Community Electricity

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Response to PUO Public Consultation

Reserve Capacity Pricing and Price Signals

Standing

Community Electricity is:

a a licensed Electricity Retailer and provider of Electricity Retail Services and Market Consultancy;
b a member of the Access Code Development Committee (2003 to 2004)
c a member of the Rule Change Panel's Market Advisory Committee since 2008;
d a member of the Economic Regulation Authority's previous Technical Rules Committees from time to time;

Further information is available at: www.communityelectricity.net.au

Response

Community Electricity establishes the context and responds to the specific issues requested by the PUO as follows.

Context

1. The previous state government conducted a comprehensive Electricity Market Review (EMR) with the objectives of:

   - reducing the subsidy paid to Synergy without commensurate tariff increases;
   - attract to the SWIS Wholesale Electricity Market (WEM) Market-Participants with investment grade balance sheets;
   - remove from government the financial burden of underwriting new generation developments.

2. The review found that the WEM should as far as practicable "join" the National Electricity Market as that market had at that time proved to be effective, efficient and robust. The government accepted many of the recommendations but decided to retain the Reserve Capacity Mechanism and implemented Market Rule Changes to:

   - substantially revise the participation of Demand Side Management;
   - implement the "Lantau Curve" linking Capacity Price to demand-supply balance
   - transition to a Capacity Price Auction

3. A change of government occurred in March 2017 and the present government has resumed a reform process which among many other things includes continuation of the Reserve Capacity Mechanism reforms.

Consultation and industry participation

4. A key feature of the original EMR is that the high level decisions were imposed by the government regardless of the wishes of industry. The process was overseen confidentially by a Steering Committee composed primarily of government officials and the chair of Synergy. This permitted Synergy to integrate its strategic planning with market development.

5. Industry participation was invited only at the lower, detailed, levels.

6. The Lantau Curve for administratively determining the Capacity Price was essentially developed by the former IMO with broad industry participation and support. However, at that time DSM participation was 550MW and its contribution to over-capacity drove the Reserve Capacity Price down the price curve to relatively low levels.

7. We suggest that there was, and remains, very little industry support for a Reserve Capacity Auction; the previous government sought to impose the notion, albeit with a transition time of several years to enable the details to be worked out.

8. A considerable issue with an auction is the mitigation of market power. We suggest that Synergy, as the principal capacity provider, is caught in an irreconcilable bind; anything it does, reasonable or not, is an exercise of market power that hugely influences the capacity price. In the prevailing transition period, this manifests via the "-4" slope of the Lantau Curve.

9. We suggest that an auction that properly mitigates the misuse of market power is practically indistinguishable from an administered process and it isn't clear how a new process would improve on the prevailing one.

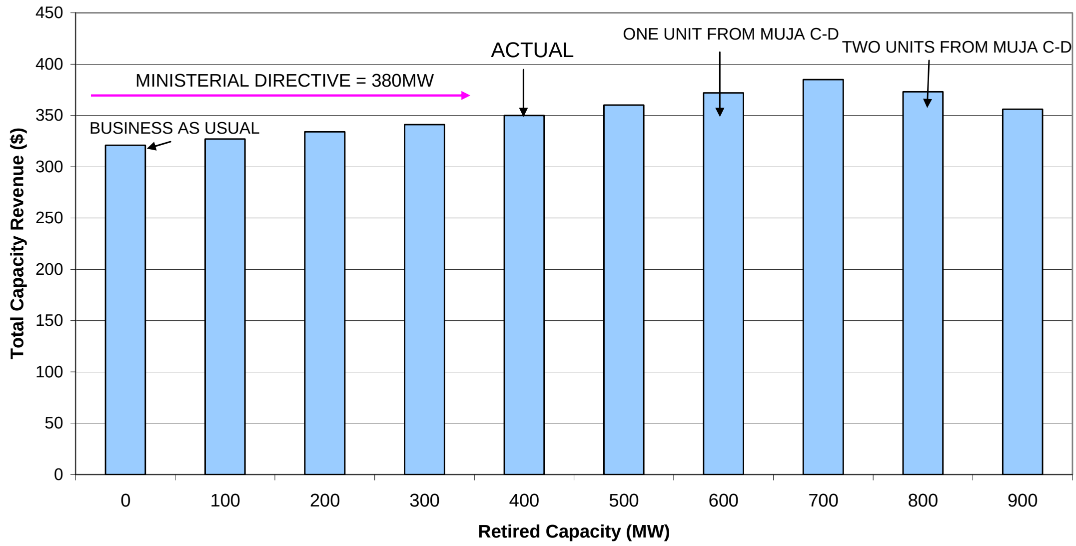
Fatal fault in the existing capacity price formula

10. We cite the example of recent experience. The EMR forecast based on expected business as usual a placeholder capacity price of $105,000 per MW per year for CY 2018-19. In contrast, the majority of the DSM was forced out of the market and Synergy additionally retired "380MW" of plant under supposed "government direction". The resulting price is $139,000 per MW per year, being a 32% increase.

