating units (Pelican Point GT11, Pelican Point GT12, Mintaro, Two Dry Creek units), with their additional generation capacity (from their minimum load to maximum capacity) being available to meet the increasing demand. This additional capacity was sufficient to alleviate the LOR2 condition.

AEMO cancelled the forecast LOR2 condition in SA at 1600 hours since the lack of reserve condition had been resolved by the action taken to comply with the Direction.

The Direction was cancelled at 1900 hours, after the minimum run time of four hours for GT12.

4. NER COMPLIANCE WITH THE INTERVENTION PROCESSES

4.1 Circumstances giving rise to the need for the directions

The Direction was issued following forecasts of lack of reserve (LOR) conditions in the SA region.

[1] 320 MW is the summation of the minimum load (160 MW) for both combined cycle GTs (CCGTs), GT11 and GT12.

[2] Reduction in generation due to counter-action = 54 MW (reduction in generation by GT11+ST18 prior to 161 hrs) + 69 MW – 30 MW (reduction in generation by Mintaro) + 75 MW – 10 MW (reduction in generation by two Dry Creek GTs) = 158 MW.

[3] The Directed amount of generation = 54 MW (increase in generation by GT12 prior to 1615 hrs) + 320 MW (total output from power station at 1900 hrs) – 214 MW (Output from power station at 1615 hrs) = 160 MW.

The 1300 hours PDPASA run on 8 February forecast an LOR1 condition in SA between 1630 hours and 1900 hours on 9 February. AEMO issued market notice MN 57268, declaring the LOR 1 condition.

The 2130 hours PDPASA run on 8 February forecast an LOR2 condition in SA between 1700 hours and 1830 hours on 9 February. AEMO issued market notice MN 57290, declaring the forecast LOR2 condition.

After declaring the forecast LOR2 condition, AEMO contacted all Scheduled Generators with thermal generating units in SA to confirm their availabilities in PDPASA for 9 February. AEMO also enquired about the availability of additional generation capacity for direction.

Only Pelican Point power station indicated additional capacity (GT12) was available for direction, with a start-up time of 1 hour, run to minimum load time of 30-45 minutes and a minimum run time of four hours.

All PDPASA runs between 2130 hours on 8 February and 1500 hours on 9 February continued to forecast LOR2 conditions in SA between 1700 hours and 1830 hours on 9 February.

4.2 AEMO's determination that a market response would not have avoided the direction and the determination of the latest time for issuing the direction

Under NER clause 4.8.5A(a) and (c), AEMO must notify the market of an anticipated power system security or reliability issue and the latest time for a market response to address that issue before AEMO would use directions to intervene in the market.

AEMO issued a number of market notices on 9 February[4] to update the market on the lack of reserve conditions and determinations on the latest time to intervene. All market notices requested market response to alleviate the lack of reserve conditions.

The market notices issued on the morning of 9 February, namely MN 57295, MN 57307 and MN 57313, indicated the latest time to intervene (LTTI) would be between 1330 hours and 1430 hours.

The 1500 hours PDPASA run (produced at 1430 hours) on 9 February forecast an LOR2 condition in SA between 1600 hours and 1800 hours. Taking into consideration the minimum synchronisation time of 1 one hour for GT12 of Pelican Point power station, AEMO made a determination at 1449 hours that the LTTI would be 1500 hours. Market Notice MN 57319 was issued advising the market about the LTTI determination and that of AEMO's intends intention to intervene in the market if sufficient market response was not achieved by 1500 hours.

[4] MN 57295, 57307, 57308, 57313, 57318, 57319, 57320

The 1530 hours PDPASA run (produced at 1500 hours) continued to forecast the LOR2 conditions.

Since sufficient market response was not achieved by 1500 hours to alleviate the lack of reserve conditions, AEMO intervened in the market by issuing a Direction.

4.3 Processes implemented by AEMO to issue the Direction

AEMO followed its relevant procedures for the management of the Direction on 9 February 2017, being System Operating Procedure SO_OP 3707 “Intervention, Direction and Clause 4.8.9 Instruction”, section 5[5].

