Decision on the Benchmark Reserve Capacity Price proposed by the Australian Energy Market Operator for the 2019/20 Reserve Capacity Year

31 January 2017

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DECISION

1. On 23 December 2016, the Australian Energy Market Operator (**AEMO**) provided the Economic Regulation ERA (**ERA**) with its final report on the 2017 Benchmark Reserve Capacity Price (**BRCP**) for the 2019-20 capacity year.

2. The ERA approves the revised value for the BRCP for the 2019-20 capacity year of $149,800 per MW, as proposed by AEMO.

3. This approval is granted on the basis that it satisfies the requirements under clause 2.26.1 of the *Wholesale Electricity Market Rules* (**market rules**):

   - the revised value for the BRCP proposed by AEMO reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules; and
   - AEMO has carried out an adequate public consultation process.

4. Currently the Reserve Capacity Price is based on a 15 per cent discount to the BRCP, with further adjustments to reflect excess capacity. The proposed changes to the reserve capacity mechanism being considered by the electricity market review would use the BRCP as the benchmark price for a new entrant when establishing the demand curve.

5. The ERA notes the proposed changes to the reserve capacity mechanism are likely to result in changes in the market rules, which may lead to changes in the current methodology for calculating the BRCP.

6. The ERA also notes that the five-yearly BRCP methodology and market procedure review is due to be undertaken by the ERA in 2017.

REASONS

Background

7. The BRCP[1] sets the maximum price that may be offered in a reserve capacity auction.[2] It is also an input in the determination of the administered RCP if no auction is required.

8. Clause 4.16 of the market rules requires the ERA to develop a market procedure documenting the methodology and process AEMO must follow in determining the BRCP (see section below titled 'Market procedure: maximum reserve capacity price').[3]

9. AEMO must follow the market procedure to review the value of the BRCP annually. AEMO must propose a revised value for the BRCP using the methodology described in the market procedure.[4]

10. AEMO must prepare a draft report describing how it has arrived at the proposed revised value for the BRCP, publish the report on the market web site, and advertise the report in newspapers widely distributed in Western Australia. It must also request submissions from all sectors of the Western Australia energy industry, including end-users.[5]

11. After considering submissions received on the draft report, AEMO must propose a final revised value for the BRCP to the ERA for approval.

12. The market rules[6] require the ERA:

    - to review the final report provided by AEMO, including all submissions received by AEMO in preparation of the report;
    - to make a decision as to whether or not to approve the revised value for the BRCP;
    - in making its decision, to only consider:
        - whether the revised value for the BRCP proposed by AEMO reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules;
        - whether AEMO has carried out an adequate public consultation

[1] The BRCP was renamed from the Maximum Reserve Capacity Price as a result of amendments to the market rules that commenced on 1 July 2016 as part of the Electricity Market Review.

[2] The reserve capacity auction is run if insufficient capacity credits have been allocated to satisfy the reserve capacity requirement. To date, a reserve capacity auction has never been held.

[3] The market procedure has not been updated to reflect the amendments to the market rules that commenced on 1 July 2016 as a result of the electricity market review. Hence, the market procedure still refers to the Maximum Reserve Capacity Price. The Maximum Reserve Capacity Price has been renamed the BRCP.

[4] Provided by clause 4.16.3(b) and 4.16.5 of the market rules.

[5] Provided by clause 4.16.6 of the market rules.

[6] Clause 2.26.1.

process; and

- to notify AEMO as to whether or not it has approved the revised value.

13. The market rules[7] provide that, where the ERA rejects a revised BRCP submitted by AEMO, it must give reasons and may direct AEMO to carry out all or part of the review process under clause 4.16 again, in accordance with any directions or recommendations of the ERA.

Market procedure: maximum reserve capacity price

14. To calculate the BRCP, AEMO must follow the principles and steps laid out in the 'Market procedure: maximum reserve capacity price.'[8] This has not changed since 2011.[9]

15. The BRCP is calculated by undertaking a technical, bottom-up cost evaluation of the entry of a new 160MW open cycle gas turbine generation facility in the South West Interconnected System (**SWIS**) in the relevant capacity year.

16. The calculation of the 2017 BRCP is based on a theoretical power station that would begin operating on 1 October 2019. In accordance with the market procedure, capital costs are escalated to 1 April 2019 and fixed Operation and Maintenance (**O&M**) costs are escalated to 1 October 2019.