11. More importantly, the revenue received by Synergy [Capacity Quantity x Capacity Price] is actually higher than it would have been had the retirements not occurred [Proportionately higher Capacity Quantity x disproportionately lower Capacity Price.]

12. This is illustrated in the following chart of Synergy Revenue as a function of Synergy Capacity Retirements. It is seen that Synergy's revenue will further increase should it retire more plant until the Capacity Price hits the price cap. The optimal level for CY 2018-19 (for which the window closed long ago) was 320MW. This is equivalent to "~1.5" units (so to speak) from Muja C-D.

Synergy Capacity Revenue as a function of Synergy's Retired Capacity - Capacity Year 2018-19



Generation Retirement signal

13. Conventional wisdom posits that generator retirements are promoted by lower Capacity Prices. We enphasise the distinction between Capacity Price and Capacity Revenue for a given quantity of capacity.

14. We challenge the conventional wisdom on the grounds that private generators are no older than the market and its development (15 years) and therefore will not retire. Rather, a low Capacity Price is more likely to breach the debt covenants for those plants (more below), put the owner into default, followed by receivership, followed by repricing of the asset and sale to a new owner.

15. Synergy is the only entity that is likely to retire generation, with 1,000MW of ageing assets.

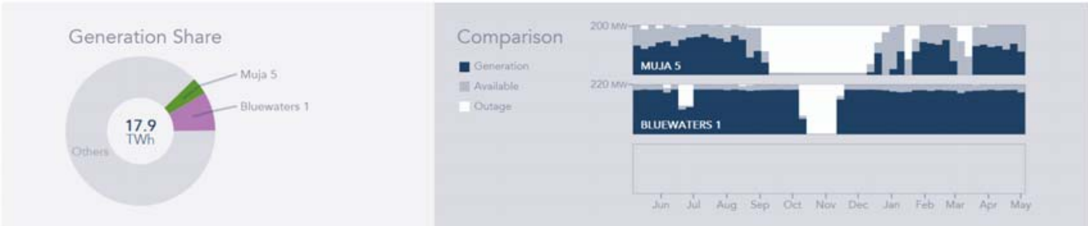
16. Noting that generation retirement increases the Capacity Price, Synergy has the ability to send the Capacity Price to the cap at any time.

17. We suggest instead that generator retirements can be promoted by allocating the pool of capacity revenues raised from buyers only to generators that are available (but not necessarily running); that is, when a generator is unavailable for any reason (including planned outage), it receives no payment. In this way, shorter duration outages would be incentivised and generators that are on planned outage for long periods would receive a signal to retire regardless of the Capacity Price. We suggest that the penalties for Forced Outages would continue as at present.

18. We cite as an example Synergy's Cockburn CCGT (15 years old) versus NewGen's CCGT (10 years old) at nominally the same location, shown below from AEMO's website. Cockburn was on outage (mostly planned, but forced towards the end of that period) for over half the year - the white spaces in the

chart [leaving aside the fact that since it "returned to service" it has rarely operated, even over the Hot Season]. In contrast, NewGen was off for 3 weeks, but both plants receive nominally the same capacity revenues (except for size differences and Cockburn being penalised for Forced Outages]. The relative contributions to energy production is starkly evident.

19. The equivalent comparison for Bluewaters 1 (10 years old) and Muja 5 (37 years old) is shown below. Both units are coal fired and nominally the same location. Bluewaters was off for 1 month compared to the older Muja 5's 4 months. The relative contributions to energy production is again starkly evident.



20. [Placeholder to retain numbering.]

21. Under this proposal, Muja 5 and Cockburn would receive substantially reduced capacity revenues.

22. We emphasise that under the present arrangement, the retirement signal for Synergy is a perverse increase in its portfolio capacity revenue; that is, a retirement bribe rather than an efficiency signal.

