Decision on the Benchmark Reserve Capacity Price Proposed by AEMO for the 2020–21 Capacity Year

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1. Decision

1. In accordance with clause 2.26 of the *Wholesale Electricity Market Rules (13 October 2017)* (market rules), the Economic Regulation Authority approves:

   - the revised value for the benchmark reserve capacity price for the 2020–21 capacity year of $153,600 per MW, as proposed by the Australian Energy Market Operator.

2. In accordance with clause 4.16.8 of the market rules, the approved revised value for the benchmark reserve capacity price will apply with effect from the date and time specified in a notice to be published on the Australian Energy Market Operator's website.

2. Background

3. The reserve capacity mechanism comprises three fundamental components:

   a. Capacity credits are assigned to generation resources on the basis of the expected capability of the plants to supply electricity at times of peak demand.

   b. The Australian Energy Market Operator (AEMO) determines the level of reserve capacity required to meet the reliability objective of the Wholesale Electricity Market (WEM).[1]

   c. A price discovery mechanism determines the price of capacity credits. The benchmark reserve capacity price (BRCP) is used as a main input to this mechanism.[2] Under the market rules, the BRCP sets the maximum price that may be offered in a reserve capacity auction.[3] It is also an input in the determination of the administered reserve capacity price, if no auction is required.

4. Clause 4.16.3 of the market rules requires the ERA to develop a market procedure documenting the method and process AEMO must follow in determining the BRCP (refer to section 3).

5. The BRCP is determined based on the annualised capital and fixed operating and maintenance costs of a particular generation technology at the time of the delivery of capacity. As the aim of the reserve capacity market is to ensure sufficient capacity to meet peak-load requirements, a peaking facility is used as the reference generation technology. A peaking gas plant is assumed to be the marginal capacity resource to meet the capacity requirement.

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1 In the market rules (clause 4.5.10 (b)), this level of required capacity is referred to as the reserve capacity target.

2 The benchmark reserve capacity price 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.

3 A 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.

6. To calculate the BRCP, AEMO follows the method laid out in the current *Market Procedure: Maximum Reserve Capacity Price* (market procedure).[4,5]

7. Using the method set in the market procedure[6], AEMO proposes a revised value for the BRCP. It prepares a draft report describing how it has arrived at the proposed value, publishes the report on the market web site, and advertises the report in newspapers widely distributed in Western Australia. AEMO must also request submissions from all sectors of the Western Australian energy industry, including end-users.[7]

8. After considering submissions received on the draft report, AEMO proposes a final revised value for the BRCP to the ERA for approval. The market rules[8] require the ERA to review the final report provided by AEMO, including all submissions received by AEMO in preparation of the report, in deciding whether to approve any revised value of the BRCP.

9. In making its decision, the ERA must consider only:

   - 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; and
   - whether AEMO has carried out an adequate public consultation process.

10. The market rules[9] require 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. This should be carried out in accordance with any directions or recommendations of the ERA.

3. Market procedure: maximum reserve capacity price

11. The BRCP is calculated by undertaking a technical, bottom-up cost evaluation of the entry of a new 160 MW open cycle gas turbine generation facility in the South West Interconnected System in the relevant capacity year.[10]

12. The calculation of the 2020–21 BRCP is based on the assumption that the benchmark power plant would begin operating on 1 October 2020. Capital costs are escalated to 1 April 2020 and fixed operation and maintenance (O&M) costs are escalated to 1 October 2020.

13. The BRCP comprises:

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4 See the ERA's website, *Market Procedure: Maximum Reserve Capacity Price*, https://www.erawa.com.au/cproot/14362/2/Market%20Procedure%20-%20Maximum%20Reserve%20Capacity%20Price.pdf

5 Under the market rules, the Independent Market Operator's responsibility to periodically revise the market procedure was transferred to the ERA in 2016.

6 Provided by clause 4.16.3(b) and 4.16.5 of the market rules.

7 Provided by clause 4.16.6 of the market rules.

8 Clause 2.26.1.

9 Clause 2.26.2.

10 A capacity year is a period of 12 months commencing at the start of the trading day on 1 October each year.

- the capital cost of building a 160 MW open cycle gas turbine power station with an inlet cooling system in the South West Interconnected System,[11] including a margin to cover legal, approval, financing and other costs and contingencies;[12]
- the costs of connecting the power station to the transmission system;[13]
- the costs of building liquid fuel storage and handling facilities;[14]
- the land cost for developing and constructing the power station;[15]
- the weighted average cost of capital;[16] and
- the fixed O&M costs of the power station and transmission facilities.