17. The costs making up the BRCP include:

- the capital cost of building a 160 MW open cycle gas turbine power station with an inlet cooling system in the SWIS;
- the land cost associated with developing and constructing the power station;
- the costs associated with connecting the power station to the transmission system;
- the costs associated with building liquid fuel storage and handling facilities;
- the fixed O&M costs associated with the power station and transmission facilities;
- a margin for legal, approval, financing and insurance costs and contingencies; and
- the Weighted Average Cost of Capital (**WACC**).

[7] Clause 2.26.2.

[8] See ERA website, *Market Procedure: Maximum Reserve Capacity Price*, https://www.erawa.com.au/cproot/14362/2/Market%20Procedure%20-%20Maximum%20Reserve%20Capacity%20Price.pdf

[9] The last market procedure review was completed in 2011.

Summary of input parameters and calculated values

18. The market procedure states that the following formulae must be used to determine the BRCP.

BRCP = (ANNUALISED_FIXED_O&M[10] + ANNUALISED_CAP_COST[11] / CC[12])

19. The market procedure states that the CAP_COST must be calculated as:

CAP_COST = ((PC[13] x (1+M[14]) + TC[15]) x CC + FFC[16] + LC[17]) x (1 + WACC[18])^1/2

20. The Table below provides a summary of the input parameters to the BRCP and its calculated values for the 2019/20 capacity year in AEMO's final report, compared with the approved BRCP and its calculated values for 2018/19.

	Proposed BRCP and calculated values for 2019/20	Approved BRCP and calculated values for 2018/19	Units	Market Procedure definition
Power station expected Capacity Credit allocation	148.5	150.5	MW	CC
Weighted Average Cost of Capital (WACC)	5.29	5.69	%	WACC
Power station costs	810,229	834,782	$/MW	PC
Factor for legal, financing, approvals, contingencies and other costs	17.19	20.00	%	M
Transmission connection works	175,444	160,280	$/MW	TC
Fixed fuel costs	6,803,924	7,089,948	$	FFC
Land costs	2,430,526	2,656,499	$	LC
Total capital cost	180,893,141	189,810,126	$	CAP_COST

[10] Annualised fixed O&M cost is the annualised fixed operating and maintenance cost for a typical OCGT power station and any associated electricity transmission facilities determined in step 2.5 of the market procedure and expressed in Australian dollars, per MW per year.

[11] CAPCOST is the total capital cost estimated for an open cycle gas turbine power station. Annualised CAPCOST is the total capital cost, expressed in Australian dollars, annualised over a 15 year period, using a Weighted Average Cost of Capital (WACC), as determined in step 2.9 of the market procedure.

[12] CC is the expected Capacity Credit allocation determined in conjunction with power station costs in step 2.3.1(c) of the market procedure.

[13] PC is the capital cost of an open cycle gas turbine power station, expressed in Australian dollars per MW, as determined in step 2.3 of the market procedure for that location.

[14] M is a margin to cover legal, approval, financing and other costs and contingencies as detailed in step 2.8 of the market procedure.

[15] TC is the estimate of total transmission costs as determined in step 2.4 of the market procedure.

[16] FFC is the fixed fuel cost as determined in step 2.6 of the market procedure.

[17] LC is the land cost as determined in step 2.7 of the market procedure.

[18] WACC is the Weighted Average Cost of Capital as determined in step 2.9 of the market procedure.

	Proposed BRCP and calculated values for 2019/20	Approved BRCP and calculated values for 2018/19	Units	Market Procedure definition
Annualised capital cost	**17,776,436**	**19,149,62**	**$/year**	**ANNUALISED_ CAP_COST**
Annualised fixed O&M cost	**30,143**	**32,582**	**$/MW/ year**	**ANNUALISED_ FIXED_O&M**
BRCP (rounded)	**149,800**	**159,800**	**$/MW/ year**	**BRCP**

21. AEMO proposes a final BRCP of $149,800 per MW per year for the 2019/20 capacity year. This is 6.3% lower than the BRCP for the 2018/19 capacity year of $159,800 per MW per year.

22. AEMO's final report states that the key changes since last year's review are:

- lower escalation factors have decreased the BRCP by 3.2%. This is largely due to lower commodity prices and labour cost forecasts;
- a reduction in the WACC has decreased the BRCP by 2.1%. This is due to a reduction in the risk free rate, which is in line with a decline in global bond yields; and
- a reduction in margin M has decreased the BRCP by 1.5%. This is due to a reduction in environmental approval and permitting costs.