The procedure requirements are summarised below, together with a description of the process AEMO followed in relation to each requirement.

I. *Publish a Market Notice of the possibility that AEMO might have to issue a direction or clause 4.8.9 instruction so that there is an opportunity for a response from Registered Participants to alleviate that need.*

   AEMO published four market notices on 9 February, namely MN 57295 (0328 hours), MN 57307 (1049 hours), MN 57313 (1320 hours) and MN 57319 (1449 hours) seeking market response to alleviate the LOR2 conditions and advising about the possibility of intervention if sufficient market response was not achieved.

II. *Determine and publish the latest time for intervention.*

   Details of the estimated LTTIs in each of the market notices published by AEMO on 9 February indicating the possibility of intervention are listed below.

   - Market Notice MN 57295 issued at 0328 hours indicated an LTTI of 1430 hours.
   - Market Notice MN 57307 issued at 1049 hours indicated an LTTI of 1330 hours.
   - Market Notice MN 57313 issued at 1329 hours indicated an LTTI of 1400 hours.
   - Market Notice MN 57319 issued at 1449 hours (last prior to the Direction) indicated an LTTI of 1500 hours.

III. *Determine which Registered Participant should be the subject of a direction or clause 4.8.9 instruction.*

   In anticipation of the tight supply-demand situation on 9 February, AEMO contacted all Scheduled Generators with thermal generating units in SA on 8 February to determine

[5] http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3707---Intervention-Direction-and-Clause-4-8-9-Instructions.pdf

their availability for direction. Only ENGIE confirmed additional capacity would be available for direction. It was therefore the only Registered Participant that could readily be directed to provide additional generation (GT12).

IV. *If a direction is to be issued, if reasonably practicable, the determination will aim to minimise the effect on interconnector flows and minimise the number of Affected Participants.*

To minimise the effect on interconnector flows and the number of affected participants, AEMO issued counter-action instructions in respect of four generating units, such that the reduction in generation due to the counter-action (158 MW) would be similar to the increase in generation due to the Direction (161 MW).

V. *Issue a direction or clause 4.8.9 instruction verbally to the relevant Registered Participant, confirming whether it is a direction or clause 4.8.9 instruction.*

AEMO control room logs indicate a verbal direction was given to ENGIE at 1505 hours for Pelican Point GT12 to synchronise and dispatch to minimum load.

VI. *Issue a Participant Notice confirming the direction or clause 4.8.9 instruction.*

AEMO issued a participant notice PN 57310 to ENGIE at 1517 hours advising of a direction under clause 4.8.9 of the NER.

VII. *Issue a Market Notice advising that AEMO has issued a direction or clause 4.8.9 instruction.*

AEMO issued market notice MN 57312 at 1517 hours advising the market that a direction under clause 4.8.9 of the NER had been issued.

VIII. *Revoke the direction or clause 4.8.9 instruction as soon as it is no longer required.*

AEMO revoked the Direction and counter-action instructions at 1900 hours, once the minimum run time for GT12 had been completed.

4.4 Basis for AEMO not following any or all processes under clause 4.8 prior to direction

AEMO considers that it followed all applicable processes under NER clause 4.8 for this Direction.

4.5 Effectiveness of responses to AEMO inquiries under clause 4.8.5A(d)

As noted in 4.1, AEMO contacted all Scheduled Generators with thermal generating units in SA on 8 February to determine their availability for direction on 9 February. All contacted Generators other than ENGIE confirmed that all of their capacity had already been made available for 9 February, and there was no additional capacity available for direction.

AEMO is satisfied that all generators responded to the inquiries made under 4.8.5A(d) in a timely manner.

4.6 Notice from Registered Participants of inability to comply with the direction

No indication was received from ENGIE under NER clause 4.8.9(d) that it would be unable to comply with the Direction.