14. Using the parameters explained in paragraph 1313, the market procedure provides methods for estimating annualised fixed operating and maintenance and annualised capital costs, which are used in calculating the BRCP.[17]

4. ERA assessment

15. Consistent with the approach in previous years, AEMO undertook the BRCP review and released a draft report for public consultation on 16 November 2017.[18] The consultation period closed on 30 November 2017. AEMO received one submission from Perth Energy (refer to section 4.8).

16. On 15 December 2017, AEMO provided its final report on the BRCP for the 2020–21 capacity year to the ERA.

17. Table 1 provides a summary of the input parameters to the BRCP estimation and its calculated values for the 2020–21 capacity year in AEMO's final report, compared with those for the 2019–20 capacity year.

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[11] Expressed in Australian dollars per MW and as determined in step 2.3 of the market procedure.

[12] As detailed in step 2.8 of the market procedure.

[13] As detailed in step 2.4 of the market procedure.

[14] As detailed in step 2.6 of the market procedure.

[15] As detailed in step 2.7 of the market procedure.

[16] As detailed in step 2.9 of the market procedure.

[17] As detailed in step 2.10 of the market procedure.

[18] See AEMO website, 2017 Energy Price Limits Review, https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/WA_WEM_Consultation_Documents/2017/Price-limits-review/Jacobs-Draft-Report.pdf

Table 1. A comparison of BRCP components for 2019–20 and 2020–21

Parameter	Units	Proposed BRCP and calculated values for 2020–21	Approved BRCP and calculated values for 2019–20
Power station expected capacity credit allocation (CC)	MW	151.4	148.5
Weighted average cost of capital	%	5.21	5.29
Power station costs	$/MW	846,751	810,229
Factor for legal, financing, approvals, contingencies and other costs	%	17.12	17.19
Transmission connection works	$/MW	174,749	175,444
Fixed fuel costs	$	6,969,444	6,803,924
Land costs	$	2,394,088	2,430,526
Total capital cost	$	190,747,133	180,893,141
Annualised capital cost	$/year	18,644,285	17,776,436
Annualised fixed O&M cost	$/MW.year	30,437	30,143
BRCP (rounded)	$/MW.year	153,600	149,800

18. AEMO proposes a BRCP of $153,600 per MW per year for the 2020–21 capacity year. This is 2.5 per cent higher than the BRCP for the 2019–20 capacity year.

19. AEMO's final report states the principal cause of increase in BRCP value is higher escalation factors (for steel and copper prices, inflation, and labour costs) used in estimating power station costs. Together, these escalation factors increase the BRCP by 2.7 per cent. This is partly offset by a decrease in the weighted average cost of capital.

20. The ERA has reviewed AEMO's BRCP draft report and final report, BRCP calculation spreadsheets, and public submissions received by AEMO in response to its BRCP draft report. The ERA has also reviewed reports from consultants GHD and PricewaterhouseCoopers, commissioned by AEMO for the BRCP review.

4.1. Power station costs

21. Section 2.1.1 of the market procedure specifies that the reference power station must be representative of an industry standard liquid-fuelled open cycle gas turbine power station and have a nominal nameplate capacity of 160 MW prior to the addition of any inlet cooling system.

22. The market procedure requires AEMO to engage a consultant to provide:

    - an estimate of the costs of 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
    - expected power station output at 41 degrees Celsius, which will take into account available turbine and inlet cooling technology, potential humidity conditions and any other relevant factors. The calculation of the output under the given conditions

determines the expected capacity credit allocation of the power station for the new entrant.

23. AEMO commissioned GHD to provide an estimate of the capital cost for a 160 MW open cycle gas turbine.

24. GHD selected a 175.6 MW nameplate capacity Siemens SGT5-2000E (33MAC) gas turbine as the reference equipment to determine the power station capital cost component of the BRCP. GHD notes that among several reviewed gas turbines, this unit provides good value in terms of capital and O&M costs. The capacity of this unit is also close to the 160 MW nameplate capacity required under the market procedure.

