Implementing recommended improvements to market power mitigation in the WEM

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I. Short run marginal cost in the WEM Rules

1. The WEM Rules use the concept of short run marginal cost (SRMC) to limit the impact of generator market power on electricity prices. This practice is commonly referred to as "market power mitigation".

2. In real-time wholesale electricity markets, demand is almost completely inelastic, so even relatively small generators may be able to raise market prices by increasing their offer prices—ie, relatively small generators may have market power. In common with wholesale electricity markets in many jurisdictions, the WEM Rules mitigate the exercise of generator market power.

3. One of the mechanisms for mitigating generator market power is to prohibit certain behaviours and empower the ERA to monitor and enforce compliance. This is an example of "ex post" market power mitigation because the regulatory action involves investigating historical behaviour and testing it against the market rules. The WEM Rules prohibit generators with market power from offering above SRMC. If the regulator finds that offers were above SRMC, it can apply financial penalties. The rules generally apply in the same way to the STEM, the Balancing Mechanism, and ancillary service markets. Specifically, the Rules rely on the concept of SRMC as follows.[1]

    a. "A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power."[2,3]

    b. The ERA must monitor the market for inappropriate behaviour, including offers that do not reflect the generator's reasonable expectation of SRMC.[4]

    c. If the ERA concludes that offers may not reflect the generator's reasonable expectation of SRMC, and the ERA "considers that the behaviour relates to market power", it must ask the generator for an explanation and investigate further.[5]

4. In addition to this "ex post" mitigation mechanism, there is also a hard cap on generator offers (a type of "ex ante" mitigation mechanism, so-called because the rule is set before market participants submit their offers, and is "hard-wired" into the WEM operational

[1] The full text of these Rules is extracted as Appendix A.

[2] Rule 6.6.3

[3] The Rules for the balancing market (Rule 7A.2.17) and ancillary services (Rule 7B.2.15) are similar.

[4] Rule 2.16.9

[5] Rule 2.16.9B

software). There are two price limits: one for generators running on liquid fuel (the "Alternative Maximum STEM Price"),[6] and one for all other generators (the "Maximum STEM Price"). The offer caps are set annually by the AEMO and the ERA. The Maximum STEM Price is defined in the Rules,[7] and is required to be:

a. "based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas", and

b. calculated "using the following formula: (1 + Risk Margin) × (Variable O&M + (Heat Rate × Fuel Cost))/Loss Factor".

5. The Alternative Maximum STEM Price is defined in the same way but "based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate".[8]

6. Energy Policy WA has asked Brattle to review how the concept of SRMC is used in the WEM Rules, and to recommend improvements. This report develops recommendations we made in a report for the Public Utilities Office on market power mitigation mechanisms (in the context of the electricity market reform process).[9] In this report we recommend how specific WEM Rules could be improved, and provide analytical support of the same. However, it is important to recognize that The Brattle Group is an economic consulting firm, not a law firm, and nothing in the report is intended to provide or should be interpreted as providing legal advice or opinions, including advice regarding specific legal drafting of WEM rules.

7. This report concentrates on two aspects of using SRMC in market power mitigation which are particular to the WEM. First, the market for natural gas in the WEM is not very transparent. As a result, it can be difficult to identify an appropriate gas price to use to calculate the cost of fuel. Second, generator offers for each trading interval in the WEM are not contingent on whether the generator was already generating in the prior trading interval. However, if a generator has to start up in order to generate in a particular interval, its costs will be higher than they would have been if it was already generating in the prior interval. This factor gives rise to significant uncertainty in estimating SRMC for a particular interval.

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6 There is a mechanism (see Rules 6.6.9 and 6.6.10) to permit a gas-fired generator to purchase gas from a generator that can run on both liquid fuel and gas, and for the former to be permitted to offer up to the Alternative Maximum STEM Price (ie, as if it were running on liquid fuel).

7 Rule 6.20.7

8 Rule 6.20.7(a)ii

9 *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, Brattle paper for the Government of Western Australia, Department of Finance, Public Utilities Office (September 2016).

8. In section II we describe our overall approach to developing recommended Rule changes. In section III we analyse gas prices, the treatment of other non-fixed costs, LFAS and overall maximum price limits. In section IV we report our recommended Rule changes.

II. Overall approach

A. Context for defining SRMC in the WEM

9. Generators have two principal sources of revenue in the WEM: first, the capacity mechanism; and second, the STEM and related spot markets for energy and ancillary services. The objective of the capacity mechanism is to ensure that there is sufficient capacity available on the system that the price mechanism in the spot market is able to equalise supply and demand, with an acceptably-small risk of requiring rationing outside of the price mechanism. In essence, the capacity mechanism pays generators to be available to generate. As a result, if a generator can recover its fixed costs in the capacity mechanism, it will continue to generate whenever the spot market provides revenue sufficient to cover the balance of its costs. This facilitates a regime where generators offer energy at their SRMC, which maximizes operational efficiency. In contrast, jurisdictions where there is no capacity mechanism have to have spot market prices above SRMC in order to provide for recovery of fixed costs.[10]

10. Since the WEM has a capacity mechanism, spot market prices do not need to provide a contribution to fixed costs. However, spot market prices should be able to cover generators' other costs. Efficient outcomes require that generators should not generate unless they anticipate recovering in spot prices the additional costs they will incur by generating. These additional costs will include fuel and variable O&M costs, as well as any other costs relating to start-up.

11. It is important that market power mitigation should not result in generators failing to recover such costs as a result of offer prices that are too low.