5. DETERMINATION OF WHETHER TO APPLY INTERVENTION PRICING UNDER CLAUSE 3.9.3(B)

Under NER clause 3.9.3(b), AEMO must set the *dispatch price* and *ancillary service prices* for an *intervention price dispatch interval* at the value which AEMO, in its reasonable opinion, considers to have applied for that dispatch interval in the relevant region had the intervention event not occurred (intervention pricing).

AEMO's relevant procedures for intervention pricing are:

- Power System Operating Procedure SO_OP 3705 "Dispatch", section 10[6]
- Intervention Pricing Methodology[7].

Under NER clause 3.9.3 (f)(2), AEMO should determine and publish the prices that apply during a period of intervention in accordance with the Intervention Pricing Methodology developed in accordance with clause 3.9.3(b).

Section 10 of SO_OP 3705 "Dispatch" requires AEMO to do the following:

I. *In accordance with NER Clause 3.9.3(a), "In respect of a dispatch interval where an AEMO intervention event occurs AEMO must declare that dispatch interval to be an intervention price dispatch interval".*

   AEMO issued market notice MN 57316 at 1517 hours to:

   - Declare an AEMO intervention event commenced at DI ending 1510 hours and is forecast to apply till 1900 hours; and
   - Declare all DIs during the AEMO intervention event to be intervention price dispatch intervals.

   This market notice advised that Intervention Pricing may be implemented during these intervention price dispatch intervals and that AEMO would provide an updated market notice once intervention pricing has been implemented in dispatch.

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[6] http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705---Dispatch.pdf

[7] https://www.aemo.com.au/-/media/Files/PDF/Intervention-Pricing-Methodology-October-2014.pdf

AEMO issued market notice MN 57321 at 1552 hours (as an update to MN 57316) to:

- Advise Intervention pricing had been implemented from DI ending 1550 hours and is forecast to apply until the end of the AEMO intervention event at 1900 hrs.

II. *AEMO may initiate 'intervention' or 'What If' pricing if the RRN test[8] is passed. If the RRN test is passed and AEMO applies intervention pricing NEMDE will do an intervention price run after completion of the dispatch or outturn run.*

The Regional Reference Node (RRN) test was met for this Direction, i.e. a direction at the RRN would have avoided the need for the Direction (NER clause 3.9.3(d)). Intervention pricing was implemented from DI ending 1550 hours (after GT12 synchronised) until the end of the Direction at DI ending 1900 hours.

Although the AEMO intervention event commenced at DI ending 1510 hours, intervention pricing was not implemented until the first DI after GT12 had synchronised at 1545 hours (DI ending 1550 hours). Prior to synchronisation of GT12, the Direction could not impact market outcomes. Once synchronised, a directed generating unit will increase (or reduce) generation at its connection point and has the potential to distort market outcomes, warranting the need for intervention pricing.

The central dispatch process has been automated to apply the Intervention Pricing Methodology into the intervention pricing run to determine the prices in accordance with 3.9.3(b).

6. CHANGES TO DISPATCH OUTCOMES DUE TO THE DIRECTION

Under NER clause 3.8.1(b)(11), AEMO is required, as far as reasonably practicable, to minimise the impact of a direction to the market, in terms of the number of Affected Participants and changes to interconnector flows.