25. GHD used several escalation factors to forecast the power station costs on 1 April 2020. It used the Reserve Bank of Australia's short-term forecasts for the consumer price index. For the labour cost forecast, it used the Australian Bureau of Statistics' electricity, gas, water and waste water labour wage price index and Western Australian wage price index historical data. For the Australian to United States dollar exchange rate, GHD used forecasts developed by CME Group. For copper and steel price forecasts, it sourced data from well-known public databases.

26. GHD scaled the costs of the selected 175.6 MW open cycle gas turbine to the expected configuration of the benchmark gas turbine to meet the requirement of the market procedure (refer to paragraph 21).

27. Based on the expected performance of the selected gas turbine under the Muja power station site conditions, GHD estimated an expected capacity credit allocation of 151.4 MW. Due to efficiency improvements in the selected machine, this value is higher than the value estimated in the 2017 BRCP review.

28. The ERA considers the scaling approach by GHD to be a reasonable application of the market procedure.[19]

29. Based on GHD's cost estimate, escalated forward to 1 April 2020 dollars, AEMO proposes a value of $846,751.15 per MW for the capital cost of the reference open cycle gas turbine.

30. The estimated capital cost of a power station has increased by 4.5 per cent compared to last year's cost, due to higher escalation factors and an increase in the capital cost.

4.2. Transmission connection costs

31. Step 2.4 of the market procedure requires Western Power to provide an estimate of the total transmission costs to connect the new entrant generator to the South West Interconnected System. The costs must be in accordance with the method in the market procedure to connect the generator and deliver the output to loads, consistent with the relevant planning criteria in the Technical Rules.[20]

[19] AEMO states that currently there is no generator unit in the market that fully matches the specified 160 MW capacity requirement in the market procedure. As a result, GHD scales the costs of a similar 175.6 MW generation unit to meet the required specification.

[20] See ERA's 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

32. The estimated total transmission costs are to be derived from capital contributions either paid historically or expected to be paid to Western Power under Access Offers[21] and Western Power's Contribution Policy as approved by the ERA.[22,23]

33. The transmission connection cost is calculated by using actual connection costs for projects completed within a five-year window. Each connection cost is weighted according to the year that the facility commenced, or is expected to commence, operation.

34. For any year where no actual project data is available, Western Power is required to estimate the shallow connection cost. The shallow connection cost refers to the cost that new generators have to pay that solely covers the direct infrastructure costs of connecting their plant to the existing transmission system. This includes costs for construction of a substation, two kilometres of overhead line to the power station and an overhead line easement.[24]

35. 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. AEMO must publish the auditor's advice on the market website.

36. In this year's review of transmission costs, there is no actual project data available in the five-year window. Therefore, Western Power based the transmission connection costs on shallow connection cost estimates.[25]

37. Western Power provided an independent review report from Ernst & Young verifying that Western Power has estimated the total transmission connection cost in accordance with the market procedure. Ernst & Young's report states that "*nothing has come to our attention that causes us to believe that Electricity Networks Corporation has not, in all material respects, adopted a process to estimate the Total Transmission cost Estimate for the Benchmark Reserve Capacity Price for 2020–21 that is in accordance with the Economic Regulation Authority's Market Procedure*".

38. AEMO proposes a value of $174,749.00 per MW for transmission connection costs. This is a decrease of 0.4 per cent from the 2017 estimate and is partly due to a fall in land values in the Kalgoorlie region.[26]

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

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

[23] This is estimated based on generators that are capable of being gas or liquid fuelled.

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

[25] The ERA notes that the method 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 method in the next five-yearly BRCP estimation method and market procedure review.

[26] For confidentiality reasons, other components of the transmission cost are not available to assess their variation over years.

4.3. Fixed operating and maintenance costs

39. Step 2.5 of the market procedure states that AEMO must determine O&M costs for the power station and its transmission connection works.[27] 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.

40. AEMO commissioned GHD to provide estimates of fixed O&M costs for the generation plant, switchyard, and transmission line. GHD calculated the generation O&M costs based on the selection of the benchmark plant and its configuration explained in section 4.1. The O&M costs are annualised and escalated to 1 October 2020 using the generation O&M escalation factor, giving a value of $14,243.65 per MW per year.

41. The estimated generation O&M costs have decreased by 2.3 per cent from last year's value. AEMO attributes this decrease to the decrease in council rates and subcontractor fees estimates and a slightly higher capacity credit value.[28]

42. GHD used a bottom-up approach to estimate the switchyard O&M costs, based on an annualised charge for the connection infrastructure. The cost estimate includes 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 2020 using the connection O&M escalation factor, providing a value of $524.80 per MW per year. This value is consistent with the value calculated for the 2017 BRCP.