12. While generators with market power should not offer above a reasonable expectation of SRMC, "SRMC" is not currently defined in the WEM Rules. In this report, we develop recommendations for how the WEM Rules could be changed to clarify what SRMC means.

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10 In this discussion it should be understood that not all generators will recover all of their costs all of the time. Some generators may recover more, and some less. However, at the margin where entry and exit decisions are made, in jurisdictions that have a capacity mechanism the marginal generator needs to anticipate spot market prices high enough to recover only non-fixed costs, whereas if there is no capacity mechanism spot prices need to be high enough to recover all costs for the marginal generator.

B. Recommendations from Brattle's prior report on market power mitigation

13. Brattle's earlier report on market power mitigation in the WEM concluded as follows:[11]

> The goal of market power mitigation is to recreate the maximally efficient outcome of a competitive market. In the WEM, where a capacity mechanism complements the energy market, the competitive ideal is for energy offers to reflect suppliers' short-run marginal costs (SRMC).
>
> 'SRMC' should be defined as 'all costs that a supplier without market power would include in forming its profit-maximising offer.' This includes all costs of generating energy that are 'marginal' over a dispatch cycle in that they would not have been incurred if the generator had been available but not running. It encompasses but is not limited to: fuel and non-fuel start-up costs amortised over a reasonable expectation of output; all fuel costs incurred once the unit is started up; variable operating and maintenance costs; and any opportunity costs, such as the opportunity cost of fuel that could otherwise have been sold. Failing to account for these costs in forming a competitive offer would not maximise profits for a price-taking supplier lacking market power, and it would lead to uneconomic operating decisions: submitting a lower offer would risk having to produce when prices do not cover all costs caused by producing; submitting a higher offer would risk failing to clear the market and earn net revenues when prices exceed one's costs.
>
> SRMC-based offers support operational efficiency by allowing the system operator to dispatch the lowest-cost available resources. Furthermore, resources with SRMCs below the clearing price earn net energy revenues, supporting investment in the most economically efficient mix of technologies. Meanwhile, the capacity mechanism provides additional fixed cost recovery to attract and retain sufficient total capacity to meet reliability objectives.

14. The report went on to recommend that the WA Government: "[r]evise the Wholesale Electricity Market rules limiting generator offers so that they clearly do not refer to intent, an elusive matter to prove. Change 'when such behaviour relates to market power' to 'when the supplier has market power and their behaviour raises prices above competitive levels.' Here, 'market power' is the ability to profitably raise the market price; [c]larify the definition of 'SRMC' as described above".[12]

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[11] *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, Brattle paper for the Government of Western Australia, Department of Finance, Public Utilities Office (September 2016), pp. ii–iii.

[12] *Ibid*., p. iv.

15. We are not aware of any reason to move away from these recommendations, and we expand on them below.

C. Behaviour that relates to market power

16. The WEM Rules prohibit offering above SRMC "when such behaviour relates to market power". It is not obvious to us exactly what this wording means, but we think the relevant qualification to a prohibition on offering above SRMC is that generators with market power should not be permitted to offer above SRMC while generators without market power should be permitted to offer at any level.

17. It is good to permit generators without market power to offer at any level because profit-seeking behaviour by market participants without market power is beneficial – it will result in offers at SRMC and will therefore contribute to efficient outcomes. There is always uncertainty in estimating SRMC, so there is a risk that the monitoring and enforcement process could cause market participants to offer below their estimate of SRMC for fear that the market monitor will come to a different view. In addition, monitoring and enforcing compliance with ex post mitigation rules takes up valuable resources, so it is beneficial if these resources can be focused on generator behaviour most likely to have an impact on prices (ie, offers by generators with market power that may have increased prices above competitive levels).

18. We think it would be beneficial to clarify the wording of the Rules so that the ERA will only investigate whether generator offers are above SRMC if the generator has market power and the ERA considers that its offers may have increased prices above competitive levels.

19. It is likely that, in practice, the ERA could employ a variety of "screens" as a way of focusing its monitoring and enforcement activity where it is most likely to be useful.[13] Since there are a variety of such screens that can be used, we would not recommend the design of the screens be "hard wired" into the Rules. However, we think that monitoring activity should focus on instances where high-priced offers may have had an impact on prices.

D. Short run marginal cost

20. The WEM uses the concept of SRMC in seeking to prevent generators with market power from raising prices. In a jurisdiction such as the WEM that has a capacity mechanism, spot market prices should be able to cover the extra costs that generators incur from actually generating that they would not have incurred if they had not generated. (Inframarginal

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[13] See, for example, the discussion in Appendix A1 of *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, Brattle paper for the Government of Western Australia, Department of Finance, Public Utilities Office (September 2016).

generators may earn revenues in the spot market that exceed their non-fixed costs; however, for the marginal capacity provider, fixed costs are covered by the capacity mechanism.) In contrast, jurisdictions without a capacity mechanism need to rely on scarcity pricing in the spot market to contribute to remunerating fixed costs. Thus spot market prices in "energy-only" jurisdictions will tend to be more volatile and will more often exceed the SRMC of the marginal generator. Energy-only jurisdictions will tend to have more frequent high-priced periods with scarcity prices than jurisdictions with capacity mechanisms, with the latter tending to have a greater margin between total generating capacity and anticipated peak demand.