23. The ERA has reviewed AEMO's BRCP draft report and final report, BRCP calculation spreadsheet, and public submissions received by AEMO in response to its BRCP draft report. The ERA has also reviewed reports commissioned by AEMO for the BRCP review.

24. The ERA is satisfied that AEMO has calculated the BRCP according to a methodology that reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure.

1.1 Power station costs (PC)

25. Section 2.1.1 of the market procedure states that the power station upon which the BRCP is based must:

- be representative of an industry standard liquid-fuelled open cycle gas turbine power station;
- have a nominal nameplate capacity of 160 MW prior to the addition of any inlet cooling system;
- operate on distillate as its fuel source;
- have a capacity factor of 2%;

- include low Nitrous Oxide (NOx) burners or associated technologies, as would be required to demonstrate good practice in power station development;
- include an inlet air cooling system and water receival and storage facilities to allow 14 hours of continuous operation, where in the opinion of AEMO[19] this would be cost effective; and
- include the minimum level of equipment or systems required to satisfy the balancing facility requirements.

26. The market procedure requires that AEMO must engage a consultant to provide:
    - an estimate of the costs associated with engineering, procurement and construction of the power station, as at April in year 3 of the reserve capacity cycle;
    - a summary of any escalation factors used in the determination; and
    - likely output at 41 degrees Celsius, which will take into account available turbine and inlet cooling technology, likely humidity conditions and any other relevant factors, which represents the expected capacity credit allocation of the power station.

27. AEMO commissioned GHD to provide an estimate of the capital cost for a 160 MW open cycle gas turbine, as required in the market procedure.

28. GHD selected a 173MW open cycle gas turbine[20] as the reference equipment to determine the power station capital cost component of the BRCP.

29. GHD notes that there is currently no generator available on the market that matches the specifications of the market procedure, i.e. a 160 MW open cycle gas turbine. As a result, GHD has identified costs that are directly affected by the size or capacity of the generating unit that are scalable. GHD scaled these costs for the 173MW open cycle gas turbine to represent the expected configuration of the 160MW open cycle gas turbine specified in the market procedure.

30. Given that the market procedure requires that the capital cost of the notional power station be based on a 160 MW industry standard liquid-fuelled open cycle gas turbine power station with inlet cooling, located within the SWIS, the ERA considers the scaling approach by GHD to be a reasonable application of the market procedure.

31. Based on GHD's cost estimate, escalated forward to 1 April 2019 dollars as required by the market procedure, AEMO has proposed a value of $810,229 per MW for the capital cost of an open cycle gas turbine.

32. The ERA notes that the estimated capital cost of a power station has decreased by 2.9 per cent compared to last year's cost, due to reductions in commodity prices and labour costs.

33. The ERA is satisfied that AEMO has calculated the capital cost of an open cycle gas turbine according to a methodology that reasonably reflects the application of the

[19] Since market operations and gas services information functions were transferred from the Independent Market Operator to AEMO on 30 November 2015, AEMO must now follow the market procedure to annually review the value of the BRCP according to the market procedure.

[20] The Siemens SGT5-2000E (33MAC) which is the only gas turbine make/model in production that is rated in close proximity to the notional power station required under the market procedure (i.e. 160MW industry standard liquid-fuelled open cycle gas turbine power station with inlet cooling).

method and guiding principles described in clause 4.16 of the market rules and the market procedure.

1.2 Factor for legal, insurance, approvals, other costs and contingencies (Margin M)

34. Step 2.8 of the market procedure states that AEMO must engage a consultant to determine the value of margin M, which shall constitute the following costs associated with the development of the power station project:

   a) legal costs associated with the design and construction of the power station;

   b) financing costs associated with equity raising;

   c) insurance costs associated with the project development phase;

   d) approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;

   a) other costs reasonably incurred in the design and management of the power station construction; and

   b) contingency costs.

35. AEMO commissioned GHD to provide an estimate of the above costs. GHD estimated these costs from similar costs associated with recent comparable developments from GHD's data bank, excluding any project specific abnormal costs. GHD has scaled the costs to a 160 MW open cycle gas turbine power station where relevant.

36. Based on GHD's report, AEMO proposed a margin of 17.19 per cent, which is added as a fixed percentage of the capital cost of developing the power station.