43. GHD uses a bottom-up approach to estimate the transmission line O&M costs, based on the annual charge for the connection infrastructure. The cost estimate includes labour, machinery parts, and general overheads incurred during routine maintenance. These costs are annualised and escalated to 1 October 2020 using the connection O&M escalation factor, providing a value of $32.53 per MW per year. This value is consistent with the value calculated for the 2017 BRCP.

44. AEMO obtained advice on insurance costs from an independent insurance broker to calculate insurance premiums. The asset insurance costs are escalated to 1 October 2020 using the Consumer Price Index escalation factor, providing an annualised value of $5,381.29 per MW per year.

45. This year's estimates have increased by 12.3 per cent compared to the previous year. AEMO states that this is consistent with an increase in global energy sector insurance premiums.

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[27] GHD provides a list of these fixed O&M costs in its report. Refer to GHD's report p. 16, section 4.1, http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/WA_WEM_Consultation_Documents/2017/BRCP/GHD-2020-21-Benchmark-Reserve-Capacity-Price-for-the-SWIS.pdf

[28] Refer to page 18 of GHD's report for a summary of O&M cost component changes.

46. AEMO estimates the fixed network access charges using Western Power's 2016–17 Price List.[29] Transmission Reference Tariff 2 is the relevant tariff applying to generation facilities. The Muja power station substation is selected as the base tariff for the calculation of the fixed network access charges.[30] The fixed network access costs are escalated to 1 October 2020 using the Consumer Price Index escalation factor, providing a value of $10,254.73 per MW per year. Due to marginally higher Consumer Price Index forecasts, the fixed network access cost estimate has increased by 0.4 per cent from the 2017 BRCP estimate.

47. Based on the cost estimates discussed above, AEMO proposes a value for the total annualised fixed O&M costs of $30,437.00 per MW per year.

4.4. Fixed fuel costs

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

49. AEMO commissioned GHD to estimate the fixed fuel costs. Based on GHD's estimates, AEMO proposes a value of $6,969,444.03 for fixed fuel costs. This is 2.4 per cent higher than the 2017 value despite GHD selecting a more efficient gas turbine. The increase is due to a 7 per cent increase in the price of delivered diesel fuel and the escalation of facility installation costs.[31]

4.5. Land costs

50. 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 requires inclusion of six specific regions within the South West Interconnected System where generation projects are most likely to be proposed and should provide a broad cross-section of options.[32]

51. 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. Estimates of the cost of each land parcel were provided as at 30 June 2017. AEMO adds the applicable transfer duty to each land parcel cost.

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

53. The calculation uses three-hectare sites for all locations except Kemerton, where the smallest available lot is five hectares.

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[29] Western Power's price list is approved annually by the ERA.

[30] Muja power station substation is the most expensive location among the regions specified in step 2.7.1 of the market procedure and hence was selected as the base tariff input for the estimation of the fixed network access charges.

[31] The fuel cost is only allowed for initial supply of fuel sufficient for the power station to operate for 14 hours at maximum capacity, as required by the market procedure.

[32] The market procedure specifies the six regions as Collie, Kemerton Industrial Park, Pinjar, Kwinana, North Country, and Kalgoorlie.

54. AEMO calculates the mean of the six valuations and escalates the land cost to 1 April 2020.[33]

55. AEMO proposes a value of $2,394,087.94 for land costs, which is a decrease of 1.5 per cent from last year's value. A 20 per cent decrease in the value of land in the Kalgoorlie region is the main contributor to the decrease in the average value of land. Land values in other regions slightly increased or remained similar when compared to last year estimates.

4.6. Factor for legal, insurance, approvals, other costs and contingencies

56. Step 2.8 of the market procedure states that AEMO must engage a consultant to determine the value of margin M, which shall constitute legal, financing, insurance, licensing, approval, and contingency costs during the construction of the power plant. This margin also accounts for any other cost reasonably incurred in the design and management of the power station construction.

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

58. Based on GHD's report, AEMO proposes a margin of 17.12 per cent. This margin is used to escalate the capital cost of the power plant and is similar to the margin values used in the 2019–20 BRCP.