21. In the WEM, spot prices need to be high enough so that all generators expect to receive revenue sufficient to cover the extra costs that each incurs by generating (costs which would not have been incurred if it did not generate). If spot prices do not provide this expectation, then generators will prefer not to be dispatched. An outcome where prices do not provide revenue sufficient to cover non-fixed costs is not efficient and will encourage wasteful consumption of electricity. Therefore market rules, including market rules relating to market power mitigation, should permit all generators to include the expected amount of these extra costs in their offers. We previously explained that SRMC should be defined to include "all costs that a supplier without market power would include in forming its profit-maximising offer", and that this would include at least: fuel and non-fuel start-up costs amortised over a reasonable expectation of output; all fuel costs incurred once the unit is started up; variable operating and maintenance costs; and any opportunity costs, such as the opportunity cost of fuel that could otherwise have been sold.[14]

22. This is similar to the approach in the Rules for determining the STEM Maximum Price and the Alternative STEM Maximum Price, which explicitly includes fuel costs, and start-up-related and other variable O&M.[15]

23. There are two particular features of the WEM which mean that it is not straightforward to identify the costs that a generator without market power would include in its profit-maximising offers.

24. First, it may not be easy to identify the appropriate price of fuel. For example, in the WEM many gas-fired generators purchase gas on long-term contracts. A large generator may have several such contracts, each with its own terms and conditions (including price). Is the relevant price the highest price across the portfolio of contracts? Or the average price? And if the generator is also in the business of selling gas, or has the option of selling gas, is the price at which it sells gas also relevant?

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14 *Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia*, Brattle paper for the Government of Western Australia, Department of Finance, Public Utilities Office (September 2016), p. iii.

15 Rule 6.20.7

25. Second, some costs that a generator without market power would include in its profit-maximising offers are not a linear function of generator output, yet the WEM market arrangements require linear offers. For example, there may be costs that are incurred when starting up, independent of how long the generator runs or how much energy it produces after starting. Generators should be able to recover these start-up costs by incorporating them into their offers. However, if a generator includes start-up costs in its offer for every trading interval, it is likely to recover more than its costs if its offer sets the market price. In order to expect to recover its start-up costs but not over-recover them, the generator will need to form an expectation about the number of trading intervals it will be running, spread its start-up costs over these intervals, and set its offers accordingly.[16]

26. We explore these issues in the next section.

III. Analysis

A. Fuel prices

1. WA gas market

27. Some natural gas markets are characterised by very active trading. For example, the Henry Hub market in the US is one of the most liquid commodity markets globally and typically has a "churn" ratio—total quantity traded divided by total US market size—of about 50.[17] One way to interpret this statistic is that, on average, a unit of gas has been bought and sold 50 times before it is burned.

28. The Henry Hub market is so liquid that large volumes of gas can be traded without moving the price. A market participant suddenly needing extra gas or suddenly having spare gas to sell can do so easily, and the price for the transaction would be the Henry Hub price. The Henry Hub price is often used as a reference point in large long term contracts. For example, 20-year contracts for the export of LNG from the US to overseas markets are

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16 This issue arises because the WEM uses "one-part" energy offers that must incorporate start-up costs, rather than the "three-part" energy offers employed in many other jurisdictions. Three-part offers include start-up costs explicitly such that the market operator can optimize unit commitment and provide generators a guarantee that, if committed, all as-offered costs will be recovered.

17 *Perspectives on the Development of LNG Market Hubs in the Asia Pacific Region*, US Energy Information Administration (March 2017), p. 16 reports a range of 61–90; *Quarterly Gas Review – Analysis of Prices and Recent Events*, Oxford Institute for Energy Studies (March 2019), p. 10 reports a figure of 53.9.

priced at the Henry Hub price (ie, the price that will be paid over the 20-year term of the contract is whatever the reported Henry Hub price turns out to be, month by month).[18]

29. There is no equivalent of the Henry Hub in the WA gas market. Gas market participants transact using large volume, long term contracts that are negotiated bilaterally. Prices in these contracts are not reported and the market is not transparent. We are not aware of any price index that represents the value of gas in WA and could therefore be used to price long-term contracts, as the Henry Hub is used in the US. While the churn ratio of the Hub is about 50, meaning that 50 times as much gas is traded as is physically consumed, the size of the spot market in WA is about 5% of the total market.[19]

30. In the Gas Statement of Opportunities, AEMO describes the market in WA as follows: [20]

> In Western Australia the domestic gas market is characterized by:
>
> - Bilateral, confidential, long-term take-or-pay gas sales contracts.
> - Residential, commercial, and small industrial consumers comprising a small proportion of total demand.
> - A small number of transmission pipelines, interconnectors, and limited surplus pipeline capacity.
> - Small volumes of short-term and spot gas sales.
> - Limited transparency into the state of the market, such as the availability of new supply or potential buyers.

31. AEMO also describes the availability of spot transactions as follows:[21]

> AEMO does not operate a spot or short-term trading market in WA. Instead, most of the short-term demand is met by confidential contracts settled between parties.
>
> Short-term gas may also be procured through two independent and non-aligned mechanisms:
>
> - gasTrading Australia Pty Ltd operates a spot market where sellers advise the operator of any surplus gas for the coming month, which is broadcast to the market and subsequently allocated depending on the ranking of the purchasers' offers and availability. The exact volumes available are confirmed by the seller

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[18] The LNG export contract between Sabine Pass Liquefaction and Korea Gas Corporation is a public document. The contract was signed in 2012, has a term of 20 years, and requires the buyer to pay $3.00/MMBTU (partly adjusted for inflation) and 115% times the Henry Hub price. The factor of 115% reflects the energy losses in liquefaction.