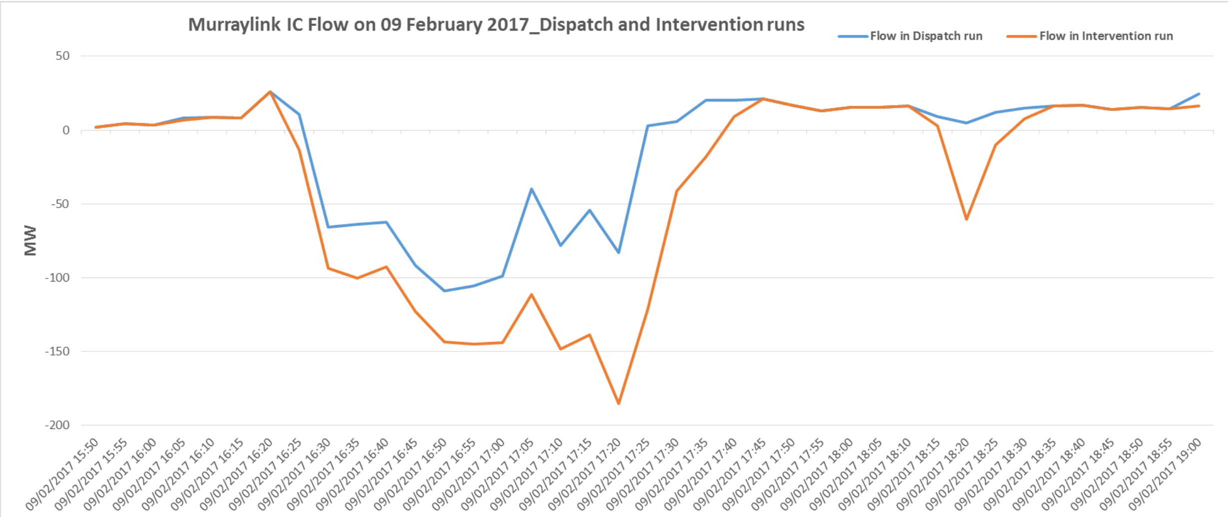
To achieve the above objective, in accordance with 4.8.9(h)(3) of the NER, AEMO issued 'counter-action' instructions in respect of four generating units in SA. The counter-action instructions involved reducing the generation output from the four generating units (Pelican Point GT11, Mintaro and two Dry Creek GTs) by roughly the same amount as the increase in generation output from Pelican Point GT12. Conceptually, this should cause minimal distortion to the market because it would be expected to contain the impact of the Direction within the region where the Direction was issued, i.e. not resulting in significant changes to interconnector flows between regions.

[8] The RRN test is reflected in NER clause 3.9.3(d).

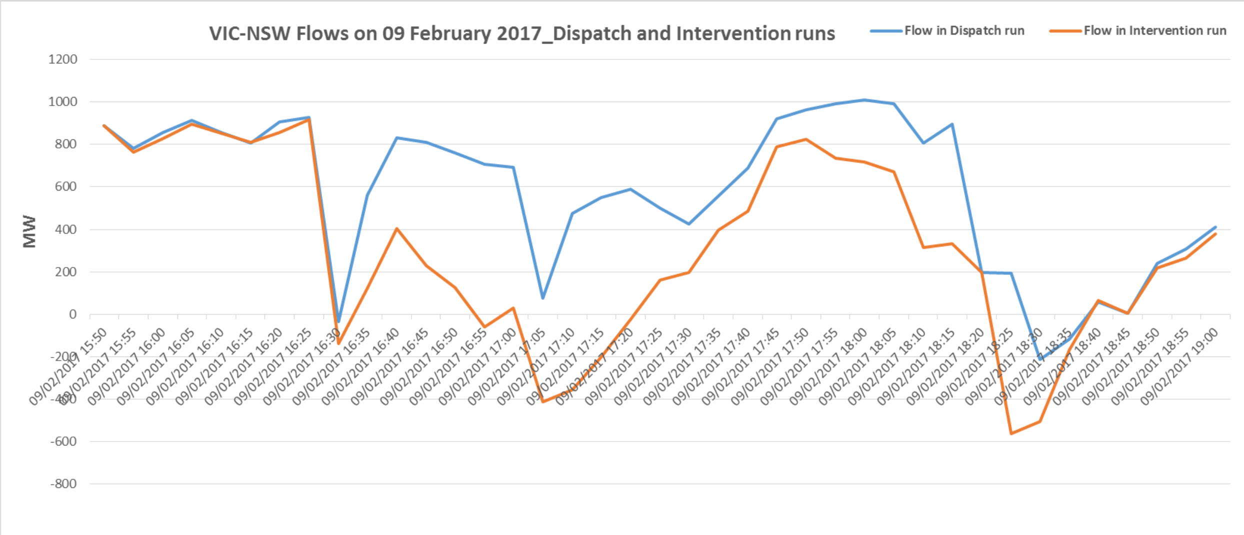
For the duration of the 9 February Direction, significant differences were observed between dispatch and intervention pricing run[9] outcomes, despite AEMO's action to counteract the Direction.