4.7. Weighted average cost of capital

59. Step 2.9 of the market procedure requires AEMO to 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.

60. The market procedure classifies the WACC parameters into two categories; the annual components and the five-yearly components. 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 the last five-yearly review of the BRCP method.[34]

61. In calculating the WACC, AEMO should estimate return on equity and return on debt parameters. AEMO has determined return on equity by using the capital asset pricing model and engaged PricewaterhouseCoopers to calculate the debt risk premium (DRP).[35]

[33] Paragraph 2.2.4 of AEMO's Final Report: 2018 Benchmark Reserve Capacity Price for the 2020–21 Capacity Year submitted to the ERA states that AEMO escalates land costs to 1 April 2019. The ERA reviewed the calculations provided by AEMO and confirmed that AEMO correctly escalates those costs to 1 April 2020.

[34] In accordance with clause 4.16.9 of the market rules.

[35] DRP is a margin above the risk free rate of return reflecting the risk in provision of debt finance.

62. To estimate the return on equity based on the capital asset pricing model, AEMO needs to determine the risk free rate of return.[36] Other parameters for estimating return on equity, e.g. the equity beta and market risk premium, are five-yearly components. AEMO uses the specified values in step 2.9.8 of the market procedure for these parameters.

Estimation of risk free rate of return

63. AEMO calculates the nominal risk free rate from the annualised yield of a selection of Commonwealth Government bonds with maturity dates of approximately ten years. A 20-day average of market observations (ending on 17 November 2017) was used to estimate the nominal risk free rate of 2.67 per cent, which is higher than the previous year's estimate.

64. AEMO adjusts the nominal rate for inflation to determine the real risk free rate of return. In line with the market procedure, AEMO uses the Reserve Bank of Australia's (RBA) inflation forecasts or the mid-point of the RBA's target inflation range outside of the RBA's forecast period. Based on RBA's forecasts and targets, AEMO estimates the expected rate of inflation at 2.42 per cent. Therefore, AEMO estimates the real risk free rate of interest at 0.24 per cent.

65. Following the method prescribed in the market procedure, AEMO underestimates the real risk free rate of return. AEMO's estimated value is lower than that observed in the Australian market. For instance, as part of its 'Determination on the 2017 Weighted Average Cost of Capital for the Freight and Urban Railway Networks, and for Pilbara railways' report, the ERA estimated the value of the real risk free rate of return at 0.57 per cent.[37,38]

66. AEMO has no discretion to deviate from the method stipulated in the market procedure.[39]

Estimation of debt risk premium

67. The market procedure requires AEMO to determine the method to estimate the debt risk premium (DRP), which, in the opinion of AEMO, is "*consistent with current accepted Australian regulatory practice*". The market procedure stipulates that AEMO should determine the DRP based on the margin between the observed annual yields of Australian corporate bonds that have a BBB (or equivalent) credit rating from Standard and Poors and the nominal risk free rate.

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[36] The risk free rate is the rate of return an investor receives from holding an asset with a guaranteed payment stream, that is, where there is no risk of default. Since there is no likelihood of default, the return on risk free assets compensates investors for the time value of money.

[37] Refer to ERA, 2017. Determination on the 2017 Weighted Average Cost of Capital for the Freight and Urban Railway Networks, and for Pilbara railways, p.4, Table 1 https://www.erawa.com.au/cproot/18364/2/Determination%20on%20the%202017%20WACC%20for%20the%20Freight%20and%20Urban%20Railway%20Networks%20and%20for%20Pilbara%20railways.PDF

[38] Real risk free rate of return and inflation rate are derived based on discounting the real yield on Treasury inflation indexed bonds out of the nominal yield on conventional Treasury bonds.

[39] The ERA will undertake the next review of the market procedure and will address the calculation of the real risk free rate of return.

68. The market procedure also footnotes the 'bond yield approach' developed by the ERA, which is published in the ERA's Rate of Return Guidelines.[40] This approach uses a sample of bonds issued in Australian dollars by Australian entities to estimate a DRP. The average term to maturity of bond samples used to estimate the DRP using this bond yield approach has a tendency to be around five years. The term basis required for the calculation of DRP in the market procedure is, however, 10 years.

69. Since 2015, the ERA has adopted a revised bond yield approach to estimate the DRP.[41] The revised bond yield approach uses a larger sample of bonds issued by entities 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. 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.