[19] AEMO, *Western Australia Gas Statement of Opportunities*, December 2019, p. 77.

[20] *Ibid.*, p. 15.

[21] *Ibid.*, p. 76.

one day ahead. The trade data is published on gasTrading's website at the completion of each month.

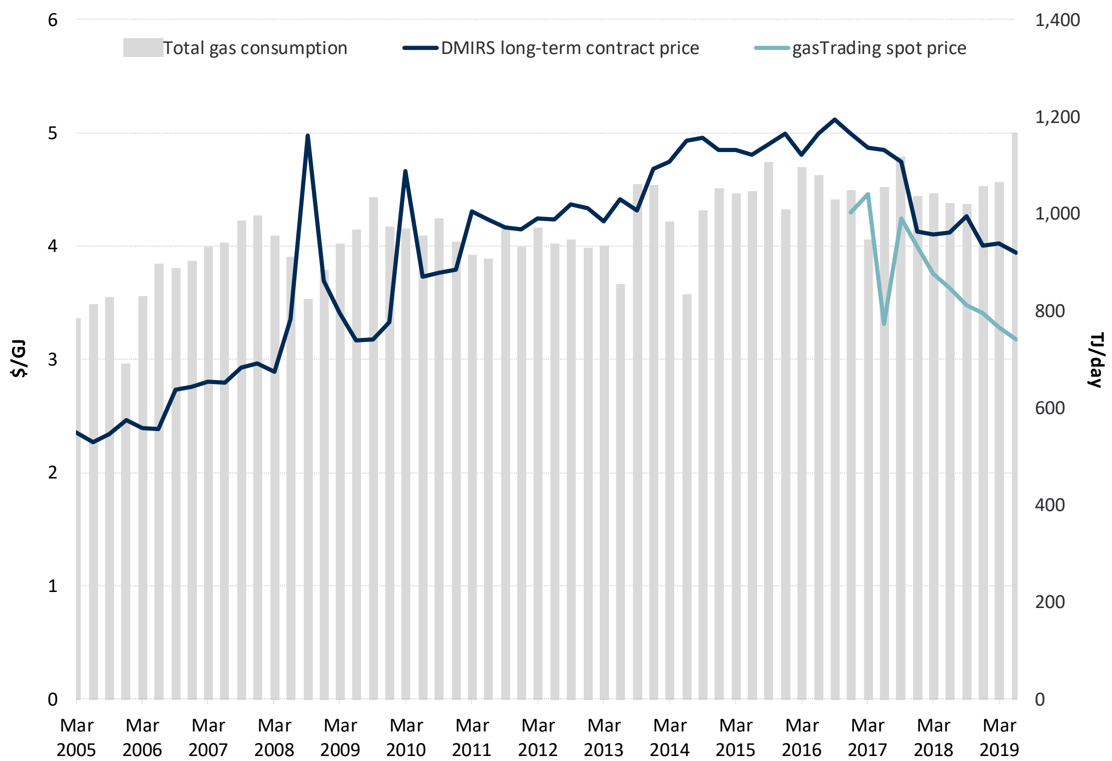
- Energy Access Services Pty Ltd operates a real-time energy trading platform where members enter gas trade agreements with a focus on supply durations of up to 90 days. The trades can encompass firm and interruptible gas arrangements, as well as imbalances. Trade data is published on the Energy Access website monthly.

32. One of the two platforms AEMO describes publishes price and quantity information for the spot transactions it facilitates.

33. Long-term contract prices are not published. However, there is a price series which reports the volume-weighted average price in these contracts on a quarterly basis.[22]

34. In Figure 1 below we show gasTrading reported spot prices and Department of Mines, Industry Regulation and Safety (DMIRS) weighted-average long-term contract prices, as well as total market volume. The spot price has been consistently below the average long-term contract price.

Figure 1: WA natural gas prices and total market size



Source: DMIRS, gasTrading.

22 *Latest Statistics Release - 2019 Major commodities resources data*, DMIRS, available at https://www.dmp.wa.gov.au/About-Us-Careers/Latest-Statistics-Release-4081.aspx.

35. Prices in different long-term contracts can be very different from each other and from spot prices, in part because the market is not transparent and in part because contracts negotiated at different times in the past reflect different expectations of future market conditions. For example, a price negotiation milestone in 2019 was said to "present an opportunity for Synergy to reduce the price it pays for gas under the contract [it had signed with the operators of the Gorgon Project], which was struck at a time when there were fears of a supply shortage."[23] In 2017 Synergy was apparently "forced to sell gas it bought to fire its power stations back into the market at a loss."[24]

2. Gas prices and SRMC

36. A gas-fired generator in the WEM may purchase gas from a range of suppliers at different prices under long-term (multi-year) gas supply agreements. We understand that, in practice, the generator must have a firm gas supply and transportation agreement in order to qualify in the capacity mechanism.[25] It may also sometimes buy smaller amounts of gas on a short-term or spot basis, and it might sometimes sell gas to other gas users. Some gas users have access to storage, so may sometimes have the choice between burning their own gas already in store or burning newly-purchased gas. A large generator is likely to have a portfolio of gas supply agreements, and could be paying several different prices for gas at a particular point in time. As a result, there are potentially several different gas prices that might be relevant for a particular generator at a particular point in time.