Bankability

23. We suggest that generator bankability is the principal issue in designing an electricity market. We suggest that electricity markets are more appropriately considered to be mechanisms for converting the credit standing of disparate and diverse revenue flows from individual "junk" to collective investment grade. We suggest that the principal mechanism for achieving this is the Market Operator's duty to impose on all Market Participants a proportionate levy to make good any payment default. We suggest that in practice, the market's credit standing is de-facto AAA because it has an unlimited obligation to "tax" a captive constituency that has unlimited ability to pay,and without political consequences.

24. Generating Projects require optimum debt financing (proportion of debt, interest rate and debt term), which in turn requires sufficient predictable and stable revenue streams. Anything that disrupts the revenue stream inhibits bankability and increases the risk premium. The ideal revenue stream is from an AAA-rated entity that buys at a defined price. The debt interest rate increases to reflect lesser credit ratings and uncontracted quantities.

25. Debt providers require covenants which when breached enabling them to call in the loan. This compels refinancing under distressed conditions. Regulatory risk (such as changes to the Reserve Capacity Mechanism) can force refinancing.

26. The principal test of a regulation is that it should facilitate bankability. The original EMR was premised on new market participants with strong balance sheets providing that bankability. This prospect was contingent on FRC providing the necessary financial incentives to attract such entities.

27. Historically, Synergy has been the principal source of bankability via its parent (state government) guarantee and its supply monopolies from time to time.

28. Other important sources of bankability include:

    - large retailers such as Alinta, ERM, and Perth Energy supplying their respective customer shares;
    - the Reserve Capacity Mechanism, whereby the market underwrites generating capacity (but not the energy it produces);
    - the Clean Energy Regulations

29. Bankability is currently driven by the Clean Energy Regulations and the blow-out in the price of LGCs. This has created a surge of investment in renewable energy plants within a window of opportunity that has, arguably, now closed.

30. The Reserve Capacity Mechanism has previously underwritten diesel peaking stations. However, this contributed to capacity oversupply and provided 'fake' generation that was very unlikely be used to produce energy. The RCM was subject to the regulatory shock of the Lantau Curve which immediately saw the capacity price fall significantly. Public submissions around this time claimed that debt covenants were potentially about to be breached. [Subsequently, the capacity price surged and those same diesel peakers instead looked to expand].

31. Large retailers have successfully developed over a quarter of the scheduled generation on the system and secured retail market shares commensurate with that. Further expansion is much more difficult within a limited and competitive market - hence the need for FRC if new invetsments are to be underwritten through this channel.

Beneficiaries of market Reform should pay

32. We suggest the principle that the beneficiaries of the market reforms should be the end-buyers of electricity and that it is therefore appropriate for the market to

carry more risk (to reduce risk premiums) on their behalf. We suggest that the technology risk and market risks are more effectively born by the market. We suggest that this is most effectively implemented through centrally planned tenders specifying the envisaged quantity, technology, and term.

Lowest price

33. The Wholesale Market Objectives are essentially concerned with market efficiency (lowest sustainable price) and supply reliability.

34. The Long Run Marginal cost of a Generator is essentially its Short Run Marginal Cost (fuel, maintenance, operating costs) plus its cost of capital.

35. Participants in the capacity mechanism are obligated to submit to central approval of outages and to offer their energy at SRMC.

36. We suggest a reframe of the perception of the Capacity Price; it is not about signalling the need to build and retire generators, rather it is the quid pro quo for the obligation to offer at SRMC and perform maintenance under central authority. From this perspective, the mechanism is about mapping capacity revenues onto the cost of capital service.

37. Principal risk parameters in the establishment of a generation project include technological obsolescence, uncertainty over market size and oversupply due to government incentives to renewable generation.

38. The WEM has traditionally considered these risks to be "slowly moving", incremental and predictable, and that they should therefore be born by the project capital.

39. This approach remains a 'nice to have', but it needs to be recognised that there is a cost attached to it via the risk premium imposed on the cost of capital, and that the new paradigm hosts dragons that previously didn't exist. Projects factor that risk into the cost of capital and map that onto the capacity price. If it doesn't match, they won't build.

Market Risk

40. System demand is reducing due to renewables penetration, energy efficiency and price elasticity. The network is transitioning to a constrained access model. For the first time, end-users can vacate the grid. [We would suggest that the grid is deserting them, but that's for another venue.] The power system is becoming increasingly unstable and the current SWIS ancillary services provisions are trending towards a crisis that will be starkly exposed if and when Synergy is forced to cease portfolio bidding. The need is increasing for fast-start high-efficiency, flexible gas turbines. However, in a few years batteries are expected to solve the stability problems and simultaneously instigate further dislocation to the generation fleet. The window between ancillary service crisis and the comprehensive solution of that crisis through batteries is fraught with dragons and brief compared to plant lifetimes. The capacity mechanism is guaranteed to

be dysfunctional until its long term future is specified, and then industry will need to see it working for a few years before embarking on the long lead times to build a scheduled generating plant. In effect, nobody will build for a decade and within that decade batteries will come of age and, presumably by then, the market will recognise their existence.