37. The ERA notes margin M has decreased from 20.00 per cent in the 2016 BRCP. This is due to a significant reduction in environmental permit and approval costs, which is now based on a less complex works approval assessment.

38. The ERA is satisfied that AEMO has calculated the margin for M according to a methodology that reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure.

1.3 Transmission connection works (TC)

39. Step 2.4 of the market procedure states that Western Power must provide an estimate of the total transmission costs. The costs must be in accordance with the methodology in the market procedure to connect the generator and deliver the output to loads, consistent with the relevant planning criteria in the Technical Rules.[21]

[21] See ERA website, *Technical Rules*, https://www.erawa.com.au/cproot/14411/2/EDM%2040518689%20-%20TECHNICAL%20RULES%201ST%20AUGUST%202016%20PUBLISH%20VERSION%20-%20FRI%20-%20R....pdf

40. The estimated total transmission costs must be derived from capital contributions either paid historically or expected to be paid to Western Power under Access Offers[22] and Western Power's Contribution Policy as approved by the ERA only for generators that are capable of being gas or liquid fuelled.[23]

41. According to the market procedure, the transmission connection cost is calculated by using actual connection costs for projects completed within a five-year window, and weights each connection cost according to the year that the facility commenced, or is expected to commence, operation.

42. For any year for which no actual project data is available, Western Power is required to estimate the shallow connection cost consistent with the market procedure.

43. The shallow connection cost refers to the cost that new generators have to pay that solely covers the direct infrastructure costs to connect their plant to the existing transmission system, which includes costs for construction of a substation, two kilometres of overhead line to the power station and an overhead line easement.[24]

44. In this year's review, there is no actual connection cost data available in the five-year window. Therefore, Western Power based the transmission connection costs on shallow connection cost estimates in accordance with the methodology described in the market procedure.

45. The underlying data used in estimating the transmission connection costs is commercially sensitive and confidential. Western Power must apply the process in the market procedure in calculating the transmission connection costs.

46. Western Power must then appoint a suitable auditor to review its application of the market procedure in calculating the transmission connection costs on an independent and confidential basis. Western Power must provide the advice of the auditor to AEMO together with its estimate of total transmission connection costs, and AEMO must publish the auditor's advice on the market website.

47. Western Power provided an independent audit report from Ernst & Young to verify that Western Power has adopted the process to estimate the total transmission connection cost in accordance with the market procedure.

48. AEMO has proposed a value of $175,444 per MW for transmission connection costs, which is an increase of 9.5 per cent from the 2016 estimate.

49. As required by the market procedure, the transmission connection cost calculation is based on costs for projects completed within a five-year window. Shallow connection costs must be estimated in any year where no actual project data is available. The 2017 transmission connection cost is based on shallow connection cost estimates for five years, and the 2016 transmission connection cost was based on shallow connection cost estimates for four years and actual connection costs for one year.

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[22] Access Offers are made in accordance with the *Electricity Networks Access Code 2004* and Western Power's Capital Contribution Policy.

[23] Facilities excluded from the Access Offers calculation are stipulated in section 2.4.1 of the market procedure.

[24] AEMO provides easement costs to Western Power for use in estimating shallow connection costs.

50. The 2017 transmission connection costs per MW have increased from 2016[25] despite a decrease in total shallow connection costs this year.[26] It can be inferred that the higher overall transmission connection costs this year is due to much lower actual connection costs last year compared to the lower estimated shallow connection costs this year.

51. The ERA notes that the methodology for calculating transmission connection costs stipulated in the market procedure is based on actual connection costs and access offers identified by Western Power. Currently, limited new generation capacity is being built in the Wholesale Electricity Market, resulting in limited project data available when calculating transmission connection costs. The ERA will review this element of the methodology in the next five-yearly BRCP methodology and market procedure review which is due to be undertaken in 2017.

52. The ERA is satisfied that AEMO has calculated transmission connected costs according to a methodology that reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure.

53. As the ERA does not have access to the underlying data and calculations of the total transmission connection costs, the ERA's approval is given on the basis that Ernst & Young's independent audit report has verified that Western Power followed the process to estimate the total transmission connection costs required by the market procedure.

1.4 Fixed fuel costs (FFC)

54. Step 2.6 of the market procedure states that AEMO must engage a consultant to determine an estimate of the costs for the liquid fuel storage and handling facilities of the power station.