37. If there were a deep and liquid spot market, like the Henry Hub in the US, the prices in a generator's portfolio of gas supply contracts would be irrelevant for its decision-making: the generator would compare the value achieved by selling its gas in the spot market with the value achieved by burning its gas and selling electricity. The price of gas on the spot market would be its opportunity cost of generating. If electricity prices fell, for example because of increased output from renewables, the generator might sell significant amounts of its gas portfolio into the spot market (since it would be more profitable to do that than to generate and sell low-priced electricity). However, the spot market in WA is not very liquid. If a generator were to try to transact significant volumes of gas in the spot market, it is likely that the price would move.

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23 *The West Australian*, "Synergy Pushes for Bargain in Gorgon Gas Deal", 22 April 2019.

24 *The West Australian*, "Synergy caught out by gas glut", 19 June 2017.

25 *Market Procedure: Certification of Reserve Capacity (version 9.0, draft for consultation)* , AEMO (March 2020), section 5.3.4. The market procedure document suggests that at least 90% of the quantity required to generate at full capacity during peak hours (8 am to 10 pm) must be available on a firm basis for the generator's full capacity to qualify.

38. For example, total WA gas consumption is about 1,000 TJ/day,[26] whereas volumes on the gasTrading platform are about 10 TJ/day.[27] 10 TJ/day is roughly equivalent to 50 MW of generation running baseload.[28] Thus the gas supply for even a relatively small power plant could easily flood the market if it were sold into the spot market.

39. Suppose, for example, that a particular gas-fired generator has access to gas at $2.00/GJ under a long-term gas supply agreement, but that other gas users are currently willing to pay $2.50/GJ in the spot market to access additional supplies of gas on a short-term basis. A profit-maximising generator without market power would consider selling its gas into the spot market rather than generating, and therefore might set its offers using an opportunity cost price of $2.50/GJ. However, it would not use a price of $2.50/GJ if it anticipated that selling its gas into the spot market would depress the price. It would use a price that actually reflects its next best alternative, which might be a price less than $2.50/GJ at which a sale could be realised, or which might be to take less gas (ie, an opportunity cost of $2.00/GJ).

40. We think that spot market prices would be relevant for setting offers if there were circumstances in which selling the corresponding quantities into the spot market was a realistic alternative. If a generator offered using a price of $2.50/GJ when its gas contract price is $2.00/GJ, and was not dispatched, and sold its gas at $2.50/GJ, the generator has successfully found a profitable use for its gas. However, if the actual sale takes place at a much lower price, the strategy is unlikely to have been profit-maximising.

41. Similarly, suppose that a generator has two long-term contracts, one at $2.00/GJ and one at $2.50/GJ. If there were a sufficiently liquid spot market, the generator might use the spot price in setting its offers. Without a sufficiently liquid spot market, however, a profit-maximising generator without market power is likely to offer some of its capacity using $2.00/GJ (up to the maximum quantity available at that price) and some using $2.50/GJ. The generator would risk missing out on profitable dispatch if it were to price all of its capacity using its marginal price of $2.50/GJ.

42. There may be circumstances where a profit-maximising generator without market power might use a price other than the price in its long-term gas supply contract in forming its offers. Suppose that a generator has a long-term contract that gives it the right to buy 30 TJ of gas per day at $2.50/GJ. That quantity is approximately half of the amount needed to run a 300 MW plant at baseload. If the generator is constrained by the availability of gas, it could not offer using $2.50/GJ in every hour: it would risk being dispatched baseload and running out of gas. It would have to offer a higher price in at least some intervals.

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26 See Figure 1.

27 Based on the volume history chart at http://www.gastrading.com.au/spot-market/historical-prices-and-volume, which shows volumes around 300 TJ/month.

28 50 MW x 24 hrs / 50% efficiency is 2.4 GWh or 8.6 TJ.

43. Furthermore, a generator constrained by the availability of gas would want to ensure that it was generating more often in high-priced hours. Suppose that the generator had enough gas only to permit generating half of the time. It might try to estimate the median price for electricity and set its offers at that price: that way, it would only be dispatched in the "top half" of the price duration curve. Note that in this strategy the generator's offers are independent of the price it pays for gas. Another way to think about this is that, for a generator constrained by gas availability, the opportunity cost of generating in one particular hour is the price of the electricity it cannot generate in some other hour. Importantly, this is the behaviour expected of a participant without market power, and it is the efficient behaviour from a system perspective: if gas supply is limited, using it in higher-priced periods maximizes overall economic surplus.

44. This example is similar to how a hydroelectric plant might set its offers, if the plant was working with a constraint on the total amount of water available.

45. Similarly, a generator with excess gas might offer using a price below its gas purchase price. Long-term gas supply agreements often have a minimum purchase obligation (known as "Take or Pay" or ToP). If a generator is taking below the ToP threshold, it is effectively paying for gas whether or not it actually receives the gas. Therefore the opportunity cost of using an additional unit of gas may be zero (or low, if gas paid for but not taken can be "banked" for future use). A profit-maximising generator without market power would be keen to see at least some revenue from this gas, so might use a very low price in setting its offer, in order to maximise dispatch. Of course, if the generator had the option of selling this gas instead of burning it, the price at which it anticipated being able to sell the gas would be the opportunity cost for the purpose of pricing its electricity offers. The spot price of gas might be relevant evidence of this price, but only to the extent that the spot price is reflective of the price at which the relevant volume could be sold.

46. For an intermediate case where the generator has a ToP floor but does not have to generate all of the time, and has additional gas available, it might set its offers with reference to the minimum of a) expected prices in the top N hours where N corresponds to the ToP quantity, and b) its gas contract price.