41. The industry has to decide who is to bear this risk - we suggest that it should be the market so as to avoid the risk premium that project capital will require. We suggest that otherwise nobody will build without government underwriting.

Technology Risk

42. Renewable technologies are innovating rapidly and the Levelised Cost of Electricity is progressively reducing. The need for ancillary services is increasing. Plants built today will be superseded in a few years. Batteries will cause further dislocation.

43. The industry has to decide who is to bear this risk - we suggest that it should be the market so as to avoid the risk premium that project capital will require.

Sovereign risk

44. Enough said already, and nobody's listening anyway. We suggest that the market should bear this risk so as to avoid the risk premium that project capital will require.

Central planning of new "capacity"

45. We suggest that renewable generation projects are largely funded through subsidy by government policy and are an artefact that has to be accommodated by the market through development of an appropriate equipment mix primarily comprising batteries and gas turbines.

46. We suggest that the hidden hand and animal spirits of the market cannot be relied on to identify and build the required equipment mix at the time it is required in response to a uniform capacity price.

47. There is an important asymmetry in capacity entry and exit; exit is easy to implement and can occur at any time whereas entry is subject to diverse permissions and decisions and has lead times up to several years.

48. Participation in an auction is also expensive; a project must sink multiple millions in establishing a bankable project as a pre-requisite for participating in the auction.

49. At present there is no mechanism for batteries to enter the market.

50. We suggest that at best the Capacity Price acting as the principal build-signal will promote development of fast pay-back projects that are small enough to not reduce the Capacity Price. We predict a business as usual outcome of

permanently capped-out Capacity Prices promoting small diesel peakers that don't help solve the problems.

51. We suggest that the solution is for central planning of a system requirement as part of the ESOO process and for AEMO to run an annual tender process to procure an equipment specification that will change from year to year; batteries, gas turbines, synthetic inertia, network augmentation, DSM or whatever. We envisage that the market will underwrite the project on terms and for a project life according to the tender. We emphasise that we consider building out of network constraints to be a legitimate outcome of a "capacity tender" and for it to be underwritten by the market. [Conditional on Western Power not being permitted to frame the issue and participating in a minimalist fit-for-purpose role.] We also consider procurement of a battery or DSM to be operated by System Management to be a legitimate outcome, again underwritten by the market.

52. We suggest that the price paid under such a tender has no relevance to the price to be paid to existing capacity; existing capacity is sunk and needs to service its capital. We suggest that the prevailing balance of supply & demand has no relevance to the price paid to existing capacity.

53. We suggest that existing capacity should be paid a proper price in return for proper service.

54. We suggest that this arrangement should be invariant to the impact of constrained access - strip participating generation of their access rights if that is necessary but pay them anyway for the full level of capacity conditional on it being available (not on outage), even if it is constrained to lower levels. If it is constrained due to a reform that is intended to benefit the end-users, then the end-users (market) should fund the building out of the constraints if that is the most cost effective solution.

55. We suggest two phases of payment of capacity revenues to existing plant - the first being for the lifetime of the project debt and the second being after the debt has been serviced.