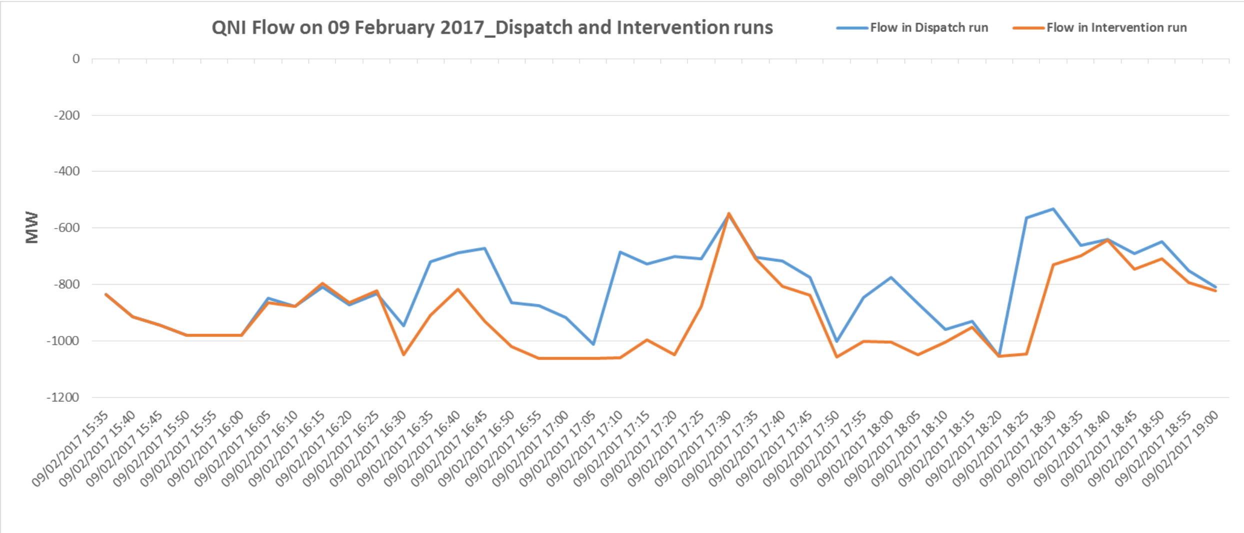
The divergence between dispatch and intervention pricing runs was particularly apparent in interconnector flows, generator output and spot prices in other regions, particularly New South Wales and Queensland.