47. It is possible that a generator with a ToP constraint might have market power and therefore may be able to influence (or even determine) electricity prices in a substantial number of trading periods. This generator is therefore not forming an expectation about electricity prices when deciding how to set its offers in order to burn its ToP quantity in the highest-price hours, so much as it is *choosing* the price at which it will generate in those hours. In principle, we think that the appropriate gas price to use would be the price at which the entire ToP quantity might be sold to another gas user (on a willing buyer / willing seller

basis).[29] This is the value of that gas in the market, and is therefore the appropriate price to use in forming offers. In practice, there is little data available to such a generator that would permit this notional price to be estimated (since the WA gas market is non-transparent and characterised by bilateral contracts, most of which the generator will not be party to). The best that the generator can do is to estimate the current notional market price for a large volume long-term contract on the basis of its own recent contracting experience. This could be from buying additional volumes, selling excess volumes, or from strong market intelligence as to the prices in third-party transactions. We think that, in this exercise, prices in the spot market are unlikely to be relevant because they are for relatively small quantities.

48. This discussion illustrates that there are many circumstances in which a generator's gas acquisition cost will not be the only consideration for a generator without market power in setting a profit-maximising offer, and sometimes the gas acquisition cost may not be relevant at all.

49. While the spot market for gas in WA is not as well developed as in other jurisdictions, it is possible that buying from or selling into the spot market may be a feasible option for some generators at some times. It is also possible that the spot market could develop more liquidity in the future. A profit-maximising generator will make use of these opportunities as they arise, and spot prices may therefore sometimes influence offers of a profit-maximising generator without market power. However, the quantity of offers should be in line with the quantity of gas that can be transacted on the spot market at the spot market price.

50. We do not consider that it would be possible to specify in the Rules any form of required mechanical relationship between gas prices and offers, except that a generator with market power should not exploit that market power to raise prices above competitive levels. An appropriate standard is therefore that *SRMC should include any costs that a generator without market power would include in its offers while attempting to maximise its profits*. Such costs would include opportunity costs (for example, the opportunity cost of not generating at a time when electricity prices are higher, if the total amount of gas available is constrained).

51. The discussion of fuel prices and opportunity cost would also apply to other fuel types. We would expect the application to other fuel types to be relatively straightforward because both solid and liquid fuels are easy to store. Also we are not aware of any "secondary" trading of solid or liquid fuel entitlements. The opportunity cost will often be simply the

[29] One way to think about this hypothetical transaction is to assume that the generator's current contract suddenly ceased to exist (for example, because it turned out that due to an error the contract has no legal effect). The gas supplier is left looking for a new customer, and the gas buyer is left looking for a new supplier, but the overall supply–demand balance in the market has not changed since both supply and demand have suddenly increased by the same amount. At what price would the supply be re-contracted?

cost of purchasing fuel to replace that which has been burned, under the generator's regular supply arrangements. In principle, however, if there is a cheaper alternative source of fuel than the regular supply arrangement, or a more valuable alternative use for the fuel than burning it, these alternatives would be the basis for the opportunity cost, as for gas.

B. Other non-fixed costs

52. Fuel usage depends on output. While fuel usage is proportional to output if the generator is running continuously at a given power output, the generator's efficiency (fuel use per MWh output) is a function of output. Particularly at very low output, and during start-up, fuel use per MWh may be much greater than at continuous regular power output. Furthermore, generators take time (and fuel) to ramp up and ramp down their output, and they may have minimum runtime-per-start constraints. In order to generate in one trading interval with an (anticipated) high price, the generator may in effect need to ramp up and down in other intervals before and/or afterwards, and prices in those intervals may be lower.

53. Other costs are a more complicated function of output. For example, some generators may conduct maintenance on a regular schedule (for example, monthly or annually), while other generators may conduct maintenance every 5,000 operating hours or every 100 start-ups, or some combination of these schedules, and the approach may differ between routine maintenance and major maintenance. Many have long-term service agreements with original equipment manufacturers for major maintenance, with terms that may depend on operating patterns.

54. When a generator submits its offers, it submits a separate offer for each of a set of specific generating intervals. When the offers are submitted, the generator will not know whether each offer will be accepted, nor whether, if an offer for one interval is accepted, offers for subsequent intervals will be too. For example, suppose a generator is undergoing planned maintenance and is preparing its offers for the first day when it is again available to generate. The generator might anticipate running for 12 hours at 250 MW, and incurring the extra costs associated with one start. The generator might therefore aggregate these costs, divide by 250 MW and by 12 hours, and offer the resulting price of $80/MWh in each interval across the upcoming 24 hours. However, as the day proceeds, it may be that there is unexpectedly more wind output than anticipated, so that market prices fall below $80/MWh in the middle of the day. As a result, the generator runs for only 8 hours and starts twice, and the costs it incurs across the 24 hour period are different from anticipated when the offers were made.

55. The discussion above shows that the total amount of non-fixed costs that will be incurred over a particular period cannot be identified with certainty in advance.

56. A profit-maximising generator without market power will attempt to anticipate the costs it will incur and the output it will produce, and will offer accordingly. It might consider various possible dispatch patterns and attempt to optimise its offers in light of this

uncertainty. It will consider all non-fixed costs when setting its offers. If it failed to do so, it would risk being dispatched and earning revenues less than its costs. It will not attempt to include in its offers any costs that will be incurred whether it runs or not: if it were to include such costs, it would risk being dispatched less often, but without a corresponding cost saving.