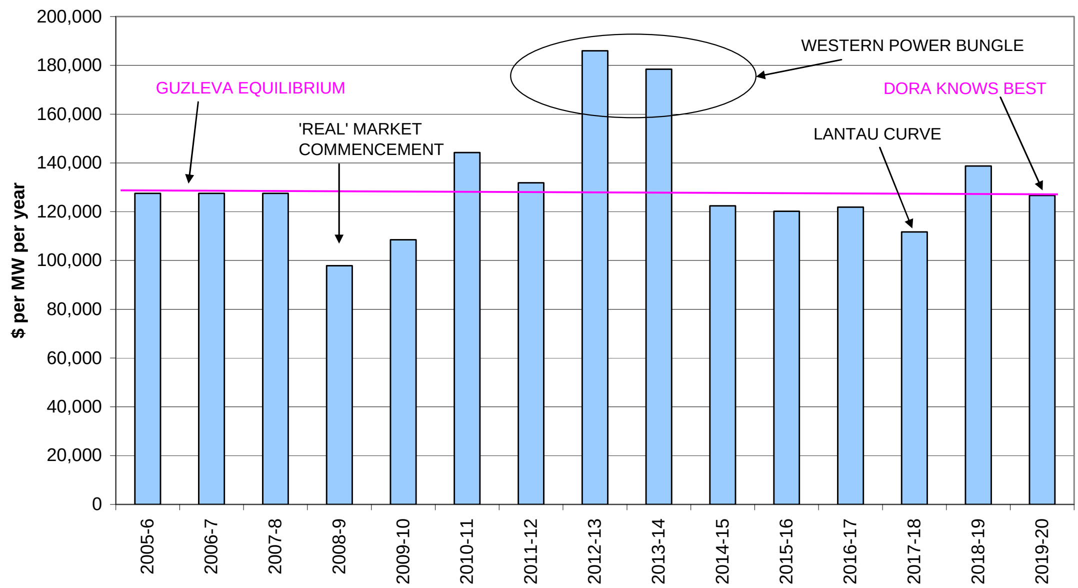
DSM

56. We consider that when properly implemented, DSM has a legitimate and important role to play in the system mix. We consider that if and when the market unfolds to our predicted capacity shortfall and capped-out Capacity Prices, the existing DSM arrangements will be invoked more frequently. This will become extremely expensive as DSM is not subject to practicable energy price caps in the same way as scheduled generation. [We suggest this is no surprise to Synergy, which post-DSM wipeout is now the principal DSM provider at its original level.] We suggest that DSM should be SCADA'd into System Management and directly dispatched under diverse circumstances at System Management's discretion with no operational limit on any participant claiming to be available. Payment could be via components for availability (via SCADA) and dispatch.

The price to be paid to existing capacity - the Guzleva Equilibrium

57. We note that over the life of the market the capacity price has been within 15% of the original regulated value ($127,500 - the "Guzleva Equilibrium") for 9 of the 12 years since that value ceased to apply.

Historical Reserve Capacity Price



58. This stability has been robust to the original price formula, the current Lantau formula, the DSM-wipe out, the Synergy retirements, Western Power's 400% hike in the network connection charge, the chaperoning of Western Power to remove the hike, the Global Financial Crisis, the global credit expansion, the reassessment of the Benchmark Technology, the reform of the process for certifying renewable plants, review of the forecasting method, and the annual reassessment of the Benchmark Price Of the three breaches, two were caused by the network-centric Western Power acting unilaterally without supervision and the third occurred in Y1 of the original administered price when after a three year lock-down at market start there was a large quantity of new entrants into the new market which drove prices to their lowest recorded level.

59. While we have previously supported the mechanisms for determining Capacity Prices, we suggest that in future there is insufficient benefit to maintaining or increasing the current complexity. Complexity equals risk, equals risk premium on the cost of capital, equals higher prices.

Conclusion

60. We emphasise our support for a capacity mechanism and its attendant obligation for generators to offer energy at SRMC.

61. We suggest that the market paradigm has changed so radically that the traditional approach to the capacity mechanism is obsolete.

62. We suggest that the current pricing formula and prospective auction will be dominated by the size of Synergy, and the current formula actually pays Synergy more when it retires plant - a retirement bribe rather than an efficiency signal.

63. We suggest that technological, market and sovereign risk are so great that the risk premiums demanded by project capital for scheduled generators are inefficiently high. As these premiums are not practicable, projects simply won't enter, which will drive the capacity price to the cap, where it will incentivise only small, fast-payback projects.

64. We suggest the principle that the beneficiaries of the market reforms should be the end-buyers and that it is therefore appropriate for the market to carry more risk (to reduce risk premiums) on their behalf.

65. We suggest that the market should make full use of its de-facto AAA credit rating and reduce project capital costs by itself underwriting revenues.

66. We suggest that the capacity quantity and style of equipment to both meet reliability standards and manage the power system should be set by AEMO annually and procured through tender on terms that lead to lowest price outcomes. We suggest that the Special Price Arrangement provision is the precedent for this.

67. We suggest that the annual procurement should not be confined to generating capacity. Rather, it should objectively consider which technology is ideally required, be that the build out of network constraints, batteries, DSM, ancillary services generation, or whatever.

68. We suggest that existing capacity should be paid a sufficient and stable price to service its capital and in return adapt to whatever imposts the system needs to make. We suggest that this price should be set by historical precedent.... and it looks to us to be a lot like the original price at market commencement.

69. We suggest that the capacity retirement signal should be the withholding of capacity payments to any generator that is on outage, planned or otherwise.

Contact

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