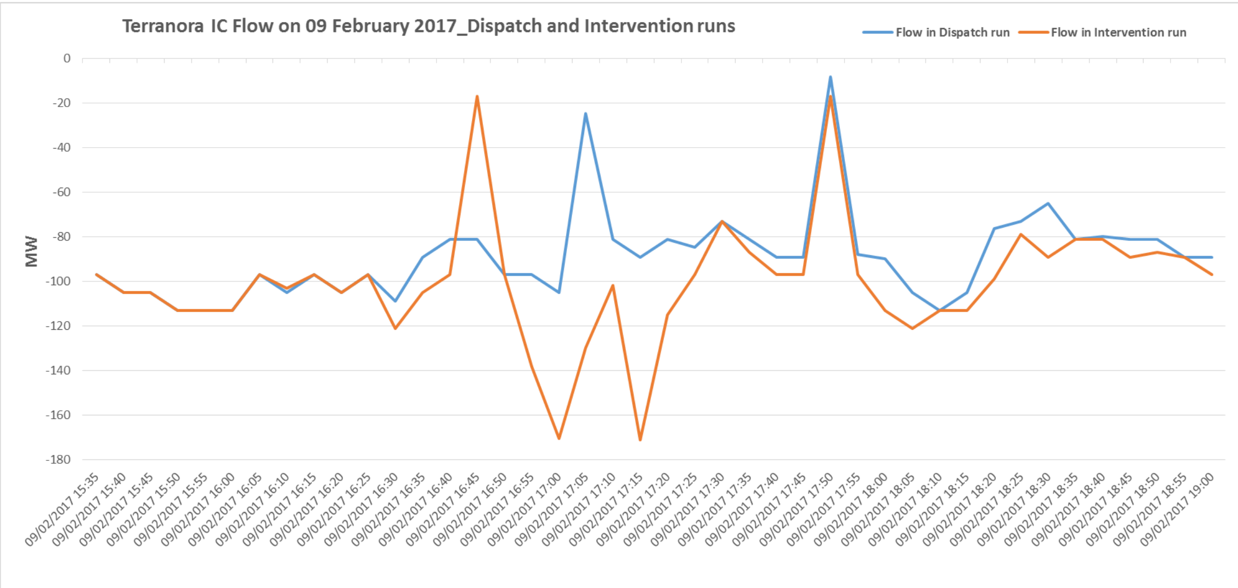
The target flows on Murraylink, VIC-NSW, QNI and Terranora interconnectors between dispatch and intervention pricing runs during the period of the Direction is shown in graphs below. The target flows on Murraylink and VIC-NSW interconnectors were materially different between the two runs. There was some difference in the flows across QNI and Terranora Interconnectors, but minimal difference to the flow on Heywood and Basslink interconnectors between the two runs.



[9] Intervention pricing run is a parallel NEMDE run to the dispatch run to determine the Intervention prices (in real-time) in accordance with the Intervention Pricing methodology. The difference between the two runs primarily relates to the existence of constraint equations relating to the Direction and counter-action in the dispatch run and the absence of these constraint equations in the intervention pricing run.


VIC-NSW Flows on 09 February 2017_Dispatch and Intervention runs
Flow in Dispatch run
Flow in Intervention run
MW

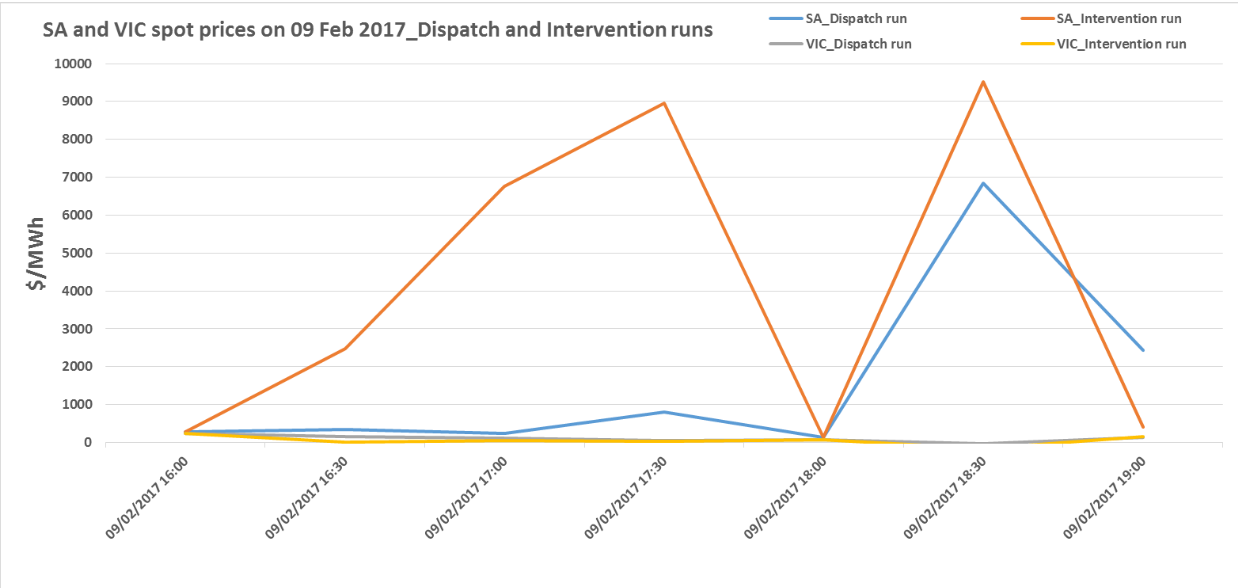

QNI Flow on 09 February 2017_Dispatch and Intervention runs
Flow in Dispatch run
Flow in Intervention run
MW