55. AEMO commissioned GHD to estimate the fixed fuel costs. Based on GHD's estimates, escalated to 1 April 2019 as required by the market procedure, AEMO has proposed a value of $6.803 million for fixed fuel costs which is 4% lower than the 2016 value.

56. The reduction in the fixed fuel costs is due to a decrease in the price of delivered diesel fuel, the lower gross output of the reference equipment, and a higher fuel to energy efficiency rating. This reduces the cost of the first fill of the storage tank.

57. The ERA is satisfied that AEMO has calculated fixed fuel costs according to a methodology that reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure.

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[25] Transmission connection costs have increased from $160,280 per MW in 2016 to $175,444 per MW in 2017.

[26] Shallow connection costs decreased from $22,983,826 in 2016 to $22,558,523 in 2017. Shallow connection costs were used in the calculation in four of the five-year window in 2016, and were used in the calculation for all five years of the five-year window in 2017.

1.5 Land costs (LC)

58. Step 2.7 of the market procedure states that AEMO must retain Landgate under a consultancy agreement to provide valuations on parcels of industrial land. The analysis is required to include the following regions:

    a) Collie;

    b) Kemerton Industrial Park;

    c) Pinjar;

    d) Kwinana;

    e) the North Country region; and

    f) Kalgoorlie;

    These areas represent the regions within the SWIS where generation projects are most likely to be proposed and should provide a broad cross-section of options.

59. The market procedure states that AEMO will provide an indication as to the size of land required, which should be limited to:

    - a three hectare parcel of land in an industrial area of a standard size, with consideration given to any requirements for a buffer zone in that specific location (where the minimum land size is greater than three hectares, the minimum available land size shall be used); and
    - the summation of multiple smaller parcels of land, as appropriate to meet these requirements.

60. Landgate assessed the land sites for each region in or near existing industrial estates for land that would be suitable for the development of a power station. Landgate provided its estimate of the cost of each land parcel as at 30 June 2016 excluding transfer duty. AEMO has added the applicable transfer duty to each land parcel cost.

61. The ERA recognises that the inclusion of the transfer duty is not explicitly specified in the market procedure but considers that it is appropriate to include the transfer duty as part of the land costs calculation, as has been the case in previous years.

62. The ERA notes that three hectare sites were used for all locations except Kemerton, for which the smallest available lot is five hectares.

63. AEMO calculated the mean of the six valuations and escalated the land cost to 1 April 2019, as required in the market procedure.

64. AEMO proposed a value of $2.431 million for land costs, which is a decrease of 8.5 per cent from last year’s value. The decrease is due to the slowdown in the WA economy, driven by a weakening resources sector. This in turn has reduced demand for industrial land and resulted in lower sales and land prices. This specifically affected the land valuations of Geraldton, Kwinana and Pinjar regions.

65. The ERA is satisfied that AEMO has calculated land costs according to a methodology that reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure.

1.6 Fixed operating and maintenance costs (Annualised fixed O&M)

66. Step 2.5 of the market procedure states that AEMO must determine fixed O&M costs for the power station and the associated transmission connection works. Fixed O&M costs must also include:

- fixed network access and/or ongoing charges, which are to be provided by Western Power; and
- an estimate of annual insurance costs as at 1 October in Year 3 of the relevant reserve capacity cycle, in respect of power station asset replacement, business interruption and public and products liability insurance, as required under network access arrangements with Western Power.

67. AEMO commissioned GHD to provide an estimate of fixed O&M costs for the power station and the associated transmission connection works.

68. GHD calculated the generation O&M costs based on costs for similar recent open cycle gas turbine projects. These costs are annualised and escalated to 1 October 2019 using the generation O&M escalation factor, providing a value of $14,572 per MW per year.

69. The ERA notes the estimated generation O&M costs have decreased by 10.8% from last year's value. This is due to the decrease in the generation O&M escalation factor, which is caused by slow growth in labour costs associated with subdued activity in the resources and energy sectors.

70. GHD used a bottom-up approach to estimate the switchyard O&M costs, based on the annual charge for the connection infrastructure. The cost estimate included labour, machinery parts, and general overheads incurred during routine maintenance, which occurs one week per year on average. These costs are annualised and escalated to 1 October 2019 using the connection O&M escalation factor, providing a value of $528 per MW per year.