57. It is important that generators are able to recover all of their start-up and other non-fixed costs by reflecting these costs in offers. In order to do so, they will need to form an expectation about future running patterns so that start-up and other costs can be appropriately divided by the anticipated output. Of course, actual running patterns will often be different from the patterns anticipated. Nonetheless, a generator without market power will attempt to predict its running patterns and divide start-up and other non-fixed costs over anticipated output accordingly.

C. LFAS

58. The WEM has an organised market for Load-Following Ancillary Services (LFAS). Generators submit LFAS offers, similar to the way in which they submit energy offers, and the LFAS market is cleared in a way similar to the way the energy market clears. These two markets are not "co-optimised" even though generating capacity which provides LFAS cannot simultaneously provide energy (and vice-versa). Co-ordination between these markets, and in particular the impossibility of the same MW operating simultaneously in both markets, is addressed by clearing the LFAS market first. Generators then have some time in which their energy offers can be adjusted to reflect the results of the LFAS market. In particular, a generator which clears some capacity in the LFAS market can adjust its energy offers to remove that capacity from the energy market.

59. Since the same MW cannot simultaneously earn revenue in both markets, providing LFAS has an "energy opportunity cost": because a MW is earning LFAS revenue, that same MW cannot also earn energy revenue.

60. Generators should be able to include this energy opportunity cost in their LFAS offers. If they cannot, inefficient outcomes would occur. Suppose that a generator has fuel costs equivalent to $40/MWh and total SRMC of $45/MWh, and that its non-fuel costs are proportional to output as output increases from 195 MW to 200 MW. Suppose that the energy market is expected to clear at $60/MWh. The generator offers 200 MW into the energy market at $45/MWh. (For the purpose of this example, we assume that there are no surprises and the energy market in fact clears at $60/MWh.) The generator is technically able to offer 5 MW of LFAS. At what price should the generator offer LFAS?

61. If the generator offers a very high price for LFAS, does not clear, and generates 200 MW in the energy market, it will:

   a. Earn energy revenue of 200 MW x $60/MWh x 0.5 hrs = $6,000

   b. Incur fuel costs of 200 MW x $40/MWh x 0.5 hrs = $4,000

   c. Incur other SRMC[30] of 200 MW x $5/MWh x 0.5 hrs = $500

   d. For a net margin of $1,500

62. If the generator offers a lower price and clears 5 MW in LFAS (and then subsequently adjusts its energy offer so that 195 MW clears in energy), in relation to its energy output it will:

   a. Earn energy revenue of 195 MW x $60/MWh x 0.5 hrs = $5,850

   b. Incur fuel costs of 195 MW x $40/MWh x 0.5 hrs = $3,900

   c. Incur other SRMC of 195 MW x $5/MWh x 0.5 hrs = $487.50

   d. For a net margin of $1,462.50

63. Just taking into account the results of energy dispatch, the generator is worse off by $37.50 (or $15 per MWh of "lost" energy).

64. Suppose that the LFAS price is $20 per MW per hour. In this case, there is no problem. The generator moved 5 MW from the energy market, where it was worth $15/MWh of net margin to the LFAS market where it was worth $20/MW/hr – an efficient outcome, because the resource was moved to where it provided more value.

65. Now suppose an alternative outcome where the LFAS price was $10 per MW per hour. In this case the 5 MW has moved from a high value use to a low value use. The 5 MW should have been in the energy market – and, had it in fact been offered into the energy market at $45/MWh instead of into the LFAS market (at $10 or less), perhaps the energy market would have cleared below $60/MWh.

66. Even though the generator incurs no out-of-pocket costs by providing 5 MW of LFAS (relative to providing 195 MW in energy), it would clearly be inappropriate to offer zero into the LFAS market. Rule 7B.2.15 is "A Market Participant must not, for any Trading Interval, offer prices within its LFAS Submission in excess of the Market Participant's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility providing LFAS when such behaviour relates to market power." We do not understand why the Rule refers to "incremental change in short run marginal cost". We

[30] For the purpose of this example, we assume that these other costs are avoidable, proportional to energy generated, and not incurred in the provision of LFAS.

think that the Rule should simply require the generator not to offer above its SRMC for providing LFAS, if it has market power (it being understood that SRMC in this context includes the generator's energy opportunity cost).

67. The correct approach is for the 5 MW to be offered into the LFAS market at $15/MW/hr – the energy opportunity cost.

68. In the example above, we assumed that the non-fuel component of SRMC was proportional to energy output. If this amount were not proportional to energy output, it could be included either in the energy offer or the LFAS offer (and, if the latter and the LFAS offer was not accepted, it could be moved to the energy offer).

69. The guiding principle should be that the generator be able to include all of its non-fixed costs in its offers. In the case of LFAS offers, this includes the opportunity costs of not selling the corresponding MW into the energy market and receiving the energy price (net of fuel and other components of SRMC).

IV. Recommended Rule changes

70. Appendix A lists the key Rules that use the concept of SRMC.

71. We recommend a new Rule or suitable modifications to the existing Rules to provide a definition for SRMC (as the term is used in Rules 2.16.9, 2.16.9B, 6.6.3., 6.6.10, 6.20.7, 7A.2.15, 7B.2.15).

72. The definition of SRMC should be "all costs that a generator without market power would include in forming its profit-maximising offer".