Terranora IC Flow on 09 February 2017_Dispatch and Intervention runs
Flow in Dispatch run
Flow in Intervention run
MW

As observed in the second graph above, the target flow across the VIC-NSW interconnector in the intervention pricing run was constrained to a large extent in the northerly direction as compared to the dispatch run. The intervention pricing run indicated that, had the Direction not occurred, total generation in Victoria would have been 872 MWh less than the dispatch run, whereas generation in NSW and QLD would have been 834 MWh higher.

For Intervention events when AEMO implements intervention pricing, financial settlements are based on the price outcomes from the intervention pricing run. The intervention pricing run spot prices in NSW, QLD and SA were materially different to their spot prices from the dispatch run. There were no material differences in the VIC and TAS spot prices between the two runs.

The intervention run spot prices for NSW, QLD, SA and VIC as compared to their spot prices from the dispatch run are shown in the graphs below.



The intervention pricing run simulates a hypothetical scenario whereby the InitialMW (actual output at the beginning of a DI) of each generator and interconnector is assumed to be the same as the dispatch instruction issued in the previous DI (assumption of perfect dispatch compliance from DI to DI), with all other inputs being retained from the dispatch run.

Based on AEMO's investigation, the main contributing factor for the divergence in interconnector, generator and price outcomes between the intervention pricing run and dispatch run was feedback constraint equations that managed line flows in the Victorian outer state grid during the intervention period. These constraint equations require real-time SCADA measurements of transmission line loadings as inputs. The intervention pricing run does not, however, have real-time SCADA measurements for line loadings, and instead uses the line loadings from the dispatch run.

On this occasion, the feedback constraint equations in the intervention pricing run were attempting to reduce the loading on the Ballarat – Bendigo 220 kV line for the loss of Shepparton – Bendigo 220 kV line, and a Mount Beauty – Dederang 220 kV line for the loss of the other parallel Mount Beauty – Dederang 220 kV line. However, the intervention pricing run was not seeing any reduction in line loading in the solutions. As a result, the VIC-NSW interconnector was constrained to a large extent by NEMDE in the intervention pricing run. Consequently, cheaper Victorian generators were progressively constrained off and replaced by higher priced NSW and QLD generators in each interval of the intervention pricing run, in an attempt by the dispatch algorithm to alleviate the feedback constraint equations.

The outcomes from the intervention pricing run, though unusual, were consistent with the Intervention pricing run methodology[10] developed in accordance with NER clause 3.9.3(e).

7. CONCLUSIONS AND FURTHER ACTIONS

AEMO has reviewed the Direction issued to ENGIE in relation to GT12 of Pelican Point power station on 9 February 2017 and the circumstances surrounding this Direction, as set out in this report.

AEMO assessed its compliance with the applicable procedures and processes for determining to issue the Direction, notification, and the application of intervention pricing, and is satisfied these requirements were met.

Based on the intervention pricing run outcomes detailed in Section 6, AEMO is currently undertaking a review of the Intervention Pricing Methodology. The use of feedback constraint equations in intervention pricing runs is a key focus area.

[10] https://www.aemo.com.au/-/media/Files/PDF/Intervention-Pricing-Methodology-October-2014.pdf

ABBREVIATIONS

Abbreviation	Expanded name
DI	Dispatch Interval
LOR	Lack of Reserve
LTTI	Latest Time to Intervene
MN	Market Notice
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NER	National Electricity Rules
NSW	New South Wales
QLD	Queensland
RRN	Regional Reference Node
SA	South Australia
TI	Trading Interval
VIC	Victoria