71. GHD used a bottom-up approach to estimate the transmission line O&M costs, based on the annual charge for the connection infrastructure. The cost estimate included labour, machinery parts, and general overheads incurred during routine maintenance. These costs are annualised and escalated to 1 October 2019 using the connection O&M escalation factor, providing a value of $32.74 per MW per year.

72. The fixed O&M costs include annual insurance costs to cover power station asset replacement, business interruption and public and products liability insurance. AEMO obtained advice on insurance costs from an independent insurance broker to calculate insurance premiums. The asset insurance costs are escalated to 1 October 2019 using the CPI escalation factor, providing an annualised value of $4,791 per MW per year.

73. AEMO estimated the fixed network access charges using Western Power's 2016-17 Price List which is approved by the ERA. It used the Transmission Reference Tariff 2 which is the relevant tariff that applies to generation facilities. The Muja Power Station substation was selected as the base tariff input for the calculation of the fixed

network access charges.[27] The fixed network access costs are escalated to 1 October 2019 using the CPI escalation factor, providing a value of $10,219 per MW per year.

74. Based on the cost estimates discussed above, AEMO has proposed a value for the total annualised fixed O&M costs of $30,143 per MW per year.

75. The ERA is satisfied that AEMO has calculated fixed operating and maintenance costs according to a methodology that reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure.

1.7 Weighted average cost of capital (WACC)

76. Step 2.9 of the market procedure states that AEMO must determine the cost of capital to be applied to various cost components of the BRCP. The market procedure sets out the parameters and a formula for calculating the WACC in real pre-tax terms.

77. The market procedure classifies the WACC parameters into two categories, i.e. the annual components and the five-yearly components.

78. The market procedure states that in determining the WACC, AEMO must review and determine values for the annual components. It may also review and determine values for the five-yearly components that differ from those in step 2.9.8 of the procedure if, in AEMO's opinion, a significant economic event has occurred since undertaking the last five-yearly review of the BRCP, in accordance with clause 4.16.9 of the market rules.

79. AEMO determined the WACC by using the Capital Asset Pricing Model. It engaged PricewaterhouseCoopers (**PwC**) to calculate the Debt Risk Premium (**DRP**) and calculated the remaining WACC components from information available from the RBA website. The nominal risk free rate is determined from observed yields of Commonwealth Government bonds, while the DRP is derived from observed yields of corporate bonds.

80. The market procedure requires AEMO to determine the methodology to estimate the DRP, which, in the opinion of AEMO, is "consistent with current accepted Australian regulatory practice".

81. The market procedure footnotes the "bond yield approach" developed by the ERA which is published in the ERA's Rate of Return Guidelines.[28] This approach uses a sample of bonds issued in Australian dollars by Australian entities to estimate a DRP. The average term to maturity of bonds samples used to estimate the DRP has a tendency to be around five years.

82. The ERA has recently adopted a revised bond yield approach to estimate the DRP. The revised bond yield approach uses a larger sample of bonds issued by entities

[27] Muja power station substation is the most expensive location and hence was selected as the base tariff input for the estimation of the fixed network access charges.

[28] Economic Regulation ERA, *Rate of Return Guidelines*, 16 December 2013, https://www.erawa.com.au/cproot/11953/2/Rate%20of%20Return%20Guidelines.PDF

whose country of risk is identified as Australia on Australian and international markets to estimate a bond yield curve to calculate a ten-year DRP.

83. This revised approach overcomes the issue of the sample of bonds producing a DRP with an average remaining term to maturity of less than ten years, and is in line with the requirement under the market procedure.

84. The ERA has recently adopted the revised bond yield approach in its:

- *Final Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System* in September 2015;[29]
- *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016-2020* in June 2016;[30] and
- *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline* in July 2016.[31]

85. AEMO considers the revised bond yield approach to be representative of current accepted Australian regulatory practice, and has calculated the DRP using this approach.

86. AEMO calculated the nominal risk free rate from the annualised yield of a selection of Commonwealth Government bonds with maturity dates of roughly ten years. AEMO then adjusted the nominal rate for inflation to determine the real risk free rate of return as required by the market procedure.

87. As per the market procedure, AEMO used the RBA's inflation forecasts which resulted in an expected rate of inflation of 2.39 per cent. This yielded a real Risk Free Rate of 0.18 per cent. AEMO notes that "a real risk free rate of 0.18 per cent is not reflective of current Australian market conditions, as it implies that riskier assets are generating low returns."