70. AEMO considers that the revised bond yield approach is representative of current accepted Australian regulatory practice. Using this approach and a 20-business day sample of corporate bonds ending on 17 November 2017, PricewaterhouseCoopers calculated the DRP at 1.8 per cent.

71. Similar to last year's review, AEMO has not followed best practice in calculating DRP. AEMO did not consolidate duplicate bonds in calculating the DRP, resulting in sixteen additional bonds in its sample.[42] The ERA Secretariat informed AEMO about the problem after the publication of its draft report in November 2017 and requested that AEMO investigate the potential effect of the duplicated bonds on the DRP and BRCP results.

72. AEMO engaged PricewaterhouseCoopers to assess the effect of the duplicate bonds. AEMO reported to the ERA that the omission of duplicate bonds raises the estimated DRP by 3 basis points and raises the BRCP from $153,600 per MW per year to $153,700 per MW per year. Given the minimal change on estimated BRCP and AEMO's limited timeline to rework its final report, the ERA accepted the estimated figures this year. AEMO has committed to rectify this in future BRCP reviews.

73. This year, AEMO took the opportunity to rectify a problem from the last two BRCP reviews where it had calculated the risk free rate and DRP on different date ranges.

74. Based on the calculated DRP and risk free rate, 5-yearly parameters specified in clause 2.9.8 of the market procedure, and a corporate tax rate of 30 per cent, AEMO estimates the weighted average cost of capital at 5.21 per cent.

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

[41] For instance, the ERA has 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; Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016-2020 in June 2016; and Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline in July 2016.

[42] The ERA also identified a bond with a BBB+ (not the required BBB) rating in the sample of corporate bonds used to estimate the BRCP in AEMO's draft report published in November 2017.

4.8. Public consultation process

75. On 16 November 2017, AEMO published a draft report on the 2018 BRCP for the 2019–21 capacity year and called for submissions by 30 November 2017.

76. AEMO received one submission from Perth Energy. Perth Energy suggested that the business interruption insurance cost should include a premium for potential capacity credit refund liability. A major risk for a peaking station is that a significant incident could require the station to repay up to two years of reserve capacity payments. In response, AEMO stated that the business interruption component of the asset insurance costs includes coverage for the potential refund liability, and therefore no further adjustment is needed.[43]

77. Perth Energy was also concerned about the accuracy of the weighted average cost of capital estimation method in the market procedure. However, Perth Energy agreed that AEMO should follow the method set in the market procedure until such a time as the procedure is revised.

78. The ERA considers that a suitably designed market procedure provides confidence in the market and facilitates investments in generation capacity. It is important that AEMO does not deviate from the market procedure to ensure that investors' decisions are not undermined.

79. However, during previous reviews and consultation processes market participants and AEMO have provided feedback and raised concerns about the method for calculating the BRCP.[44]

80. The ERA has considered feedback received from market participants and AEMO in reviews of the BRCP. The ERA will address concerns about the BRCP calculation method in its next review of the market procedure. In anticipation of changes in the reserve capacity mechanim and its potential implications for the BRCP calculation, the ERA has delayed its review of the market procedure since 2016. Recently, the Public Utilities Office published a roadmap for energy sector reform that includes a review of alternative pricing models for the reserve capacity mechanism.[45] The ERA will consider changes to the reserve capacity mechanism in its next review of the method used to calculate the BRCP.

5. Conclusion

81. The ERA is satisfied that AEMO has met the requirements of the market rules in proposing the BRCP for the 2020–21 capacity year for the following reasons:

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[43] AEMO stated that while a construction period of one year was assumed in the application of the weighted average cost of capital, a period of time would be required prior to commencement of construction work following a loss event (for example, for service procurement, building approvals, and any demolition or clearing works).

[44] For a summary of these issues in the market procedure refer to AEMO's Final Report: 2018 Benchmark Reserve Capacity Price for the 2020–21 Capacity Year, December 2017, p.17, Table 8.

[45] Refer to Public Utilities Office, 2017. Electricity Sector Reform Initiatives – A roadmap for the current reform work program, http://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Roadmap-reform-work-program.pdf

- 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
- AEMO has carried out an adequate public consultation process.

82. Based on the above assessment, the ERA approves the proposed revised value for the BRCP for the 2020–21 capacity year of $153,600 per MW per year. The approved revised value for the BRCP will apply with effect from the date and time specified in a notice to be published on the AEMO's website.