73. We recommend modifying the Rules to remove the phrase "when such behaviour relates to market power" and similar phrases, because it is not clear to us what this expression means. We think that it is appropriate to focus ex post enforcement on generators that have market power and use it to raise prices above competitive levels. We therefore recommend the following changes.

    a. Rule 2.16.9(b) could be modified as follows: "inappropriate and anomalous market behaviour, including ~~behaviour related to~~the exploitation of market power and the exploitation of shortcomings in the Market Rules or Market Procedures by Rule Participants including, but not limited to".

    b. Rule 2.16.9B could be modified as follows: "and the Economic Regulation Authority considers that the Market Generator may have exploited its market power to raise prices above competitive levels~~behaviour relates to market power~~".

    c. Rule 6.6.3 could be modified as follows: "A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when the Market Generator has market power ~~such behaviour relates to market power~~".

    d. The same modification could be made in Rule 7A.2.17 and 7B.2.15.

74. Rule 7B.2.15 is "A Market Participant must not, for any Trading Interval, offer prices within its LFAS Submission in excess of the Market Participant's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility providing LFAS when such behaviour relates to market power." We recommend modifying the Rule as follows: "in excess of the Market Participant's reasonable expectation of the ~~incremental change in~~ short run marginal cost incurred by the LFAS Facility ~~providing~~ to provide LFAS, when the Market Participant has market power ~~such behaviour relates to market power~~.". If need be, it could also be made clear that in this context short run marginal cost includes energy opportunity costs.

Appendix A

This appendix provides extracts of the Wholesale Electricity Market Rules (version of 22 Feb 2020)[31] which involve the concept of short run marginal cost (SRMC).

RULE 2.16.9

The Economic Regulation Authority is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives and must investigate any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively. The Economic Regulation Authority, with the assistance of AEMO, must monitor:

(a) …

(b) inappropriate and anomalous market behaviour, including behaviour related to market power and the exploitation of shortcomings in the Market Rules or Market Procedures by Rule Participants including, but not limited to:

i. prices offered by a Market Generator in its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;

ii. prices offered by a Market Generator in its Balancing Submission that exceed the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;

iii. prices offered by a Market Generator in its LFAS Submission that exceed the Market Generator's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility in providing the relevant LFAS;

iv. …

RULE 2.16.9B

Where the Economic Regulation Authority concludes that—

(a) prices offered by a Market Generator in its Portfolio Supply Curve may not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity;

[31] ERA, Wholesale Electricity Market Rules, 22 Feb 2020.

(aA) prices offered by a Market Generator in its Balancing Submission may exceed the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity; or

(b) prices offered by a Market Generator in its LFAS Submission may exceed the Market Generator's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility in providing the relevant LFAS,

and the Economic Regulation Authority considers that the behaviour relates to market power, the Economic Regulation Authority must as soon as practicable, request an explanation from the Market Participant which has made the relevant STEM Submission, Balancing Submission or LFAS Submission and investigate the identified behaviour.

RULE 2.16.9C

The Market Participant must submit the explanation requested under clause 2.16.9B within two Business Days from receiving the request.

RULE 2.16.9D

The Economic Regulation Authority must publish the explanation submitted under clause 2.16.9C on the Market Web Site as soon as practicable.

RULE 6.6.3

A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power.

RULE 6.6.9

A Market Generator may apply to AEMO for all or part of the capacity of one of its Scheduled Generators that is not Liquid Fuel capable to be treated as if it was dual-fuel capable where one fuel is Liquid Fuel for the purposes of the STEM, the Balancing Market and settlement. The application must be in a form specified by AEMO, including evidence of the arrangement described in clause 6.6.10(a), and must specify the period to which the application relates.

RULE 6.6.10

AEMO must assess an application made under clause 6.6.9 and inform the Market Participant whether or not the application is approved. AEMO must approve the application only where the Market Participant provides evidence satisfactory to AEMO that:

(a) the Market Participant has an arrangement with a user of fuel ("Fuel User") to release a quantity of fuel for use in a Scheduled Generator which is not Liquid Fuel capable and is registered by the Market Participant;

(b) the use of fuel released under the arrangement would result in the Fuel User using Liquid Fuel in a Facility or other equipment; and

(c) as a consequence of clause 6.6.10(a) and (b), the short run marginal cost of generating electricity using the Scheduled Generator using fuel released under the arrangement would be above the Maximum STEM Price.

Rule 6.20.6

AEMO must annually review the appropriateness of the value of the Maximum STEM Price and Alternative Maximum STEM Price.

Rule 6.20.7

In conducting the review required by clause 6.20.6 AEMO:

(a) may propose revised values for the following:

i. the Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas and is to be calculated using the formula in paragraph (b); and

ii. the Alternative Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate and is to be calculated using the formula in paragraph (b);

(b) must calculate the Maximum STEM Price or Alternative Maximum STEM Price using the following formula:

$(1 + \text{Risk Margin}) \times (\text{Variable O\&M} + (\text{Heat Rate} \times \text{Fuel Cost}))/\text{Loss Factor}$

Where

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW open cycle gas turbine generating station, expressed in $/MWh, and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.

Where AEMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

RULE 7A.2.17

Subject to clauses 7A.2.3, 7A.2.9(c) and 7A.3.5, a Market Participant must not, for any Trading Interval, offer prices in its Balancing Submission in excess of the Market Participant's reasonable expectation of the short run marginal cost of generating the relevant electricity by the Balancing Facility, when such behaviour relates to market power.

RULE 7B.2.15

A Market Participant must not, for any Trading Interval, offer prices within its LFAS Submission in excess of the Market Participant's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility providing LFAS when such behaviour relates to market power.

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