88. The ERA considers that although the calculated real Risk Free Rate of 0.18 per cent is lower than that observed in the Australian market, AEMO has no discretion to deviate from the methodology stipulated in the market procedure. The ERA will review this element of the methodology in the next five-yearly review of the BRCP methodology and market procedure.

89. The ERA notes that AEMO has not followed best practice in calculating the Risk Free Rate and DRP parameters in deriving the WACC. Firstly, AEMO did not consolidate duplicate bonds in calculating the DRP, resulting in eleven additional bonds in its

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[29] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution System*, 30 June 2015, as amended on 10 September 2015, https://www.erawa.com.au/cproot/13880/2/GDS%20-%20ATCO%20-%20AA4%20-%20Amended%20Final%20Decision%20-%20PUBLIC%20VERSION.PDF

[30] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016*-2020, 30 June 2016, https://www.erawa.com.au/cproot/14325/2/DBP%20AA4%20-%20Final%20Decision%20-%20REDACTED%20Version.PDF

[31] Economic Regulation Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline*, 30 June 2016, as amended on 21 July 2016, https://www.erawa.com.au/cproot/14401/2/GGP%20-%20GGT%20-%20AA3%20-%20Amended%20Final%20Decision%20-PUBLIC%20VERSION.PDF

sample. Secondly, AEMO calculated the Risk Free Rate and DRP based on different date ranges.[32] This issue has been identified in the last two BRCP reviews.

90. On this occasion these inconsistencies have had an immaterial impact on the final WACC figure. The ERA also notes that, unlike a regulatory WACC reset in the context of Access Arrangements, its role in the current context is to ensure AEMO has calculated the annual WACC parameters in accordance with the market procedure.

91. In the ERA's next five-yearly review of the BRCP methodology and market procedure, it will ensure sufficient clarity is provided in the procedure so that best practice can be achieved in calculating the BRCP.

92. The ERA is satisfied that AEMO has calculated the WACC according to a methodology that reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure.

Public consultation process

93. AEMO published a draft report on the 2017 BRCP for the 2019-20 capacity year on 21 November 2016. It described how it arrived at the proposed revised value for the BRCP and called for submissions by 2 December 2016.

94. The ERA notes the 2017 BRCP draft report and supporting documents were published for public consultation on 21 November 2016. AEMO advised market participants and other industry stakeholders of the publication and published an announcement in the West Australian on 22 November 2016.[33]

95. AEMO received submissions from Perth Energy and Tesla Corporation through the public consultation process on the BRCP draft report. The ERA notes the issues raised include the assumptions and methodology to estimate the cost of a representative power station and the methods used to calculate the WACC components. Chapter 4 of the 2017 BRCP for the 2019-20 capacity year final report summarises the details the submissions and responses to the submissions.

96. Issues similar to these have been raised over the past few reviews. AEMO noted the proposed BRCP is based on the current market procedure and these issues would need to be addressed as part of the next five-yearly BRCP methodology and market procedure review. The ERA will appropriately address issues raised by market participants in this year's and previous years' reviews as part of the next BRCP methodology and market procedure review, which is due in 2017.

97. The ERA is satisfied with the public consultation process undertaken by AEMO.

98. In the context of the application of the method and guiding principles described in clause 4.16 of the market rules and the market procedure, the ERA is satisfied that AEMO has addressed the comments raised by stakeholders appropriately in its final report.

[32] The DRP and Risk Free Rate were estimated from data ending in 25 November 2016 and 30 November 2016, respectively.

[33] AEMO website, *2017 BRCP*, http://wa.aemo.com.au/Stakeholder-Consultation/Consultations/Draft-Report-2017-Draft-Benchmark-Reserve-Capacity-Price-for-the-2019-20-Capacity-Year

CONCLUSION

99. The ERA is satisfied that AEMO has met the requirements of the market rules in proposing the BRCP for the 2019-20 capacity year for the following reasons:

- the ERA is satisfied that the proposed revised value of the BRCP reasonably reflects the application of the method and guiding principles described in clause 4.16 of the market rules; and

- the ERA is satisfied that AEMO has carried out an adequate public consultation process.

100. Based on the above assessment, the ERA approves the proposed revised value for the BRCP for the 2019-20 capacity year of $149,800 per MW per year, effective from 1 October 2019.